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Rosemary Chiavetta, Secretary  
PA Public Utility Commission  
Commonwealth Keystone Bldg.  
400 North Street  
Harrisburg PA

**RE: Comments of the Keystone Energy Efficiency Alliance on Alternative  
Ratemaking Methodologies Docket No. M-2015-2518883**

Dear Secretary Chiavetta:

Please find attached the Comments of the Keystone Energy Efficiency Alliance (KEEA) for the above referenced proceeding.

Respectfully Submitted,

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Eric D. Miller, Esq.  
Policy Counsel  
Keystone Energy Efficiency Alliance  
Pa Bar I.D. No. 321519

**BEFORE THE  
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**Alternative Ratemaking  
Methodologies**

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**Docket No. M-2015-2518883**

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**COMMENTS OF THE KEYSTONE ENERGY  
EFFICIENCY ALLIANCE**

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Eric D. Miller,  
Policy Counsel  
Keystone Energy Efficiency Alliance  
1501 Cherry St.  
Philadelphia, PA 19102  
(267)-519-5317

Dated: May 31, 2017

## **I. INTRODUCTION**

On March 2, 2017, the Pennsylvania Public Utility Commission (Commission) entered 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.<sup>1</sup> Building on the testimony and reply comments received for its March 3, 2016 *En Banc* hearing, the Commission seeks responses to a number of questions regarding the efficacy of several alternative ratemaking methodologies.<sup>2</sup> The Tentative Order requests written comments 45 days after the entry date of the order, and reply comments 30 days thereafter. On March 23, 2017, the Commission issued a Secretarial Letter extending the comment period to 90 days, and 60 days thereafter.

The Keystone Energy Efficiency Alliance (KEEA) commends the Commission for continuing this important conversation and hopes its comments will assist the Commission as it moves forward on alternative ratemaking methodologies. KEEA is a 501(c)(6) trade association committed to advancing energy efficiency and other clean energy technologies in the Commonwealth of Pennsylvania. With more than fifty business, organizational, and non-profit members operating throughout the Commonwealth, KEEA is growing the market for energy efficiency and helping Pennsylvania secure a prosperous, sustainable future.

## **II. BACKGROUND**

The current discussion about alternative ratemaking methodologies began on March 3, 2016, when the Commission invited interested parties to provide testimony on three topics: (1) Whether revenue decoupling or other similar rate mechanisms encourage energy utilities to better implement energy efficiency and conservation programs; (2) whether such rate mechanisms are just and reasonable and in the public interest, and; (3) whether the benefits of

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<sup>1</sup> Public Utility Commission, Alternative Ratemaking Methodologies, Tentative Order, Docket No. M-2015-2518883 (Mar. 2 2017), [Hereinafter Tentative Order].

<sup>2</sup> See Tentative Order.

implementing such rate mechanisms outweigh any associated costs.<sup>3</sup> In that proceeding, KEEA and other stakeholders expressed strong support for full revenue decoupling and performance incentive mechanisms to increase the incentives for utilities to deploy energy efficiency measures. However, as the Commission observed in its Tentative Order, the proceeding did not produce any common consensus concerning alternative ratemaking methodologies other than it “is a complicated issue with numerous effects and that a number of issues should be considered when evaluating different rate methodologies.”<sup>4</sup> KEEA agrees with the Commission’s observation and believes that these comments offer new and additional information that better explores the complexity of various rate methodologies as well as a real-world look at the advantages and disadvantages each methodology beyond its theoretical underpinnings.

### III. COMMENTS

To address the challenges facing the Commonwealth’s regulated utility industry, KEEA again proposes the Commission pursue full revenue decoupling alongside Performance Incentive Mechanisms (PIMs) that reward utilities for measurable outcomes and progress made in categories that support public policy goals, such as demand-side management, peak reduction, customer engagement, and low-income assistance, among others. Additionally, KEEA proposes new and additional forms of rate-design that eschews high customer charges and demand charges in favor of well-designed Time-of-Use (TOU) rates that reflect the true cost of each customer to the grid and leverages the Commonwealth’s robust and growing Advanced Metering Infrastructure (AMI) and Distributed Energy Resources (DERs). Finally, KEEA recommends new standby procedures that better incents the growth of combined heat and power (CHP) systems and other DER’s. KEEA believes its proposed rate methodologies would work best if adopted in their entirety. However, the adoption of any one of these measures would help incentivize Pennsylvania’s regulated utility industry meet customer needs through the least cost resource—energy efficiency. The Commission can act on most of KEEA’s recommendations under its existing statutory authority.

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<sup>3</sup> Public Utility Commission, *En Banc* Hearing on Alternative Ratemaking Methodologies, Docket No. M-2015-2518883 (Dec. 31, 2015), [Hereinafter *En Banc* Hearing].

<sup>4</sup> Tentative Order, at 2.

KEEA's proposed ratemaking and rate-design mechanisms would complement the existing suite of tools that the Commission adopted in recent years to meet the growing challenges facing the regulated utility industry. Existing tools include the Distribution System Improvement Charge (DSIC), the Long-Term Investment Plan (LTIP), the Fully Projected Future Test Year (FPFTY), and the Commonwealth's growing deployment of AMI. Together, these tools assist the Commonwealth's regulated utilities adapt to the changing utility landscape. Well-designed alternative ratemaking and rate-design methodologies should integrate these tools into their structure.

Despite the success of these tools, the industry still faces persistent issues around cost recovery, incentive structure, innovation, and affordability. The Commission identified many causes of these issues in its Tentative Order, including declining energy demand, technological advancement on the demand-side of the meter, and changes to the economic environment.<sup>5</sup> The symptoms of these issues include increased fixed charges, lagging efficiency gains, and an extremely high energy burden for Pennsylvania's most vulnerable customers. Thus, why the existing tools address some issues in the utility industry, these tools alone are not enough.

KEEA closely examined common rate-design principles to help guide its policy recommendations in its comments. While the primary purpose of utility regulation is to impart competitive market pricing principles on natural monopolies, there are many secondary policies advanced by numerous stakeholder groups which include revenue stability, cost recovery, affordability, reliability, simplicity, conservation, and avoidance of cross-subsidies. KEEA most strongly agrees with the rate-design principles articulated by the American Council for and Energy-Efficiency Economy (ACEEE). ACEEE's three principles of rate-design are:

- **Promoting Efficiency and Conservation:** Rates should send price signals to customers to discourage wasteful use of electricity. This principle underscores that rates should be cost-based, and send accurate price signals to customers related to the long-run marginal cost of service.

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<sup>5</sup> Tentative Order, at 14.

