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April 27, 2015

Via Electronic Filing
Rosemary Chiavetta, Secretary
PA Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105-3265

Re: Act 129 Energy Efficiency Program – Phase III
Docket No. M-2014-2424864

Dear Secretary Chiavetta:

Enclosed for electronic filing please find the Comments of the Demand Response Supporters on Tentative Implementation Order with regard to the above-referenced matter. Copies to be served in accordance with the attached Certificate of Service.

Sincerely,

Daniel Clearfield

Daniel Clearfield

DC/lww

Enclosure

cc: Megan Good (megagood@pa.gov)
Kriss Brown (kribrown@pa.gov)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Act 129 Energy Efficiency Program - Phase III	: : :	Docket No. M-2014-2424864

COMMENTS OF THE
DEMAND RESPONSE SUPPORTERS
ON TENTATIVE IMPLEMENTATION ORDER

I. INTRODUCTION

The Demand Response Supporters[1] hereby offer their Comments on the Tentative Order, in the above-captioned docket, entered March 11, 2015 ("Tentative Order"), which proposed required consumption and peak demand reductions for each electric distribution company ("EDC") subject to Act 129,[2] as well as guidelines for implementing Act 129 Phase III Energy Efficiency and Conservation ("EE&C") Plans ("Phase III" or "Plan").[3]

The Demand Response Supporters consist of Comverge, Inc. ("Comverge"),[4] Enerwise Global Technologies d/b/a CPower Corporation ("CPower"),[5] EnergyConnect, a Johnson

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1 The comments expressed in this filing represent only those of the Demand Response Supporters, which is a coalition of providers and supporters of demand response united to overcome barriers to the use of demand response, and do not necessarily represent the views of each particular member.

2 Act 129 of 2008, 66 Pa. C.S. § 2806.1, et seq., as amended ("Act 129").

3 The Commission invited interested parties to submit comments on the Tentative Order. *See* Tentative Order, p. 10, 120, and at Ordering Paragraph 3; *Notice*, 45 Pa.B. 1586 (March 28, 2015).

4 Comverge is focused exclusively on delivering world-class solutions to help electric utilities deploy successful DR, energy efficiency, and customer engagement programs targeting residential and small business customers. Comverge has been an active Conservation Service Provider ("CSP") in Pennsylvania and has served several electric distribution companies ("EDCs") who are in the Act 129 Phase II Programs. For more information, please visit: http://www.comverge.com.

5 CPower is focused on delivering a full spectrum of demand response offerings to commercial and industrial customers across the United States. CPower is one of the largest demand response

Controls Company,[6] and EnerNOC, Inc. ("EnerNOC").[7] The contact information for the Demand Response Supporters is as follows:

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companies in North America. It was formed in November 2014 by combining the commercial and industrial DR businesses of Comverge and Constellation. For more information, please visit: http://www.cpowercorp.com.

6 EnergyConnect Inc., is a wholly owned subsidiary of Johnson Controls, Inc. ("Johnson Controls"). The unit operates as integrated Demand Resources (iDR), and combines the power of building automation, with easy-to-implement DR technology. Johnson Controls is a global diversified technology and industrial leader serving customers in more than 150 countries. Johnson Controls employees more than 2500 people in the Commonwealth of Pennsylvania, and owns and operates several large manufacturing facilities in the state and is member of the large industrial energy users coalition supporting ACT 129 EE&C in phase III For more information go to: www.johnsoncontrols.com.

7 EnerNOC provides demand response software, technology, and managed services to hundreds of clients, including vertically integrated utilities, system operators, transmission and distribution companies, and energy retailers—in both traditionally regulated and restructured markets around the world. For more information, please visit: http://www.enernoc.com/for-utilities/demand-response.

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With these Comments, the Demand Response Supporters (a) support the inclusion of a Low-Income Sector Carve-Out which is important to make sure that all Pennsylvania ratepayers, including low-income customers, benefit from next Act 129 program (b) support the commitment of unspent Phase II dollars, if any, to additional programs in Phase III; and (c) urge the Pennsylvania Public Utility Commission ("PUC" or "Commission") to recognize the significant benefits that will redound to the Commonwealth and its citizens by increasing the role of demand response ("DR") in the next Act 129 program. To do this it should make a number of modifications to its Tentative Order.

First, the Commission should reverse the prohibition on customer participation in both PJM Interconnection LLC's ("PJM") Emergency Load Response Program ("Emergency Program" or "ELRP") and Pennsylvania's Act 129 DR Programs. The two programs complement each other well, and to capture the full range of benefits, dual participation needs to be allowed. The "either-or" decision proposed in the Tentative Order places each DR program in competition with the other, ignoring the different fundamental purposes of each program. PJM's Emergency Program is a Federal Energy Regulatory Commission ("FERC") regulated program intended to address system emergencies and works to ensure system reliability across the PJM footprint.[8] It was not in any way developed to allow the EDC to manage peak loads or for Pennsylvania consumers to manage their distribution-level electricity costs. Moreover, the "no dual participation" requirement appears to be a misreading of the Statewide Evaluator ("SWE") recommendations, which actually indicated that the two programs complement each other and rarely overlap. In the event that a customer participating in both programs was curtailed for the same hour – an unlikely occurrence – the Commission could limit payments to the customer to a single program by directing a refund to the Act 129 program of economic DR payments – if an economic settlement is also made by PJM for the same hour, thus eliminating any legitimate concerns about double counting.

Second, the Commission should provide flexibility and clarification regarding one of the proposed DR program parameters: "Each curtailment event shall last four hours." The Commission could realize incremental value from the DR programs by ordering separate dispatch strategies for residential and Commercial and Industrial ("C&I") customers. Moreover, the Commission should also change the minimum four hour dispatch requirement for residential customers. If any call does not necessitate a four-hour performance than the utility should have the flexibility to limit the request.

Third, the Commission should review the inputs utilized by the SWE in generating the Residential Total Resource Costs ("TRC") in its DR Potential Study and recalculate the TRCs using appropriate data assumptions for Phase III demand response programs. Correcting three issues in the SWE's TRC calculation shows that residential demand response would have TRCs well in excess of 1.0 – **perhaps as high as 2.71** –and generally greater than the TRCs seen from Energy Efficient ("EE") measures.

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8 PJM has the responsibility of ensuring the reliability of the electric transmission system in thirteen states, including Pennsylvania as well as the District of Columbia.

