BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Energy Efficiency and	:	**Docket Nos. M-2012-2289411**
Conservation Program	:	**M-2008-2069887**

PECO ENERGY COMPANY'S
COMMENTS ON THE COMMISSION'S
NOVEMBER 14, 2013 TENTATIVE ORDER

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INTRODUCTION

Pursuant to the November 14, 2013 Tentative Order (the "Order") entered by the Pennsylvania Public Utility Commission ("Commission") in the above-referenced dockets, PECO Energy Company ("PECO" or the "Company") hereby submits its Comments on the Amended Act 129 Demand Response Study (the "Study") prepared by the Statewide Evaluator ("SWE"). In addition, PECO comments on the SWE's recommendations for changes to the Act 129 (the "Act") peak demand reduction program and the Commission's proposed price suppression and demand response ("DR") studies.

The Act 129 energy efficiency and conservation program (the "EE&C Program" or "Program") will continue to play an important role in the Commonwealth's energy future. In order to ensure that the Program is cost-effective for customers, as required by Act 129, PECO believes that the Commission's development of the third phase ("Phase III") of the Program should reflect the following key principles, which are incorporated in PECO's Comments.

Reliance on Competitive Markets. As the Commission is aware, PJM Interconnection L.L.C. ("PJM") administers extensive DR programs for large commercial and industrial ("C&I") customers who are able to participate either directly or through aggregation programs operated by competing third-party service providers ("CSPs"). These competitive PJM markets are efficient and successful, with more than 12,000 megawatts ("MW") procured in PJM's most recent capacity auction.[1] The Commission should not seek to duplicate these markets or use C&I customer funds to provide improper subsidies to a smaller group of large C&I customers who choose to participate in DR programs. Furthermore, the Commission should not attempt to value "benefits" of "price suppression" to justify any DR; such efforts will distort market signals and likely undermine the competitive wholesale markets.

However, residential and small C&I customers (collectively, "Mass Market" customers)[2], as a general matter, cannot directly participate in PJM's DR markets in light of PJM requirements for minimum demand reductions of at least 100 kilowatts ("kW").[3] Accordingly, PECO believes that cost-effective Mass Market DR programs sponsored by electric distribution companies ("EDCs") remain appropriate offerings.

Clear Allocation of Funds For Peak Load Reduction and Energy Savings. PECO recommends that the Commission establish a common percentage allocation of an EDC's Act 129 customer funds for achieving peak load reduction and energy savings targets. Establishing consistent spending limits for both DR and energy efficiency for all EDCs to use in future plans will avoid inequities for Pennsylvania customers based solely on which EDC serves them, and will also help ensure that an EDC's risk of Act 129 penalties arising from peak load reduction and energy savings requirements is equal. If the Commission subsequently determines that the portion of Act 129 funds dedicated to achieving peak load reduction should not be spent by an EDC in a particular phase, customers should be allowed to keep those funds.

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[1] *See* "PJM Capacity Auction Attracts Record Amount of New Generation and Imported Capacity", dated May 24, 2013, available at http://www.pjm.com/~/media/about-pjm/newsroom/2013-releases/20130524-pjm-capacity-auction.ashx .

[2] Mass Market customers are residential and small C&I customers with demand up to 100kW.

[3] *See* PJM Manual 19, Section 3A.4.2.3; *see also* PJM Open Access Transmission Tariff, Section 1.5A.10 (noting that customer DR may be aggregated to meet the 0.1 megawatt minimum load reduction requirement), available at www.pjm.gov.

Adequate Time for Implementation. In light of the Commission's potential consideration of additional DR-related studies and analysis, PECO believes it is essential that the Commission provide customers, CSPs, and EDCs with adequate time to comment on future findings. In addition, EDCs need time to develop plans to implement any additional requirements well in advance of the Act 129 peak demand reduction statutory deadline of May 31, 2017.[4] As detailed below, PECO believes that it must have a Commission-approved plan in place by June 1, 2015, in order to obtain and confirm the resources needed to satisfy a further peak load reduction requirement by the statutory deadline. The Commission should also ensure that all stakeholders are given a full opportunity to participate in the design of any DR studies to be performed by the SWE and to address any conclusions regarding peak load reduction requirements before any requirements are finalized.

