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December 30, 2013

VIA ELECTRONIC FILING

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor North
P.O. Box 3265
Harrisburg, PA 17105-3265

Re: Energy Efficiency and Conservation Program (Amended Demand Response Study)
Docket Nos. M-2012-2289411 & M-2008-2069887

Dear Secretary Chiavetta:

Enclosed for filing are the Comments of PPL Electric Utilities Corporation to the above-referenced proceeding.

Respectfully submitted,

Andrew S. Tubbs

AST/jl
Enclosure

cc: Megan Good (*Word version via E-Mail*)
Kriss E. Brown (*Word version via E-Mail*)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Energy Efficiency and Conservation Program (Amended Demand Response Study)	: :	Docket Nos. M-2012-2289411 M-2008-2069887

COMMENTS OF
PPL ELECTRIC UTILITIES CORPORATION

TO THE PENNSYLVANIA PUBLIC UTILITY COMMISSION:

On November 14, 2013, the Pennsylvania Public Utility Commission ("Commission") entered a Tentative Order[1] in the above-captioned proceeding. The Commission's *Demand Response Tentative Order* was published in the *Pennsylvania Bulletin* on November 30, 2013. Through its *Demand Response Tentative Order*, the Commission released for comment its amended Act 129 Demand Response Study ("Amended DR Study"), which includes the Preliminary Wholesale Price Suppression and Prospective Total Resource Cost ("TRC") Test Analysis prepared by the Statewide Evaluator ("SWE") to assess the cost-effectiveness of the Phase I peak demand reduction program. In addition, the Commission requested comments on a proposed alternative peak demand reduction program for inclusion in a subsequent phase of the energy efficiency and conservation ("EE&C") program. As discussed in detail below, it is the position of PPL Electric Utilities Corporation ("PPL Electric" or the "Company") that the Phase I demand reduction programs were not cost-effective. Therefore, further demand reduction programs are not justified. Further, PPL Electric does not support the Commission's proposed

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[1] *Energy Efficiency and Conservation Program*, Tentative Order at Docket Nos. M-2012-2289411 and M-2008-2069887 (Order Entered November 14, 2013) ("*Demand Response Tentative Order*").

alternative peak demand reduction programs. Nevertheless, if the Commission disagrees with PPL Electric's legal analysis, the Company also submits technical comments on the issues identified by the Commission in its *Demand Response Tentative Order*.

I. **BACKGROUND**

PPL Electric is a public utility and an electric distribution company ("EDC") as defined in Sections 102 and 2803 of the Pennsylvania Public Utility Code, 66 Pa.C.S. §§ 102, 2803, and is subject to Act 129 of 2008.[2] PPL Electric furnishes electric distribution, transmission, and default supply services to approximately 1.4 million customers throughout its certificated service territory, which includes all or portions of twenty-nine counties and encompasses approximately 10,000 square miles in eastern and central Pennsylvania.

On July 1, 2009, in compliance with Section 2806.1(b)(1)(i) of Act 129, PPL Electric filed its Phase I EE&C Plan for the period of June 1, 2009 through May 31, 2013 ("Phase I EE&C Plan"). PPL Electric's Phase I EE&C Plan was approved, with modification, by the Commission on October 26, 2009.[3] The Commission thereafter approved several modifications to PPL Electric's Phase I EE&C Plan.[4]

On August 3, 2012, the Commission issued its Phase II EE&C Plan Implementation Order, which determined the required consumption reduction targets for each electric distribution company ("EDC") and established guidelines for implementing Phase II (June 1, 2013 – May 31,

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2 Act 129 of 2008, P.L. 1592, 66 Pa.C.S. §§ 2806.1 and 2806.2.

3 *Petition of PPL Electric Utilities Corporation for Approval of its Energy Efficiency and Conservation Plan*, Docket No. M-2009-2093216, 2009 Pa. PUC LEXIS 2242 (October 26, 2009).

4 *See, e.g.*, *Petition of PPL Electric Utilities Corporation for Approval of its Energy Efficiency and Conservation Plan*, Docket No. M-2009-2093216, 2010 Pa. PUC LEXIS 392 (February 17, 2010); *Petition of PPL Electric Utilities Corporation for Approval of its Energy Efficiency and Conservation Plan*, Docket No. M-2009-2093216, 2011 Pa. PUC LEXIS 2009 (May 6, 2011).

2016) of the EE&C program.[5] In addition, by its *2012 Implementation Order*, the Commission determined not to set additional peak demand reduction requirements for the EDCs' Phase II EE&C Plans. *2012 Implementation Order*, p. 38 The Commission stated that it was unable to set additional peak demand reduction requirements prior to completing its assessment of the cost-effectiveness of the EDCs' Phase I EE&C Plans' peak demand programs. *2012 Implementation Order*, p. 38.

On November 15, 2012, pursuant to Act 129 and the Commission's *2012 Implementation Order*, PPL Electric filed a Petition with the Commission requesting approval of its Phase II (June 1, 2013 – May 31, 2016) Energy Efficiency and Conservation Plan ("Phase II EE&C Plan" or the "Plan"). The Commission approved PPL Electric's Phase II EE&C Plan, with modifications, on March 14, 2013.[6] Pursuant to the *March 2013 Order*, on May 13, 2013, PPL Electric submitted a compliance filing. The Commission approved PPL Electric's compliance filing on July 11, 2013.[7]

PPL Electric has actively participated in all of the proceedings instituted by the Commission to implement Act 129. The Company appreciates the opportunity to comment on the Amended DR Study and the potential subsequent demand reduction program. PPL Electric's comments will provide the Commission with a valuable perspective in its evaluation of demand response ("DR") programs for Phase III of the EDCs' EE&C Programs.

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5 *Energy Efficiency and Conservation Program*, Docket Nos. M-2012-2289411 and M-2008-2069887, 2012 Pa. PUC LEXIS 1259 (Implementation Order entered on August 3, 2012) ("*2012 Implementation Order*").

6 *Petition of PPL Electric Utilities Corporation for Approval of its Act 129 Phase II Energy Efficiency and Conservation Plan*, Docket No. M-2012-2334388 (March 14, 2013) ("*March 2013 Order*").

7 *Petition of PPL Electric Utilities Corporation for Approval of its Phase II Act 129 Energy Efficiency and Conservation Plan*, Docket No. M-2012-2334388 (Order Entered July 11, 2013) ("*July 2013 Order*").

II. COMMENTS OF PPL ELECTRIC

A. SUMMARY OF COMMENTS

PPL Electric's assessment is that future Act 129 EE&C Plans should exclude DR programs and DR compliance targets, and that additional Commission studies to determine the viability or to define the scope of future Act 129 DR programs and DR compliance targets are not warranted. The reasons for this assessment are summarized below.