- The TRC for Phase III was calculated from data taken from a program that used the extremely flawed "top 100 hours" program design. Simply correcting for this error would increase the TRC by approximately 1.33 times.
- The Commission has outlined a program where customers will be curtailed a total of six times during a year for four hours each curtailment. As discussed above, it may be more appropriate to curtail residential customers more frequently, but for shorter duration. Making this change would also result in an increased TRC.
- As discussed herein, the Commission should allow residential Direct Load Control ("DLC") programs to be offered into the PJM Emergency Program by the EDCs. If this were allowed, the TRC would need to be adjusted to reflect both (a) the revenue the EDC earns by selling capacity in Reliability Pricing Model ("RPM"), and (b) the cost the EDC avoids by reducing its 5 Coincident Peak ("5CP") hour demand.

Correcting for each of the factors described above individually raises the PPL DLC TRC to 0.95 or higher. Correcting for all of the factors raises the PPL DLC TRC to 1.89.

Fourth, in light of this evidence, and the increased potential for C&I DR if the restriction on dual participation is lifted, the Commission should revise its decision to limit DR programs to just 10% of the overall Act 129 program spend and consider increasing the allocation of Act 129 funds to DR programs to at least 20%. At the very least, it should ask the SWE to recalculate the TRC for DR programs, after adopting the modifications proposed herein and reconsider its program funding allocations in light of those revised findings.

Detailed comments on these recommendations and other relevant issues are set forth herein.

II. BACKGROUND ON DEMAND RESPONSE

A. Demand Response

DR is a mechanism designed to result in a reduction in electricity consumption.[9] Electricity customers can, either individually in the case of large commercial or industrial customers, or in aggregate, provide a substantial amount of DR without significantly affecting their comfort or their businesses (e.g., if a service provider deploys software to enable real-time control of thermostats for air conditioners or hot water heaters).[10] It is simplistic, however, to think of DR as individual customers flipping off a light switch or turning down a thermostat. DR generally involves a new kind of business service, i.e., an aggregator that automates demand-side flexibility for businesses and consumers and offers their aggregated reductions as a block into wholesale markets and utility-based programs.[11]

B. PJM Demand Response Programs

DR programs within PJM, a FERC approved Regional Transmission Organization ("RTO"), are split into two main categories:[12]

- Emergency Program: The Emergency Program functions within the Capacity Market. The Emergency Program is a mechanism by which end-use customers are compensated by PJM for reducing their load from the grid during an emergency

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9 *See* 18 CFR § 35.28(b)(4) (defining demand response as "a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy").

10 *Enernoc, Inc. et al., Petitioners, v. Electric Power Supply Association, et al., Respondents*, US Supreme Court Docket No. 14-841, Petition for a Writ of Certiorari (January 15, 2015), p. 10.

11 *Id.* at 10-11, *citing*, Joel Eisen, *Who Regulates the Smart Grid?*, 4 San Diego J. of Climate & Energy L. 69, 81 (2012-13).

12 PJM State of the Market Report (2014), p. 217, 220. This report is available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014.shtml.

or pre-emergency event.[13] DR participation in this program enhances bulk level reliability and lowers system capacity costs.

- Economic Load Response Program ("Economic Program"): The Economic Program is designed to enable customers to respond to pricing conditions in the wholesale energy market. DR participation in this program lowers wholesale energy costs for all consumers.

As detailed herein, DR participation in these PJM programs increases the competitiveness of the Pennsylvania economy and strengthens the reliability and resiliency of the electric grid.

C. **Phase III Demand Response Proposals**

To prepare for Phase III, the Commission, *inter alia*, directed the Act 129 SWE to perform a Demand Response Potential Study ("DR Potential Study") using certain proposed load curtailment models.[14] The DR Potential Study was highly comprehensive. However, the Commission directed the SWE to exclude dual participation in both state and PJM programs when it performed its load curtailment ("LC") analysis as part of its DR Potential Study.[15]

The SWE submitted its final version of the DR Potential Study to the Commission on February 25, 2015.[16] In the DR Potential Study, the SWE "removed estimates of PJM DR commitments based on historical trends, as well as any potential tied to non-cost-effective DLC measures. These new numbers represented cost-effective potential net of any PJM Emergency Program commitments."[17] Notably, C&I customers participating in PJM's Emergency Program

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13 PJM State of the Market Report (2014), p. 220.

14 *See Energy Efficiency and Conservation Program Final Order*, Docket Nos. M-2012-2289411 and M-2008-2069887, entered February 20, 2014 ("Peak Demand Cost Effectiveness Final Order" or "PDR Cost Effectiveness Determination Final Order").

15 *See* PDR Cost Effectiveness Determination Final Order, p. 56-57.

16 Tentative Order, p. 6, citing, Demand Response Potential for Pennsylvania – Final Report, submitted by GDS Associates, Inc., et al., February 25, 2015 (DR Potential Study).

17 Tentative Order, p. 28.

were excluded to prevent a scenario in which a customer is compensated by both PJM and an EDC for the same curtailment hour(s).[18] The SWE noted:

> "This need for mutual exclusivity is contentious as the mechanisms of producing benefits to ratepayers of the Commonwealth differ somewhat between the programs. PJM uses DR to meet the reliability requirement for a given year. The prospective Act 129 program relies on actual load reductions in a given year lowering resource requirement in future years."[19]

The DR Potential Study was released publicly via Secretarial Letter served February 27, 2015.[20] In that letter, the Commission indicated that it would solicit formal comments on the DR Potential Study through its Phase III implementation proceeding.

The DR Potential Study largely influenced the Tentative Order,[21] which was issued about two weeks after the Commission received that Study and the final Energy Efficiency Potential Study[22] ("EE Potential Study"). To wit, the Commission proposed the following allocation of peak demand reduction requirements between EE and DR:

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18 Tentative Order, p. 25.

19 DR Potential Study, p. 9, 65.

20 *See Release of the Act 129 Statewide Evaluator Energy Efficiency and Demand Response Market Potential Studies and Stakeholder Meeting Announcement* Secretarial Letter, at Docket No. M-2014-2424864, served February 27, 2015 (EE Potential Study).

21 *See, e.g.,* Tentative Order, p. 25-39.

22 Tentative Order, p. 7. *See Energy Efficiency Potential for Pennsylvania – Final Report*, submitted by GDS Associates, Inc., *et. al.*, February 2015; *Release of the Act 129 Statewide Evaluator Energy Efficiency and Demand Response Market Potential Studies and Stakeholder Meeting Announcement* Secretarial Letter, at Docket No. M-2014-2424864, served February 27, 2015 (EE Potential Study).

