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April 17, 2012

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

Re: Docket No. M-2012-2289411 – Act 129 Energy Efficiency and Conservation Program Phase Two

Dear Secretary Chiavetta:

Enclosed herewith please find the original and three (3) copies of the **"Comments on Behalf of EnerNOC, Inc. in Response to the Act 129 Energy Efficiency and Conservation Program Phase Two Secretarial Letter"** in the above-captioned proceeding. Please enter this into the docket and timestamp the additional two (2) copies.

Should you have any questions, please do not hesitate to contact me at (717) 237-6716.

Sincerely,

RHOADS & SINON LLP

By: Scott H. DeBroff

Scott H. DeBroff, Esq.
Alicia R. Duke, Esq.
Counsel for EnerNOC, Inc.

Enclosures
cc: Megan Good at megagood@pa.gov

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COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION

ACT 129 ENERGY EFFICIENCY AND CONSERVATION PROGRAM PHASE TWO	Docket No. M-2012-2289411

COMMENTS ON BEHALF OF ENERNOC, INC. IN RESPONSE TO THE ACT 129 ENERGY EFFICIENCY AND CONSERVATION PROGRAM PHASE TWO SECRETARIAL LETTER

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Dated: April 17, 2012

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COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION

ACT 129 ENERGY EFFICIENCY AND CONSERVATION PROGRAM PHASE TWO	Docket No. M-2012-2289411

COMMENTS ON BEHALF OF ENERNOC, INC. IN RESPONSE TO THE ACT 129 ENERGY EFFICIENCY AND CONSERVATION PROGRAM PHASE TWO SECRETARIAL LETTER

AND NOW COMES, **EnerNOC, Inc.** ("EnerNOC") by and through its counsel, **Scott H. DeBroff, Esquire** and **Alicia R. Duke, Esquire,** of Rhoads & Sinon LLP, for the purpose of these "Comments" with respect to this proceeding before the Commonwealth of Pennsylvania Public Utility Commission ("PUC" or the "Commission") pursuant to 52 Pa. Code §§ 5.71-5.74. In support of this docket, EnerNOC avers the following:

1. EnerNOC is a leading provider of clean and intelligent energy management applications and services for the smart grid, which include comprehensive demand response and energy efficiency applications and services. EnerNOC manages a demand response (DR) portfolio of over 7,000 MW from over 4,000 commercial, institutional, and industrial end-use customers across more than 11,000 sites. EnerNOC actively participates in a range of capacity, energy, and ancillary services markets, and is an active Aggregator of Retail Customers (ARC) in the demand response programs of ISO New England, the New York ISO, ERCOT and PJM. In addition, EnerNOC partners with utilities both inside ISO/RTO regions and in traditionally

regulated utility territories to provide cost-effective and reliable demand-side management services to utilities and their customers.

2. EnerNOC operates specifically in the Commonwealth of Pennsylvania as a Conservation Services Provider (CSP). As a CSP, EnerNOC provides commercial, industrial and institutional organizations with demand response and energy efficiency services. By letter dated July 2, 2009, the PUC approved EnerNOC's Application to register as an Act 129 Conservation Services Provider.

3. EnerNOC has participated in the other related Act 129 proceedings before this Commission. EnerNOC participated as a party in all of the Energy Efficiency and Conservation (EE&C) Plan proceedings for each Pennsylvania investor owned utility.

4. On March 1, 2012, a Secretarial Letter was entered in this proceeding seeking comments on a number of important topics that will be instrumental in designing and implementing any future phase of EE&C Programs.

5. On March 17, 2012, the Secretarial Letter was published in the PA Bulletin.

6. EnerNOC would like to submit the following Comments in response to the questions posed in the Secretarial Letter.

7. EnerNOC's counsel and parties to whom all correspondence and pleadings in this docket should be directed to are:

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1. Planning Timeline

EnerNOC generally supports the timeline laid out in the Secretarial letter, particularly for energy efficiency. However, as discussed below under Issue 3, the proposed schedule is not adequate enough to receive the Statewide Evaluator's report on the Demand Response Curtailment Program and still provide direction to the EDCs in time for the 2013 summer season. Specifically, the Statewide Evaluator's report will not likely come out until this fall, much later than the Final Implementation Order which is currently due on August 2, 2012. Therefore, prior planning needs to be done to preserve the demand response programs so that they can continue to provide value in 2013, assuming the Commission finds them cost-effective.