I. BACKGROUND

Act 129 of 2008 required Pennsylvania EDCs with at least 100,000 customers to develop EE&C plans designed to achieve retail energy consumption savings of at least 1% by May 31, 2011 and at least 3% by May 31, 2013. As part of these EE&C plans, the Act also required EDCs with at least 100,000 customers to develop plans to achieve peak demand savings over the 100 highest hours of demand of at least 4.5% by May 31, 2013.

In accordance with Act 129 and the Commission's EE&C Program Implementation Orders, PECO prepared and submitted its initial EE&C plan ("Phase I") on July 1, 2009. PECO's plan was subsequently reviewed and approved by the Commission in an Order entered October 28, 2009 at Docket No. M-2009-2093215.

Act 129 also directed the Commission to evaluate the costs and benefits of the Phase I

[4] 66 Pa.C.S. § 2806.1(d)(2)

Program consumption reductions by November 30, 2013. If the consumption reduction benefits of the EE&C Program are found to exceed their costs, the Commission must adopt additional incremental consumption reduction requirements.[5]

In addition, the Act directed the Commission to evaluate the costs and benefits of the Phase I peak demand reductions by November 30, 2013. If these reductions are found to be cost effective, the Commission must establish additional peak demand reductions.[6] The Commission may establish these reductions for the 100 hours of greatest demand, as specified for Phase I, "or an alternative reduction approved by the commission" to be measured against the EDCs' peak demands over the period June 1, 2011 through May 31, 2012.[7] These additional peak demand reductions are to be accomplished no later than May 31, 2017.

On August 3, 2012, the Commission entered an Implementation Order tentatively adopting EDC-specific targets for reducing energy consumption for the next EE&C Program term (June 1, 2013-May 31, 2016) ("Phase II"), but declining to set any peak demand reduction targets.[8] The Commission explained that DR programs must be proven to be cost-effective before it will set additional targets.[9] Although the Commission had previously directed the SWE to complete a study to determine the cost-effectiveness of DR, the results of the study were not available when the Phase II Implementation Order was issued. Therefore, the Commission did not have the information it required to determine whether additional peak demand reduction

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[5] 66 Pa.C.S. § 2806.1(c)(3).

[6] 66 Pa.C.S. § 2806.1(d)(2).

[7] *Id.*

[8] *See Energy Efficiency and Conservation Program*, Docket Nos. M-2008-2069887 and M-2012-2289411 (the "Phase II Implementation Order").

[9] *Id*. at 32.

targets would be appropriate.[10]

On May 17, 2013, the Commission released the SWE's Demand Response Study, which was reviewed by stakeholders and subsequently amended to include a preliminary wholesale price suppression and prospective total resource cost ("TRC") analysis of the peak demand reduction program. The SWE's analysis was completed on November 1, 2013, and publicly released by the Tentative Order. The Commission has sought comment on the Amended Demand Response Study, recommendations for regulatory changes to the Act 129 peak demand reduction program, and proposed demand response potential and price suppression studies. PECO's Comments are detailed in the following section.

II. PECO'S COMMENTS

A. PECO Supports The Commission's Proposed Changes To Mass Market Direct Load Control Programs

In the Order, the Commission identifies several changes to EDC Mass Market Direct Load Control ("DLC") programs, recommended by the SWE, which primarily concern the proper calculation of the costs and benefits of these programs for TRC purposes.[11] As set forth below, PECO generally agrees with many of these recommendations and believes their adoption will improve the accuracy of the TRC test in measuring the cost-effectiveness of future Act 129 programs. The Company notes that its existing, Phase II DLC program for Mass Market customers was approved by the Commission as cost-effective earlier this year.[12]

[10] *Id.* at 32-33.

[11] *See* Order, pp. 8-9 & 29-30.

