December 30, 2013

To: Secretary's Bureau
From: Logan Welde, Clean Air Council

M-2012-2289411, M-2008-2069887

Please accept these Joint Comments on the Tentative Order on the Amended Demand Response Study. The Clean Air Council did attempt to file the comments electronically, however, there was a problem with the login.

Sincerely,

Logan Welde

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DEC 30 2013

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Act 129 Energy Efficiency and Conservation Program Phase Two

Docket Numbers: M-2012-2289411 and M-2008-2069887

RECEIVED

DEC 30 2013

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

JOINT DEMAND RESPONSE COMMENTS ON THE TENTATIVE ORDER ON THE AMENDED DEMAND RESPONSE STUDY OF: CITIZENS FOR PENNSYLVANIA'S FUTURE; CLEAN AIR COUNCIL; KEYSTONE ENERGY EFFICIENCY ALLIANCE; THE SIERRA CLUB

Dated: December 30, 2013

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

	)	
Energy Efficiency and Conservation Program	)	**Docket No. M-2012-2289411**
	)	**Docket No. M-2008-2069887**
	)	

AMENDED DEMAND RESPONSE STUDY COMMENTS

I. INTRODUCTION

Citizens for Pennsylvania's Future ("PennFuture"); Clean Air Council; Keystone Energy Efficiency Alliance ("KEEA"); the Sierra Club (hereinafter "Joint Commenters"), respectfully submit these Joint Demand Response Comments in response to the Commission's Tentative Order, the Amended Demand Response Study[1] in the above referenced dockets. These comments represent a unified position of a large group of stakeholders interested in the continued implementation of Act 129.[2]

Peak demand reduction can be very beneficial to both ratepayers and the environment. Reducing electricity demand when it is highest helps control capacity prices and wholesale electricity prices, and can help avert the need for costly transmission upgrades. It also reduces the need to operate some of the least efficient and most polluting facilities, thus reducing air pollution and benefiting public health. It is for these reasons that the Pennsylvania Legislature included a peak demand reduction requirement of 4.5% in Act 129.[3]

Despite these potential benefits, the Statewide Evaluator ("SWE") has found that the Act 129 Phase I demand response programs were not cost-effective according to the Total Resource Cost test ("TRC"). This is largely because the demand reductions were required over the top 100 hours of demand which led to difficulties in predicting when demand response ("DR") resources should be deployed, and resulted in expenditures to reduce demand when power prices did not justify it. Furthermore, it is likely that excessive incentives for load curtailment ("LC") were paid to participants which also participated in PJM DR programs, resulting in a free rider effect.

The Joint Commenters do not dispute the SWE's finding that Phase I DR programs were not cost-effective under the current TRC test. The Joint Commenters also agree with the SWE that there are likely alternative ways to design a DR program under Act 129 that would be cost-effective. The Joint Commenters generally support the proposals in the tentative order to evaluate alternative program designs and quantify additional avoided costs associated with DR. The Joint Commenters believe a more targeted approach to DR programs could offer net benefits, but caution that spending on DR may have the deleterious effect of reducing the

[1] *See Energy Efficiency and Conservation Program*, Docket Nos. M-2012-2289411 and M-2008-2069887, *Tentative Order* (*hereinafter* "TO").
[2] *See* Pa. C.S. §2806.1.
[3] *Id.*

funding available for cost-effective energy efficiency and conservation ("EE&C") programs, so the SWE and the Pennsylvania Public Utility Commission ("PUC") should carefully consider this tradeoff.

II. FUNDING SHOULD BE ALLOCATED TO OBTAIN THE GREATEST NET BENEFIT TO THE ENVIRONMENT AND TO RATEPAYERS

Act 129 established a spending cap for each electric distribution company ("EDC") of 2% of 2006 revenues on all Act 129 programs.[4] Due to this limiting feature, funds spent on DR reduce money available for EE&C programs. The Commission has already found the EE&C programs to be cost-effective.[5] The SWE's market potential study which informed the Final Order, adopted August 2, 2012, identified economic efficiency potential that could reduce consumption by over 27% over a ten-year period,[6] and given that less than 10% of these savings are required over the next three-year phase of EE&C programs, there will continue to be cost-effective efficiency potential for years to come. Therefore, it is imperative that any funding diverted from EE&C programs to DR programs provide at least as much benefit to the ratepayer as would have been achieved by the EE&C program. It is also critical that the factors used to measure cost-effectiveness are applied consistently to both EE&C and DR programs.

Although the Joint Commenters strongly support DR as important and complimentary to the EE&C programs, the Joint Commenters believe it is likely that EE&C programs are inherently more beneficial to ratepayers and the environment because EE&C programs produce benefits that are more permanent and persist for many years, whereas DR programs require continuous incentive payments to maintain benefits. In addition, EE&C programs likely reduce emissions to a greater extent than DR programs. As previously stated, EE&C programs completely eliminate demand for electricity, while DR programs generally shift consumption to times of lower demand. Furthermore, a significant portion of DR capacity is comprised of unregulated diesel generators, which emit more particulates and ozone precursors than conventional fossil generation.

It is for these reasons that the Joint Commenters want to be very cautious about diverting funds away from EE&C programs to DR programs under the 2% spending cap, and support a very thorough analysis of DR program cost-effectiveness particularly as they apply to customers who are benefiting financially from participation in both PJM and Act 129 DR programs. At the same time, there are potential synergies in utility programs that offer both EE&C and DR programs, such as economies of scale in administration, enhanced customer education opportunities, and the potential for more integrated program offerings.[7] Further analysis should help clarify which aspects of DR are most cost-effective. However, the relative benefits of DR and EE&C must be

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[4] *Id.*

[5] *See* TO.

[6] *See Act 129 Demand Response Study – Final Report*, Prepared for the Pennsylvania Public Utility Commission, GDS Associates *et al.*, Submitted May 13, 2013, Addendum Added November 1, 2013 available at http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_129_information/act_129_statewide_evaluator_swe_.aspx (*hereinafter* "GDS").