- **Rate Simplicity:** Rates should be easy for customers to understand and respond to accordingly. This principle is important to the present conversation, because customers cannot respond to a price signal unless they understand it.
- **Utility Revenue Stability:** Rates should allow utilities the ability to earn commission-authorized revenues to maintain financial health.<sup>6</sup>

With these three principles in mind, the suite of ratemaking and rate-design options proposed by KEEA would better incentivize energy efficiency and conservation, provide customers with bill simplicity and transparency, and increase utility revenue stability. Further, this forward-looking suite of ratemaking and rate-design measures would reconcile the conflict between decreasing load growth and revenue recovery, while adhering to the principles of cost causation; it would better allow ratepayers to meaningfully interact with the grid, and control their usage and energy bills; all while keeping energy affordable and reliable for all ratepayers.

## **A. Rate Methodologies for Electric Distribution Companies**

### **1. Current Alternative Rate Methodologies**

KEEA strongly supports the continued use of several discrete rate mechanisms that the Commission identified as existing alternative rate methodologies. Specifically, KEEA believes the DSIC and accompanying LTIP, FPFTY, and the AMI program provide an incremental improvement to Pennsylvania's utility industry, and helps EDCs react to a changing utility environment. KEEA believes that the new ratemaking methodologies can incorporate and build upon these existing methodologies to varying degrees. However, each methodology is not without shortcomings.

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<sup>6</sup> Brendon Baatz, *Rate Design Matters: The Intersection of Residential Rate Design and Energy Efficiency*, AMERICAN COUNCIL FOR AN ENERGY-EFFICIENT ECONOMY, at v (Mar. 2017), available at: <http://aceee.org/research-report/u1703>.

First, KEEA supports the continued use of the Distribution System Improvement Charge (DSIC). Authorized for use by EDCs and NGDCs in 2012, the DSIC allows utilities to recover the reasonable and prudently incurred costs related to the repair, improvement, and replacement of existing utility infrastructure on a timelier basis, subject to reconciliation, audit, and other consumer protections.<sup>7</sup> A required component of the DSIC is the long-term infrastructure improvement plan (LTIP). See Pa. C.S. §1353(b)(3). The LTIP horizon is five to ten years and must include a schedule for the repairs and replacements. Section 1358(a)(1) provides that a DSIC may not exceed 5% of distribution rates billed. However, upon petition, the Commission may grant a waiver of the 5% limit if necessary to ensure and maintain safe and reliable service. KEEA is supportive of the DSIC and believes that it serves as an important tool to allow continued utility investment without the need for a costly base rate case. Moreover, the DSIC represents prudent utility planning that identifies the infrastructure most in need of replacement.

Second, KEEA strongly supports the use of a Fully Projected Future Test Year (FPFTY). Section 315(e) permits Pennsylvania's utilities to use a FPFTY to reflect prospective lost revenues in a base case. Ideally, the FPFTY sets base rates to reflect future reductions in revenues caused by EE&C programs and other factors. Thus, the FPFTY may cause a utility's revenue requirement to track sales changes more accurately over time. The FPFTY, however, does not address the throughput incentive. As previously stated by KEEA, the primary goal of revenue decoupling is to make utilities revenue neutral regarding investments in advanced energy resources.<sup>8</sup> No type of test year addresses the throughput incentive, nor does it address the issue of under- or over-collection of utility revenues between rate cases. Therefore, while the FPFTY is an important tool for utilities, it does not reduce the need for full revenue decoupling and other rate mechanisms.

Finally, Pennsylvania's AMI program can be considered an innovative ratemaking and rate-design strategy because it opens the door to more data transparency and two-way communication between customers and utilities. Most importantly, AMI allows the

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<sup>7</sup> Public Utility Commission, Implementation of Act 11 of 2012, Final Implementation Order, Docket No. M-2012-2293611, at 4 (Aug. 12 2012).

<sup>8</sup> Comments of KEEA, NRDC, & CAC, *En Banc* Hearing on Alternative Ratemaking Methodologies, Docket No. M-2015-2518883, at 8 (Mar. 16 2016).

Commonwealth to pursue Time-Based Rates (TBRs) such as TOU and real-time pricing. However, whether the proliferation of AMI is beneficial to Pennsylvania's ratepayers largely depends on what policies leverage AMI. Specifically, Pennsylvania's AMI should not be used for programs that would unreasonably increase remote disconnects, or erode customer protections and notice requirements. Instead, AMI should be a tool to increase customer control over their energy bills, with the goal of reducing energy consumption and increasing transparency.

## 2. Proposed Alternative Rate Methodology for EDC's

KEEA recommends several alternative ratemaking and rate-design methodologies that would address the issues facing the EDC industry while furthering the principles of energy efficiency and conservation, cost causation, and revenue stability. Regarding ratemaking, KEEA supports decoupling and performance incentives (PIMs). Regarding rate-design, KEEA supports the broad implementation Time-of-Use of (TOU) rates, and low fixed customer charges. Finally, KEEA supports updates to the Commonwealth's standby rate structure for distributed energy resources (DERs). Each of these methodologies represents the next step in Pennsylvania's utility regulation, and can build upon the alternative rate methodologies already in use by Pennsylvania's EDCs. The Commission can adopt many of these methodologies using its existing statutory authority.

### i. Full Revenue Decoupling

KEEA recommends the Commission pursue full decoupling as a method to remove any disincentive that may exist for utilities to pursue demand-side reduction to its full cost-effective potential. KEEA has already commented extensively on revenue decoupling in this proceeding and incorporates those comments by reference.<sup>9</sup> Such a decoupling mechanism would address the throughput incentive, whereby utilities recover increasing costs by increasing their

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<sup>9</sup> See Testimony of KEEA, NRDC, & CAC, *En Banc* Hearing on Alternative Ratemaking Methodologies Docket No. M-2015-2518883 (Feb. 25 2016); *see also* Comments of KEEA, NRDC, & CAC, *En Banc* Hearing on Alternative Ratemaking Methodologies, Docket No. M-2015-2518883, (Mar. 16 2016).

volumetric sale of electricity to each customer. By decoupling volumetric electricity sales from utility revenues, EDC's would no longer face revenue erosion when customers decrease electricity consumption and sales decline. Revenue decoupling varies little from current cost-of-service ratemaking. The chief difference is that revenue decoupling includes a target revenue requirement set for each year between rate cases, and an adjustment mechanism that adjusts rates up or down to reflect differences between a utility's target revenues and actual revenues. Between 2009 and 2015 the number of electric utilities with revenue decoupling doubled from 12 to 25, with 16 states having adopted some form of revenue decoupling.<sup>10</sup>

Decoupling would provide numerous advantages to the Commonwealth. First, revenue decoupling would reduce the pressure on all utilities to seek increased fixed charges to cover rising costs. To the extent that a customer's bill is a fixed charge, it increases the payback period for demand-side efficiency measures and reduces customer control over bills. Therefore, keeping rates largely volumetric using revenue decoupling would keep control in the hands of customers, and stop the trend of increasing customer charges.