[12] *See Petition of PECO Energy Company for Approval of its Act 129 Phase II Energy Efficiency and Conservation Plan*, Docket No. M-2012-2333992 (Order entered May 9, 2013) ("Phase II Amendment Order").

1. Useful Life Of DLC Equipment

The SWE recommends that the actual eight to ten-year useful life of DLC switches be used in TRC calculations instead of the shorter time period initially used by EDCs during Phase I.[13] PECO believes that the use of the actual life of the switch equipment is appropriate in this circumstance and, in fact, has used a ten-year life in its most recent TRC calculations for its Mass Market program approved by the Commission. PECO therefore supports this SWE recommendation.

2. Use Of Full Load Reduction Scenario

PECO agrees with the SWE's proposal to calculate demand savings from Mass Market DLC programs by multiplying the number of DLC devices by the average kW savings per device, and has used this mechanism in calculating demand reductions for submission to PJM.[14] However, PECO notes that upon completion of the installation of smart meters in its territory, PJM is expected to require a measured baseline for each participating device and subsequently will evaluate performance at the level of a participating customer.[15] Any benefits on TRC calculations from the adoption of this methodology may thus be available only for a limited time.

3. Treatment Of Costs For Existing Mass Market DLC Equipment

In the Study, the SWE recognized that PECO chose to purchase and own the Mass Market DLC equipment installed in its service territory, with the entire cost of the equipment being recovered in PECO's Phase I Program. As a result, the SWE found that PECO's cost for continuing its Mass Market DLC program would be relatively low compared to those EDCs who

[13] *See* Order, p. 29; Study, pp. 40 & 44.

[14] *See* Study, pp. 38-39.

[15] *See* Attachment A: Load Drop Estimate Guidelines, PJM Manual 19: Load Forecasting and Analysis (2013), p. 25.

chose to lease DLC equipment, and recommended that equipment costs already paid for and recovered be excluded from TRC calculations in future Mass Market DLC programs.[16]

PECO agrees with the SWE's recommendation, but believes that the Commission should clarify that this conclusion does not constitute "double counting" of benefits from prior Program phases or a carryover of previous costs. The TRC test in each phase should only include the benefits produced and costs incurred in that phase. The costs of Mass Market DLC equipment paid for and recovered from customers in a prior phase should not be either counted, or recovered, a second time.

4. Adoption Of 75% Of Incentive Payment As Proxy For Participant Costs

In its Study, the SWE noted that the TRC test previously applied by the Commission to all Mass Market program measures used 100% of the incentive paid to customers as a proxy for the cost to the participant. The SWE recommends that Pennsylvania adopt 75% of incentive value for TRC calculations, which is the standard used in California's DR programs, in recognition of the fact that a customer is more likely to participate in DR if the benefit is greater than the costs to participate (i.e., a customer is not incentivized to participate if they will only "break even"). PECO supports the proposal and believes that 75% of incentive value is an appropriate proxy for participant cost.

5. Bidding Mass Market DLC Demand Reductions Into PJM Capacity Markets

In order to fully recognize the benefits of Mass Market DLC programs, the SWE also proposes that EDCs be required to bid the capacity of these programs into PJM's capacity markets, with any resulting benefits provided to customers. While PECO generally supports this

[16] *See* Study, pp. 43-44.

recommendation, PECO notes that the actual PJM benefits that could accrue to customers would be derived primarily from capacity auctions (the “Base Residual Auctions”, or “BRAs”) conducted each year by PJM for a period three years in advance, during which a demand resource accepted in the auction could actually be called.

Because PJM’s BRAs are not synchronized with the term of the EDC Act 129 plans approved by the Commission, it is not practical to bid Mass Market DLC demand reductions into PJM capacity auctions since an EDC cannot be certain that incentives will be available to pay for demand resources for periods beyond its existing plan. For example, since PECO does not have any funds available to procure DR resources (including Mass Market DLC) after the end of its existing Phase II plan, PECO is unable to bid any DR resources in the BRA for the period encompassing the May 31, 2017 statutory demand reduction deadline since the 2017/2018 BRA is scheduled for May 2014. Thus, any requirement to bid Mass Market DLC demand reductions into PJM should thus make clear that an EDC is not required to bid any resources for periods outside of an EDC’s approved plan when an EDC has no established DR obligation or funds to procure DR resources.