EDC	Funding Scenario (EE/DR) (%)	5 Year DR Spending Allocation (Million $)
Duquesne	90/10	$9.77
PECO	90/10	$42.70
FE: Penn Power	90/10	$3.33
FE: West Penn Power	90/10	$11.78
FE: Met-Ed	92/8	$9.95
PPL	95/5	$15.38
FE: Penelec	100/0	$0.00
Source: Tentative Order, p. 36, 42; DR Potential Study, at Table 7.		

In its Tentative Order, the Commission proposed the following DR program design for Phase III Implementation:[23]

- Curtailment events shall be limited to the months of June through September.
- Curtailment events shall be called for the first six days that the peak hour of PJM's day-ahead forecast[24] for an EDC is greater than 96% of the EDC's PJM summer peak demand forecast[25] for the months of June through September each year of the program.
- Each curtailment event shall last four hours.
- Each curtailment event shall be called such that it will occur during the day's forecasted peak hours.
- Once six curtailment events have been called in a program year, the peak demand reduction program shall be suspended for that program year.
- Compliance will be determined based on the average MW performance across all event hours in a given program year.
- Customers participating in PJM's ELRP shall not be eligible to participate.

23 Tentative Order, p. 37-38.

24 The Commission is proposing to use the PJM 7-day load forecast.

25 The Commission is proposing to use Table B-1 of the annual PJM Load Forecast Report.

III. COMMENTS OF THE DEMAND RESPONSE SUPPORTERS

Robust DR participation in Phase III will benefit all Pennsylvania electric customers and the Commonwealth. A successful statewide DR program will avoid millions of dollars in transmission & distribution ("T&D") costs, reduce peak period energy prices, lower emissions, positioning Pennsylvania well for the Clean Air Act ("CAA") Section 111 (d) compliance,[26] and exert downward pressure on forecasts of summer peak demand, reducing the generation capacity required to meet PJM's reliability requirements.[27] The program as outlined in the Tentative Order represents an improvement over the Phase I programs. However, as detailed below, critical modifications are necessary to increase the overall effectiveness of the program and attract customer participation.

A. Allow Dual Participation in PJM's Emergency Program and the Act 129 DR Program

Most importantly, the proposed prohibition on dual participation in the PJM Emergency Program and Act 129 programs should be reversed because it would deprive all Pennsylvania consumers of significant benefits and because the PJM Emergency Program and Act 129 DR program delivers separate, incremental value streams to Pennsylvania consumers. In sum, the two programs complement each other well, and to capture the full range of benefits, dual participation needs to be allowed.

On its face, the prohibition will force end-user customers to make a choice between participation in the Act 129 Phase III DR program or PJM's Emergency Program. This "either-

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26 On June 18, 2014, the US Environmental Protection Agency ("EPA") proposed new regulations governing greenhouse gas ("GHG") emissions from existing power plants for the states. The EPA's proposed CAA Section 111 (d) regulations represent a far-reaching first step in controlling GHG emissions on a national basis. *See* Preamble and Proposed Rule at 40 CFR Part 60 published at 79 FR 34830 (June 18, 2014).

27 DR Potential Study, p. 2, 17, 23, 25.

or" decision places each DR program in competition with the other,[28] ignoring the different fundamental purposes of each program. PJM's Emergency Program is a FERC regulated program intended to address system emergencies and works to ensure system reliability across the PJM footprint. It was not in any way developed to allow the EDC to manage peak loads or for Pennsylvania consumers to manage their distribution-level electricity costs. In comparison, Act 129 and the Phase III DR Program is a peak load shaving program that is focused on conservation and reducing overall costs for Pennsylvania EDCs and Pennsylvania electricity customers. The goals of each program are exclusive of one another, as are the trigger mechanisms. Forcing EDC's to compete with PJM for participants is neither cost effective, nor beneficial to ratepayers in the Commonwealth.

If customers choose the PJM Emergency Program over the Act 129 Program, then they will only be dispatched during system emergencies, which typically average three to five hours a year. Therefore, they will not be dispatched to reduce load during the majority of the 24 peak hours of the year, as contemplated in the Tentative Order. Consumption during peak hours requires additional infrastructure, as typically 10% of electric costs are caused by consumption in 1% of the hours. Without reductions during these peak hours, millions of dollars in T&D costs will be incurred that could have been avoided if dual participation were allowed. The potential avoided T&D costs from Act 129 are summarized in Table 1-3 of the SWE DR Potential Study, and are reproduced below:[29]

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28 *See* PDR Cost Effectiveness Final Order, p. 57.

29 DR Potential Study, p. 4 at Table 1-3.

EDC	Average T&D Avoided Cost per kW/year for 2016	Average Transmission Only Avoided Cost per kW/year for 2016
Duquesne	$40.88	$40.88
FE: Met-Ed	$40.98	$14.77
FE: Penelec	$40.98	$14.77
FE: Penn Power	$40.98	$14.77
FE: West Penn	$40.98	$14.77
PECO	$49.27	$3.88
PPL	$20.10	$0.00

Also, while DR in the PJM program meets supply needs for that delivery year, it does not reduce capacity requirements for future years. As noted by the SWE, by dispatching DR during the hours that determine PJM's future capacity requirement, the Act 129 programs reduce future capacity needs. "PJM uses DR to meet the reliability requirement for a given year. The prospective Act 129 program relies on actual load reductions in a given year lowering resource requirements in future years."[30] In fact, if PJM calls an emergency event during one of its calculated 5CP hours, it will add back any load reduction it called in that hour when calculating the next year's PLC.[31] Peak period reductions in Act 129 programs can also serve to lower wholesale energy costs during the most expensive periods of the year.

Moreover, if customers only participate in the PJM program, they will be consuming during peak hours, requiring the heaviest emitting generators to be dispatched. This will

30 DR Potential Study, p. 9.

31 PJM Tariff. Attachment K, Section 8.9, p 1998 "Actual Emergency Load Response, Pre-Emergency Load Response and Economic Load Response load reductions for Load Management resources registered as Emergency Load Response or Pre-Emergency Load Response Full Program Option or Capacity Only resources which occur from June 1 through September 30, will be added back for the purpose of calculating peak load for capacity for the following Delivery Year…"

complicate Section 111 (d) compliance. If they participate in both PJM and Act 129, customers will reduce usage during these peak periods, lessening dependence on these generators and facilitating Section 111 (d) compliance.

On the other hand, if customers choose to participate solely in the Act 129 programs, Pennsylvania customers will lose out on well-documented bulk level reliability and cost-savings benefits of customer participation in the PJM program. To its immense credit, the PUC has repeatedly recognized these benefits and has helped lead the fight to preserve customer participation in the PJM DR program in light of recent legal challenges. It would be puzzling and counterproductive if the PUC then created a deterrent to realizing those benefits.