Further, rate changes under decoupling are symmetrical and typically modest in size; in the event of over-collection, customers are refunded through a bill credit. Alternatively, if an EDC under-collects, a surcharge is added to customers' bills. It is well documented that revenue decoupling does not usually result in more than a three percent change in customer's bills each period—and usually much less.<sup>11</sup> Further, it has been observed that nearly 40% of all revenue decoupling adjustments nationwide result in customer refunds.<sup>12</sup>

Given the complexity of decoupling, and the transformative effect it would have on Pennsylvania's regulated utility industry, KEEA would recommend that the Commission convene a stakeholder working group to discuss the efficacy of decoupling, and whether it is permissible under the Commission's existing statutory authority for electric utilities. Regarding

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<sup>10</sup> Berg *et al.*, ACEEE, THE 2016 STATE ENERGY EFFICIENCY SCORECARD, at 45 (Sept. 2016), *available at*: <http://aceee.org/sites/default/files/publications/researchreports/u1606.pdf>

<sup>11</sup> Pamela Morgan, A DECADE OF DECOUPLING FOR US ENERGY UTILITIES: RATE IMPACTS, DESIGNS, AND OBSERVATIONS (Dec. 2012).

<sup>12</sup> *See Id.*

the Commission's authority to pursue revenue decoupling, KEEA reiterates its prior Comments that full revenue decoupling is fundamentally different than a lost revenue adjustment mechanisms, which Act 129 prohibits.

**ii. Performance Incentive Mechanisms**

KEEA strongly supports Performance Incentive Mechanisms (PIMs) as one of the most useful tools the Commission has at its disposal to incentivize utilities to meet and exceed public policy goals, specifically increasing the deployment of energy efficiency measures. KEEA has already commented extensively on PIMs in this proceeding and incorporates its previous comments and testimony by reference.<sup>13</sup> PIMs are financial incentives that aim to reward utilities for reaching or exceeding program goals, regardless of whether they are related to efficiency. PIMs can be used for a multitude of desired policy goals, such as energy efficiency, advanced metering, peak load reduction, and reliability, among others. By rewarding utilities for performance, not investment, the Commonwealth could better meet its public policy goals and adapt to the changes underway in the regulated utility industry.

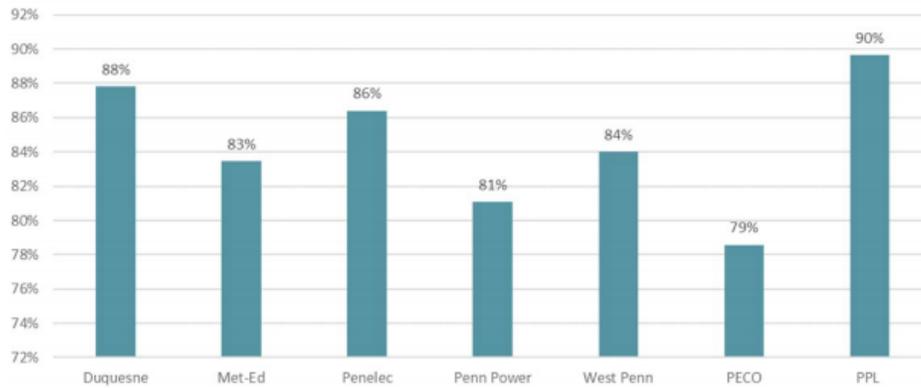
For example, a well-designed demand-side management (DSM) PIM would provide more incentive for Pennsylvania's EDC's to spend up to the 2% budget cap contained in Act 129 and invest more in cost-effective energy efficiency. In Phase II of Act 129 EE&C programs, EDC's achieved more than 3 million MWh of annual electricity savings, resulting in \$1.7 of benefits for every \$1.0 spent.<sup>14</sup> EDC's were able to achieve this impressive result, and beat their savings targets, without spending up to the 2% budget cap for Phase I and II of EE&C programs.

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<sup>13</sup> See Testimony of KEEA, NRDC, & CAC, *En Banc* Hearing on Alternative Ratemaking Methodologies Docket No. M-2015-2518883 (Feb. 25 2016); *see also* Comments of KEEA, NRDC, & CAC, *En Banc* Hearing on Alternative Ratemaking Methodologies, Docket No. M-2015-2518883, (Mar. 16 2016).

<sup>14</sup> Act 129 Statewide Evaluator Phase II Final Report, at 31 (Feb 28 2017), *available at*: [http://www.puc.pa.gov/Electric/pdf/Act129/Act129-SWE\\_PhaseII\\_FinalAR.pdf](http://www.puc.pa.gov/Electric/pdf/Act129/Act129-SWE_PhaseII_FinalAR.pdf)

Figure 6-8: Cumulative Utility Spending for Phases I and II as Percentage of Phase I and II Budgets



As the Statewide Evaluator’s (SWE’s) Final Phase II report observed, across Phase I and II, Pennsylvania EDC’s left up to 20% of budgeted funds on the table.<sup>15</sup> A DSM PIM that provides an EDC’s an incentive to spend up to the budget cap would benefit all Pennsylvanians by decreasing consumption, shaving peak demand, and keeping costs down regardless of direct participation in the programs.

Many jurisdictions already use the type of PIMs proposed by KEEA. In its 2016 State Score Card, ACEEE found that 28 states offer a performance incentive for at least one major electric utility.<sup>16</sup> The type of compensation a utility receives under a PIM takes several forms. For instance, compensation could be based on shared savings, and would grant the utility a share of the estimated net benefits that result from their EE&C programs. Alternatively, the PIM could provide EDCs with a bonus at a set rate for each MWh of load savings beyond their savings target. Of the different types of PIMs, KEEA supports a multi-factor incentive based on performance, and urges the Commission to explore the incentives currently in place in states like Rhode Island and Massachusetts. Many potential performance incentives for Pennsylvania are discussed in an in-depth report published by the Advanced Energy Economy Institute (AEEI) titled Performance-Based Regulation for Pennsylvania.<sup>17</sup>

<sup>15</sup> *Id.*, at 109.

<sup>16</sup> Berg *et al.*, ACEEE, THE 2016 STATE ENERGY EFFICIENCY SCORECARD, at 45 (Sept. 2016), available at: <http://aceee.org/sites/default/files/publications/researchreports/u1606.pdf>

<sup>17</sup> AEEI, PERFORMANCE-BASED REGULATION FOR PENNSYLVANIA: AN OPPORTUNITY FOR PENNSYLVANIA TO DRIVE INNOVATION IN THE UTILITY SECTOR (Mar. 27 2017), available at: <http://info.aee.net/hubfs/PDF/PBR-in-PA.pdf?t=1496186156245>

The Commission has two sources of statutory authority that it could use to implement PIMs. First, §523 of Act 114 authorizes the Commission to use criteria to “make adjustments to specific components of a utility’s claimed cost of service.” *Id.* Among those criteria is §523(b)(4), which allows the Commission to evaluate the performance of utilities in “[a]ction or failure to act to encourage development of cost-effective energy supply alternatives such as conservation or load management, cogeneration, or small power production.” *Id.* Section 523 applies to all fixed utilities. Second, during the restructuring of the electric industry in 1996, the legislature passed Act 138 that includes §2806(i), which reads:

Performance-based Rates and Alternative Regulation. The Commission has authority to use performance-based rates as an alternative to existing base/rate of return regulation, subject to the restriction pertaining to rate caps in section 2804(4) (relating to standards for restructuring of electric industry).<sup>18</sup>

The Commission has experience with §523, but has yet to rely on §2806(i) for a ratemaking action. The Commission previously relied on §523 in its 1993 Order relating to incentive payments in connection to EE&C programs. In that Order, the Commission originally contemplated payments for performance outside of base rate cases. Upon review, however, the Court in *PIEC* held that performance-based adjustments pursuant to §523 may only take effect in the context of a base rate proceeding. Pennsylvania Indus. Energy Coalition v. Pennsylvania Public Utility Comm’n, 653 A.2d 1336, 1359 (1995). More recently, the Commission’s authority concerning performance incentives adopted under §523 was discussed in its 2011 American Reinvestment and Recovery Act (ARRA) Order, which identified §523 as authority for positive incentives for EDCs so long as they are (1) implemented in a base rate proceeding and (2) not tied to decreased revenues arising from EE&C programs.<sup>19</sup> A similar conclusion was reached by the Commission in its Phase III implementation order. There, the Commission rejected KEEA’s proposal for a “well-designed performance incentive structure” in the context of EE&C plans “contrary to [Act 129],” which the Commission determined is, “nothing more

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<sup>18</sup> 66 PA. C.S. § 2806(i).

<sup>19</sup> See Public Utility Commission American Recovery and Reinvestment Act Investigation, Working Group Final Report Docket No. I-2009-2099881, at 30 (Jan. 24 2011).

than an additional revenue stream . . . , which can only be recovered by EDCs through a distribution rate proceeding.’’<sup>20</sup>

Based on the *PIEC* holding and the Commissions interpretation of §523, the Commission has the authority to include incentive payments for utilities, so long as recovery of those payments occur on a deferred basis through a rate proceeding and not a §1307 automatic adjustment mechanism. The ARRA Order discussed such a system. Specifically, it found that performance payments could be made through a surcharge the following year, or reflected as a regulatory asset in the rate of return in a future general rate proceeding.<sup>21</sup> Such a system could work to implement PIMs, but it is not the only avenue open to the Commission.

Fortunately, the Commission has broad authority under §2806(i) to consider performance-based rates. The General Assembly enacted §2806(i) to respond to the rapid changes in the regulated utility industry. While the causes of the transformation may differ today, the tools made available to the Commission are still available *via* §2806(i). Moreover, no court has ever ruled on whether performance-based payments made under §2806(i) must occur during a distribution rate case. Therefore, the Competition Act arguably serves as an untested and open pathway for PIMs or similar mechanisms.

### **iii. Time-of-Use Rates**

KEEA proposes that the Commission explore the broad application of a bi-seasonal time-of-use (TOU) rate with a peak-time rebate (PTR) element as an alternative to increased customer charges or demand charges for small commercial and residential customers. If well-designed, a TOU rate structure can allow customer bills to remain largely volumetric, while sending easy-to-understand price signals to customers that better reflects the true cost of their electricity consumption and costs to the grid. The benefits of TOU rates are numerous: reduction in energy peak energy consumption (both summer and winter), decreased payback period for efficiency

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<sup>20</sup> Public Utility Commission, Phase III Implementation Order, Docket No. M-2014-2424864, at 134-36 (Jun. 19 2015).

<sup>21</sup> See Public Utility Commission, American Recovery and Reinvestment Act Investigation, Working Group Final Report Docket No. I-2009-2099881, at 30 (Jan. 24 2011).

measures, better protection of low-income ratepayers when compared to other forms of rate-design, and measured success in decreasing peak demand and incentivizing energy efficiency across several jurisdictions. These benefits contrast strongly with increased customer charges, which can “increase overall consumption and discourage investments in energy efficiency technologies.”<sup>22</sup> TOU rates would meet the principles outlined by KEEA, and coupled with the growing AMI deployment and TOU pilots, the Commonwealth is well-positioned to implement TOU rates using its existing authority and technology.

TOU rates are a form of time-variable pricing whereby the volumetric fee for electricity varies depending on the time of day or the season. The primary purpose of TOU rates is to send customers a price signal that more accurately reflects the costs of their usage in a way that is easy to understand. TOU rates allow better customer interaction with the grid by charging a higher price for electricity during on-peak hours when costs are highest for utilities, and lower charges when cost is the lowest. TOU rates better reflect the true cost of supplying electricity to customers than existing flat rate structures. Although TOU rates are designed to reflect the true cost of electricity, the rate variations are announced ahead of time on a fixed schedule. This provides customers with more predictable prices, and does not expose them to the full risk of the real-time electricity prices.

TOU rates can be designed in several ways to produce energy savings, peak reduction, and allow greater customer interaction with the grid. The portion of TOU rates shown to have greatest impact on peak reduction and energy efficiency is the peak to off-peak period (POPP) ratio. The POPP is the ratio of the price charged for peak period consumption to that charged for off-peak consumption. POPP ratios typically range from 1:1 to 7:1. Studies have found that a ratio of 2:1 result in a 5% peak reduction, while a ratio of 5:1 results in approximately 10% reduction in peak.<sup>23</sup>

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<sup>22</sup> Brendon Baatz, *Rate Design Matters: The Intersection of Residential Rate Design and Energy Efficiency*, AMERICAN COUNCIL FOR AN ENERGY-EFFICIENT ECONOMY, at iv (Mar. 2017), available at: <http://aceee.org/research-report/u1703>.

<sup>23</sup> Herman K. Trabish, *Rate design roundup: demand charges vs. time-based rates*, UTILITY DIVE (Jun. 2 2016), <http://www.utilitydive.com/news/rate-design-demand-charges-time-based-rates/419997/>.

Another important design element of TOU rates is the length of the peak period, which correlates with on-peak hours when load reduction is most needed.<sup>24</sup> According to the Rocky Mountain Institute (RMI), TBR durations can range from 4 to 16 hours, but the best customer response comes from durations that are as short as possible while still capturing the necessary peak hours.<sup>25</sup> Surveys show that the best peak durations are typically no longer than 5 hours. Additionally, TBR rates typically have 3 or fewer pricing periods, including bi-seasonal price variation.<sup>26</sup> KEEA recommends that the Commission and EDC's engaging in TOU pilots consider a bi-seasonal program with 5- to 6-hour peak durations with at least a 5:1 POPP ratio.