First, Act 129 states that the Commission shall set additional demand reduction targets (beyond the end of Phase I on May 31, 2013) if DR benefits exceed the costs.[8] However, the Phase I DR programs were not cost-effective. Both the Commission's Demand Response Study ("DR Study"), released on May 17, 2013, and the Amended DR Study, released on November 1, 2013, concluded that DR was not cost-effective for Act 129 Phase I based on actual program results.[9] Furthermore, each EDC's Program Year 4 Final Annual Report demonstrates that none of the 18 DR programs offered in Phase I of Act 129 was cost-effective. Therefore, since DR benefits do not exceed the costs, the Commission may not set additional demand reduction targets beyond the end of Phase I.

Second, it is unlikely that future Act 129 DR could be cost-effective. The Amended DR Study concludes that DR might be cost-effective if several fundamental changes are included in future DR programs. These proposed changes include the method for determining TRC benefits and costs, changes to DR program rules, changes to DR program incentives, the addition of hard-to-quantify TRC benefits such as presumed market price suppression and avoided T&D

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8 *See* 66 Pa.C.S. § 2806.1(d)(2).

9 Actual and final costs, benefits, and TRC results were not available from EDCs when the SWE prepared the Amended DR Study. Therefore, the TRC results in the Amended DR Study are noted as estimates. PPL Electric's actual TRC benefit-cost ratios for its DR programs were lower (worse) than estimated by the SWE. The actually benefit-cost ratio for the residential Direct Load Control was substantially lower than the SWE's estimate (0.08 compared to 0.58).

expansion costs, and the definition of peak hours. However, most of the proposed changes are not valid because they will overstate the TRC benefits, are very unlikely to materialize, will not significantly improve cost-effectiveness, will limit the pool of eligible participants ("market potential") to very small levels, and/or are arbitrary adjustments to the method for determining "cost-effectiveness."

Third, even if future DR programs were cost-effective, such Act 129 DR programs would unfairly compete and interfere with competitive market DR programs (such as those established through PJM) and competitive retail electricity markets.

Finally, Act 129 energy efficiency programs that focus on reducing energy consumption are cost-effective[10] and provide significant permanent peak load reductions as a byproduct at no incremental cost.[11] In contrast, DR programs generally shift loads from one period to another and will not continually recur without additional actions by the customer and additional financial incentives from the EDC.

PPL Electric addresses these points, as well as those issues identified by the Commission in its *Demand Response Tentative Order*, in detail below.

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10 *Final Annual Report for Year 4 of PPL Electric Utilities Corporation's Act 129 Plan*, Docket No. M-2009-2093216, pp. 27-28 (Nov. 15, 2013); *PECO's 2013 Final Annual Energy Efficiency & Conservation Report for the program year of June 1, 2012 through May 31, 2013*, Docket No. M-2009-2093215, pp. 36-37 (Nov. 15, 2013); *Pennsylvania Power Company Final Annual Report to the Pennsylvania Public Utility Commission and Act 129 Statewide Evaluator*, Docket No. M-2009-2112956, p. 32 (Nov. 15, 2013); *Pennsylvania Electric Company Final Annual Report to the Pennsylvania Public Utility Commission and Act 129 Statewide Evaluator*, Docket No. M-2009-2112952, p. 34 (Nov. 15, 2013); *Metropolitan Edison Company Final Annual Report to the Pennsylvania Public Utility Commission and Act 129 Statewide Evaluator*, Docket No. M-2009-2092222, p. 33 (Nov. 15, 2013); *Duquesne Light Company's Final Annual Report to the Pennsylvania Public Utility Commission for the Period of June 2012 through May 2013, Program Year Four for its Act 129 of 2008 Energy Efficiency Conservation and Demand Response Plan*, Docket No. M-2009-2093217, p. 26 (Nov. 15, 2013).

11 Amended DR Study, p. 54.

B. ADDITIONAL DEMAND REDUCTION COMPLIANCE TARGETS ARE NOT PERMISSIBLE

Additional demand reduction requirements (compliance targets) are not permissible because the Phase I DR programs were not cost-effective. Act 129 states that the Commission shall set additional demand reduction targets (beyond the end of Phase I on May 31, 2013) if DR benefits exceed the costs.[12] Specifically, Act 129 provides:

> By November 30, 2013, the commission shall compare the total costs of energy efficiency and conservation plans implemented under this section to the total savings in energy and capacity costs to retail customers in this Commonwealth or other costs determined by the commission. If the commission determines that the benefits of the plans exceed the costs, the commission shall set additional incremental requirements for reduction in peak demand for the 100 hours of greatest demand or an alternative reduction approved by the commission. Reductions in demand shall be measured from the electric distribution company's peak demand for the period from June 1, 2011, through May 31, 2012. The reductions in consumption required by the commission shall be accomplished no later than May 31, 2017.

66 Pa.C.S. § 2806.1(d)(2). It is a definitive requirement that DR actually be cost-effective. However, the Commission's own DR Study, its Amended DR Study, and the EDCs' Program Year 4 Final Annual Reports all demonstrate that the Phase I DR programs were not cost-effective. Therefore, no further DR programs should be included in any potential Phase III EE&C Plans.

PPL Electric also notes that unlike EE&C energy efficiency programs under Section 2806.1(c)(3), 66 Pa.C.S. § 2806.1(c)(3), DR programs were not intended by the General Assembly to persist beyond a second phase without further legislative action. *See* 66 Pa.C.S. § 2806.1(d)(2). Section 2806.1(c)(3) provides that "the commission shall evaluate the costs and benefits" of the EE&C program "[b]y November 30, 2013, *and every five years thereafter*." 66

[12] *See* 66 Pa.C.S. § 2806.1(d)(2).

Pa.C.S. § 2806.1(c)(3) (emphasis added). No such provision that the Commission shall evaluate the benefits of DR programs every "five years thereafter" exists in Section 2806.1(d)(2). *See* 66 Pa.C.S. § 2806.1(d)(2). Therefore, because the Commission has not been able to demonstrate that the DR programs were cost-effective, the statute mandates that no additional incremental reductions in peak demand or alternative reductions may be implemented by the Commission, and the Commission is precluded from implementing any future DR programs absent further legislative action.