Because there may be value in DR from a Mass Market DLC program even after a BRA has been conducted for a relevant period, EDCs should have flexibility to conduct competitive procurements or enter into bilateral contracts with CSPs to realize such value for the benefit of customers.[17] In addition, when PJM conducts incremental auctions for additional necessary

[17] For example, a CSP may have submitted DR resources of a manufacturing facility in a BRA and the facility is no longer in operation in the year when the CSP must honor its PJM commitments. *Cf. Petition of PECO Energy Company for Approval if its Act 129 Phase II Energy Efficiency and Conservation Plan,* Docket No. M-2012-2333992 (Secretarial Letter issued June 13, 2013) (approving PECO contract with CSP to bid in portion of Mass Market DLC resource in the 2013/2014 PJM planning year).

capacity following the BRA for a PJM planning year, EDCs should have the flexibility to participate in such auctions for customer benefit.

Should the Commission impose a requirement to bid Mass Market DLC program demand reductions into PJM capacity auctions with the benefits accruing to participating customers through incentives paid to those customers, the Commission should also clarify that any penalties or fees associated with the PJM demand response programs will be "passed through" as part of the costs of the program. An EDC should not be responsible for PJM penalties arising from the failure of participating customers to curtail their demand when the benefits of participation will flow to all customers through reductions in the cost of the program and continued incentives.

6. Reduction In Incentives For Participating Mass Market DLC Customers

The SWE also proposes that EDCs reduce incentives for participation in their Mass Market DLC programs. PECO has already lowered its participation payment from $30.00 to $20.00 for each of the four monthly summer bills in its Phase II Mass Market DLC program.[18] At this time, PECO believes that its incentive is set at an appropriate amount to maintain the current level of customer participation in its program, but will consider additional changes for its future Act 129 plans.

7. Estimates For Avoided Generation Capacity And Transmission And Distribution Costs

In the Study, the SWE devotes substantial analysis to support its retrospective finding of variations in capacity and energy market pricing between EDC service territories, and expresses its belief that "additional research" is needed to assess avoided transmission and distribution costs. Accordingly, the Commission specifically requested comments regarding the appropriate

[18] *See* Phase II Implementation Amendment Order, p. 4.

estimates for avoided generation capacity and avoided transmission and distribution costs.[19]

PECO agrees that careful analysis is required to estimate avoided generation capacity and avoided transmission and distribution costs, but does not support the SWE conducting any prospective analyses of these costs. Each EDC has already shown that it is well-capable of conducting such analysis as part of its Act 129 plans to date. PECO believes that EDCs, not the SWE, should continue to prepare these analyses as part of Act 129 plans where it can be considered fully by the Commission and other stakeholders in the course of plan approval proceedings.

B. The Commission Should Eliminate Large Commercial And Industrial Load Curtailment Programs In Light Of Existing PJM Programs

In the Order, the Commission highlights the SWE's conclusions that DR capacity secured from large C&I customers who also participate in PJM's demand response market may provide "little or no additional value" since no further actual load reduction will occur as a result of an EDC's Act 129 DR program despite incentive payments to customers.[20] While the SWE suggests that inclusion of avoided transmission and distribution costs could perhaps make these programs cost-effective and specifically notes that Act 129 payments by EDCs contribute to customers' participation in PJM markets, the SWE concludes that DR programs face "significant challenges." Accordingly, the SWE recommends that the Commission be "very cautious about establishing any goals for C&I DR programs" and, if goals are established, "carefully consider[]" how "Act 129 can offer incremental value to the competitive markets already in place."[21]

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[19] Order, p. 31.

[20] *Id*.

[21] Study, p. 56.