In addition to a bi-seasonal TOU rate, KEEA also recommends the Commission and EDCs explore the additional element of a Peak-Time Rebate (PTR). A PTR structure awards customers with a rebate for energy saved during peak events announced ahead of time by a utility. This is a low-risk option compared to other forms of peak pricing, because there is no associated penalty with a PTR, only potential savings. According to 2015 study by the Department of Energy, the average peak demand reduction for customers in a PTR program programs was 11%.<sup>27</sup>

In addition to peak-load reduction, TOU rates can also have a positive impact on payback periods for efficiency measures, especially when compared to increased fixed charges or demand charges. ACEEE reviewed payback periods for fourteen energy efficiency measures or programs under twenty rate-design scenarios.<sup>28</sup> It found that broadly, TOU rates decrease the payback period for efficiency measures. This contrasts with customer charges, which can significantly increase payback periods for efficiency measures. For instance, the same study found that moving from a \$5 to a \$25 customer charge increased payback periods by 25-34%,

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<sup>24</sup> Aman Chitkara *et al.*, *A Review of Alternative Rate Designs*, at 30.

<sup>25</sup> Herman K. Trabish, *Rate design roundup: demand charges vs. time-based rates*, UTILITY DIVE (Jun. 2 2016), <http://www.utilitydive.com/news/rate-design-demand-charges-time-based-rates/419997/>.

<sup>26</sup> *Id.*

<sup>27</sup> Neil Strother, *Time-Based Rates: What Works, What Doesn't*, NAVIGANT RESEARCH (Jun. 30 2015), <https://www.navigantresearch.com/tag/time-of-use-pricing> (citing *Interim Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies*, U.S. DEP'T OF ENERGY, available at: [https://www.smartgrid.gov/files/CBS\\_interim\\_program\\_impact\\_report\\_FINAL.pdf](https://www.smartgrid.gov/files/CBS_interim_program_impact_report_FINAL.pdf)).

<sup>28</sup> Brendon Baatz, *Rate Design Matters: The Intersection of Residential Rate Design and Energy Efficiency*, AMERICAN COUNCIL FOR AN ENERGY-EFFICIENT ECONOMY (Mar. 2017), available at: <http://aceee.org/research-report/u1703>.

depending on the measure.<sup>29</sup> This mirrors the types of fixed charges requested by many utilities over the past 5 years. However, such a large increase in payback periods would have a chilling effect on the adoption of efficiency measures by ratepayers, and undermine Pennsylvania's successful EE&C programs.

Other jurisdictions have documented success with TOU rate programs. One example is the program piloted and adopted by Oklahoma Gas & Electric (OG&E). OG&E's smart meter-enabled SmartHours opt-in program offers four pricing levels for peak time periods on weekdays from 2 p.m. to 7 p.m. during the months of June through September.<sup>30</sup> The customers' off-peak rate is \$0.05/kWh, while their peak period rates, communicated a day in advance, range from the standard \$.09/kWh to a high \$.18/kWh, with a critical peak of \$.42/kWh.<sup>31</sup> A free smart thermostat enables customers to manage their household usage. The program was piloted in Norman, Okla., in 2011 and deployed across the OG&E service territory in 2012.<sup>32</sup> Almost 15%, or 115,000, of the utility's residential and business customers save an average of \$200 per summer on the program. The SmartHours program has produced an approximate peak demand reduction of 150 MW and has enabled OG&E to delay building incremental thermal generation.<sup>33</sup> Because of the success of the SmartHours program, OG&E plans to continue promoting SmartHours and has also introduced a marketing campaign to increase the use of smart thermostats.

Pennsylvania already has limited experience with TOU programs due to requirements in Act 129. Specifically, the Act directed Pennsylvania EDCs to file with the PUC a smart meter technology procurement and installation plan by August 14, 2009. Additionally, the Act requires EDCs to submit one or more proposed time-of-use rates and real-time price plans by January 1, 2010, or at the end of the applicable generation rate cap period, whichever is later. PECO already completed a pilot program.

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<sup>29</sup> *Id.*

<sup>30</sup> Herman K. Trabish, *Rate design roundup: demand charges vs. time-based rates*, UTILITY DIVE (Jun. 2 2016), <http://www.utilitydive.com/news/rate-design-demand-charges-time-based-rates/419997/>.

<sup>31</sup> *Id.*

<sup>32</sup> *Id.*

<sup>33</sup> *Id.*

PECO's Smart Time Pricing had a peak generation rate of \$0.1595 per kWh on weekdays from 2 p.m. to 6 p.m., excluding holidays, and an off-peak generation rate of \$0.0685 per kWh during the remaining hours of the year. PECO identified nearly 121,000 residential customers eligible for the program, and through direct mail, bill inserts, and email solicitations signed up 4,882 customers to the program (an acceptance rate of approximately 4%).<sup>34</sup> The pilot delivered "an average of nearly 6% reduction in peak electricity demand between the hours of 2 p.m. and 6 p.m. during the summer months."<sup>35</sup> Those load reductions led to a 5% average cost savings for consumers enrolled in the program. According to PECO's data, most of the cost savings came from customers altering usage of large appliances and HVAC systems.<sup>36</sup> KEEA is confident that the expansion and refinement of similar successful programs would yield even better results across the Commonwealth.

In addition to its success in multiple jurisdictions at reducing peak and the payback period for efficiency measures, TOU rates have also been shown to be a better rate-design alternative than increased customer charges or demand charges. For example, OG&E observed that in Phase 1 of its SmartStudy Together pilot, low-income participants "demonstrated a higher percentage savings and higher demand savings than other income segments in some cases."<sup>37</sup> Additionally, during the PECO Smart Time Pricing Pilot, low-income customers on TOU rates responded at a much higher rate than average accounts. ACEEE notes that "[u]nder the default TOU pricing plans, low-income customers showed very similar absolute and percentage load reductions"<sup>38</sup> Perhaps most importantly, the study found that low-income customers "did not report greater levels of discomfort or hardship while responding to the CPP events."<sup>39</sup>

The Commission has already taken substantial steps towards empowering EDC's to implement TOU rates. Both the Public Utility Code and recent jurisprudence at the Commonwealth Court require that EDC's offer voluntary TOU rates for all customers that have

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<sup>34</sup> Gavin Bade, *Inside the surprising lessons from PECO's time-of-use-rate pilot*, UTILITY DIVE (May 22 2015), <http://www.utilitydive.com/news/inside-the-surprising-lessons-from-pecos-time-of-use-rate-pilot/399629/>.

<sup>35</sup> *Id.*

<sup>36</sup> *Id.*

<sup>37</sup> Brendon Baatz, *Rate Design Matters*, at 32.

<sup>38</sup> *Id.*

<sup>39</sup> *Id.* at 32.

smart meter technology. Most recently, the Commission issued a Secretarial Letter on April 6, 2017, that provides TOU guidance to all EDC's.<sup>40</sup> KEEA urges the Commission to consider such guidance as a form of alternative rate-design relevant to this proceeding, and to look to other states for best-practices.