Regarding reliability benefits, the Act 129 programs are not dispatched in response to system contingencies. Therefore, if customers chose Act 129 over PJM, during events like the Polar Vortex or unexpected generator outages, or system challenges experienced just last week in the Penelec service territory or wide-spread challenges as experienced in September 2013, PJM would not have DR at its disposal to prevent brownouts and blackouts. PJM has noted the importance of having DR available during such periods:

> "Although demand response is usually only needed by grid operators in the summer, operators also successfully deployed it during the power emergencies occasioned by the bitter cold "Polar Vortex" weather in January 2014. As PJM set multiple winter peak records early that month, it called on demand response, and received more megawatts as load reductions than it could obtain as generation from all but the very largest generating stations. In the midst of those challenging conditions, demand response – responding to PJM's dispatch as a wholesale market resource – helped maintain the reliability of the system."[32]

Further, DR participation in PJM forces market competition, and has saved billions of dollars for Pennsylvania customers. The PJM Independent Market Monitor ("IMM") reported

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[32] *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events*, 19-21 (May 8, 2014).

that DR participation in the 2013/14 PJM Reliability Pricing Model Base Residual Auction resulted in a savings of $11.8 billion to all customers in the PJM region for that one year[33] The IMM also estimated that removing DR resources from PJM's capacity auction would cost customers approximately $9 billion in the 2017/2018 delivery year.[34] These cost savings drive economic competitiveness in Pennsylvania. Using publicly available data, the Demand Response Supporters estimate that Pennsylvania electric customers realized over $2 billion in annual savings from demand side participation in PJM's capacity market.[35] The Demand Response Supporters estimate that during the current PJM delivery year (2014/15) the 5,300 DR participants that operate in Pennsylvania are earning over $100 million for their participation.[36]

The Commission has explained that this "dual participation" prohibition is aimed at preventing "the payment of Act 129 EE&C Program funds to a customer for an event during which the customer was already curtailing due to signals from PJM (and subsequently receiving payment from PJM)."[37] However, the PUC has addressed this issue in the Tentative Order, as

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33 *Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated*, September 20, 2010, p. 52. This document is available at: http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf.

34 *Analysis of the 2017/2018 RPM Base Residual Auction (2014), p.* 6. This document is available at http://www.monitoringanalytics.com/reports/Reports/20 14/IMM_Analysis_of_the_20 17 2018_RPM_Base_Residual_Auction_20141006.pdf.

35 To wit: as noted, in 2013-14 alone, DR saved consumers in the mid-Atlantic region $11.8 billion. Those savings resulted from a total of 10,416 unique MWs, of which 21.77% (or 2267.3 unique MWs) were located in Pennsylvania. *See* PJM 2014 Demand Response Activity Report, p. 3-5 at Figure 1. 21.77% of $11.8 billion results in savings of $2,568,561,828 attributable to unique MWs in Pennsylvania.

36 For example: capacity payments to demand response resources were $632.8 million in 2014. See 2014 State of the Market Report for PJM, p. 217. Those payments resulted from a total of 10,416 unique MWs, of which 21.77% (or 2267.3 unique MWs) were located in Pennsylvania. *See* PJM 2014 Demand Response Activity Report, p. 3-5 at Figure 1. 21.77% of $632.8 million results in payments of $137,744,570 attributable to unique MWs in Pennsylvania.

37 Tentative Order, p. 38. *See also* PDR Cost Effectiveness Final Order, p. 65.

customers will not receive energy payments from Phase III of Act 129. (Energy payments composed a significant portion of Phase I revenue.) Given this modification, the Demand Response Supports believe that dual participation can't result in double payments. However, if the PUC still has concerns in this regard, the Demand Response Supporters are confident that an agreeable solution can be found that is far less harmful than banning dual participation.

For example, if the PUC is concerned about increased potential overlapping dispatches between the PJM economic program and Act 129 program, energy payments received from the PJM economic program that coincide with Act 129 dispatches could be subtracted from Act 129 revenues, and be distributed to ratepayers. That being said, and as highlighted above, PJM dispatches and Act 129 dispatches will rarely overlap. PJM typically dispatches for 3 to 5 hours per year, compared to 24 expected hours for Act 129. It would be unfortunate to ban dual enrollment because of potential overlap for a potential couple hours every year.[38] Such a ban would be more in line with the stated intent quoted above from the PUC.[39] But banning dual participation altogether far exceeds the stated intent.

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38 It should also be noted that, having voluntarily agreed to participate in the PJM DR programs, it would not appear that the Commission has the authority to selectively prohibit such participation for certain customers.

39 Indeed, it would be reasonable to conclude that payments from both programs for the same curtailment are reasonable. The Demand Response Supporters are sensitive to the concern that customers only pay once for each service, but the Commission needs to recognize that when two services are being provided, and there is no way to be sure ahead of time that both will overlap, it is appropriate to pay for those services separately. That being said, the prohibition on multiple payments is based on the flawed conclusion that customers receive compensation for same service. The Emergency Program and Act 129 Peak Load Management programs are not the same, and seek different services from ratepayers. It is both reasonable and prudent for ratepayers to be paid for each service they provide If the ratepayer satisfies the differing program requirements, and meets the very different performance criteria, that ratepayer should be paid for each service provided (peak saving and/or emergency response). That reality is that dual payments would not be a frequent occurrence. There is not a perfect correlation between PJM emergency DR event days and either customer-specific or coincident system peak hours. This should be unsurprising, as the programs are intended, as noted above, to target different things. PJM system emergencies can occur during peak periods, but they can also occur during shoulder

Importantly, support for the prohibition cannot be found in the DR Potential Study as the SWE actually did not recommend a prohibition on participation in PJM's Emergency Program. In fact, the SWE presented criteria to reach "incremental" benefits, i.e., benefits that go beyond the benefits related to participation in PJM's DR programs. In other words, the SWE contemplated dual participation, and intended for the Phase III DR program to **complement** PJM's DR programs not replace them. To wit, the SWE stated:

- This approach does not account for the differences in dispatch frequency, duration, and notification between the PJM emergency program and a potential Act 129 program. That is, the same customer may commit more load reduction to the PJM emergency program because of the historically infrequent dispatch compared to an Act 129 program where dispatch is expected to be more frequent. Conversely, the additional notification time of an Act 129 day-ahead or day-of program could attract larger commitments from customers because of the ability to schedule processes around event dispatch.[40]
- The SWE Team believes a day-ahead notification program is the most logical option for an Act 129 load curtailment program. In addition to having the largest load reduction potential, it is most different from the PJM Emergency DR product, which is very much a Fast Response program. Offering a different DR product could appeal to customers with different DR preferences and make the two programs more complimentary than competitive. [41]

So, clearly, the parameters evaluated by the SWE can be – and were intended to be – layered on top of the PJM programs.