[7] National Action Plan for Energy Efficiency (2010). Coordination of Energy Efficiency and Demand Response. Prepared by Charles Goldman (Lawrence Berkeley National Laboratory), Michael Reid (E Source), Roger Levy, and Alison Silverstein available at http://www.epa.gov/cleanenergy/documents/suca/ee_and_dr.pdf.

considered when determining the role of DR in Phase III, and any additional avoided costs or benefits that are considered for DR programs must also be considered for EE&C programs.

III. UNDERSTANDING THE VALUE OF ACT 129 DR PROGRAMS COMPARED TO PJM PROGRAMS

Several events have occurred that have fundamentally changed the DR market in Pennsylvania since Act 129's passage in 2008. First, in 2011 the Federal Energy Regulatory Commission ("FERC") finalized its Order 745, directing grid operators (like PJM) to pay Curtailment Service Providers ("CSPs"), which represent electricity users that participate in DR programs, the same rate that is paid to electricity generators who supply grid power. This means that DR programs now receive full wholesale price as opposed to the lower amounts paid under the previous pricing rules. As a result, DR programs have become more economically attractive to customers and CSPs alike. In addition, PJM's DR market has been evolving, enhancing both emergency and economic DR program offerings and markets. The Interruptible Load for Reliability ("ILR") product was discontinued after the 2011/2012 delivery year, making way for three different categories of emergency DR products (annual, extended and limited) in the capacity market. On the economic side, DR products can participate in the energy, synchronized reserve and regulation markets. PJM's DR market resources have grown considerably since the passage of Act 129 in 2008. Based on PJM's December 2013 Demand Response Load Activity Report, for the 2013/2014 delivery year there are 2,123.3 megawatts ("MW") of emergency DR and 581.6 MW of economic DR located in Pennsylvania. Based on the Reliability Pricing Model ("RPM") auctions for 2014/2015 and 2015/2016 even higher amounts of DR are anticipated over the next two years. However, administrative changes filed at FERC in 2013 had an immediate effect on reducing cleared DR offers across PJM's territory by roughly 2,000 MW. In addition, recent filings by PJM indicate that there will be a reduction of PJM-wide quantities of limited DR by at least 6,000 MW in future years.

The Joint Commenters support the Act 129 program mix (EE&C and DR) that delivers the greatest ratepayer and environmental benefits; thus determining the correct program mix is vital to achieve that goal. Specifically, by holding overall program budgets constant, it is important the commission get a clearer understanding of what the proper mix of DR to EE&C programs based on ratepayer and environmental value. Both provide value, but until action is taken to lift the 2% utility spending cap, further analysis is warranted. The Joint Commenters understand that lifting the cap is a legislative matter, but we seek assistance from the commission to help legislators understand that the TRC is a more accurate mechanism for evaluating whether a program or measure is cost-effective. The 2% spending cap is no longer needed to ensure ratepayers are not spending money on non-cost-effective programs which will restricts both cost-effective DR and EE&C from going forward.

A. What is the Value of EDC-Based DR Programs in PJM Service Territory?

Given FERC's groundbreaking order, anticipated high levels of DR in the coming years, and PJM's administrative contraction of the DR markets beginning in 2016/2017, the relative benefits of EDC administered DR programs is drawn into question. The Joint Commenters request that PUC and the SWE examine the value of these EDC-based programs in the context of the shifting impacts of PJM's programs. For example, given PJM's robust DR market, what are the ratepayer, and other benefits associated with an EDC-run Act 129 DR program? The Joint Commenters appreciate the SWE's efforts to develop and calculate the Incremental Benefits Ratio ("IBR"), in order to express the allocation of benefits between the PJM and Act 129 programs when overlapping participation exists. Based on the IBR, it appears that both PJM emergency and economic DR participants benefited from Act 129 incentives, with the economic DR programs receiving a slightly higher benefit. Given this information, the Joint Commenters seek to better understand Act 129 DR programs' value to PJM's competitive markets. Specifically, if Act 129 DR programs were not in place, would certain resources currently participating in the PJM market cease to participate at all? Could PJM's markets adjust to attract additional DR resources if Act 129 programs or incentives are reduced? How do IBR values and the importance of Act 129 DR programs change as PJM DR revenues fluctuate? Will Act 129 DR programs be most effective if structured to operate in different ways depending on quantities known and expected from the RPM auctions? In other words, should the Commission vary Act 129 DR programs depending on the robustness of the PJM market? For example, should Act 129 DR be deemphasized in the upcoming years when there are high quantities of DR in the PJM capacity and then follow with more aggressive Act 129 DR when PJM's rules force the amounts of PJM DR down?

The Joint Commenters understand that EDC-run programs can be an important tool to mitigate market entry obstacles in the PJM administered DR market. This could include high start-up costs, multi-year deliverability issues, enhancing price certainty for customers when PJM base residual auction ("BRA") prices fluctuate, etc. What value can Act 129 DR programs produce that cannot or will not be available from PJM? What additional incremental value can Act 129's DR program add to the competitive PJM DR program? Are there DR approaches or technologies that are likely to be more valuable to the ratepayer to promote at the EDC level (i.e. those that enhance voltage regulation as well as emergency energy supply, geographically focused programs at the highest priced or most vulnerable sub-zones or even nodes, those that can be implemented to avoid expensive or controversial EDC equipment upgrades)?

The Joint Commenters also understand that residential customers do not typically participate in PJM's DR programs, and that 100% of the residential load reductions are attributable to Act 129's DR program. However, the SWE's preliminary analysis indicates the residential DR programs were not cost-effective. The Joint Commenters support the SWE's recommendations to amend the residential direct load control ("DLC") programs in an effort to improve cost-effectiveness. SWE's recommendations include 1) extending the useful life of the equipment, 2) implementing full load reduction scenarios, 3) treating investments in DLC equipment as sunk costs, 4) reducing DLC incentives, and 5) aggregating and bidding residential DLC reductions into PJM's BRA with benefits accruing in the TRC test, applying those benefits to marginally cost-effective DR/EE programs, or used as a contribution to the overall Act 129 budgets for both EE/DR. In addition, the Joint Commenters believe that any revenues received by EDCs from bidding Act 129 DR capacity into the PJM BRA should be returned for use in the Act 129 program budget.