Based on actual program results, the Commission's first DR Study concluded that DR was not cost-effective for Phase I (June 1, 2009, through May 31, 2013). The Commission then directed the SWE to conduct a Preliminary Wholesale Price Suppression and Prospective TRC Analysis of the peak demand reduction program, which the SWE included in its Amended DR Study. The Amended DR Study released on November 1, 2013 also concludes that the overwhelming majority of DR programs would not be cost-effective, even after including the new analyses and consideration of additional presumed benefits. In particular, the Amended DR Study, as described by the Commission in its *Demand Response Tentative Order*, concludes the following: (1) none of the seven direct load control programs were cost-effective (provided a TRC benefit-cost ratio of 1.0 or greater) in 2012; (2) the eight load curtailment programs and one critical peak rate program were not cost-effective in 2012; and (3) even after including a presumed $25/kW-year avoided T&D benefit, only two load curtailment programs would have exhibited a TRC ratio over 1.0 *Demand Response Tentative Order*, pp. 18-20. Moreover, the Amended DR Study, in its Prospective TRC Analysis section, observes that even with the inclusion of estimated price suppression benefits, only four of the 15 programs would result in a

TRC ratio greater than 1.0. Amended DR Study, p. 66. Thus, both the first DR Study and the Amended DR Study conclude that the DR programs were not cost-effective.[13]

Further, as shown in Table 1 below, this conclusion is also supported by each EDC's Program Year 4 Final Annual Report which provides the actual cost-effectiveness results for Phase I EE&C programs as determined by each EDC's independent evaluator in accordance with the TRC Test. Statewide, EDCs offered 18 DR programs in Phase I of Act 129. Not one was cost-effective, and actual benefit-cost ratios ranged from 0.0 to 0.79. Therefore, because none of the Phase I benefit-cost ratios exceed 1.0, the EDCs' Program Year 4 Final Annual Reports demonstrate that the Phase I DR programs were not cost-effective.[14]

Table 1 - Summary of Actual Cost-Effectiveness Results from Phase I EE&C DR Programs

EDC	Direct Load Control Program Benefit-Cost Ratio	Load Curtailment Program Benefit-Cost Ratio	Other Type of DR Program Benefit-Cost Ratio
PPL Electric	0.08	0.49	
Duquesne	0.01	0.20	
PECO	0.05	0.08 - 0.31	
Met Ed	0.04	0.78	
Penelec	0.05	0.79	
Penn Power	0.0	0.79	
West Penn Power	0.0	0.0	0.0 - 0.44

13 PPL Electric notes that although the first DR Study and the Amended DR Study both conclude that the DR programs were not cost-effective, the Commission intends to conduct additional studies on the cost-effectiveness of the programs. Specifically, the Commission proposes that the SWE perform a Demand Response Potential Study and a Wholesale Price Suppression Study. It is unclear whether the Commission intends these to be the final studies on the DR programs' cost-effectiveness.

14 Concerns relative to the cost-effectiveness of the DR programs are compounded when one realizes that EDCs spent $136 million statewide for Phase I DR programs. That is a significant amount of money to spend on DR programs that have been found not to be not cost-effective.

In addition, the Commission itself has found that Section 2806.1(d)(2) requires actual cost-effectiveness to be shown. In its *2012 Implementation Order*, the Commission concluded "that the language at 66 Pa.C.S. § 2806.1(d)(2), regarding the comparison of the costs and benefits, is clear in that the Commission may only impose additional peak demand reduction requirements *if proven to be cost-effective*." *2012 Implementation Order*, p. 38 (emphasis added). However, despite the conclusions from the DR Study, the Amended DR Study, and the EDCs' Program Year 4 Final Annual Reports that DR programs were not cost-effective, the Commission is evaluating whether to implement additional peak demand reduction requirements and conduct additional DR studies. The only rationale for imposing additional peak demand reduction requirements or conducting additional studies appears to be a belief that DR programs could potentially be cost-effective. It is PPL Electric's position that the Commission has fulfilled its obligation to evaluate the cost-effectiveness of the Phase I DR programs and that analysis clearly demonstrated that the DR programs were not cost-effective. Therefore, no additional DR requirements can or should be set, and additional DR studies are not warranted.

In summary, additional demand reduction requirements are not permissible because the Phase I DR programs were not cost-effective. Under Act 129, the Commission may set additional incremental demand reduction requirements if the DR programs are proven to be cost-effective. Indeed, the Commission's interpretation of Section 2806.1(d)(2) in its *2012 Implementation Order* supports such a conclusion. Therefore, because the first DR Study, the Amended DR Study, and the EDCs' Program Year 4 Final Annual Reports all demonstrate that the DR programs were not cost-effective, the Commission may not impose additional demand reduction requirements.

C. TECHNICAL COMMENTS

As addressed above, because the Phase I DR programs were not cost-effective, additional demand reduction requirements are not permissible. Therefore, the Commission should decline to set any additional DR requirements. However, as requested by the Commission, PPL Electric provides the following technical comments to the proposals set forth in the Commission's *Demand Response Tentative Order*.

1. Future Act 129 Demand Response Will Not Be Cost-Effective

The Commission's Amended DR Study proposes several changes, such as how DR program benefits and costs are determined/quantified, changes to program rules, the definition of peak hours, etc., and concludes that DR might be cost-effective if these changes are included in future DR programs. However, for reasons discussed in more detail below, most of the proposed changes are not valid because they overstate the TRC benefits, understate the TRC costs, are uncertain, are difficult to quantify or confirm, do not significantly improve cost-effectiveness, and limit the pool of eligible participants ("market potential") to very small levels. Further, although the proposed changes may appear to make DR programs more cost-effective, most are arbitrary adjustments to the method for determining "cost-effectiveness" that have no tangible impact on actual costs or actual benefits and appear to have no sound technical basis. Moreover, their validity cannot be confirmed or substantiated.

If the Commission modifies the rules for determining cost-effectiveness of DR (as described in the Amended DR Study), the TRC method for DR programs will be different than the TRC method for energy efficiency measures/programs that also provide peak load reductions. This will cause a peak load reduction from an energy efficiency measure to be valued differently than a peak load reduction from a DR program. Creating different TRC rules/methods for peak load reductions and energy efficiency reductions:

- Has no sound technical or policy basis;
- Skews the TRC results and the design of programs offered to customers;
- Is overly complex; and
- Adds administrative burden and costs.

PPL Electric notes that many of the estimated Phase I benefit-cost ratios in the Amended DR Study are also overstated when compared to the actual benefit-cost ratios determined by the EDCs' independent evaluators in the Final PY4 Annual Reports. These reports were not available when the Amended DR Study was prepared.

PPL Electric offers these specific comments about the changes proposed by the Amended DR Study and the Study's conclusion that those changes could lead to cost-effective DR programs.

a. PJM Price Suppression

The Amended DR Study assumes that Act 129 DR programs suppress PJM prices and, therefore, recommends including price suppression as a benefit in the TRC calculations. The Amended DR Study also recommends conducting a price suppression study to quantify such benefits. For the reasons described below, price suppression should not be an adder to TRC benefits, and a price suppression study is not warranted.

First, some-to-all of the presumed price suppression identified in the Amended DR Study is likely already reflected in the forward market energy and capacity price estimates that are currently components of the TRC avoided cost calculation.[15] Wholesale forward market energy and capacity pricing, set by the competitive market and reflected in bilateral transactions and

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[15] TRC avoided costs (energy, capacity, transmission, distribution, etc.) are multiplied by energy and peak load reductions to calculate TRC benefits.