The SWE's concerns are well-founded, and the Commission should not set any peak load reduction target that would require EDCs to offer DR programs to large C&I customers. Large C&I customers are able to participate directly in the PJM demand response markets or indirectly through aggregation programs offered by competing CSPs. The Study makes clear that customer load which is already enrolled in PJM DR programs will be dispatched by PJM, and load that is enrolled only in an EDC's Act 129 DR program will not be recognized by PJM and used to reduce short-term capacity needs.[22] As explained in PECO's opposition to the proposed price suppression study in Section II.C *infra*, payments for uneconomic DR resources could also have significant long-term adverse effects on competitive electric markets in Pennsylvania and throughout PJM.

The Commission appears to believe that a reduction in Act 129 DR incentives for C&I customers could reduce participation in PJM DR programs because those customers identified Act 129 programs as a primary motivation for participation (Order, p. 32). However, PECO does not believe that the SWE's data or analysis support this conclusion. For example, PECO paid incentives directly to CSPs – not customers – and the amount of incentive that an individual customer enrolled in both Act 129 and PJM DR programs was actually paid by a CSP is unclear and not part of the SWE's analysis. Moreover, the Study makes clear that incentives paid by CSPs were well in excess of the **actual value received** from customer curtailment:

[22] *Id.*, p. 48 ("If PJM has already secured capacity from a customer, EDC enrollment of that customer offers little to no value"); *see also id.*, p. 21 ("The fundamental difference between the PJM capacity market and the Act 129 DR programs is that PJM capacity resources are paid for the ability to curtail if needed and Act 129 DR resources are paid for actual curtailment, *irrespective of whether that load reduction was needed to maintain system reliability or not*") (emphasis added).

> The SWE calculated that the average LMP during the top 100 hours across the state was $104.05/MWh during the summer of 2012. EDC program payments ranged from $150/MWh in the FirstEnergy voluntary program to nearly $900/MWh in PECO's Demand Response Aggregator program.[23]

As the SWE observes, because customers were motivated primarily by financial incentives, "it follows that the program which offered the higher payment was listed as the primary driver of participation."[24] But it does not follow that EDCs should therefore continue to use C&I customer funds to pay above-market prices to large C&I customers for DR resources which contribute little to no value to energy markets or other customers.

In the Order, the Commission envisions the possibility of an incentive structure that would not "compete" with PJM DR markets, but would still provide the same above-market level of incentives to large C&I customers to participate in an Act 129 DR program.[25] PECO respectfully submits that an excessive incentive structure based on hoped-for "favorable" market conditions is unlikely to result in any meaningful DR benefits; indeed, as the SWE observes, "securing capacity outside of the PJM's competitive markets could prevent DR from realizing its full potential in the region."[26] The Commission should therefore not establish any requirements for large C&I demand response in future Act 129 programs.

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[23] *Id.*, p. 33.

[24] *Id.*

[25] Order, p. 32.

[26] Study, p. 50.

C. The Commission Should Eliminate The Top 100 Hours Definition Of DR Performance And Adopt A Demand Response Methodology Based On An EDC's Day-Ahead Load Forecast

In its Study, the SWE concluded that the "top 100 hour" methodology utilized during Phase I of the EE&C Program had a negative impact on the cost-effectiveness of the DR programs offered in 2012. In particular, the SWE described a number of inherent limitations in the methodology that failed to capture energy price variations based on geography and the level of grid constraint. This resulted in EDCs deploying DR resources at times that were not cost-effective in order to satisfy the DR target and avoid substantial Act 129 penalties.[27]

For these reasons, the SWE recommended that the top 100 hours definition of DR performance be eliminated. The SWE further recommended that, if additional DR targets are established, resources should only be dispatched when they are needed for reliability or likely to be cost-effective. To this end, it presented two possible DR "triggers" as alternatives to the top 100 hour requirement – one based on the real-time Locational Marginal Price ("LMP") for an EDC and another based on the EDC's day-ahead demand forecast.[28]

PECO agrees with the SWE's conclusions that the top 100 hours requirement has not supported cost-effective procurement of DR resources, and strongly supports its elimination. With respect to the alternative triggers identified by the SWE, PECO supports the day-ahead forecast approach under which DR resources would be called if an EDC's day-ahead forecast is 97-99% of its summer peak demand forecast. The Company believes this trigger appropriately links DR deployment to load conditions. In addition, and as noted by the SWE, this

[27] *See id.*, pp 39-40.