IV. DEMAND RESPONSE COST-EFFECTIVENESS

In their report, the SWE analyzed the Phase I Demand Response (DR) programs using the cost-effectiveness test prescribed to them by the PUC, the TRC test. Using this test, few of the programs were given a benefit-cost ratio ("B/C") of greater than 1.0 (i.e. only a few of the programs were determined to have benefits that outweigh the costs). In the updated report they include an estimate of the wholesale price impact from these DR programs, and the B/C of all programs increased, although none of them were greater than 2.0. Finally the SWE put forth a "prospective" TRC test, which analyzes a hypothetical program designed by the SWE and greatly improved the statewide B/C to 2.45 for residential and 3.34 for commercial and industrial ("C&I"). The Joint Commenters' consultant, Synapse, recently did work attempting to determine the appropriate use of the various common cost-effectiveness tests in use to evaluate EE&C and DR programs. In a recent report with The Regulatory Assistance Project ("RAP"), Synapse helped identify what is currently considered best practices in a DR TRC Test. This report is identified by the SWE as the "National Action Plan on Demand Response." (hereinafter "the Action Plan on DR"). Based on an examination of the SWE final report (amended November 1, 2013), the Joint Commenters believe there are five major issues with the methodology employed by the SWE. While any one of these alone would probably not greatly impact the end result of the TRC test, collectively the Joint Commenters believe they do impact the TRC test. In the interest of better quantifying all of the components that make up the true costs and benefits, the Joint Commenters asked Synapse to analyze the following:

A. Cost categories omitted from the SWE TRC test
B. Benefit categories omitted from the SWE TRC test
C. Benefit categories included but underestimated in the SWE TRC test
D. Whether benefits and costs should be analyzed on a forward looking basis
E. A prospective TRC test
F. Whether more transparency is needed when evaluating costs and benefits

The Joint Commenters recognize that many of issues raised here regarding the SWE's examination of costs and benefits are aligned with the PUC's tentative order. The SWE appears to assert an alternative program design and TRC analysis in the SWE's Prospective TRC, these comments will also outline Synapse's analysis of this cost-effectiveness test and program design.

A. Cost categories omitted from the SWE TRC test

The SWE final report identified five categories of costs that it included in its evaluation of demand response. They include equipment & installation costs, program administrative costs, marketing costs, evaluation costs, and incentives paid to participants.[8] These costs, and the assumptions that the SWE used to evaluate the costs, appear to be aligned with PUC orders. According to the Final Report:

> Including incentives as a cost in the TRC test makes an implicit assumption that the incentive represents the economic value the participant puts on the discomfort or qualitative costs they incur to participate in the program. Therefore, the incentive

[8] GDS at 36.

becomes a proxy for participant costs. The base case TRC analysis presented in the report considers 100% of customer incentives as program costs as directed by the 2011 TRC.[9]

The Joint Commenters recommend breaking the costs into eight defined categories. The five categories that the SWE used correspond to five of the eight categories which Synapse/RAP has identified as necessary to include in evaluation of the TRC test (although, the labeling of these categories and what is included in each category are slightly different).

Demand Response Program Costs for TRC Test[10]

[illegible]	[illegible]	SWE
Program Administrator Expenses	Yes	Yes
Program Administrator Capital Costs	Yes	Yes
DR Measure Cost: Program Administrator	Yes	Yes
DR Measure Cost: Participant Contribution	Yes	Yes
Participant Value of Lost Service	Yes	Yes
Participant Transaction Costs	Yes	Yes
Increased Energy Consumption	Yes	No
Environmental Compliance Costs	Yes	No

Because it is unlikely that DR participants would only engage in a program when the benefits would exceed the costs, a 100% proxy is not realistic. The Joint Commenters agree with the SWE's suggestion to follow California's recommendation of using a 75% proxy. Incorporating this suggestion would increase the B/C.

1. Increased Energy Consumption

"A demand response program that shifts load from peak to off-peak hours may result in a net increase in the total consumption of energy."[11] However, typically even if the total energy use is the same, because the energy is purchased at off peak hours, the programs still result in a net cost savings to the ratepayers. Incorporating increased energy consumption costs might reduce the benefit to cost ratio, but the Joint Commenters expect this effect to be small. Further, there is no clear consensus that shifting load from peak periods increases overall consumption.

2. Environmental Compliance Costs

For those DR programs that use backup generators, specifically those that are fossil fuel-fired, the DR program can result in increased SO2, NOx and greenhouse gases. If these pollutants are regulated, the cost of complying with environmental regulations should be accounted for in the TRC test. Incorporating environmental compliance costs might reduce the B/C, but the Joint Commenters expect this effect to be small.

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[9] *Id.* at 38.

[10] Woolf *et* al., *A Framework for Evaluating the Cost-Effectiveness of Demand Response* February, 2013 (*hereinafter* "Framework").

[11] *Id.* at 30.

B. Benefit categories omitted from the SWE TRC test

While each of the categories omitted on their own would likely not significantly alter the B/C, together they would have an additive impact that could tip the scale from a B/C less than 1.0 to a B/C greater than 1.0.

Demand Response Program Benefits for TRC Test[12]

[illegible]	[illegible]	[illegible]
Avoided Capacity Costs	Yes	Yes
Avoided Transmission & Distribution Costs	Yes	Yes
Market Price Suppression Effects	Yes	Capacity Only
Avoided Energy Costs	Yes	No
Avoided Ancillary Service Costs	Yes	No
Revenues from Wholesale DR Programs	Yes	No
Avoided Environmental Compliance Costs	Yes	No
Tax Credits	Yes	No
Other Benefits (e.g., market competitiveness, reduced price volatility, improved reliability)	Yes	No

1. Avoided Energy

DR programs avoid energy costs in one of two ways. Either it shifts load when participants defer energy consumption from high-price hours to lower-priced hours, or DR programs result in LC—when participants opt to reduce their energy consumption for some period of time. While the benefits associated from avoided energy costs are expected to be significantly less than avoided capacity costs, they remain an important item to include in the TRC test. The SWE asserts that avoided energy benefits are "insignificant."[13] This finding is contradictory to that of a TRC test provided by a California Utility; the calculated value of avoided energy benefits was roughly the same as the value of avoided transmission and distribution ("T&D") benefits over a three-year forecast.[14] Incorporating avoided energy would certainly increase the B/C.