2. Length of Second EE&C Program

EnerNOC firmly supports the continuation of the EE&C Programs. The Secretarial Letter seeks input from interested parties on the optimal length of the program, specifically mentioning three-, four- or five-year lengths as options. EnerNOC supports a five-year program cycle. As further explained in the next section, "Inclusion of a Demand Response Curtailment Program," EnerNOC believes that a five-year program length, both for energy efficiency and demand response, best balances the factors listed in the Secretarial Letter, such as accuracy of forecast data; evolving energy efficiency marketplace; consumers' tendencies to adopt efficiency measures; changes in Federal legislation and regulations that set minimum efficacy standards; with the administrative costs incurred by all parties in designing, filing, litigating and implementing programs.

Even though a five year program is longer than a three year program, it is still short enough to accurately forecast data and plan for the different energy efficiency and demand response programs. Planning for a longer term program will help to alleviate administrative burdens of having to prepare and litigate the next EE&C program phase. Act 129 requires the Commission to evaluate the costs and benefits of the EE&C Program at least every five years[1]. A longer program also allows initial start-up costs of EE&C programs to be amortized over more years, thereby improving the cost-effectiveness.

As explained below, a significant benefit from extended programs can and should be their participation in the relevant PJM Base Residual Auction (BRA). Since these auctions are conducted in May, three years in advance of the delivery year, and because it is likely to take some time for the Electric Distribution Companies ("EDCs") to determine which CSPs are providing what share of their needs (whether through auctions or through tariff-based offerings), programs effectively need to be extended for at least four (4) years in order for CSPs to have executed agreements with EDCs before they make their BRA commitments to PJM.

In addition, one of the factors that increases customer participation, and importantly customer satisfaction, is regulatory certainty. Particularly when recruiting commercial, industrial and institutional customers to energy efficiency and demand response programs, it is helpful if they know that if they choose to participate, they will be able to plan on the incentive revenue for more than three years.

If, during the five-year term, an EDC believes it needs to alter its programs to maximize cost-effectiveness and customer participation, the Commission should allow the EDC to file yearly updates and revisions to the plan as it currently does.

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[1] 66 Pa.C.S. § 2806.1(c)(3)

3. Inclusion of a Demand Response Curtailment Program

EnerNOC strongly supports the inclusion of demand response curtailment programs in the next round of EE&C programs, and the continuation of a peak reduction goal in 2013 and subsequent years.

In this section EnerNOC will:

- Present evidence that the 2012 demand response curtailment programs are extremely likely to be found cost-effective;
- Propose a mechanism that would allow the Commission to provisionally authorize the EDCs to move forward with planning for DR programs in 2012 while still providing an off-ramp if the Commission does not find these programs to be cost-effective; and
- Propose certain changes to the program design guidelines to make administration and operation more effective for EDCs, CSPs and customers.

The Demand Response Curtailment Programs Are Very Likely to Be Found Cost-effective Therefore the Commission Should Put In Place a Contingency Plan to Allow Them to Continue Uninterrupted in 2013.

Act 129 requires the Commission to conduct cost-effectiveness analysis of the DR Curtailment programs by November 2013. Unless there is a contingency plan in place, that date will be too late for the EDCs to plan and initiate a new DR program for 2013. EnerNOC believes there is sufficient evidence to show that those programs will be found cost-effective and therefore the Commission should put a contingency plan in place, either through the May 10, 2012 Tentative Implementation Order, or the August 2, 2012 Final Implementation Order.