Under § 2807(f)(5), Pennsylvania's EDC's must provide TOU rates to all customers who have a smart meter. Specifically, the Code requires that:

[T]he default service provider shall offer the time-of-use rates and real-time price plan to all customers that have been provided with smarter meter technology. . . . Residential or commercial customers may elect to participate in time-of-use rates or real-time pricing.<sup>41</sup>

Further, under recent jurisprudence, each EDC must offer a TOU programs directly, rather than through an Electric Generation Suppliers (EGS). In 2015, the Commonwealth Court in *Dauphin County Industrial Development Authority v. Pa PUC (DCIDA)* reversed and remanded the Commission's September 2014 order approving PPL's TOU Plan that delegated TOU responsibilities to EGSs that chose to provide a TOU rate. The Court held that PPL must provide TOU rates to its customer-generators, and that PPL may not satisfy this burden by transferring it to EGSs. DCIDA, 123 A.3d at 1136. In response to the Court's remand order, the Commission noted that "The Commonwealth Court's directive in *DCIDA* is *equally applicable to all Pennsylvania EDC's that are required to offer a TOU Plan in order to comply with Act 129.*" (emphasis added).<sup>42</sup> The Commission further noted: "This proceeding will be to explore not only a TOU Plan that will satisfy the Court's holding in *DCIDA* but also identify a program structure that all other EDC's can incorporate into their own compliance with Act 129 to the extent necessary."<sup>43</sup> KEEA agrees with the Commission's determination that the DCIDA holding is equally applicable to all Pennsylvania EDC's, and all customers; not just customer-generators.

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<sup>40</sup> Public Utility Commission, Secretarial Letter Re: *Petition of PPL Electric Utilities Corporation for Approval of a New Pilot Time-of-Use Program* Docket No P-2013-2389572; Docket No. M-2016-2578051, at 4 (Apr. 6 2017).

<sup>41</sup> 66 Pa. C.S. § 2807(f)(5).

<sup>42</sup> Public Utility Commission, Secretarial Letter Re: *Petition of PPL Electric Utilities Corporation for Approval of a New Pilot Time-of-Use Program* Docket No P-2013-2389572; Docket No. M-2016-2578051, at 2 (Apr. 6 2017).

<sup>43</sup> *Id.*, at 4.

In its April 6, 2017, Secretarial letter in the proceeding, the Commission issued a proposed TOU design for PPL. The Commission further stated that its proposed design:

May be considered as guidance for EDCs, thereby permitting EDCs the flexibility to propose other alternatives and/or modifications regarding their TOU operations that can be analyzed and approved by the Commission as part of their individual default service proceedings. Therefore, in their individual TOU filings, EDCs may propose any variations to the Commission's proposed PPL TOU design as long as such variations are permissible under DCIDA and supported by facts and in compliance with Chapter 28 of the Public Utility Code and the Commission's regulations.<sup>44</sup>

Therefore, every Pennsylvania EDC must develop a TOU rate structure that is permissible under the DCIDA decision, that will comply with Chapter 28. KEEA strongly supports the Commission's and EDCs' actions thus far, and urges the Commission to consider the efficacy of TOU rates as an alternative to demand charges and increased customer charges as this proceeding continues. As the data presented by KEEA demonstrates, well-designed TOU rates can provide important consumer choice, while reducing demand and supporting the principles of cost causation. Further, the Commission and EDCs are already acting on this alternative rate methodology. Thus, KEEA recommends the Commission include TOU activities in its conversation around alternative ratemaking and rate design.

#### iv. Standby Rates

KEEA recommends the Commission evaluate standby rates that would better incentivize Pennsylvania businesses to develop DERs such a solar and combined heat and power (CHP) at their facilities. DER's assist in reducing energy costs, enhancing reliability, and increasing Pennsylvania's business competitiveness. Because these systems can operate independently of the grid, they assist with resiliency. However, existing standby rate structures vary significantly by service territory. To address this issue, KEEA recommends the Commission adopt the

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<sup>44</sup> *Id.*

standby rate proposal offered by the Alliance for Industrial Efficiency on this Docket, and incorporates those comments by reference.<sup>45</sup>

## **B. Directed Questions of Vice Chair Place for EDC Proposal**

### **1. Provide Overall supportive or critical comments on the proposed rate-design structure**

While KEEA is generally supportive of proposals for innovative rate-design, it does not support the three-part rate proposed in the Statement of Vice Chair Place. Specifically, KEEA believes that the demand charge component of the three-part rate is not the best option for the residential or small commercial rate classes. Although demand charges may be appropriate for large customers, their benefits are not easily transferable residential and small commercial sector. This is due, in large part, to the unique characteristics of residential sector which include bill transparency, the extent of customer control, equity issues, and usage diversity, among others. Moreover, a survey of existing and past attempts at demands charges shows little to no empirical evidence supporting the use of demand charges for these rate classes. Instead, KEEA strongly believes that TOU rates would better conform to the principles of cost causation, bill simplicity, and energy efficiency and conservation.

Residential demand charges, both coincident and non-coincident, have not been implemented in any notable scale across the country. Indeed, a recent study by ACEEE notes that demand charges “have yet to undergo have yet to undergo rigorous pilots or pricing studies.”<sup>46</sup> Moreover, the limited information that does exist is dated and does not consider modern technologies, such as AMI deployment. This lack of empirical data led ACEEE to warn that demand charges for residential customers “should be approached with caution,” mainly because so little evidence exists on the “implications of demand charges for overall customer consumption.”<sup>47</sup>

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<sup>45</sup> Comments of the Alliance for Industrial Efficiency, Alternative Ratemaking Methodologies Docket No. M-2015-2518883 (May 31 2017).

<sup>46</sup> Brendon Baatz, *Rate Design Matters: The Intersection of Residential Rate Design and Energy Efficiency*, AMERICAN COUNCIL FOR AN ENERGY-EFFICIENT ECONOMY (Mar. 2017), available at: <http://aceee.org/research-report/u1703>.

<sup>47</sup> *Id.* at 35.

Alternatively, a significant amount of research regarding the efficacy of time-based rates is available, and provides clear insight on the best-practices for those rate design choices. That research indicates that a well-designed timed-based rate is effective at “sending more accurate price signals to customers.”<sup>48</sup> Thus, KEEA recommends the Commission explore the types of TOU rates discussed in Section (A)(2)(iii) of its Comments in place of a demand charge.

Despite KEEA’s stated opposition to residential and small commercial demand charges, KEEA included responses to the directed questions of Vice Chair Place if the Commission does decide to pursue demand charges.

**2. How many hours should be used to calculate the demand billing determinant?**

If a demand charge is used, it should be applied to the highest hour, or hours, of demand, not to a shorter usage period. Short periods of measured billing demand are more difficult for customers to manage. For instance, an apartment tenant who “takes a shower and dries their hair while something is in the oven can run up demand of 10 kW or more, even though the average contribution to the system peak across units in the same apartment building is typically no more than 2 or 3 kW.”<sup>49</sup> Further, “[l]onger periods of measurement, such as 60 minutes or the average demand over several hours, tend to dilute the impacts of very short-term events,” making it easier for customers to respond.<sup>50</sup> Although there are instances of commercial rates being based on the highest fifteen minutes of demand, shorter periods increase the risk of certain random or inadvertent behaviors by customers that could drive charges beyond their ability to manage.<sup>51</sup>

Additionally, KEEA does not support the use of a demand “ratchet” for the residential rate class. While ratchets smooth revenue recovery for the utility, “they are the antithesis of cost

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<sup>48</sup> *Id.* at 34.