2. Avoided Ancillary Service Costs

Many DR programs are capable of providing ancillary services, including quick responses to transmission and generation failures, more efficient use of generation facilities, better integration

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[12] *Id.*

[13] GDS at 27.

[14] "The avoided capacity benefits represent the majority of benefits (roughly 90%). Avoided transmission and distribution and avoided energy benefits are relatively small portions of the benefits (roughly six percent and four percent, respectively). The avoided cost of complying with greenhouse gas requirements is a very small portion of the total benefits (roughly one percent)." Framework at 61.

of variable energy resources, frequency regulation, VAR support, and black start capability.[15] It is import to note that (1) these benefits do exist and (2) omission of the avoided ancillary services reduces the B/C. Determining the value of the avoided ancillary services is a two-step process of (1) quantification and (2) monetization. Because PJM has a market value for these ancillary services, the second step is relatively easy at least compared to those areas where a market does not exist. Incorporating avoided ancillary services would increase the B/C.

3. Avoided Environmental Compliance Costs

One key example of avoided environmental compliance costs will likely be due to the potential coal plant shutdowns and retirements brought on by the Environmental Protection Agency's ("EPA") upcoming revised compliance regulations. While these regulations are not final at this time, the impact on both generation supply and cost should be given consideration as part of a forward looking approach. Under this scenario, the economics of DR (and energy efficiency) will only get stronger.

4. Tax Credits

Tax credits for DR do not yet exist on the federal level. For the Commonwealth, the Joint Commenters are aware of no local level tax credits. Consequently, the inclusion of tax credits as a benefit to DR is a moot point in Pennsylvania at this time. However, under the framework for demand response cost-effectiveness, the Joint Commenters suggest including tax credit benefits which are or may become associated with DR. Under this framework, any expected tax credits which may become available in the future should be included in the calculation of the B/C. The SWE essentially used \$0.00 for this value, which is appropriate if the SWE does not know of any tax benefits that will become available in the future. However, such an assumption should be justified, and potential tax credits should at least be a consideration in the SWE's assessment.

5. Other Benefits

Synapse and RAP identified several other benefits to DR programs including enhanced market competitiveness, reduced price volatility, demand response modularity, insurance against extreme events, customer control over their bills (or from the utility side: credit and collections benefits), overall productivity gains from better utilizing industry investment, non-energy benefits (including but not limited to environmental benefits), and innovation in retail markets.[16] Inclusion of any of these benefits would increase the B/C. These are sometimes referred to as Utility System Benefits. RAP would include losses, reserves and risks.

C. Benefit categories included but underestimated

The SWE's amended assessment does include benefit items that are typically considered the "big ticket items," mainly avoided capacity, avoided T&D, and price suppression. However, the SWE's assessment appears to make several assumptions resulting in an undervaluation of the benefits. Based on the SWE's calculation for avoided T&D costs and price suppression, the Joint Commenters believe that both of these items are underestimations.

[15] *Id.* at 45.
[16] Framework at 53-54.

1. Avoided Capacity Costs

The original analysis of avoided capacity costs used BRA results from 2015/2016 instead of 2016/2017 because the 2016/2017 data was not yet available. While it is true that the 2016/2017 capacity values dropped significantly, the methodology employed by the SWE is not suspect. More importantly, when the SWE updated the calculations of benefits and costs (as reported in the amended draft) the SWE again used the most recent BRA values available (which at that time was the 216/2017 data). While the SWE calculated the costs and benefits on a forward looking basis, it kept the capacity price constant (in constant dollars). Using the most recent BRA value and holding it constant or escalating the price slightly, are both reasonable methods for projected capacity market prices. While the Joint Commenters acknowledge that a different methodology to calculate future capacity prices and avoided capacity costs could have been used, the SWE's methods are acceptable and likely less impactful than the omission of several benefits.

2. Avoided T&D Costs

The SWE correctly recognizes the uncertainty and difficulty in assessing a proper value for avoided T&D costs. The SWE describes estimating the avoided T&D costs as "challenging," going on to say:

> Some utilities, in order to develop a conservative TRC analysis, might assign no additional benefit for T&D savings. On the high end, it has been SWE's experience that avoided T&D costs typically do not exceed $50 per kW-year. Therefore, the sensitivity analysis includes a base case of $25/kW-year, a low case of $0/kW-year and a high case of $50/kW-year.[17]

The SWE needed to select some value for avoided T&D cost, and chose a value of $25/kw-year in part because it was the midpoint in their range of $0-$50 per kW-year.[18] While there is uncertainty in what the current and future value of avoided T&D costs may be, the Joint Commenters can say with reasonable certainty that it will be greater than $0/kW-year, providing us with assurance that $0/kW-year is not an accurate lower limit. While some utilities may choose to use this as a "conservative" estimate, it is nevertheless a significant underestimation of the avoided T&D costs. Furthermore, while the SWE's claim that avoided T&D costs typically do not exceed $50/kW-year may prove to be true for Pennsylvania, the SWE provides no support to this claim. The lack of transparency in this regard is discussed in greater detail in part "F" of this section, discussing the importance of transparency.

While the SWE's analysis may not have uncovered avoided T&D costs greater than $50/kW-year, the Joint Commenters would point to several studies showing avoided T&D costs that do exceed $50/kW-year. The AESC 2013 report analyzed avoided T&D costs for all of the New England States (CT, VT, MA, NH, RI, and ME). That report found that avoided T&D costs ranged from $32.24 to $200.01 per kW-year, with the average being $95/kW-year. In a 2009 RAP report—based on estimates from utilities in California, Washington, and Oregon—avoided

[17] GDS at 38.
[18] GDS at 37.

T&D costs were estimated to have ranged from $33 to $114 per kW-year, with an approximate average of $54/kW-year (values adjusted for inflation to 2013 based on the BLS CPI Inflation Calculator).[19]

Avoided costs for T&D will vary across the country and depend on anticipated T&D expenditures. As such, the Joint Commenters agree with the SWE's conclusion that additional study needs to be performed to determine the value of avoided T&D costs.