Eliminating the prohibition on dual enrollment would create significantly more DR potential and competition in the market, as evidenced in the SWE report. For example, as seen below, for 2018, the DR potential net of PJM commitments is 1,139 MW. The DR potential without PJM commitments would be 3,224 MW, a difference of over 2,000 MW. Since there are

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peak periods, as indeed occurred across PJM in September 2013 and in the Penelec service territory April 2015.

40 DR Potential Study, p. 86.

41 DR Potential Study, p. 87.

several areas of the Commonwealth in which there are likely to be no DR deployment if the dual participation ban is maintained, revising the prohibition will enhance the chances that customers throughout the Commonwealth will be able to participate in the Act 129 programs. This will also ensure that the EDCs can reasonably meet peak reduction goals.

Table III-1: Day-Ahead MW Potential Net of Projected PJM Commitments[42]

EDC	2016 (PY8)	2017 (PY9)	2018 (PY10)	2019 (PY11)	2020 (PY12)	TRC Ratio
Duquesne	319	324	323	321	318	1.94
FE: Met-Ed	50	52	51	49	48	1.90
FE: Penelec	-33	-31	-36	-41	-46	0.0
FE: Penn Power	67	68	66	64	62	1.93
FE: West Penn	153	157	154	155	155	1.94
PECO	494	499	488	474	460	1.69
PPL	93	99	94	95	95	1.88
Statewide	**1,142**	**1,168**	**1,139**	**1,117**	**1,091**	**1.78**

Table III-2: Day-Ahead MW Potential Net of Current PJM Commitments[43]

EDC	2016 (PY8)	2017 (PY9)	2018 (PY10)	2019 (PY11)	2020 (PY12)	TRC Ratio
Duquesne	281	268	427	426	423	1.94
FE: Met-Ed	-48	-32	266	264	263	1.90
FE: Penelec	-166	-90	262	257	252	1.92
FE: Penn Power	-3	53	123	121	119	1.93
FE: West Penn	120	-10	498	499	499	1.94
PECO	392	448	917	903	889	1.69
PPL	-269	50	731	732	731	1.88
Statewide	**306**	**687**	**3,224**	**3,202**	**3,175**	**1.82**

The issue of dual participation is slightly different for residential customers. The vast majority of these customers are not comparing offers and making a choice of whether to enroll in the PJM Emergency Program or their EDC's Act 129 program. Given the size of their individual

42 DR Potential Study, p. 87 at Table 6-9.

43 DR Potential Study, p. 87 at Table 6-10.

load, they cannot enroll in the Emergency Program except as part of an aggregation of many customers, and the Act 129 DLC programs are likely to be the only aggregation they are recruited to join.

Therefore, the relevant question for residential customers is not whether they should be allowed to participate in both the PJM Emergency Program and an Act 129 program; instead, the relevant question is how the EDC operating a residential Act 129 program should be allowed to make use of the program to generate maximum benefits for all ratepayers. The Demand Response Supporters urge the Commission to allow the EDCs to: (a) enroll the program in the PJM Emergency Program, indicating a willingness to respond during emergency events, so that ratepayers benefit from revenue directly in PJM's capacity auctions; and (b) allow the EDC, at the same time, to dispatch the asset to reduce load during likely 5CP hours to reduce their purchase obligation in RPM in future years. This is fully consistent with PJM's RPM market design and is the method that EDCs in neighboring states employ to realize maximum value from their residential demand response programs.

Note that residential customers are typically compensated by their EDC with a flat annual incentive payment for their participation. Thus, any revenue accrued from the Emergency Program can be pooled with any cost savings resulting from targeting 5CP hours to reduce rates for all Pennsylvania ratepayers.

New York is an example of a jurisdiction that allows the same customer to participate in both the wholesale emergency program , or "Special Case Resources" ("SCR") and distribution level utility programs, mainly the Con Edison Distribution Load Relief Program[44] ("DLRP") and

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[44] Rider U to Con Ed's Electric Tariff (PSC No. 10), which is available at: http://www.coned.com/rates/elec.asp.

Commercial System Relief Program[45] ("CSRP"). CSRP is most analogous to the Act 129 programs, as both are dispatched when the forecasted load is at 96% of peak. The New York Public Service Commission has recognized the distinct and additive value streams of these programs, and recently issued an Order to all of the utilities in New York to create programs similar to Con Ed's.[46] This is not surprising, given that Con Ed's most recent annual report highlighted their programs achieved a TRC of 1.69 in 2014 and was projected to deliver $200 Million in net benefits.[47] While avoided T&D costs are high in New York, the incentive payments for DLRP and CSRP are also much higher than those proposed in Pennsylvania. Therefore, dual participation in Pennsylvania should achieve a similarly high if not higher TRC than the Con Ed programs.

With distinct but additive value streams, the PJM and Act 129 programs are a strong complement for each other, and dual participation should be allowed. Prohibiting dual participation would deny Pennsylvania consumers millions of dollars in net benefits.

The "dual participation" prohibition is also unjust to ratepayers. All ratepayers pay a generation charge, which includes costs for energy and capacity procured through PJM. All ratepayers also pay an Act 129 surcharge.[48] Without dual participation, if less PJM participation

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45 Rider S to Con Ed's Electric Tariff (PSC No. 10), which is available at: http://www.coned.com/rates/elec.asp.

46 On December 11, 2014, the New York Public Service Commission ordered each utility to develop a demand response tariff and to participate in ongoing collaborative efforts to develop dynamic load management measures similar to those at implemented by Con Ed. *See Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs*, New York Public Service Commission Case 14-E-0423, Order Instituting Proceeding Regarding Dynamic Load Management And Directing Tariff Filings (entered December 15, 2014); 2014 N.Y. PUC LEXIS 380.

47 *Proceeding on Motion of the Commission to Consider Demand Response Initiatives*, New York Public Service Commission Case Nos. 09-E-0115 *et al.*, Con Ed Report On Program Performance And Cost Effectiveness Of Demand Response Programs (filed December 1, 2014).

48 66 Pa. C.S. § 2806.1.

occurs, the result will be ratepayers paying a higher price for capacity than would otherwise be necessary. In fact, for many customers, the capacity component is a significant cost, and they should have every opportunity to mitigate that charge for themselves and other ratepayers and earn payments from DR programs for the service that they provide to the EDC (peak shaving) and/or PJM (emergency response). Additionally, it should be clear that said prohibition runs counter to the fundamental premise of Act 129 – reducing costs and prices by, *inter alia*, providing tools for ratepayers to reduce their total energy and capacity costs – by unduly creating barrier to participation in otherwise available programs.