NYMEX futures,[16] is influenced by many market factors. One factor is the actual PJM spot market prices for energy. Another is the PJM Base Residual Auction price for capacity. Both of these factors reflect actual or expected price suppression that was caused, or influenced, by Act 129 DR and Act 129 energy efficiency in prior years, and the expected amount of energy efficiency and DR in future years. Therefore, adding price suppression to the TRC calculation would result in double-counting some of these benefits.

PPL Electric notes that there are many other factors such as projected generation fuel prices, generation supply, load and economic growth forecasts, and weather. These factors, however, are much more difficult to forecast than DR/EE. They also influence wholesale energy/capacity pricing much more than DR/EE and, therefore, have greater influence on TRC cost-effectiveness than DR/EE.[17]

Second, any price suppression study conducted in 2014 would be based on current or projected information and data. Those data are not likely representative of the actual results from Act 129 DR to be implemented during 2016 to 2021 (the presumed five-year period for Act 129 Phase III). Given the high volatility and uncertainty of PJM real-time energy prices, future energy prices, and forward capacity prices, it is very likely that the results from a price suppression study conducted in 2014 will not be applicable to DR programs in future years. In addition, PJM prices and the shape/slope of the capacity and energy supply curves[18] are influenced by many market factors beyond Act 129 DR, including generation availability and

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16 In accordance with the Commission's TRC Order, NYMEX futures for energy and natural gas are the basis for estimating the energy cost component for "TRC Avoided Costs".

17 In accordance with the Commission's TRC Order, TRC avoided costs (TRC benefits) are based on estimates of energy and capacity prices for the next 15 years. NYMEX electricity futures are used to project energy prices for the first 5-year period. NYMEX natural gas futures are used to project energy prices for the next 5 years. EIA estimates are used for the final 5 years.

18 Amended DR Study, Figure I-1. The Amended DR Study estimates price suppression based on the slope of the supply curve (clearing price versus resource requirement MW).

performance, bidding behavior of market participants, supply and demand, and natural gas and other fuel prices. Therefore, it may not be possible to reasonably isolate Act 129 DR's price suppression impacts or accurately predict future prices.

Third, for the reasons explained in Section C.1.e, the DR Study significantly overestimates any price suppression benefits.

For these reasons, price suppression should not be an adder to TRC benefits since it will overstate TRC benefits. Further, a price suppression study is not warranted because it may not be possible to reasonably isolate the impact of Act 129 DR price suppression on future energy prices, and price suppression impacts likely have much less of an effect than other factors that influence TRC avoided costs. Therefore, any price suppression benefits are likely "lost in the rounding" compared with all the other uncertainties that impact TRC avoided cost estimates.

b. Treatment of Incentives in the TRC Calculation for DR Programs

The Amended DR Study recommends that the Commission consider reducing the portion of the incentive amount that is treated as a "cost" in the TRC analysis from 100% to 75%, thus reducing "TRC Costs" and improving the benefit-cost ratios of DR programs. This is an arbitrary adjustment to the method for determining "cost-effectiveness" that does not consider actual costs or benefits and that only gives the appearance of more cost-effectiveness.[19]

TRC costs include EDC costs and participant costs. For DR measures, it is not usually possible to estimate the participant's cost (such as "foregone" use of an air conditioner, productivity, or occupant comfort levels), or there are no participant costs. Therefore, the TRC

[19] The rationale for the 75% fraction is derived from the California Demand Response Cost Effectiveness Protocol (Attachment 1, Final, R.07-01-041 ALJ/JHE/jt2. December 2010). In that protocol, it is argued that because costs to participants in DR are extremely difficult to quantify, the incentives paid to participants may be used as a proxy for participant costs. The protocol further argues that, because it is more likely that customers participate in DR programs when the benefits exceed the costs, it is appropriate that only a portion of the incentive amount be considered in benefit-cost calculations. As far as PPL can determine, the 75% fraction does not appear to be based on empirical evidence.

costs for a DR program are usually equal to the EDC's program delivery costs. EDC program delivery costs are primarily the payments to the DR program conservation service provider ("CSP"), some of which the CSP provides to the customer as an incentive.[20]

In accordance with the Commission's TRC Order,[21] 100% of the payments from the EDC to the CSP were treated as an "EDC program cost" in the TRC in Phase I. Reducing that amount from 100% to 75% is arbitrary and has no material bearing on actual participant costs or actual benefits achieved by participants. It merely assumes, hypothetically, that the incentive payment received for participating in the DR program is greater than the actual cost to the participant.

Therefore, it is not appropriate to adjust the rules, somewhat arbitrarily, for what percentage of program costs can be included in the TRC when determining "cost-effectiveness."

c. Avoided Cost of T&D Infrastructure

The Amended DR Study suggests that Act 129 DR reduces the need to build new transmission and distribution ("T&D") facilities and, therefore, recommends including avoided T&D infrastructure as a benefit in the TRC calculation. The Amended DR Study further recommends conducting additional research to estimate the avoided T&D cost in each EDC's territory. For the reasons described below, avoided T&D infrastructure expansion should not be included as a TRC benefit and an avoided T&D cost study is not warranted.

First, any avoided T&D infrastructure expansion ultimately reduces the T&D rates paid by customers (or reduces or defers the amount that would otherwise increase). Those T&D rates (actual and projected) are currently accounted for in the TRC avoided costs. Therefore,

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20 In Phase I, PPL Electric did not determine or know the actual incentive amounts paid by the CSP to each customer.

21 *Implementation of Act 129 of 2008 – Total Resource Cost (TRC) Test*, Docket No. M-2009-2108601 (June 23, 2009), *refined by Implementation of Act 129 of 2008 – Total Resource Cost (TRC) Test 2011 Revisions*, Docket No. M-2009-2108601 (Aug. 2, 2011).

including additional benefits for avoided T&D infrastructure would result in double-counting of the benefits in the TRC calculation.

Second, even if the Commission determines that DR reduces the need to build T&D infrastructure and that the reduced T&D rates are not accurately reflected in the TRC avoided costs, it may not be possible to estimate or discern the portion of avoided T&D that is due to DR from the portion that is due to other, more significant, factors such as:

- Replacement of obsolete or damaged T&D equipment;
- Improving T&D reliability and redundancy (as determined by the EDC or by PJM); and
- New customers/load.

Such estimates would likely be very rough at best, arbitrary at worst, and may be "lost in the rounding" compared to other uncertainties, as PPL Electric stated earlier in its comments about price suppression. Indeed as the Amended DR Study points out, measurement of these benefits are challenging[22] and, if measurable, would likely have only a marginal effect on TRC results.[23]

Thus, avoided T&D infrastructure should not be added as a TRC benefit and an avoided T&D cost study is not warranted because the inclusion of T&D rates as a component in TRC avoided costs already accounts for any avoided or deferred T&D infrastructure, and it may not be possible to reasonably estimate the portion of avoided T&D costs attributable to DR because they are likely "lost in the rounding" compared to other avoided cost components and uncertainties.