3. Price Suppression Effects

While the SWE price suppression calculation is labeled "Total Price Suppression," the Joint Commenters believe that the value represents only a portion of the price suppression benefit. In the original draft of the SWE analysis of DR benefits and costs, the SWE quotes the Action Plan on DR—a report co-authored by Synapse and RAP and heavily cited in these comments. The Joint Commenters would point to the paragraph directly above the one quoted in the SWE assessment, which states:

> In regions of the country with organized wholesale energy and capacity markets, an expansion of demand response programs can reduce peak demands, which can then lead to reduced wholesale energy and capacity prices. Because wholesale energy and capacity markets provide a single clearing price to all wholesale customers purchasing power in the relevant time period, the reductions in wholesale energy and capacity clearing prices are experienced by all customers of those markets. Thus, even a small reduction in a market clearing price can result in significant cost reductions across the entire market.[20]

The SWE asserts that inclusion of wholesale price suppression "would not materially impact the benefit cost assessment as presented in [the original report]."[21] In the amended report, the SWE calculated that including wholesale capacity price suppression would increase benefits significantly. In fact, inclusion of capacity market price suppression alone increased the B/C by over 50 percent.[22] This evaluation excluded energy price suppression which would have only increased the B/C even further. While the Joint Commenters agree that energy price suppression is not as big of a benefit as other components (like avoided capacity or capacity price suppression) it is still an important to monetize benefit that should be included in the analysis.

D. Whether benefits and costs should be analyzed on forward looking basis

While the SWE does acknowledge that the B/C analysis should be done on a forward looking basis, it appears that much of the original analysis looked at past performance as a measure of cost-effectiveness.[23] There are several reasons why this is not best practice. The Joint Commenters are of the opinion that "[i]deally, cost-effectiveness analyses should be conducted

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[19] Neme and Sedano, *US Experience with Efficiency as a Transmission and Distribution System Resource*. February, 2012. p. 3.

[20] Framework at 47.

[21] GDS at 51.

[22] GDS at 65.

[23] It appears that DLC programs were analyzed on a ten-year basis for their avoided capacity costs and benefits, however lack of transparency of calculations makes it difficult to assess.

over a study period that includes all of the years over which costs and benefits are expected to accrue."[24] This means that determining the economic effectiveness of DR should be evaluated on a forward-looking basis. While the SWE is accurate that forecasting does add uncertainty, DR programs today help avoid future costs. Again, the Joint Commenters point to the Synapse RAP report on DR:

> *In assessing cost-effectiveness of demand response, it is important to account* explicitly for all **potential** benefits, including avoided/deferred generation capacity costs, avoided energy costs, avoided transmission and distribution losses, deferred/avoided T&D grid system expansion, environmental benefits, system reliability benefits, and benefits to participating customers. (Emphasis added)[25]

One reason to look at DR on a forward looking basis is that energy efficiency ("EE") cost-effectiveness tests are done on a forward looking basis. The latest EE study for Pennsylvania—completed in 2012—looks at costs and benefits over three time frames: 2013-2016, 2013-2018, and 2013-2023. It is also worth noting that the TRC ratio increases over time. For example, under "Scenario 1" the B/C looked at for a three-year period is 1.75, for a five-year period it is 1.83, and for a ten-year period it is 1.95.[26]

The reason the B/C increases as the analysis covers longer time periods is that revenue and cost streams fluctuate temporally. Cost streams, for example, fluctuate over time with capital costs typically being realized in the first program year (unless the project is 100% debt financed). Additionally, benefits fluctuate over time. For example, often there is a delay in market response, an observation the SWE makes in their initial analysis. The PJM capacity market auction for 2016/2017 has already been completed, so the Joint Commenters would not expect a DR program that comes online this year to have any effect on the capacity market until 2017/2018. These temporal fluctuations are also observed for EE programs, which is why larger B/Cs are observed with longer analysis time frames.

Finally, the Joint Commenters urge the Commission to allow the use of forecasted future benefits because it will often capture future avoided costs that were not effective in the recent past, such as the costs to comply with environmental regulations. One example is included in part IV section B number 3 of these comments. In theory, cost-effectiveness tests should explicitly account for the avoided costs of compliance with environmental regulations. It is now common practice to account for the cost of complying with current environmental regulations, such as the costs of purchasing SO2 and NOx allowances. However, it is much less common to fully account for the costs of complying with future environmental regulations. Failing to do so skews the cost-effectiveness evaluations of EE and DR programs, can lead to programs that are significantly less cost-effective, and can result in customers paying for alternative environmental compliance options that are much more expensive than those funded by Act 129.

These avoided costs of environmental compliance should not be confused with avoided environmental externalities. Instead, these costs represent the anticipated costs that will be

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[24] Framework at 56.
[25] Framework at 55.
[26] Electric Energy Efficiency Potential for Pennsylvania. GDS Associates and Nexant. May, 2012. p. 2.

incurred by utilities in the future to comply with environmental requirements; costs that will eventually be passed on to ratepayers, and thus are clearly within the definitions of the TRC test. The combined effect of a suite of upcoming EPA regulations has forced some utilities to announce the retirement of several older, less-efficient fossil fuel-fired power plants; many more plant retirements are expected over the next five to seven years. Those fossil fuel plants that remain on-line are likely to have to install costly pollution abatement equipment and are likely to experience higher operating costs and reduced heat rates. These changes are likely to have significant effects on the avoided costs of EE programs.[27]

E. A Prospective TRC Test

In the SWE report, amended November 1, 2013, the SWE outlines what it describes as a "prospective" TRC test. This test is as much an alternative TRC test as it is a TRC test performed on an alternative program design. The key assumption of the prospective program design is that it would use the day-ahead load forecast as the trigger for dispatching DR resources. The SWE assumed only 32 hours in the year would call on DR resources, and suggest that 32 hours be the upper bound for a requirement to achieve program goals. Due to the lack of transparency in the SWE's report, it is difficult to definitively compare the initial TRC test to the prospective TRC. However, the Joint Commenters believe this program design alteration was one of the main drivers for the improvement of the B/C.