<sup>49</sup> Paul Chernick et al., *Charge Without a Cause? Assessing Electric Utility Demand Charges on Small Consumers*, ELECTRICITY POLICY (Aug. 2016), available at: <https://electricitypolicy.com/images/2016/August/10Aug2016/Chernick/Chernick2016Aug10final.pdf>.

<sup>50</sup> *Id.* at 7.

<sup>51</sup> Carl Linvill, John Shenot, and Jim Lazar, *Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition*, REGULATORY ASSISTANCE PROJECT (Nov. 2013), available at: <http://www.raponline.org/wp-content/uploads/2016/05/rap-linvillshenotlazar-faircompensation-2013-nov-27.pdf>

causation in a utility system with diversified loads, and can severely penalize seasonal loads.”<sup>52</sup> The unavoidable fixed costs that would result impair price signals to customers about energy conservation. RMI importantly notes that ratchet mechanisms are “widely used in demand charge rates for large C&I customers, but adoption is limited in existing residential programs (5 out of 24 programs).”<sup>53</sup> Ratchet mechanisms need to be coordinated with cost allocation, especially because the high load diversity of residential customers may require different cost allocation strategies than C&I. No research has studied the impact of ratchet mechanisms on customer peak reduction but, theoretically, it may disincentivize customer response.

Moreover, ratchet mechanisms are not appropriate for residential demand charges, since system infrastructure is shared by a large number of residential customers whose combined load diversity results in a much higher load factor than individual large C&I customers. Ratchets turn a fee that would otherwise vary with changes in demand into something more like a fixed charge that locks a customer into a minimum monthly payment for the duration of the ratchet.

### 3. How should peak demand be measured?

All existing residential demand charge rates “use an averaged demand interval of 15, 30, or 60 minutes—70% of non-coincident-peak rates use a 15-minute interval, while 75% of coincident-peak rates use a 30-minute interval.”<sup>54</sup> Shorter measurement intervals and instantaneous measurement lead to higher, but also more variable, measured peak demand.<sup>55</sup> RMI found measurements of less than 60 minutes may be problematic, as they might not “provide enough time for the typical mass-market customer to respond and adjust their demand to avoid peak load.”<sup>56</sup> If customers are unable to respond to the interval because of its length, then the rate “may effectively function as a fixed charge that varies month-to-month.”<sup>57</sup>

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<sup>52</sup> Chernick et al., *Charge Without a Cause*, at 8.

<sup>53</sup> Chitkara et al., *A Review of Alternative Rate Designs*, at 68.

<sup>54</sup> Aman Chitkara et al., *A Review of Alternative Rate Designs: Industry Experience With Time-Based And Demand Charge Rates For Mass-Market Customers*, ROCKY MOUNTAIN INSTITUTE (May 2016), available at: [http://www.rmi.org/alternative\\_rate\\_designs](http://www.rmi.org/alternative_rate_designs).

<sup>55</sup> *Id.* at 61.

<sup>56</sup> *Id.*

<sup>57</sup> *Id.*

#### 4. Should tiered demand rates be used?

KEEA does not support the use of tiered demand rates. Tiered demand rates are not widely used, nor have they been studied thoroughly to determine whether they are effective. Though others have been proposed, Salt River Project (SRP) in one utility that has proposed a tiered demand charge.<sup>58</sup> The demand charge applies to distributed generation (DG) customers. There are three price tiers that make up the demand charge. The first two tiers of SRP's demand charge "generally fall within the range of demand charges being offered by other utilities, but the third-tier price is "higher than other rate offerings."<sup>59</sup> SRP is primarily using the demand charge to recovery capacity costs. SRP's rate design has been criticized by solar advocates, including SolarCity, which filed a lawsuit against SRP alleging that SRP's new rate design is attempting to make rooftop solar uneconomical.<sup>60</sup> In the year immediately prior to implementing the fees, SRP received an average of 600 new rooftop solar applications per month. Today, it receives approximately 25 applications per month, a drop of 95% percent.<sup>61</sup>

#### 5. Should large customer demand charges be modified?

KEEA believes large C&I customer demand charges could be modified to incorporate coincident peak-based charges to encourage demand shifting to reduce to peak demand, and to encourage the growth of DERs. The Ontario Energy Board published a staff discussion paper in March 2016, which considers a new rate-design that would affect all commercial and industrial customers who receive electricity from a distribution company.<sup>62</sup> One of the rate designs considered is a three-part demand rate. The first part of the charge is a fixed monthly service

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<sup>58</sup> Ahmad Faruqui and Ryan Hledik, *An Evaluation of SRP's Electric Rate Proposal for Residential Customers with Distributed Generation*, SALT RIVER PROJECT (Jan. 5 2015), available at: <http://www.srpnet.com/prices/priceprocess/pdf/DGRateReview.pdf>.

<sup>59</sup> *Id.*

<sup>60</sup> Julia Pyper, *Arizona Court Advances SolarCity Lawsuit Against Salt River Project Over Solar Fees*, GREENTECH MEDIA (Nov. 10 2015), <https://www.greentechmedia.com/articles/read/arizona-court-advances-solarcity-lawsuit-against-salt-river-project>.

<sup>61</sup> Bobby Magill, *New Fees May Weaken Demand for Rooftop Solar*, SCIENTIFIC AMERICAN (Nov. 11 2015), <https://www.scientificamerican.com/article/new-fees-may-weaken-demand-for-rooftop-solar/>.

<sup>62</sup> Sharon Wong and Doug A. J. Taylor, *OEB Considering Changes to Commercial and Industrial Customers' Rate Design*, LEXOLOGY (Apr. 25 2016), <http://www.lexology.com/library/detail.aspx?g=99f658eb-4e8a-41ba-8499-1c3a0e61b3bb>.

charge to reflect the direct customer costs.<sup>63</sup> The second part is a variable rate “based on the ‘anytime’ demand or non-coincident peak demand to represent the cost of the design demand.”<sup>64</sup> The third part is a variable rate “based on on-peak demand or coincident peak demand to represent the customer’s contribution to peak capacity requirements.”<sup>65</sup> The paper notes that “having a non-coincident demand rate should provide some rate stability for the distributor,” while the higher coincident demand rate “should encourage shifting and DER to reduce peak demand.”<sup>66</sup> Although such a rate structure may be appropriate for large C&I customers, KEEA does not believe the benefits of demand charges transfer well to other customer classes.

#### 6. What would the range of cost impacts be for low-income customers?

KEEA stresses that demand charges on residential customers should not be implemented because of concerns about customers being able to respond effectively to price signals. This effect could be more pronounced for low-income customers. Without sophisticated load control and automation devices, which is out-of-reach for many small and low-income customers, KEEA believes a demand charge is simply not an effective price signal. A demand charge only serves as an effective price signal if the customer can respond to it. There is a lack of evidence indicating that large numbers of residential consumers could respond to demand charge price signals.<sup>67</sup> It is also reasonable to expect that considerable time and effort will be required to build a broad understanding of demand charges among residential customers who have not dealt with the concept in the past.