EnerNOC has conducted its own analyses regarding the cost-effectiveness of demand response programs in Pennsylvania based on the original EDC filings. Our review of those filings suggests that the utilities are not appropriately treating the program costs within the TRC calculations in their filings. As a result, the cost-effectiveness of DR programs is actually higher than the EDCs estimated. Our analysis shows that appropriate accounting of program costs results in the utility DR programs being highly cost-effective. Moreover, in most of the utility filings, DR program benefits are being assessed only over the 2009-12 timeframe. In the event that these programs are allowed to continue beyond 2012, the cost-effectiveness of these programs is greatly improved. We also propose consideration of two additional benefits to the TRC calculation: 1) the bill savings to non-participating customers due to demand response's effect of controlling price spikes during peak hours[2]; and 2) the avoided costs of building new transmission and distribution infrastructure.

We reviewed utility filings in the Commonwealth of PA in order to understand the methodology individual utilities adopted for assessing cost-effectiveness of DR programs. A review of these filings indicates that all utilities have included customer incentives in the total TRC costs. Traditional TRC cost-effectiveness methodology treats incentives as a transfer or pass-through from the utility to a customer, so none of the incentive is booked as a "total resource cost" to society. If $100 enters the bucket of costs because the utility pays it out, that same $100 leaves the bucket because a customer pockets it.[3]

As a first step, we attempted to reproduce the TRC calculations in the utility filings for

[2] "The Implementation Order directs that the TRC test take into account the effects of an EE&C plan on both participating and non-participating customers" From: Docket No. M 2009-2108601 Implementation of Act 129 Total Resource Cost (TRC) Test Order Adopted June 18, 2009 at Page 21. http://www.puc.state.pa.us/electric/docs/Act129/TRC_Test_Order061809.docx.

[3] See Table 1 on page 17 of the CPUC DR cost-effectiveness protocols, where incentives are not a cost in the TRC calculation. http://www.cpuc.ca.gov/NR/rdonlyres/7D2FEDB9-4FD6-4CCB-B88F-DC190DFE9AFA/0/Protocolsfinal.DOC

demand response programs available to large Commercial and Industrial ("C&I") customers using publicly available data. At this stage, we duplicated the way utilities included customer incentives in total costs in order to calibrate to their results with no attempt to correct their methodology. Table 1 compares our estimate with the values filed by the utilities.

TABLE 1: TRC Calculations Using PA Utility Methods

Company	Program	TRC B/C Ratio as Filed in Plans	EnerNOC's reproduction of TRC Calculation with public information[4]	TRC burdened with customer incentive costs?	Timeframe Considered
Philadelphia Electric Company (PECO)	DR Aggregator Contracts	1.09	1.08	Yes	15 year NPV (2009-2023)
Pennsylvania Power and Light (PPL)	Load Curtailment Program	0.61	1.28[5]	Yes	4 year NPV (2009-2012)
Duquesne Power and Light	Curtailable Load Program	4.4	4.09	Yes	4 year NPV (2009-2012)
West Penn Power (Allegheny)	Customer Load Response	0.5	0.55	Yes	4 year NPV (2009-2012)
West Penn Power (Allegheny)	Customer Resources DR Program	0.8	0.86	Yes	4 year NPV (2009-2012)
First Energy Companies (MetEd, Penn Power, and Penelec)	C/I Large Sector Demand Response Program[6]	No ratio reported	Insufficient data to calculate B/C ratio		

Except for PPL, our basic model closely correlated with the original findings of the EDCs.

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[4] The methodology for reproduction of TRC ratios includes customer incentives in the total costs, similar to the approach utilities adopted in their filings. This was done in order to be able to compare our estimates directly with the values that the utilities filed.

[5] We were not able to reproduce PPL's filed B/C ratio of 0.61 for the Load Curtailment Program. Using the exact same methodologies, we obtained significantly higher benefits ($11.9 million vs. $4.8 million). We have been unable to reconcile the differences with the publicly available data.

[6] Program name indicated in the annual reports is 'Commercial / Industrial Large Sector Demand Response Program – CSP Mandatory and Voluntary Curtailment Program'.

Next, we corrected the cost-effectiveness calculations by appropriately removing customer incentives from the TRC cost. A large portion of the budget paid to CSPs is actually passed through directly as incentive payments to the customers, and therefore should not be counted as a TRC cost. Since the actual contract arrangements of individual CSPs are sensitive business information, we considered a reasonable range of incentives passing through to the customer: from 40% to 60% of the total CSP budget. For comparison, we also present the original case from the utility filings where none of the CSP budget is considered a pass-through incentive (in other words, 100% of the incentives are treated as costs.) See Table 2 below.