[28] *See id.*, pp. 56-57. PECO's day-ahead forecast is currently derived from a day-ahead forecast that PJM develops for the Mid-Atlantic region, but the Company would move to utilizing a PJM zonal day-ahead forecast if it becomes available.

methodology would provide EDCs and customers with sufficient advance notice of the need to curtail load and would also remove the possibility that deployed DR resources would not count towards the compliance target.

The second alternative trigger, where DR would be dispatched during any hour where the EDC's real-time LMP is above a certain threshold, is less desirable because the volatility of LMPs can lead to both forecasting and deployment difficulties. As noted by the SWE, an LMP forecasting error could result in resources being dispatched in an hour which will not ultimately be used to assess compliance. Even with accurate forecasting, an EDC could face deployment challenges given that the response time of its DR programs is typically 1-2 hours, and LMPs could have returned to lower levels by the time demand resources are actually deployed. Finally, local LMPs can increase (and could trigger deployment of DR resources) due to factors unrelated to demand for power in the PECO zone (e.g., loss of a transmission line for a plant outside the PECO zone).

As the SWE notes, a relatively cool summer could result in neither of the proposed mechanisms being "triggered". While the SWE suggests that such a weather condition should be addressed by a "test event" to confirm demand resources, PECO does not believe that such a test should be required of customers and EDCs by the Commission if it is not required by PJM. Each EDC will remain incentivized to ensure that its participating demand response resources are in fact available, since such a cool summer cannot be predicted accurately in advance.

D. The Commission Should Not Conduct A Price Suppression Study

In the Order, the Commission proposes that the SWE perform "a full Wholesale Price Suppression Study" to "determine the benefits to wholesale prices from Act 129 DR programs." PECO does not believe that the proposed price suppression study would serve any useful purpose and therefore opposes the incorporation of asserted wholesale market price suppression "benefits" from demand response programs in TRC calculations. The adoption of programs that are not economic on their own, but instead are justified on the basis of speculative price suppression effects, constitutes government intervention in the competitive electricity markets, which could have detrimental long-term effects of devaluing merchant generation and investment and causing investors to reassess the risk of future uneconomic regulatory action. Furthermore, quantification of the alleged degree of any temporary price suppression, even with further study, would be tenuous and unreliable.

In the Study, the SWE acknowledged that "[t]here is certainly a market response from the downward pressure exerted on wholesale prices by EE and DR programs. In the long term, supply-side resources are aware of these programs and may increase their [capacity] bids to counteract price suppression efforts …"[29] In fact, the reaction to reliance on the speculative suppression of wholesale prices could be quite swift or even immediate, and may not be limited to a simple compensatory market response. If merchant capacity were devalued by adopting customer-funded projects that are not economic on a stand-alone market basis, merchant electricity suppliers would reassess the risk that regulators would take similar actions in the future, and they would adjust their behavior accordingly, becoming generally less likely to enter the market and more likely to exit it. This, in turn, would result in higher long-term prices for customers.

A December 2012 report prepared for the COMPETE Coalition[30] examined the impact of

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[29] *See id.*, p. 65.