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<sup>63</sup> *Id.*

<sup>64</sup> *Id.*

<sup>65</sup> *Id.*

<sup>66</sup> *Rate Design for Commercial and Industrial Electricity Customers: Aligning the Interests of Customers and Distributors*, ONTARIO ENERGY BOARD (Mar. 31 2016), [http://www.ontarioenergyboard.ca/oeb/\\_Documents/EB-2015-0043/Staff\\_Discussion\\_Paper\\_RDCI\\_20160331.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2015-0043/Staff_Discussion_Paper_RDCI_20160331.pdf).

<sup>67</sup> Lisa Wood et al., *Recovery of Utility Fixed Costs: Utility, Consumer, Environmental and Economist Perspectives*, LAWRENCE BERKELEY NATIONAL LABORATORY (Jun. 2016), available at: <https://emp.lbl.gov/sites/all/files/lbnl-1005742.pdf>.

7. What type of consumer education programs should be provided?

KEEA does not believe that a consumer education program, no matter how well implemented, could adequately educate the typical customer on how a demand charge works, and how it would impact their monthly bill. Instead, KEEA believes that a TOU rate is easier to understand, and would be a better pathway to entice customers to decrease their peak consumption.

C. Directed Questions of Vice Chair Place for NGDC Proposal

1. Provided overall supportive or critical comments on the proposed rate design structure

KEEA enthusiastically supports Vice Chair Place's proposal for revenue-per-customer decoupling for NGDCs. KEEA believes that this type of revenue decoupling would assist NGDCs in addressing the revenue erosion caused by decreasing demand, warmer weather, and more efficient appliances. However, KEEA believes that decoupling should occur alongside a well-designed EE&C program that effectively assists customers in reducing their usage. Moreover, KEEA urges the commission to consider performance incentive mechanisms (PIMs) discussed in Section A of its comments for NGDCs.

2. Has the proposal been successfully implemented in other jurisdictions?

Yes, as of 2016 23 states have a revenue decoupling for gas utilities, and 19 have incentives for natural gas efficiency programs.<sup>68</sup>

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<sup>68</sup> Berg *et al.*, ACEEE, THE 2016 STATE ENERGY EFFICIENCY SCORECARD, at 45 (Sept. 2016), *available at*: <http://aceee.org/sites/default/files/publications/researchreports/u1606.pdf>

3. Are there any statutory or regulatory barriers to revenue-per-customer decoupling for NGDCs?

There do not appear to be any explicit barriers to the implementation of revenue decoupling for NGDCs. Though EDCs and NGDCs share many similar statutory and regulatory provisions, NGDCs are not regulated under the Act 129 amendments to the Competition Act. Therefore, there is no explicit limitation on automatic adjustment mechanisms to recover lost revenue. Moreover, §523 of Act 114 authorizes the commission to use criteria by which it “make adjustments to specific components of a utility’s claimed cost of service.” *Id.* Among those criteria is §523(b)(4), which allows the commission to evaluate the performance of utilities in “[a]ction or failure to act to encourage development of cost-effective energy supply alternatives such as conservation or load management, cogeneration, or small power production.” *Id.* Section 523 applies to all fixed utilities, including NGDCs. Thus, §523 likely provides the Commission with the necessary authority to implement revenue decoupling and performance incentive mechanisms.

4. What are the general potential bill impacts?

In general, bill impacts under a RPC decoupling scheme should have minimal impacts on customer bills. Further, decoupling would likely have less serious consequences than increasing customer fixed charges. As previously discussed by KEEA, revenue decoupling does not usually result in more than a three percent change in customer’s bills each period.<sup>69</sup> Further, it has been observed that nearly 40% of all revenue decoupling adjustments nationwide result in rate decrease.<sup>70</sup>

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<sup>69</sup> Pamela Morgan, A DECADE OF DECOUPLING FOR US ENERGY UTILITIES: RATE IMPACTS, DESIGNS, AND OBSERVATIONS (Dec. 2012).

<sup>70</sup> *See Id.*

5. Should it be limited to NGDCs with conservation programs?

Yes, in addition to ensuring more revenue stability, a central purpose of revenue decoupling is to remove the disincentive that utilities have to help their customers become more efficiency. Well-designed efficiency programs alongside revenue decoupling will assist utilities in stabilizing revenues while helping customers consume less energy. Revenue decoupling in absence of robust EE&C programs would provide NGDCs with revenue stability without the added benefit of more efficiency for customers.

6. Should the Commission incorporate caps on rate adjustments?

Yes, the Commission should include a 3% asymmetrical cap on adjustments. It is well documented that revenue decoupling does not usually result in more than a three percent change in customer's bills each period.<sup>71</sup> Further, it has been observed that nearly 40% of all revenue decoupling adjustments nationwide result in rate decrease.<sup>72</sup> However, to fully address this important concern, revenue decoupling can be designed to include an asymmetrical cap on the amount of revenues that can be recovered from customers from any single adjustment. An asymmetrical cap would only apply to rate increases, not rate decreases. Therefore, if the utility collects more than its revenue target, there is no limit on how much excess revenue it could return to the customer. A cap constructed in this manner is preferred, because a utility would still meet its revenue requirement even if it returned all its excess revenue to customers. Alternatively, if the utility collects significantly less revenue than its allowed revenue, customers could be harmed because of the rate increase. Thus, the price cap would limit the extent to which customers would be exposed to price increases.

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<sup>71</sup> Pamela Morgan, A DECADE OF DECOUPLING FOR US ENERGY UTILITIES: RATE IMPACTS, DESIGNS, AND OBSERVATIONS (Dec. 2012).

<sup>72</sup> *See id.*

7. Should the Commission periodically review the costs, sales, and revenues (i.e., a general rate case or equivalent)?

Yes, the commission should periodically have a general rate case or equivalent every 3 to 5 years. Rate cases provide opportunities for stakeholder input, ensuring utilities receive revenues that are adequate to cover their prudently incurred costs plus a reasonable rate of return, and confirming that utilities are not over-, or under-collecting revenues. Despite these benefits, however, rate cases can be extremely burdensome for all parties involved. Therefore, balancing the benefits of rate cases with their costs is essential for efficient utility regulation

**IV. CONCLUSION**

KEEA commends the Commission for continuing its inquiry into the efficacy of alternative ratemaking and rate-design methodologies. While Pennsylvania has made significant progress towards more innovative rate mechanisms, there is still significant opportunity to adopt policies that would better assist the regulated utility industry in meeting persistent challenges, while providing customers with new opportunities to decrease their consumption and lower their energy bills. KEEA believes that the policy recommendations offered in these comments will do just that. KEEA looks forward to providing additional information and responding to other interested parties in its reply comments.