TABLE 2: TRC Calculations as filed and with appropriate treatment of incentive costs (2009-2012)

Company	Program	TRC ratio burdened with 100% of aggregator and incentive costs[7]	TRC ratio where 40% of payment to aggregator is "passed through" as incentive	TRC ratio where 60% of payment to aggregator is "passed through" as incentive
Philadelphia Electric Company (PECO)	DR Aggregator Contracts	0.81	1.29	1.84
Pennsylvania Power and Light (PPL)	Load Curtailment Program	1.28	2.06[8]	2.97
Duquesne Power and Light	Curtailable Load Program	4.09	5.08	5.79
West Penn Power (Allegheny)	Customer Load Response	0.55	0.64	0.70
West Penn Power (Allegheny)	Customer Resources DR Program	0.86	1.15	1.38
First Energy Companies (MetEd, Penn Power, and Penelec)	C/I Large Sector Demand Response Program	Insufficient data to calculate B/C ratio	Insufficient data to calculate B/C ratio	Insufficient data to calculate B/C ratio

[7] This column corresponds to EnerNOC's calculation methods in Table 1, except for PECO, which is analyzed here in the 2009-2012 time-frame to be consistent with the other utility filings.

[8] In PPL's revised filing, customer incentives are shown to be zero. However, a comparison with the original filing reveals the fact that customer incentives are being categorized within the "CSP Labor cost" item. Using the information from the original filing, customer incentive costs were estimated as a % of total direct program costs. This % was then applied to the direct total program cost budget in the revised filing to estimate customer incentives.

Information presented in Table 2 shows that DR program cost-effectiveness is greatly improved when incentives are appropriately accounted for in the TRC test. All programs, except one[9], are cost-effective under this assessment.

Next, we consider cost-effectiveness of the different levels of incentive treatment by analyzing three different time-frames: 1-year (2011), 3-year (2011-2013), and 5-year (2011-2015) periods. For simplicity, we aggregate all the programs considered in the analysis to this point so we can view the effects on the Commonwealth of Pennsylvania as a whole.

TABLE 3: TRC Ratios using traditional calculation methods under different time periods with varying levels of incentive treatment

Analysis Time Periods	TRC ratio burdened with 100% of aggregator and incentive costs	TRC ratio where 40% of payment to aggregator is "passed through" as incentive	TRC ratio where 60% of payment to aggregator is "passed through" as incentive
2011	0.68	1.07	1.49
2011-13	1.10	1.74	2.46
2011-15	1.20	1.90	2.68

Information presented in Table 3 reveals that the portfolio of DR programs over all three time-frames is cost-effective at both 40% and 60% levels of aggregator payment passed through as incentives to customers. In addition, Table 3 shows that multi-year programs are more cost-effective than single-year programs, which makes intuitive sense. DR programs, like most demand side programs, have initial start-up costs that are not present in subsequent years. Amortizing these one-time costs over longer periods results in enhanced cost-effectiveness.

[9] West Penn Power's Customer Load Response Program is the only one which has a TRC ratio less than 1.

Thus, one can see that these DR programs are expected to be highly cost-effective, within the context of traditional utility analysis if two variables are considered appropriately - the categorization of customer incentives and use of a multi-year calculation.

The programs become even more cost-effective if we consider two additional benefits, described earlier, namely reductions in prices to non-participants and savings on transmission and distribution infrastructure costs. These benefits are at times neglected in TRC calculations because they are difficult to quantify. However, these benefits can be significant.

To quantify the economic benefits to non-participants, we note the capacity price reduction effected by the presence of demand response programs and multiply that difference in price by the total amount of load affected. We used PJM auction information to find prices for the 2013 and 2014 auctions.[10] Scenarios are available in these two years to show what prices would have been by excluding DR. To be conservative, we chose to apply the lower price delta from the 2014 auction scenario analysis. We calculate that for every megawatt (MW) of DR in Pennsylvania for the 2014 auction, the price decreases by $0.82/MW-year. This is then multiplied by the total load served in PA per year to find the total dollar amount saved by customers. The estimated total NPV of benefits accruing to the state of PA from lowered capacity costs is presented in Table 4.