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22 Amended DR Study, p. 38.

23 Amended DR Study, p. 41.

d. Amortization of DR Fixed Costs over 10 Years.

The Amended DR Study recommends that EDCs amortize certain fixed/initial costs for DR (such as the initial cost of direct load control devices and special meters for load curtailment measurements) over 10 years for the TRC calculations. The Amended DR study concludes that these changes will improve the benefit-cost ratios. However, this amortization will not change the cumulative TRC (over the life of an EE&C Phase). It will merely increase the first year's TRC benefit-cost ratio and reduce subsequent years' TRC benefit-cost ratios. In other words, the cumulative TRC benefit-cost ratio (all years) would not materially change compared to amortizing fixed costs over a single year.[24]

In addition, costs should not be amortized across multiple Phases of Act 129 EE&C. The amortization period should be limited by the duration of an EE&C Phase to accurately align the costs and benefits of measures/programs installed during that particular phase. Otherwise, all of the benefits will be shown in the TRC for the phase in which the measure was installed, while the costs for that same DR program would be counted partially in the TRC for one phase and partially in the TRC for a subsequent phase.[25] Consequently, the method proposed by the Amended DR Study is inconsistent with the method used for energy efficiency measures with a measure life that spans multiple phases. Regardless of the measure life, a measure should be included in the TRC for the phase in which the measure was installed. For example, a measure installed in Phase I should be reflected in the Phase I TRC even though its measure life continues into Phase II, and the Phase II TRC should not include any energy efficiency measures installed in Phase I.

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[24] There may be some minor differences due to present value impacts.

[25] In addition, it may be very difficult for EDCs to track these costs and align them with cost recovery tariffs.

The Amended DR Study also recommends that any DR equipment installed in Phase I and reused in future DR programs should be treated as a sunk cost and, therefore, ignored for future TRC calculations. PPL Electric agrees so long as the entire Phase I cost was included in the Phase I TRC calculation. Otherwise, a portion of that cost would never be reflected in the TRC calculation.

e. TRC Benefit-Cost Ratios Are Overstated in the Amended DR Study

The estimated Phase I benefit-cost ratios in the Amended DR Study are overstated compared to the actual Phase I benefit-cost ratios determined by the EDCs' independent evaluators and provided in the EDCs' Final PY4 Annual Reports. These reports were not available when the Amended DR Study was prepared. Moreover, since the estimated Phase I benefit-cost ratios were used in the Amended DR Study as the "starting point" for determining the benefit-cost ratio of future DR programs (with changes to DR rules and TRC methods), the projected benefit-cost ratios are also overstated.

First, Tables I-7 and I-8 in the Amended DR Study overstate the benefit-cost ratio of PPL Electric's Phase I Direct Load Control ("DLC") program by more than four times. The Amended DR Study estimates a benefit-cost ratio of 0.58 for PPL Electric's Phase I DLC program, including an adder of 0.06[26] for avoided T&D infrastructure benefits. However, PPL Electric's actual Phase I benefit-cost ratio was 0.08 (0.14 with the Amended DR Study's T&D adder). The Amended DR Study then increases the benefit-cost ratio by 0.29 for the price suppression adder (as explained earlier, this adder is inappropriate), and concludes that the benefit-cost ratio of PPL Electric's Phase I DLC program would be 0.87 with T&D and price

[26] $25/kw-year x 18,000 kw of DLC = $450,000 avoided T&D benefits. Total DLC TRC benefits from PPL Electric's PY4 report are $7,473,000. Therefore, the additional benefit-cost ratio from T&D adder is $450,000/$7,473,000 = 0.06. Please note that the Amended DR Study does not include enough detail to confirm the total TRC benefits assumed. Therefore, PPL Electric used the value from its PY4 report.

suppression adders. If the Amended DR Study used the correct, actual benefit-cost ratio for DLC, it would be 0.43 with the T&D and price suppression adders recommended in the Amended DR Study. Regardless, the Phase I DLC program was clearly not cost-effective, even with those adders.

In Table I-8, the Amended DR Study concludes that price suppression benefits for PPL Electric's DLC program will be more than five times greater in Phase III than in Phase I (1.62 compared to 0.29), thereby concluding that the price suppression benefits alone will cause the DLC program to be cost-effective in the future. While there is not enough detail or transparency in the Amended DR study to confirm the price suppression estimate, PPL Electric maintains that it is highly unlikely for PJM price suppression benefits to increase by a factor of five, given that PJM forward prices are relatively flat and the magnitude of any Phase III DR is unlikely to be much greater than actual DR in Phase I.

PPL Electric has a similar concern for the price suppression assumptions used for its Load Curtailment ("LC") Program. Table I-8 estimates that the price suppression benefit-cost ratio will increase more than 11 times, from 0.29 in Phase I to 3.39 in Phase III. In addition, PPL Electric questions how the Amended DR Study concluded that its LC price suppression adder will be the highest of all Pennsylvania EDCs, because PJM local marginal prices ("LMPs") and forward capacity prices are not typically higher than other EDCs within the PJM zones.

There is also insufficient detail in the Amended DR Study for PPL Electric to estimate the benefit-cost ratios for future DLC and LC programs. However, the DLC program is very unlikely to have a cumulative (all years in an EE&C Phase) benefit-cost ratio greater than 1.0 in the future, even with adders for T&D and price suppression as previously explained. In addition, PPL Electric's Phase I DLC program produced approximately 18 MW of peak load reductions and it was difficult to recruit all of those participants. This accounts for a relatively small proportion of PPL Electric's 343 MW of total peak load reductions. Since DLC is likely to be a relatively small contributor of peak reductions in the future, it is not worth implementing such a small program if it is not cost-effective. Instead, PPL Electric could achieve that level of peak load reductions more permanently through cost-effective energy efficiency measures.

f. Bidding Act 129 DR into PJM's Base Residual Auction

The Amended DR Study recommends that EDCs bid Direct Load Control DR into PJM's Base Residual Auction ("BRA" or "forward capacity market"), pass all of the revenue earned from that PJM market back to Act 129 ratepayers, and treat that revenue as a benefit in the TRC calculation. It is not practical or prudent for EDCs to bid DLC, or any other EE&C program, into the PJM BRA for the reasons described below in Section C.3.a.

g. Discontinuing the 100-hour Requirement

The Amended DR Study recommends discontinuing the 100-hour requirement for DR and that any future DR should occur only when needed for reliability or when it is likely to be cost-effective. The Amended DR Study proposes two alternative methods for determining the applicable "trigger" for implementing peak load reductions from Act 129 DR programs. One is based on real-time PJM LMPs that exceed a specified threshold. The other is based on the PJM day-ahead load forecast that exceeds an EDC-specific threshold. Both alternatives would include a maximum number of DR events per year and a maximum number of hours per event. Should the Commission decide to the set additional DR requirements, the day-ahead load forecast alternative is much better than the LMP method for determining when to implement DR, although both methods may result in Act 129 DR events that are not warranted or cost-effective.