[30] See *State Subsidization of Electric Generating Plants and the Threat to Wholesale Electric Competition*, prepared by Continental Economics, December 2012, and available at http://www.competecoalition.com/files/State%20Subsidization%20of%20Electric%20Generating%20Plants__Final.pdf. The COMPETE coalition is a group of 749 electricity stakeholders, including customers, suppliers, energy generators, transmission owners, trade associations,

(continued)

a similar form of state government intervention in the electricity markets. Using the results of recently published work by the Pennsylvania State University Electricity Markets Initiative, the report concludes that government subsidization of new generation both raises capacity costs for the very customers whom the subsidies are supposed to benefit and jeopardizes resource adequacy and reliability in the long run for all consumers. While this report specifically addresses attempts to achieve price suppression "benefits" through state subsidies to build new generating resources, similar logic can be applied to a state government effort to have customers finance demand response programs that are not economic on a stand-alone basis. As the report explains:

> Whatever the specific form of intervention, the costs of the new capacity in these state-subsidized efforts are underwritten by the local "poles and wires" utility's customers, thus eliminating the normal financial risk that competitive generation suppliers bear. (In fact, allocating financial risk back to generation suppliers was one of the key purposes of electric industry restructuring.) The new generating capacity is then offered into the capacity and energy markets so as to purposefully "suppress" market prices and supposedly "benefit" consumers. However, it is a basic economic fallacy that price distortions caused by government subsidies in a free market are "benefits." The lower prices made possible by subsidized entry are short-lived because they drive competitive suppliers from the market…The reality is that such policies <u>never</u> work: they are a form of 'free lunch' economics that fails to account for market dynamics.[31]

While the potential for detrimental long-term effects on the competitive electricity markets and customers is the most important reason to not incorporate price suppression "benefits" in TRC calculations, the Company also believes that the quantification of such

technology innovators, environmental organizations and economic development corporations which support well-structured competitive electricity markets. Exelon Corporation, PECO's parent company, is a member of COMPETE.

[31] *Id.*, p. 2.

“benefits” would be tenuous and unreliable for several reasons. First, any suppression of electricity prices likely would be short-lived because, as described earlier, the reduction in market prices would make it less economical for merchant electricity suppliers to remain in or enter the market and thereby lead to higher wholesale market prices. Moreover, since PJM capacity prices are, for the most part, established three years ahead of delivery, it is unlikely that any significant capacity price suppression would be experienced for at least three years, leaving more time for the market to respond to and offset price suppression efforts.

Second, any quantification of price suppression “benefits” would depend heavily upon projections of future electricity supply and demand conditions which, by their nature, are highly speculative. For example, any temporary effect on the capacity market clearing price would be dependent upon the slope of the RPM demand curve along the segments of the curve at or near the market clearing price, which changes from year to year based on changing market conditions. In addition, any temporary effect on the capacity market clearing price would be dependent upon the relevant regional capacity supply curve, which is driven by changing transmission congestion conditions within PJM and by the quantity of regional capacity resources and the associated bid prices of those resources, all of which are constantly changing as market conditions change. As noted in the Study, “[t]he same load reductions in a different [PJM BRA] could produce far different (either higher or lower) price suppression estimates.”[32]

Third, even if it were determined that some degree of temporary net energy price suppression could be expected, the forecasted “benefits” likely would be overstated. Customers may simply shift their usage, rather than actually reduce their overall load, in response to the

[32] *See* Study, p. 66.

additional demand response programs.[33] In addition, as the Study states, "the benefits of energy price suppression would likely be offset by increasing capacity costs…therefore, the long-term view, which is appropriate for analysis of Phase III demand response, would likely include capacity prices that have incorporated these energy price suppression impacts."[34]

Finally, it is uncertain whether any energy price suppression would be felt by retail customers. As explained in the Study: "[t]he mechanism by which reduced wholesale energy prices (LMPs) translate into benefits for DR non-participant ratepayers is unclear. One school of thought within the industry is that a short-term reduction in LMP actually benefits suppliers rather than ratepayers and benefits to electric generators are not considered in the TRC test."[35] For all these reasons, PECO believes that additional price suppression studies are not warranted and that price suppression "benefits" should not be incorporated into TRC calculations.

E. The Commission Should Establish A Statewide Percentage Allocation Of Act 129 Funds For Demand Response Instead Of EDC-Specific Targets And Permit EDCs, Rather Than The SWE, To Conduct Any Additional DR Studies That Prove Necessary

While PECO opposes the continuation of large C&I customer DR programs and a price suppression study for the reasons explained in these Comments, PECO believes that future Mass Market DR programs could be investigated in light of the Company's existing cost-effective Mass Market DLC program and its expectation that residential and small C&I customers will be unable to participate directly in the PJM DR markets during upcoming Act 129 plans.