TABLE 4: NPV of Statewide Non-Participant Benefits from Analyzed DR Portfolio

Analysis Time Periods	NPV of Statewide Non-Participant Benefits due to market price reduction effect of DR
2011	$2,988,470
2011-13	$19,132,834
2011-15	$33,600,893

[10] http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx

Factoring these benefits into the cost-effectiveness calculations results in the following TRC ratios (See Table 5).

TABLE 5: TRC Ratios from Table 3 with Non-Participant Benefits Added

Analysis Time Periods	TRC ratio burdened with 100% of aggregator and incentive costs	TRC ratio where 40% of payment to aggregator is "passed through" as incentive	TRC ratio where 60% of payment to aggregator is "passed through" as incentive
2011	0.91	1.43	2.00
2011-13	1.49	2.36	3.33
2011-15	1.60	2.54	3.59

Finally, another benefit to demand response programs that is not currently considered in the Pennsylvania TRC methodology is the avoided cost of new transmission and distribution (T&D) infrastructure. To the extent that reduced system peaks avoid the construction and upgrading of T&D systems, future expenditures are avoided. An estimate of these benefits was provided in a study for the State of Connecticut with a valuation of $29.2/kW-year.[11] Adding these benefits in succession to the TRC tests from Table 5 produces the following TRC ratios.

[11] "Assessment of Avoided Cost of Transmission and Distribution" Prepared for: Connecticut Light and Power Company by: ICF International, October 30, 2009. www.dpuc.state.ct.us

TABLE 6: TRC Ratios from Table 3 with Avoided T&D and Non-Participant Benefits Added

Analysis Time Periods	TRC ratio burdened with 100% of aggregator and incentive costs	TRC ratio where 40% of *payment to* aggregator is "passed through" as incentive	TRC ratio where 60% of payment to aggregator is "passed through" as incentive
2011	1.30	2.04	2.85
2011-13	1.95	3.09	4.36
2011-15	2.06	3.27	4.62

EnerNOC did not calculate the savings to non-participants from energy price reductions caused by demand response but believes they are significant. EnerNOC supports the comments of Viridity Energy being filed today in this proceeding on the importance and size of these benefits to Pennsylvanians.

As can be seen from this analysis, demand response can provide very economical benefits for Pennsylvania. The portfolio considered here always has a TRC benefit to cost ratio higher than 1.0, and for several cases higher than 4, when the following is true: 1) incentives are considered appropriately, 2) multiple-year time-frames are considered, 3) non-participant benefits are included, and 4) avoided transmission and distribution costs are included. The point of this analysis is not to predict specific cost-effectiveness numbers. Rather, the point of this analysis is to show that under a very reasonable range of assumptions these programs are very likely to be found cost-effective next November and therefore the Commission should start making contingency plans now, so that the benefits can be realized in 2013 and beyond.

How to Provide a Contingency Plan So that DR Curtailment Programs will Not be Interrupted in 2013.

Act 129 indicates that as long as it is cost effective, the Commission shall set additional requirements for peak demand reductions.

> By November 30, 2013, the Commission shall compare the total costs of energy efficiency and conservation plans and capacity costs to retail customers in this Commonwealth or other costs determined by the Commission. If the Commission determines that the benefits of the plans exceed the costs, the commission shall set additional incremental requirements for reduction in peak demand for the 100 hours of greatest demand or an alternative reduction approved by the Commission. Reductions from demand shall be measured from the Electric Distribution Company's peak demand for the period from June 1, 2011 through May 31, 2012. The reduction in consumption required by the Commission shall be accomplished no later than May 31, 2017.[12]

The Commission has indicated that it will complete the cost-effectiveness analysis in 2012, a year earlier than required. However, as described above, even that acceleration of the analysis will not provide the Commission sufficient time to approve, and the EDCs sufficient time to implement, a DR curtailment program for the summer of 2013 because the current program requirements expire in May of 2012.