First, the day-ahead load forecast "trigger" is specified in advance (such as whenever PJM's day-ahead load forecast for PPL Electric is 6,600 MW or greater) and communicated the day before each operating day. That provides sufficient lead time for the EDC to notify participants to prepare for the DR event, and for the EDC to implement DR programs for the event. The Commission would have to determine if an EDC is required to implement DR during the operating day if the day-ahead load forecast exceeds the "trigger" but the actual load in real-time does not. Even though the actual load reaches the trigger, DR may not be warranted because LMPs could be low and there could be no PJM operational challenges during those times.

In contrast, the real-time LMP trigger is specified in advance (such as whenever the LMP is greater than $300/MWh) but cannot be activated until near "real time" when the actual real-time LMP hits that "trigger" value. That method lacks advance warning and, since LMPs can be very volatile, is subject to starting and stopping DR hourly on a very unpredictable basis. It may also not provide enough advanced notice (at least one to two hours) to notify participants and achieve the desired reductions. In addition, the LMP may be high during periods of mild weather and low loads, due to the loss of generation, transmission constraints, or other factors. In that case, any DR that relies on air conditioning may not be possible because the air conditioners are not in operation or are operating infrequently during the event.

Related to the top 100 hour requirement, the Amended DR Study recommends that any future DLC programs should use a Full Load Reduction scenario and seeks comments about this recommendation. In this scenario, demand savings are determined by multiplying the number of DLC devices by the average kW savings per device. In Phase I, the demand savings for DLC programs were determined by averaging impacts from all hours within the top 100 hours, even if no curtailment event occurred in certain hours. The Amended DR Study further states that the Full Load Reduction scenario would be an appropriate savings calculation methodology because the value of a DR program is the EDC's ability to have load under control when needed.[27] PPL Electric agrees that a Full Load Reduction scenario should apply to any future DLC programs and encourages the use of a stipulated deemed savings value (or a chart of deemed savings values corresponding to specific device cycling rates) in the Technical Reference Manual to provide predictability and transparency and to significantly reduce evaluation costs.

In summary, should the Commission decide to the set additional DR requirements, the day-ahead load forecast alternative is much better than the LMP method for determining when to implement DR, although both methods may result in Act 129 DR events that are not warranted or cost-effective. PPL Electric agrees, however, that a Full Load Reduction scenario should apply to any future DLC programs and encourages the use of a stipulated deemed savings value.

h. Adjust DR Program Incentives to Improve Cost-effectiveness

For future DR programs, the Amended DR Study recommends that EDCs reduce the incentives paid compared to Phase I and concludes that will improve the cost-effectiveness of DR programs in the future. However, PPL Electric believes a determination of the appropriate incentive levels for any measure requires: (1) known program rules (such as eligible measures, eligible participants, number of DR events, duration of events, etc.); and (2) a market potential study with sufficient market research to determine the relationship between incentives and consumers' willingness to participate in DR programs. In any event, the Commission should refrain from recommending incentive levels for any program because that would constrain program design and make it very difficult for the Commission to enforce EE&C compliance if those incentive levels produce insufficient participation or if those incentives are too high.

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27 *See* Amended DR Study, pp. 41-42.

i. Appropriate Estimates for Avoided Generation Capacity

The Commission seeks comments on the appropriate estimates for avoided generation capacity.[28] If the Commission determines that additional DR requirements are appropriate for Act 129 Phase III, the Commission should then seek input for all TRC avoided cost components (energy, capacity, distribution, transmission, escalation factors, etc.) through a TRC Order, not through the DR Study. All of those components should be researched at the same time and with consistent assumptions for future energy market conditions and consistent sources of estimates. In particular, energy cost forecasts have the largest impact on the accuracy of the TRC avoided cost. Therefore, energy cost forecasts should get more focus than other components of TRC avoided cost, such as generation capacity or avoided T&D infrastructure.

j. Demand Response Potential Study

The Commission seeks comments on the merits of conducting a DR Potential Study.[29] As indicated throughout these Comments, additional DR targets are not permissible or warranted. If there are no additional DR targets, there is no need to conduct a DR Market Potential Study.

However, if the Commission determines that additional DR targets are appropriate, those targets must have a sound technical basis and must be determined from a DR Market Potential Study. Otherwise, those targets are merely based on assumptions without a way to confirm whether they are reasonably achievable. In addition, a DR Market Potential Study (and establishing DR compliance targets) must be conducted simultaneously with an Energy Efficiency Market Potential Study (and establishing energy reduction compliance targets) because they are highly inter-related. Similar to the market potential study previously conducted

28 *Demand Response Tentative Order*, p. 31.

29 Tentative Order, page 34.

by the Commission to set Act 129 Phase II compliance targets, the Market Potential Study for EE and DR should determine the following components of "market potential:"[30]

- Technical Potential-- theoretical maximum amount of energy efficiency/DR possible, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end-users to participate in DR/EE programs;
- Economic Potential-- the portion of technical potential that is cost-effective (per TRC Test in PA);
- Achievable Potential-- the portion of economic potential that can be realistically achieved, given market barriers;[31] and
- Program Potential-- the portion of achievable potential that is likely within a constrained cost budget and constrained timing.[32]

2. Act 129 DR Programs Unfairly Compete and Interfere with Free-market DR Programs and the Competitive Retail Energy Market

There are other DR programs currently operating in the competitive energy market, particularly the PJM wholesale market, through Electric Generation Suppliers ("EGSs"), Curtailment Service Providers/DR Aggregators, and PJM. In fact, the Amended DR Study concludes that these competitive market DR programs are "thriving."[33] These competitive market programs existed long before Act 129 EE&C began in 2009. In an unbundled electricity market, such as in Pennsylvania, any mandatory/EDC-subsidized Act 129 DR programs would

30 Statewide Evaluator's Phase II Market Potential Study, page 3.

31 Achievable potential takes into account real-world barriers such as convincing end-users to adopt efficiency/DR measures (could vary considerably depending on program incentive levels), the non-measure costs of delivering programs (for administration, marketing, tracking systems, monitoring and evaluation, etc.), and the capability of programs and administrators to ramp up program activity over time.

32 For this component of market potential, the Commission will have to determine how much of each EDC's total Act 129 budget should be dedicated to energy efficiency programs (and the peak demand reductions that are a by-product of energy efficiency programs) and how much should be dedicated to DR programs. Program potential is the basis for establishing Act 129 compliance targets.