Several elements of the "Prospective TRC test" are an improvement over the TRC test originally reported. Firstly, the prospective TRC uses the California protocol and only includes 75% of the incentive amount as costs. Secondly, the prospective TRC test uses a ten-year prospective TRC Model.[28] This helps incorporate the importance of the forward looking aspect of the TRC test and makes the results of the DR B/C more comparable to the EE B/Cs of the ten-year period TRC test. However, while using a forward-looking basis for analysis of the TRC test is an improvement, most of the benefits appear to be held constant (in constant dollars). The Joint Commenters believe that it is more accurate to escalate these values in constant dollars; typically proportionally to electricity prices or to indices that track energy industry construction costs (e.g., Handy-Whitman). Incorporating this recommendation would likely increase the B/C.

Several elements of the prospective TRC test still fall short of what the Joint Commenters would consider a complete TRC test. Once again the SWE excludes energy price suppression, avoided energy costs, avoided ancillary service costs, revenues from wholesale DR programs, avoided environmental compliance costs, tax credits, and other benefits. Additionally, the SWE removed avoided T&D benefits from the TRC analysis.[29] This means, once again, the B/Cs are understated.

F. Whether more transparency is needed when evaluating costs and benefits

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[27] For a more complete description of addressing environmental regulations in cost-effectiveness tests, see Woolf, Tim. *Energy Efficiency Cost-Effectiveness Screening*. November 2012 available at www.synapse-energy.com/Downloads/SynapseReport.2012-11.RAP.EE-Cost-Effectiveness-Screening.12-014.pdf.
[28] GDS at 67.
[29] *Id.*

The framework for DR states that, "It is important that program administrators use models, inputs, assumptions, and methodologies that are transparent and well documented."[30] The Commission should encourage that all analysis performed regarding the cost-effectiveness of DR be done with the greatest amount of transparency possible. It is been difficult for stakeholders to understand the underlying premise behind some of the SWE's analysis. Clearly laying out assumptions, detailing justification for those assumptions, providing detailed tables of input data, and making all of this information publicly available. While the details contained in the SWE's analysis are a good start, they fall short of the level of transparency that the Commission requires. For example, many of the assumptions the SWE uses go unsupported and are contrary to the Joint Commenters' analysis. For example, the SWE provides no source for their assertion that the value of avoided T&D does not exceed $50/kW-year. The Joint Commenters have found no publicly available report to support or refute this statement.

Analyzing the Prospective TRC test was particularly challenging due to the lack of transparency. For example, the discount rate and what wholesale energy price forecast the SWE used is still a mystery. The SWE commented that, "One school of thought within the industry is that a short-term reduction in locational marginal pricing ("LMP") actually benefits suppliers rather than ratepayers and benefits to electric generators are not considered in the TRC test."[31] This claim is made without justification, citation or supporting argument.

V. DEMAND REDUCTION GOALS

Contrary to the conclusion in the SWE report, a 2% effective peak demand reduction goal is entirely reasonable and achievable, with many regions in the United States achieving over three, four, or even five times as much. In Table C-1 of their report the SWE compares program goals in various states, and concludes that the effective 2% peak demand reduction goal from DR in Act 129 is an aggressive one. However, while 2% may be higher than that targeted in some other states, it would be a mistake to consider it unreachable or even unreasonable. In their 2011 *Assessment of Demand Response & Advanced Metering Staff Report*[32] FERC included a table of demand response amounts compared to peak load in various regions of the country. As seen in the table below, many regions have reached peak load reduction amounts of 7%, 8%, and even 10.7%. While these programs have been in place for several years the experience of these areas plainly demonstrates that 2% in a single year is not only a reasonable goal to be achieved, but may indeed be needlessly conservative.

[30] Source?
[31] GDS at 52.
[32] FERC. *Assessment of Demand Response & Advanced Metering Staff Report - November 2011*. Federal Energy Regulatory Commission, 2011.

	2009 (MW)	Percent of 2009 Peak Demand[9]	2010 except as noted (MW)	Percent of 2010 Peak Demand[9]
California ISO	3,267[1]	7.1%	2,135[1]	4.5%
Electric Reliability Council of Texas	1,309[2]	2.1%	1,484[3]	2.3%
ISO New England, Inc.	2,183[2]	8.7%	2,116[4]	7.8%
Midwest Independent Transmission System Operator	5,300[2]	5.5%	8,663[5]	8.0%
New York Independent System Operator	3,291[2]	10.7%	2,498[6]	7.5%
PJM Interconnection, LLC	10,454[2]	7.2%	13,306[7]	10.5%
Southwest Power Pool, Inc.	1,385[2]	3.5%	1,500[8]	3.3%
Total RTO/ISO	27,189	6.1%	31,702	7.0%

Sources:
[1]California ISO 2010 Annual Report on Market Issues and Performance
[2]2010 FERC Survey
[3]ERCOT Quick Facts (June 2011)
[4]2010 Annual Markets Report, ISO New England Inc.
[5]2010 State of the Market report, Potomac Economics (Midwest ISO)
[6]2010 State of the Market report, Potomac Economics (New York ISO)
[7]PJM Load Response Activity Report, July 2011, "delivery year 2011-2012 active participants"
[8]Informational Status Report Concerning Incorporation of Demand Response In SPP Markets and Planning (September 2, 2011)
[9]Estimated based on peak demand data from the following: California ISO 2010 Annual Report on Market Issues and Performance, 2010 State of the Market Report for the ERCOT Wholesale Electricity Markets, 2010 Assessment of the Electricity Market in New England, 2010 State of the Market Report for the MISO Electricity Markets, New York ISO 2010 State of the Market Report, 2009 State of the Market Report for PJM and 2011 Quarterly State of the Market Report for PJM: January through June, and the Southwest Power Pool 2010 State of the Market.

VI. ALTERNATIVE PROGRAM DESIGN

In its report, the SWE makes several recommendations that would alter the Phase I design. Some of these recommendations are valuable, but there are also further improvements that the Joint Commenters believe should be made.

A. Reduced Program Hours

The first and most important recommendation is to reduce the requirement from 100 hours to a maximum of 32 hours, consisting of 8 events of 4 hours each. Although 32 may not be precisely the right value, the Joint Commenters agree with the SWE on this point. The most common successful DR programs target a much smaller set of hours than the Phase I design, and this smaller subset better targets the hours when DR can be a more cost-effective resource than available generation. The Commission should incorporate this change.