The Demand Response Supporters submit that increased incentives will be required if dual participation is prohibited in Phase III. If dual participation is prohibited, customers will almost certainly choose to participate in the PJM program instead of Act 129 Phase III. This would minimize the effectiveness of the programs and severely inhibit an EDC's ability to meet Act 129 Phase III peak reduction goals. The suggested incentive prices in the SWE DR report will compete directly with the incentive prices for the more established PJM Emergency Program (if dual participation is not permitted).

PJM ELRP (Emergency Dispatch)

PJM Zone	MW*	Number of Annual DR Events					Avg. Event Duration	Incentives ($/MW-yr**)
		2010	2011	2012	2013	2014		
DUQ (Duquesne Light)	244.7	-	1	-	1	-	4h	$33,138
METED (FE: Met-Ed)	348.6	-	1	-	1	-	3h 33m	$56,157
PENELEC (FE: Penelec)	525.6	-	-	1	1	-	2h 53m	$56,157
ATSI (FE: Penn Power)	1,763.70	N/A	-	-	5	-	3h 24m	$33,349
APS (FE: WPP)	935.5	2	-	-	-	-	5h 30m	$33,138
PECO (PECO)	801.8	1	1	1	2	-	2h 57m	$57,998
PPL (PPL)	1,155.00	-	-	-	2	-	2h 53m	$56,157

* 2015/2016 BRA Cleared MW

** Average clearing prices, 2010-2014

Act 129 Phase III - Tentative Order Program Design (Peak Shaving)

EDC	MW	Proposed Number of Annual DR Events (Max.)					Avg. Event Duration	Incentives ($/MW-yr***)
		2016	2017	2018	2019	2020		
Duquesne Light	42	-	6	6	6	6	4h	$47,581
FE: Met-Ed	49	-	6	6	6	6	4h	$41,535
FE: Penelec	-	-	-	-	-	-	-	-
FE: Penn Power (ATSI)	17	-	6	6	6	6	4h	$40,067
FE: WPP (APS)	64	-	6	6	6	6	4h	$37,649
PECO	166	-	6	6	6	6	4h	$52,615
PPL	92	-	6	6	6	6	4h	$34,195

*** Calculation: (Annual EDC Budget minus Administration Costs (10%) / (Target MW plus a Reserve Margin of 10%)

The number of events, event duration, and customer expectations for DR payments are set by experience in PJM's Emergency Program. That is not the case for the Act 129 Phase III program. Customers will be reluctant to choose participation in the Act 129 Phase III DR program when the financial incentives are equivalent or less than PJM's Emergency Program but the curtailment expectations are higher. Accordingly, if dual participation is not accepted by the Commission, the Demand Response Supporters recommend an increase in the per MW incentive payments to better compete with PJM. Otherwise, all Pennsylvania electric customers will not gain the benefits of DR participation in Phase III, including lower capacity requirements, avoided T&D costs, and reduced emissions.

B. The Demand Response Supporters Generally Endorse the DR Dispatch Parameters but Support Additional Implementation Flexibility

The DR program design proposed by the Commission targets peak shaving curtailments. As proposed, DR resources would be "called" upon by the EDC,[49] in the Summer months (June

[49] The Tentative Order is not clear on who would be "calling" curtailment events under the Phase III DR programs. However, given the Commission's intention to create a program that operates

to September), when the peak hour of PJM's day-ahead forecast for an EDC exceeds a specified threshold of the EDC's PJM summer peak demand forecast.[50] Each curtailment event is proposed to last four hours, and occur during the day's forecasted peak hours.[51] For each year, the DR program will end once six curtailment events have been called.[52] The proposed program design for Phase III as it relates to dispatch parameters is vastly improved over the Phase I program design, but the Commission should allow additional flexibility. Specifically, the Commission should consider changing the minimum four hour dispatch requirement for residential customers.

During a four hour dispatch, consumption might dip below the day-ahead forecast exceeding 96% of system peak. It is possible that the forecast will exceed the threshold for only an hour, or not at all. If any call does not necessitate a four-hour performance than the utility should have the flexibility to limit the request. There is no need to push demand resources to perform above and beyond what is necessary. In many instances reducing the duration of the call may reduce any potential resource fatigue and will not interfere with the overall goals of the program.

As a tradeoff to that flexibility, residential customers can be curtailed on different schedules than C&I customers. Given the technologies available for curtailing load at residential properties, it is possible to curtail those customers more frequently but for shorter periods, without any consumer discomfort. Taking this approach with residential customers would significantly increase the likelihood of load being reduced during PJM's 5CP hours and

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"independent of and separate from" the PJM wholesale markets (Tentative Order, p. 33), we read the program design as requiring the EDC (as opposed to PJM or the Commission) to "call" curtailment events under the proposed program design.

50 Tentative Order, p. 37-38.

51 Tentative Order, p. 38.

52 Tentative Order, p. 38.

simultaneously decrease the risk of participant fatigue and churn out of the program. It should be clear, however, that this "more events/shorter duration" approach is not appropriate for business customers. That segment is financially impacted with every curtailment, and the current framework of proposed dispatches is appropriate for the C&I market.

Specifically, if the Commission were to issue an order whereby residential customers could be curtailed 12 times in a summer, but for no more than two hours in each curtailment, the SWE report[53] estimates that the program would capture 70% of the 5CP hours. The SWE report analyzed various permutations of dispatch criteria, event start times, end times, durations and number of events. Under the current program design, the SWE report calculated based on historic information that the program would only capture 57.5% of the 5CP hours.

Clearly, the Commission could realize incremental value from the DR programs by ordering separate dispatch strategies for residential and C&I customers. Not only would this bifurcated approach yield a higher intrinsic value of the programs, it also would give customers a program that is more suited to their specific needs. The Commission recognizes differences between residential customers' needs and desires and C&I customers' needs and desires in many different areas within its jurisdiction. The Commission should recognize those differences here and order programs that generate the highest value while balancing the customers' needs. By way of a specific example, residential demand response programs could be called if the system peak is forecast to be greater than 96% of the forecast as envisioned by the Commission in its Tentative Order. Then, if the EDC calculates that the deployment of residential resources lowers the forecast peak to below 96%, there would be no reason to call the C&I customers. If the load forecast considering the residential deployment remains above 96%, then the C&I resources

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[53] DR Potential Study, p. 31 at Table 2-8.

could be curtailed. This bifurcated strategy would increase program TRCs, increases customer satisfaction for both C&I and residential customers and give the EDCs some operational flexibility.