The simplest, and most logical contingency plan is for the Commission to direct the EDCs to continue their existing DR programs, *as is*, for one additional summer season through September of 2013 in the Commission's proposed May 10, 2012 Tentative Implementation Order if possible, but certainly no later than the August 2, 2012 Final Implementation Order. This approach has several advantages. First, it would provide certainty for EDCs, CSPs and customers. The EDCs could then easily build the programs into their EE&C plans due for filing

[12] 66 Pa. C.S. §2806.1(D)(2)

on November 1, 2011. Secondly, it would provide the Commission more time to both evaluate the cost-effectiveness of the programs, as well as vet potential program improvements with the EDCs and stakeholders. The resulting 2014 programs would undoubtedly benefit from a more thorough, less rushed evaluation and subsequent planning cycle.

If the Commission believes it does not have the statutory authority to make a simple one summer extension, the alternative would be to direct the EDCs to plan for DR Curtailment Programs in 2013 and the duration of the years in the EE&C cycle (3, 4 or 5 years as the Commission determines), including potential improvements and changes to those programs, but not allow them to implement the programs unless, and until, the Commission makes a final determination on cost-effectiveness. If the determination is that the programs **are** cost-effective, then the EDCs would continue onward with implementation in 2013. If the determination is that the programs **are not** cost-effective, the EDCs would cease their planning activity and re-allocate funds to other EE&C programs. It would be important to make sure that the EDCs were allowed to recover their costs incurred for the planning effort up to the point of final determination. Of the three options presented in Issue 3 of the Secretarial Letter, this option most closely resembles Option 3. It is basically a "full speed ahead unless we tell you to stop" option.

EnerNOC Recommends Two Changes to the Structure of the DR Programs Going Forward

The Secretarial Letter asks the following question regarding future DR programs:

"... how should these demand response programs be structured to be cost-effective?"

EnerNOC recommends two changes going forward that should make the programs more efficient and workable for all concerned.

First, peak reduction targets should be annual and for every year of the EE&C cycle. So, for example, if the Commission determines that the EE&C program cycle should be five years, then there should be a goal for each EDC each year. To have one goal that has to be met in 2017 means we will be back in the very same situation we are in now, which is no time to adequately analyze program success before a potential interruption to the program. With a five year program cycle, data about success against goals in the first four years can be used to evaluate the programs before they expire.

Demand response is not a permanent change. It goes away if the incentives for participation and the infrastructure for dispatching and monitoring events goes away. So, having annual goals will mean that all parties, EDCs, CSPs and customers will be exercising the program and not caught flat-footed once every three to five years.

Demand response is also not cumulative. That is to say, if 4.5% was shaved off of the peak last year, that does not mean a total of 9% would be shaved the second year with the same resources. Therefore it is not appropriate to have ever increasing peak reduction targets. A well designed program should probably have some ramp-up in the first couple of years but sooner or later the goals should level out.

The 100 Hour Criteria Should Be Modified

The Legislature has granted the Commission the flexibility to apply a peak load reduction eligibility criteria that is different from the current "Top 100 Hour" approach. EnerNOC believes that the Commission should exercise this flexibility and instead use an alternative methodology that preserves the intent and benefits of the prior criteria but relieves the EDCs of the risk associated with inaccurately forecasting the top 100 load hours.

Briefly, we believe that the Commission should instead use an "X% of Forecast Peak" criteria, subject to a cap of no more than 50 hours. This would capture the majority of the market benefits using a more objective approach. Under this mechanism, each EDC would activate its demand reduction programs during any hour in which the EDC's day-ahead peak load forecast equaled or exceeded X% of the PJM Annual Peak Load Forecast for that EDC. If the day-ahead forecast equaled or exceeded a given percentage of their territory-specific forecasted annual peak published by PJM, that hour would become an Act 129 program hour. Peak load reductions in such hours, as measured using the existing TRM criteria, would count toward the EDC's peak load reduction mandate.