33 Amended DR Study, pp. 4, 56.

inevitably compete and interfere with free-market DR programs and electricity pricing, confuse customers, stifle retail (and wholesale) electric competition, and prevent market actors (such as EGSs and Trade Allies) from developing innovative market-based DR programs and electricity pricing tied to load shaping. In addition, unless Act 129 overpays for that DR, Act 129 DR is unlikely to add significant, incremental cost-effective peak load reductions above those that would be normally provided by the competitive market.

PPL Electric's non-residential customers are very experienced with competitive market DR programs, particularly those offered through PJM. Non-residential customers currently fall into one of the following three general categories:

1. Those who participate (and will participate) in PJM's Emergency Load Response Program (the "PJM Emergency Program");
2. Those who participate (and will participate) in PJM's Economic Load Response Program (the "PJM Economic Program"); and
3. Those who are not interested in any DR.

Adding a fourth category, "Act 129 DR," will not provide any additional DR, will force customers to decide between PJM and Act 129 DR programs (*i.e.,* Act 129 DR and PJM DR would be competing programs), and will merely supplant DR provided by PJM for several reasons.

First, any future Act 129 DR proposed by the Commission is likely to prohibit customers from "double dipping" (*i.e.*, claiming Act 129 reductions if those reductions are also claimed for a PJM DR program).[34] In addition, PJM is currently proposing similar restrictions to Manual 11: Energy & Ancillary Service Market Operations, Section 10: Overview of Demand Response, which will prevent a customer from receiving DR credit from PJM if that DR is achieved from normal operational fluctuations or from a DR program outside of PJM. Since customers (or a

[34] Amended DR Study, p. 66

curtailment service provider/DR aggregator) cannot participate in PJM DR and Act 129, they will have to pick one (possibly as much as three years ahead of time), effectively establishing Act 129 DR and PJM DR as competing DR products.

Second, if a customer elects to participate in an Act 129 DR program instead of the PJM Emergency Program, EDCs would have to submit/bid that DR into PJM's Economic Program in order for PJM to recognize those Act 129 load reductions as "valid" reductions that PJM can include in their planning and operations. However, this will not be possible if the proposed changes at PJM stated above go into effect. Therefore, in order to get greater load reductions than what would have otherwise resulted from PJM's Economic Program alone, EDCs would have to provide greater incentives than PJM, and PJM would have no way of realizing these loads were being curtailed. As a result, the entire amount of Act 129 reductions would not be reflected in any of PJM's planning and operations.

Even if an EDC's Act 129 DR program could attract additional participants above and beyond those in PJM's Economic Program, it would have done so by "overpaying" for those demand reductions above PJM's LMP incentive, an incentive which was approved by FERC as "just and reasonable," or by providing an additional upfront "reservation" incentive as suggested in the Amended DR Study. Since PJM does not pay an upfront "reservation" incentive for its Economic Program, the Amended DR Study acknowledges that Act 129 DR would have to pay more than PJM in order to get participants in the Act 129 DR program. It is counterintuitive to pay more for the same load reductions that would have occurred in PJM absent Act 129 DR. Furthermore, even with those greater Act 129 DR incentives, it may not be possible to determine if those Act 129 incentives produced more demand reductions than would have otherwise occurred in the PJM Economic Program.

Third, many customers (or curtailment service providers/DR aggregators) have already committed to the PJM Emergency Program for 2016/2017 (the first year of the next Act 129 Phase) because those binding bids were cleared in May 2013. By the time the next phase of Act 129 starts in June 2016, customers will have already committed to PJM's Emergency Program through the 2019/2020 delivery year and, therefore, would be ineligible to participate in Act 129 DR. This forces customers to choose (well in advance of each Act 129/PJM delivery year) between an Act 129 DR program or a PJM program, and is akin to "competition" between Act 129 and competitive market DR programs. This will likely cause confusion, frustrate customers, and make it difficult for an EDC to recruit Act 129 DR participants.

Fourth, in unbundled, competitive electricity markets like Pennsylvania, the free-market should determine and provide the appropriate level of DR at the appropriate price. As evidenced in PJM's programs, the level of DR varies widely from year to year based on the competitive market prices for wholesale electricity, retail electricity, and capacity. Subsidized, EDC DR programs serve only to interfere with market price signals and create an unfair playing field with other competitive market actors desiring to provide DR products and services. DR programs should be complementary to and a natural extension of competitive generation service, not part of the electricity delivery service.

For example, EGSs or competitive market curtailment service providers/DR aggregators may want to help customers to "shape their load" and provide:

- Efficient equipment or DR measures in return for lower retail pricing (that each DR participant realizes directly and immediately, and not by long-term market price impacts indirectly realized through Act 129 DR programs);
- Longer-term fixed-price retail electricity contracts;

- Time-of-use or on/off peak pricing; and
- An opportunity to provide other products and services to that customer.

Some of these types of competitive market products are currently underway in PPL Electric's service territory through a DLC-type joint venture between a curtailment service provider and an EGS. These innovative market products and joint ventures are not possible if the DLC program is implemented by the EDC.

The EGS, not the EDC, has the capacity obligation and is the load serving entity for its customers. As such, it should have the ability and the incentive to work with its customers to shape their load and to shift loads from peak periods to off-peak periods when it makes sense. This is especially the case if the EGS offers time-of-use or peak/off-peak pricing that provides an immediate cost savings to participants who shift/reduce their load. DLC programs provide no energy savings or other cost savings to the participant (other than the relatively small $25 - $50 program incentive) unless they have time-of-use or peak/off peak retail electricity rates.

Furthermore, PPL Electric notes that DR is implemented to permanently eliminate or shift end-use load from one period (a high-usage/high-priced period) to another period (a low-usage/low-priced period) for any of the following reasons:

1. To mitigate a system-wide or localized T&D reliability problem or constraint;
2. To reduce the energy costs/peak demand costs for DR participants;
3. To reduce the capacity obligation and costs for DR participants;
4. To reduce the need for long-term capacity resources (additional generating plants); or
5. To "clip" the spot market wholesale prices in a way that will lead to lower forward market wholesale and retail electricity prices for all consumers.

Only item 1 above is a Pennsylvania EDC responsibility. In most situations (except for localized distribution problems) it is directed or coordinated by PJM, including PJM's Economic and Emergency DR Programs, using localized pricing incentives to curtail load. The other four reasons relate to the competitive electricity market, primarily EGSs, merchant generators, curtailment service providers/DR aggregators, and Default Suppliers. In essence, all of these items are directly or indirectly (in the case of the first reason) tied to competitive market mechanisms. Therefore, DR should be part of the competitive market.