C. The TRC Analyses for Residential Programs Presented in the SWE Report Should Be Reconsidered

Should the current tentative order and SWE analysis stand, Pennsylvania will be the lone state across the country to find that residential demand response does not meet a standard cost-effectiveness test. Correcting three issues in the SWE's TRC calculation shows that residential demand response would have TRCs well in excess of 1.0 and generally greater than the TRCs seen from EE measures.

The most significantly flawed piece of data used to calculate the TRC for Phase III is the kW factor, or the kilowatts of reduction recognized per air conditioner. When the SWE reviewed Phase I results, it used hours of air conditioning load reductions during the "top 100 hours" of demand. These included hours when curtailments were not called (even when the hours subsequently turned out to be part of the top 100 hours), when curtailments were called but not needed (because the hour turned out not to be part of the top 100 hours) and perhaps when air conditioners were not even running. The SWE calculated a kW factor of 0.63 kW of load reduction per air conditioner in the PPL territory and used that number to project the TRC of the residential program in the PPL territory going forward. This amounts to taking the results of the flawed program design of Phase I and assuming that the same mistakes would be made in Phase III.

If the assumption for Phase III is that demand response will be called only when the day-ahead forecasted load is 96% of the projected annual peak (as the Commission has proposed), it is extremely likely (in fact a near certainty) that the curtailment events will be called on a day when the temperatures and humidity in the zone are high and air conditioners will be running. In fact, it is highly likely (almost certain) that air conditioning load will be the driving force behind the forecast peak above that 96% threshold. But the SWE made no adjustment to the kW factor in the TRC analysis to account for such drastically different program designs.

Post Phase I PPL data provides a useful indication of a more reasonable kW factor. Because the residential demand response program in the PPL service territory was a functioning asset beyond Phase I, the program was continued in a "deregulated" manner outside the province of Act 129. During that period, the DR assets realized a kW factor of 0.84 when dispatched during the CP hours. Simply increasing the kW factor from 0.63 to 0.84 would increase the TRC by approximately 1.33 times.

Table A: TRC for PPL Direct Load Control with Revised kW Factor

		SWE Calculation	Revised Calculation
		[a]	[b]
Present Value of Benefits per kW	[1]	$965	$965
kW Realized per Participant	[2]	0.632	0.840
Present Value of Benefits per Participant	[3]	$610	$810
Present Value of Costs per Participant	[4]	$801	$801
TRC	[5]	0.761	1.011

Notes

[1] SWE Report pp. 61 and 63; (PV Penefits)/(Program Participants)/(Central A/C kW factor)
[2][a] SWE Report p. 61
[2][b] Result from open market operation of PPL load control switches
[3] = [1] * [2]
[4] SWE Report p. 63; (PV Costs)/(Program Participants)
[5] = [3] / [4]

Second, the Commission has outlined a program where customers will be curtailed a total of six times during a year for four hours each curtailment. As discussed above, it may be more appropriate to curtail residential customers more frequently, but for a shorter duration. This strategy accomplishes three goals. Initially, as discussed above, it increases the likelihood of capturing the 5CP hours, while increasing customer satisfaction (less discomfort). Additionally, it allows for a more rigorous "cycling" of air conditioners. All of these outcomes can result in an increased TRC.

From a customer comfort perspective, a homeowner should be nearly neutral about a 50% cycling strategy for four hours and a 100% cycling strategy for two hours. All else being equal, the comfort level in the home should be the same at the end of these respective scenarios. The Demand Response Supporters do not suggest a 100% cycling strategy for two hours, but rather use it only as a reference point. If the curtailment approach is increased from 50%, which is typical under residential demand response program, to 75%, the resulting change in TRC would be an increase of 1.5 times and the customers are likely to be more comfortable at the end of the event than they would be in the scenario outlined in the tentative order.

Table B: TRC for PPL Direct Load Control with 75% Cycling Strategy

		SWE Calculation	Revised kW Factor	Revised Cycling Level
		[a]	[b]	[c]
Present Value of Benefits per kW	[1]	$965	$965	$965
kW Realized per Participant	[2]	0.632	0.840	1.260
Present Value of Benefits per Participant	[3]	$610	$810	$1,215
Present Value of Costs per Participant	[4]	$801	$801	$801
TRC	[5]	0.761	1.011	1.517

Notes

[1] SWE Report pp. 61 and 63; (PV Penefits)/(Program Participants)/(Central A/C kW factor)
[2][a] SWE Report p. 61
[2][b] Result from open market operation of PPL load control switches
[2][c] Revised to reflect 75% cycling strategy [= [2][b] * (75% / 50%)]
[3] = [1] * [2]
[4] SWE Report p. 63; (PV Costs)/(Program Participants)
[5] = [3] / [4]

Finally, and as discussed above , the Commission should allow residential DLC programs to be offered into the PJM Emergency Program by the EDCs. If this were allowed, the TRC would need to be adjusted to reflect both (a) the revenue the EDC earns by selling capacity in RPM, and (b) the cost the EDC avoids by reducing its 5CP demand. The former is already effectively included in the TRC presented by the SWE, since the SWE assumes that Act 129 capacity will lead to a 1:1 reduction in the amount of capacity EDCs are obligated to purchase. The latter benefit can be accounted for by: (1) multiplying the SWE's projected annual capacity benefit by the 70% of 5CP hours that are expected to hit based on the 12-2 strategy outlined in Section II.B above and (2) adding that value to the TRC benefits presented by the SWE.

Table C: TRC for PPL Direct Load Control with PJM Revenue and 5CP Targeting

TRC Reported by SWE (includes value of RPM revenue)			
Present Value Benefits	[1]	$48,813,983	SWE Report p. 63
Present Value Costs	[2]	$64,151,543	SWE Report p. 63
TRC	[3]	0.76	= [1] / [2]
Additional Value from 5CP Targeting			
PV Capacity Benefits per kW at Generator	[4]	$311	See note below
T&D Loss Factor	[5]	8.30%	SWE Report p. 54
PV Capacity Benefits per kW at Meter	[6]	$339	= [4] / (1 - [5])
kW Realized per Participant	[7]	0.63	SWE Report p. 61
Participants	[8]	80,072	SWE Report p. 63
Total Capacity Value Implied by SWE Analysis	[9]	$17,099,504	= [6] * [7] * [8]
Average 5CP Hours Curtailed	[10]	70%	See note below
Additional Value from Targeting 5CP	[11]	$11,969,653	= [9] * [10]
Revised TRC (RPM revenue + 5 CP targeting)			
Present Value Benefits	[12]	$60,783,636	= [1] + [11]
Present Value Costs	[13]	$64,151,543	= [2]
TRC	[14]	0.95	= [12] / [13]

Additional notes

[4] Calculated using SWE's stated annual capacity values from SWE Report p. 23. Extended projections to 10 years using SWE's 1.87% annual escalation value. Discounted 10 year projections to present value at 8%

[10] Expected portion of 5CP hours that would be hit calling 12, 2-hour events per year; SWE Report p. 31

Correcting for any one of the factors described above individually raises the PPL Direct Load Control TRC to 0.95 or higher. Correcting for all of the factors raises the PPL DLC TRC to 1.89.