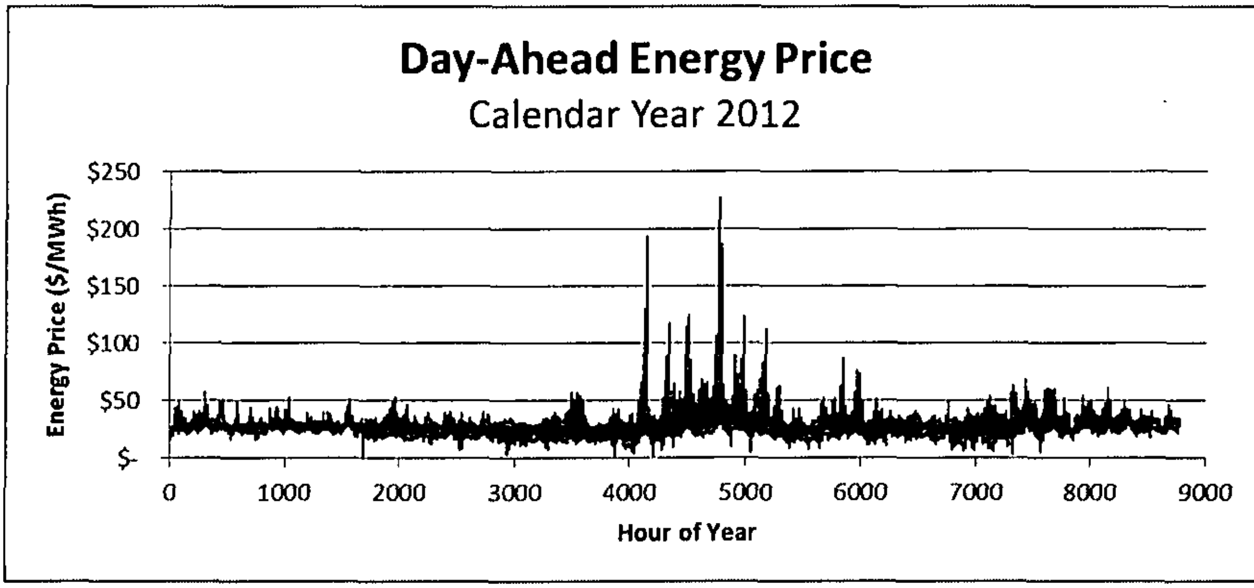
While this smaller set of hours would be more likely to target those hours of highest wholesale energy market prices, it would also have other effects. PJM creates forecasts of future peak demand to set the target amount purchased in the RPM and also in their transmission planning processes. Reducing peak loads now will have the effect of reducing both the amount of capacity required in the RPM and the level of new transmission projects that are approved.

In its report the SWE considers two design alternatives to use for triggering the DR programs.[33] One would have a threshold measured in \$/MWh of real-time locational marginal price (RTLMP) and the other would have a threshold in MWh of forecasted day-ahead load. For each approach, the SWE discuss both the benefits and drawbacks. For example, the trouble with using a RTLMP threshold price is that customers would have very little advance notice, and therefore very little time to respond. Using the forecasted day-ahead load limits the ability for DR to mitigate real-time price spikes that occur at moderate load levels (the "red zone" explained in Section D of SWE's report). Another issue with using forecasted day-ahead load as the trigger mechanism is that it ignores known generation or transmission outages that might not affect expected demand, but will affect expected price by altering the supply stack.

It is surprising that the SWE did not discuss a useful combination of these two: a threshold based upon a \$/MWh price in the day-ahead energy market. This approach could have several advantages. It sets a trigger mechanism based upon wholesale market price instead of forecasted load, which more directly affects avoided costs. The trigger would be available on a day-ahead basis, providing customers with advance notice of their required response. Influencing the day-ahead energy market is likely to have the greatest impact on total wholesale costs as more load clears in the day-ahead market than in the real-time market. To quantify this the Commission should study the impact that reductions in day-ahead and real-time market cleared amounts – or the addition of low-cost supply – would have on retail costs. In practice, impacting the day-ahead market has a greater effect on actual costs paid by end-use customers.

As with a real-time trigger, an effective day-ahead threshold price should be chosen to achieve the desired results. For example, the chart below shows the actual day-ahead energy market clearing price for all of the hours in calendar year 2012, in this case for the ComEd zone which covers most of northern Illinois including the city of Chicago. As can be seen from the chart, a threshold price between \$50 and \$100 would target 8 days in that summer where demand response would have had a large effect on market prices. This fits well with the SWE's recommendation of 32 hours. A threshold at \$100 would have limited the response to six events.

[33] GDS at 56-57.



Over time the average level of these prices will change. The threshold price should be reset monthly or annually, or indexed to the price of the marginal fuel in the region during summer afternoons, which is currently natural gas. The threshold should be chosen-such that it targets the eight 4-hour events suggested by the SWE, and typically these programs will also include a maximum number of hours to be called. If the program targets 32 hours in total, a reasonable maximum number of calls would be 60 hours, which coincides with the most limited of the DR programs available in the RPM. In milder summers prices are likely to remain low and capacity events are less likely. The DR programs might not be dispatched at all in these years. However, they still provide value to customers even in those years, as a hedge against high prices and emergency events. Like all hedge products, the value remains even if the programs are not dispatched in every year. Accordingly, this test event should be used to verify capability in those milder years.

This approach could be enhanced to include the "red zone" hours defined by the SWE if a secondary threshold were also adopted for the real-time energy market. The real-time threshold price should be a separate value, and would likely be higher than the day-ahead threshold price. If the DR customer (or aggregation of customers) offered in the day-ahead market at or below the day-ahead threshold and cleared, they could respond the following day and meet the requirements of both the PJM markets and Act 129. If their offer failed to clear because the day-ahead energy price was lower than their offer, they would offer into the real-time market at or below the real-time threshold price indicated by Act 129. This double-threshold approach is more complicated, and might not be applicable to all DR customers, such as manufacturing process loads, and would be more difficult to implement.