[33] The Demand Response Study provides the example of a beer distributor precooling his stock prior to a demand response event so that he can change the refrigerator set point to save energy during the control hours. Study, p. 52.

[34] *Id.*, p. 53.

[35] *Id.*, p. 52.

A necessary first step in the development and evaluation of future Mass Market DR programs is for the Commission to establish a common percentage range of an EDC's total Act 129 funding that will be dedicated to achieving peak load reduction instead of attempting to calculate EDC-specific targets. PECO recommends that the Commission adopt a range of funding between 14% and 18% of an EDC's Act 129 funds. This amount corresponds to the funds that PECO will expend on its existing Commission-approved Mass Market DLC program, and therefore is a reasonable division of customer funds to support cost-effective programs for both DR and energy efficiency. By using a percentage of total Act 129 funds (instead of adopting an exact dollar amount or a particular MW reduction target), Pennsylvania customers will not be paying for different proportions of DR and energy efficiency benefits depending upon the EDC territory in which the customer is located and variations in energy and capacity pricing. Furthermore, since the difficulties of achieving peak load reductions and energy efficiency are not proportional, a common percentage will mitigate unequal treatment and risks of Act 129 penalties for EDCs. While the differences in capacity prices between EDC territories examined by the SWE are a significant issue for the development of DR and EE programs, these differences will be accounted for in projected estimates of avoided generation, transmission and distribution costs already performed by EDCs and included in EDC Act 129 plans.

PECO also believes that the Commission should make clear that the funds which may be allocated to DR in future Act 129 plans may not be transferred to energy efficiency programs. In the absence of such clarification, EDCs may face difficulty in maintaining the interest and commitment of customers and CSPs for participation in future programs. The Commission should further consider the implementation of such programs during each year of an Act 129 phase as well as potential operation in subsequent years; programs are likely to be far more cost-effective if program interruptions and associated customer re-acquisition costs are avoided.

Once the funding parameters are established, EDCs can begin to develop cost-effective DR programs, and, if necessary, conduct their own DR studies to support such programs. PECO does not believe that an additional DR study should be performed by the SWE. However, should the Commission direct the SWE to conduct its own DR study, the scope of the DR study should be focused on dispatchable DLC programs. The Company notes that the Optional Demand Response Potential Study work plan identifies a wide range of other program offerings, including non-dispatchable resources such as critical peak pricing, time-of-use rates, and real time pricing, and also discusses research concerning “distributed energy” resources. The Company believes these resources should be excluded from the DR study as such resources are not considered potential DR by PJM.

F. The Commission Should Adopt An Integrated Schedule For Consideration Of The Potential DR Response Study And Phase III Plans

As previously explained in these Comments, PECO believes that it is essential for the Commission to ensure that customers, CSPs and other competitive suppliers, and EDCs have sufficient time to participate fully in the design and review of any additional studies by the Commission and to integrate any Commission directives arising from those studies relating to any demand respond goals in Phase III plans. PECO therefore proposes the following schedule for the Commission’s consideration:

August 1, 2014	Release SWE Demand Response Study and Phase III Tentative Implementation Order
September 12, 2014	Tentative Order Comments due
September 26, 2014	Tentative Order Reply Comments due
November 3, 2014	Final Phase III Implementation Order
February 2, 2015	EDCs File Phase III Plans
June 1, 2015	Anticipated Commission rulings on Phase III Plans
June 1, 2016	Commencement of Phase III Programs

III. CONCLUSION

PECO appreciates the opportunity to comment on the Tentative Order and requests that the Commission consider its Comments and adopt the foregoing recommendations in developing the final Order. PECO looks forward to continuing to work with the Commission and other stakeholders as the transition to a Phase III Program progresses.

Respectfully submitted,

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