Table D: Cumulative Effect of Revisions to PPL DLC TRC Calculation

TRC Reported by SWE			
Present Value Benefits	[1]	$48,813,983	SWE Report p. 63
Present Value Costs	[2]	$64,151,543	SWE Report p. 63
TRC	[3]	0.76	= [1] / [2]
TRC Revised to Include RPM + 5 CP Benefits			
Additional TRC Benefits	[4]	$11,969,653	Calculated in previous table
Revised PV Benefits	[5]	$60,783,636	= [1] + [4]
Present Value Costs	[6]	$64,151,543	= [2]
TRC	[7]	0.95	= [5] / [6]
TRC Scaled to Appropriate kW Factor			
Ratio of Actual kW Factor to SWE kW Factor	[8]	1.33	= 0.84 kW / 0.632 kW
Revised PV Benefits	[9]	$80,788,377	= [5] * [8]
Present Value Costs	[10]	$64,151,543	= [2]
TRC	[11]	1.26	= [9] / [10]
TRC Scaled for 75% Cycling Strategy			
Ratio of 75% Cycling kW to 50% Cycling kW	[12]	1.50	= 75% / 50%
Revised PV Benefits	[13]	$121,182,565	= [9] * [12]
Present Value Costs	[14]	$64,151,543	= [2]
TRC	[15]	1.89	= [13] / [14]

The analyses presented above are all related to the PPL service territory. This territory is used because the SWE projects it to have the lowest TRC of the territories for which DR supporters have enough data to conduct this alternative analysis. A similar analysis can be conducted for PECO, which has a higher starting point based on SWE analyses. Applying the same concepts at PECO raises the TRC on residential demand response from 1.05 to 2.71.

Finally, in doing its TRC analysis for residential demand response, the SWE only looked at direct load control switch technologies. The SWE did not consider any alternative, new, innovative residential DR methods such as behavioral demand response or thermostat based DR.

Given that technologies change and evolve, the EDCs should not be constrained to deploying only the programs and measures included in the DR Potential Study. The use of these new technologies may be more cost-effective and, if so, will increase the overall cost-effectiveness of residential DR programs specifically and the DR requirement generally. In the future, the SWE should integrate these newer measures into future potential studies and cost-effectiveness calculations.

D. Increase the Allocation of Act 129 Funds to demand response ("DR") Programs to 20%

The Commission proposed that 90% of the EDC funding go towards the EE programs and the remaining 10% should be allotted to DR programs. The Commission summarized how it reached this position in the following statement:

> "The SWE has provided four separate spending scenarios: 100/0; 90/10; 85/15 and 80/20. As referenced earlier in this Tentative Order, the EDCs on average spent 16% of their budgets on Phase I DR programs. The Commission does not believe the EDCs should spend greater than the Phase I average of 16%. We initially agree with the SWE's assessment that EE programs provide a better return on investment than DR programs."[54]

For several reasons, including the analyses presented above, the budget for DR programs should be significantly increased. In addition to the analyses presented above, the following reasons support a more diversified budget:

- The measures implemented for DR and EE differ, and it is important to capture all of them. For example, a large industrial customer can shut down their production during the peak hours of the year for DR events, but would quickly go out of business if it shut down production for the entire year. The meaningful benefits achieved during the peak hour reduction would not be realized if too much funding went to EE.
- DR serves as a gateway to EE, as customers often use the revenue they receive for DR participation to undertake investments in EE.

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54 Tentative Order, p. 34.

- DR is dispatchable, and can therefore stabilize the grid in a way that EE cannot.
- Lifting the ban on dual participation, as recommended above, would increase the potential customer base by nearly 2,000 MW. The 10% budget for DR was done without these 2,000 MW of potential MW in mind.

Customers respond very favorably to DR services and there is evidence that potential penetration could be at least 20% of residential customers – and far more over time. While the SWE calculated a potential penetration rate of 12.5% , only four of the companies examined in reaching that conclusion were in PJM and were not part of Pennsylvania's flawed "100 top hours" program. The average for the remaining companies was 47%:

Extract of Table 4-1 from DR Potential Study.[55]

Utility	% of Eligible Residential Customers Participating Based on Data Obtained Directly from Utility	Year
SMECO	60%	2013
PEPCO	53%	2013
BG&E	38%	2013
DPL	37%	2013
Average	47%	

If the 47% average penetration rate is halved (in the same way that the SWE halved its findings to estimate a level of penetration for the shorter time frame at issue in this phase of the Act 129 program), the result is a projected penetration of 23.5%.

The analyses presented above indicate that, when calculated correctly, DR actually earns a higher TRC than EE measures and has a far higher potential penetration than assumed by the

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55 DR Potential Study, p. 56 at Table 4-1.

SWE. While this perhaps suggests the majority of the funding should be used for DR measures, the Demand Response Supporters recognize the difficulty inherent in major revision of program focus. As such, the Demand Response Supporters request an allocation of funds in all markets, including Met-Ed, Penelec and PPL of at least 20% of the Act 129 budget, which is a slightly higher percentage of funds than were allocated during Phase I and higher than what was proposed in the Tentative Order. The TRC calculations and potential penetration levels presented here support such a change from the Tentative Order. At the very least, the Commission should ask the SWE to recalculate the TRC and penetration levels for DR programs, after adopting the modifications proposed herein, and reconsider its program funding allocations in light of those revised findings.

IV. CONCLUSION

The Demand Response Supporters appreciate the opportunity to offer comments on the Tentative Order, and look forward to working cooperatively with all interested stakeholders in this proceeding.

Through reduced costs, increased reliability and resiliency, and lower emissions, robust DR participation in Phase III will be beneficial to all Pennsylvania electric customers and the Commonwealth. The Demand Response Supporters urge the Commission to adopt the comments, suggestions and recommendations described in these Comments to ensure that all Pennsylvanians and the Commonwealth receive the benefits provided by DR resources as intended by the Legislature when Act 129 was enacted.

Respectfully submitted,

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