3. Logistical, Programmatic, Timing, and Technical Challenges that Inhibit Act 129 DR

Even if future DR programs could be cost-effective, there are too many logistical, programmatic, timing, and technical challenges, risks, and uncertainties to warrant Act 129 DR. This is especially true considering the following:

- The need for potential Act 129 DR participants to decide (and commit) three years in advance whether to commit to PJM or Act 129 DR programs;
- The highly uncertain and volatile future market prices for electricity and capacity;
- The likely need to impose penalties on participants for failing to meet their Act 129 DR commitments (since EDCs would be exposed to penalties from PJM); and
- The exposure to changes in PJM's DR market rules that will ultimately impact any Act 129 DR programs beyond the control of the Commission and the EDCs.

a. Bidding Energy Efficiency and DR into the PJM Base Residual/Forward Capacity Market.

The Amended DR Study recommends that EDCs should bid Direct Load Control DR into PJM's Base Residual Auction ("BRA" or "forward capacity market"), pass all of the revenue earned from that PJM market back to Act 129 ratepayers, and treat that revenue as a benefit in the TRC calculation. Presumably, this would also apply to DR from other Act 129 programs and peak reductions from Act 129 energy efficiency measures because DLC is a very small proportion of total Act 129 peak reductions.[35] However, it is neither practical nor prudent for EDCs to bid DLC, or any other EE&C program, into the PJM BRA for the reasons described below.

First, the PJM BRA is a binding commitment, incurred more than three years in advance of delivery. It will be very difficult for EDCs to accurately predict how many customers it will recruit and the peak load reductions it will achieve from those customers three years ahead of each Act 129 program year. In addition, if an EDC delivers more or less DR than they committed in the PJM BRA, it will incur financial penalties from PJM.[36] EDCs will not accept the financial risk of penalties without the Commission's assurance that those penalties are recoverable via the Act 129 cost rider. To mitigate the risk of penalties, EDCs would likely bid only a small amount of their projected peak reductions into the PJM BRA or impose penalties on their CSPs or Act 129 DR participants for failure to meet their DR commitments. The risk of penalties will make it very difficult to recruit DR participants and certainly is not in the spirit of "voluntary customer participation in Act 129 programs."

Second, in an unbundled electricity market like Pennsylvania, the EDC does not have the capacity obligation for its customers. Therefore, it is unclear whether the EDC or the customer has the legal "ownership rights" to bid the peak load reductions into the PJM BRA (forward capacity market). Those rights would have to be determined "en masse" or for each specific DR participant more than three years ahead of the actual DR reduction, which may not be possible because the EDC will not know the identity of participants that far in advance. Ownership rights

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35 In Phase I for PPL Electric, DLC was 18MW and total peak reductions from all programs were 343MW.

36 PJM has a +/- threshold. Any DR outside of that relatively tight threshold will incur a penalty.

may have to be determined when a customer submits an EE&C rebate form or enrolls in an EE&C/DR program that does not have a rebate form. At that time, the customer would indicate whether they want to retain ownership of AEPS/capacity credits or if the EDC can use them. It is also unclear whether an EDC can unilaterally determine that the EDC owns these rights.

Third, the timing of the PJM BRA limits the opportunity to bid in Act 129 EE&C/DR. PJM BRA bids are due more than three years in advance of the PJM delivery year and each Act 129 program year. Unless EDCs are allowed to commit Act 129 Phase III expenditures well before their Phase III EE&C Plans are approved (probably May 2016) and their Phase III programs launch (June 2016), the earliest Phase III BRA available would be May 2017. The May 2017 BRA is for delivery year 2020/2021, the fifth year of Act 129 Phase III. Also, the Commission would need to determine if EDCs could commit to a BRA in Phase III that is for a delivery year in a subsequent Act 129 phase.

Fourth, the volatility and uncertainty of PJM BRA clearing prices make it very difficult for EDCs to estimate BRA revenues and accurately reflect those revenues in Act 129 EE&C Plans and tariffs. For example, PJM BRA clearing prices varied from approximately $40/MW-day to approximately $245/MW-day for the 2007 through 2016 delivery years.[37]

Fifth, the potential for PJM rule changes creates a high level of risk for Act 129 EE&C programs. If PJM changes its rules, similar to what happened in May 2012 and what PJM recently proposed for Manual 11, those changes could impact Act 129 programs (favorably or unfavorably) and could lead to changes to an EE&C Plan with insufficient lead time to obtain Commission approval. The Commission's and the EDCs' Act 129 EE&C personnel have very limited interface, participation, and influence over PJM rules and procedures. Therefore, no

[37] Figure 2 of PJM's 2016/17 RPM Auction Results, page 16.

direct interfaces should be required between Act 129 programs and PJM's programs. Timing for the Next Phase of Act 129 EE&C.

The timing for the next phase of Act 129 EE&C programs will not permit peak reduction targets to be met by the statutory deadline. Act 129 requires any future DR reduction targets (after Phase I) to be met by May 31, 2017.[38] Assuming that any future DR reduction targets would apply only to summer peak periods, DR targets would need to be met during the June 2016 to September 2016 summer period in order to satisfy the May 31, 2017 statutory requirement. The following schedule would be required for Act 129 Phase III to meet the legislative deadline for DR:

- 6/1/16 – 9/30/16 Act 129 compliance period (peak load reductions must be attained by May 2017 per the legislation and, presumably, occur in the summer only).
- 6/1/16 EDCs must implement DR programs (begin peak load reductions).
- 6/1/15 Award DR CSP contracts. EDCs need 1-year lead time to design programs and recruit participants before the compliance period starts.
- 2/1/15 Issue RFP for DR CSPs.
- 2/1/15 Commission approves EDC's EE&C Plan.
- 10/1/14 EDC submits EE&C Plan for Commission approval.
- 6/1/14 Commission issues Phase III compliance targets and rules. The energy efficiency and DR market potential studies must be completed before June 2014 in order to set Phase III energy efficiency and DR targets. This schedule appears to be unrealistic.

If Phase III does not have any DR targets (*i.e.*, if it has energy reduction targets only), the following schedule would be required for Act 129 Phase III:

- 6/1/16 EDCs begin to implement EE&C programs.
- 3/1/16 Commission approves EE&C Plan.
- 10/1/15 EDC submits EE&C Plan for Commission approval.
- 6/1/15 Commission issues Phase III compliance targets and rules. This is one year later than Phase III with DR. The energy efficiency market potential study must be completed before June 2015 in order to set Phase III targets. This schedule appears to be realistic.

[38] *See* 66 Pa.C.S. § 2806.1(d)(2).

III. CONCLUSION

For the reasons set forth above, PPL Electric Utilities Corporation respectfully requests the Commission (1) exclude DR programs and DR compliance targets from any future Act 129 EE&C Plans; and (2) find that additional Commission studies to determine the viability or to define the scope of future Act 129 DR programs and DR compliance targets are not warranted.

Respectfully submitted,

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