Using a price threshold in the DA and RT energy markets would require revising the current compliance criteria. Instead of requiring a measurement of demand reduction during the top 100 peak hours, customers and programs would need to demonstrate that they have offered the appropriate amount of capacity into the relevant BRAs, and are offering their demand reduction into the DA and RT energy markets at a price that is at or below the specified threshold price for each market, at least during the required time period. This time period might be limited to the months of June through September, as is done for the more limited RPM DR products. If they cannot demonstrate that they have made these offers, penalties should apply. If they have made these offers, but do not deliver the required energy reduction or capacity required by the PJM rules, then PJM will penalize them according to their market rules. Those penalties are likely to be sufficient incentive to perform, and Act 129 would not need to address this issue separately. Act 129 would only need to specify participation in the markets, and the required offer price thresholds. In essence, Act 129 would enforce availability, and PJM would enforce performance.

B. Act 129 and PJM Wholesale Markets

The SWE report indicates that most Act 129 customers, to date, also participate in the PJM energy market, the capacity market, or both. If, under an alternative design, DR customers procured through Act 129 continue to participate in the wholesale energy and capacity markets at the thresholds above, then what is the appropriate method for the two revenue sources to interact? Two potential avenues exist.

First, the SWE recommends that wholesale market revenues be accounted for as a benefit in any cost-effectiveness test.[34] Whether included as a benefit or as an offset to costs, the Joint Commenters agree that wholesale market revenues should always be included in the test. This accounting can be done at the time that the screening test is applied to each individual customer or aggregation of customers, to ensure cost-effectiveness of each project or program. This approach is common for large, custom energy efficiency measures, usually at commercial and industrial buildings. When the set of projects is proposed, all costs and expected benefits, including wholesale market revenues, are included in the screening test to ensure that the project will be cost-effective for the ratepayers who are providing the incentive. That screening often also includes a trigger for those projects that do not need an added incentive. If the proposed projects are cost-effective for the end-use customer and have a very short payback period—typically one or two years—the screening test indicates that no incentive should be provided. The projects should be funded entirely by the end-use customer, who will reap a return on their investment quickly and enjoy cost-free rewards for the remaining life of the measures. In this instance, the DR screening test might include a cap that rejects those customers, for whom, wholesale market revenues alone entirely cover their costs to provide DR. In this way, Act 129 would fund only that set of customers who are deemed cost-effective and still need funding above the level provided by wholesale market revenues. Ideally, this screening test would cover the life of the project or program, which could span several years.

Second, a different approach would be to allow end-use customers or curtailment service providers ("CSPs") to perform their own screening tests, the results of which are unknown to the EDC or the PUC. Instead of screening projects in advance, this method would work like a request for proposals ("RFPs") issued by the EDC for a fixed amount of MW needed to achieve the peak reduction goal. The RFP would specify the threshold prices as indicated above, and would specify compliance criteria. Prospective customers or CSPs would figure out their own internal costs, subtract expected wholesale market revenues, and offer the project with its remaining cost to the EDC. If their offer is among the lowest, they would be funded. Any programs directly implemented by the EDC, such as residential direct load control ("DLC"),

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[34] GDS at 55.

would be evaluated for its cost alongside all other proposals. This method would also ensure the lowest-cost set of customers needed to fulfill the requirement. If the required amount could not be procured within cost-effectiveness limits, some of the purchase amount would remain unfilled, perhaps until the next round of procurement.

C. Separate Requirements per EDC

The SWE recommends having separate requirements for each of the EDCs, as the prices in each EDC can vary widely both in the energy and capacity markets; such separate requirements could best be set through adoption of cost-based thresholds as discussed above. In those EDCs where prices are typically lower the DR programs would be called in fewer hours, and this is the appropriate action.

VII. RECOMMENDED STUDY UPDATES

A. Further Study Needed on Transmission and Distribution Costs

The SWE recommends further study of the avoided T&D costs from the implementation of DR programs. Their range of $0 - $50/kW-year seems quite low, and the mid-point they have used of $25/kW-year is therefore also too low. As indicated above (see part IV section C number 2 above) the Joint Commenters' research shows that other studies indicate much higher avoided T&D costs. Additionally, as stated previously, the low-end will be higher than $0/kW-year, thus choosing a "mid-point" of $25 is fatally flawed. The Joint Commenters agree with the SWE's recommendation that this T&D value, and the report released for comment should be studied further. However, until the study is complete, there is ample evidence that the estimated value, based on the $25/kW-year value be raised to a more reasonable value.

B. Ongoing Cost-Effectiveness Evaluation, as Program Design Changes

We recommend that the Commission continue to evaluate the cost-effectiveness of both the DR and the EE programs, in concert with changes to program design and the cost-effectiveness test used, and use the periodic evaluation to balance the amount of DR to EE until there are changes to the cost cap that limit the amount of cost-effective DR and EE available to customers. Both sets of programs should have B/Cs greater than 1.0. If one or the other consistently shows ratios far above the other, further changes to program design should be considered.

C. PJM Wholesale Markets and Act 129 DR Implementation

The Commission should study the appropriate implementation of Act 129 DR programs in concert with the PJM wholesale markets. Revenues from the wholesale markets are available to customers who are willing to reduce their demand, and this revenue source should not be ignored. The study should determine which markets give overall greatest cost savings to Pennsylvania customers (e.g., day-ahead or real-time energy), including how impacts on wholesale prices affect load suppliers and then flow through to end-use consumers. To the extent necessary, this study should include interviews with wholesale suppliers to understand typical contract structures.

VIII. Conclusion

The Joint Commenters agree with the SWE's determination that the DR programs as designed in Phase I were not cost-effective as designed. The Joint Commenters also agree that alternative program designs, most likely involving a more finely tuned DR program, could be cost-effective and support the effort outlined in the Tentative Order to further study the issue and identify the optimum conditions for DR programs in phase III. The Joint Commenters have outlined a number of suggestions for these studies here. However, the Joint Commenters ask the Commission to carefully consider the fact that DR programs would be competing with EE&C programs for funding in phase III, and that funding should be focused on those programs that result in the greatest benefit to ratepayers and the environment.

Finally, we ask the commission to give the stakeholders an opportunity to comment on both of the SWE reports before the commission accepts them. Further, it will be important to set a clear deadline for the SWE to provide a draft for review. We would like a see this process move as quickly as possible so there is greater certainty by the time of the next BRA auction in May.

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