Our analysis of the PJM system suggests that the event trigger should be 94% of forecast day-ahead peak, as it would capture the top 50 hours. However, analysis at the EDC level might suggest other values. As a corollary benefit, costs will decrease as EDCs will no longer need to engage in costly and risky forecasting. This approach mirrors that adopted several years ago by the New York Public Service Commission (NYPSC) for Con Edison (ConEd) and subsequently modified to improve its effectiveness.

In February 2009, the NYPSC instituted a proceeding requesting that ConEd file an identification and description of proposed cost-effective demand response programs for New York Independent System Operator ("NYISO") Zone J. On June 1, 2009, ConEd filed a proposal which included four new peak load shaving programs designed to reduce the system coincident peak, individual network peaks, and operation of generating units in environmental justice areas.

On September 23, 2010, ConEd proposed the re-design of these programs[13]. These design changes were intended to increase enrollment, improve response to events, leverage NYISO enrollment, and make it easier for customers to participate in these programs. On January 20, 2011, the NYPSC issued its *Order Adopting Modifications to Demand Response*

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[13] Case 09-E-0115, Proceeding on Motion of the Commission to Consider Demand Response Initiatives, *Petition of Consolidated Edison Co. of New York, Inc. for Approval of Changes to Demand Response Programs* September 23, 2010.

Programs, approving most of the changes proposed by the Company, with the exception of some proposed changes that were rejected or modified[14]. Subsequently, ConEd proposed further refinements on November 11, 2011 that were recently accepted by the NYPSC[15].

The ConEd program that is relevant to this proceeding is the Commercial System Relief Program (CSRP.) CSRP was approved as an ongoing program (Tariff Rider S) and is open to participants in New York City who can curtail load or bring on certain on-site generation to reduce their demand by a minimum of 50 kW individually, or to Aggregators/Curtailment Service Providers ("CSPs") who aggregate greater than 100 kW of demand reduction with a minimum of 21 hours notice before a planned event (a day-ahead forecasted load level that is at least 96 percent of the Company's forecasted summer system peak). Participants receive monthly reservation payments to participate in the program. The summer period for CSRP typically runs from May 1 through October 31. Program participants are notified at least 21 hours before the peak load shaving event is scheduled to begin, and are expected to reduce load based upon their pledged kW. The call window is five hours and is dependent upon whether the network is daytime or nighttime peaking. The daytime peaking networks are called from 12pm-5pm and the nighttime peaking networks are called from 5pm-10pm. In addition to the reservation payment, participants receive an energy payment that is equal to $0.50 per kW reduced during each event hour.

While EnerNOC would welcome this Commission mandating the continuation of the PA EDCs' Act 129 programs on similar terms to ConEd's CSRP, our point here is to highlight that the use of an objective trigger that avoids the need to forecast the top 100 hours can be entirely

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[14] Case 09-E-0115, Proceeding on Motion of the Commission to Consider Demand Response Initiatives, *Order Adopting Modifications to Demand Response Programs*, issued and effective January 20, 2011.

[15] Case 09-E-0115, Proceeding on Motion of the Commission to Consider Demand Response Initiatives, *Order Adopting with Modifications Tariff Amendments Related to Demand Response Programs*, issued and effective March 15, 2012.

consistent with a viable peak load reduction program. We understand this to be the principle objection raised by EDCs to the continuation of the peak load reduction aspects of Act 129.

4. **Aligning EDC Targets and Funding Using Dollars per MWh of Expected Reductions**

EnerNOC does not have any comments on this section of the Secretarial Letter at this time.

5. **Inclusion of a Reduction Target Carve-Out for the Government, Educational and Non-Profit Sector**

EnerNOC works extensively with state and local governments and educational institutions. They are often good candidates for demand response and have the long term perspective to value energy efficiency investments. Typically, they do not require additional assistance to participate in these programs and so, in general, a carve-out for them is not required. However, because Pennsylvania energy customers are also taxpayers, directing funds towards this segment may make policy sense and therefore EnerNOC has no objection to such a carve-out. EnerNOC only requests that the Commission ensure that both the peak reductions and energy savings from local governments and educational institutions participating in demand response programs be credited against both the EDCs' goals and the amount of the carve out.

6. **Inclusion of a Low-Income Sector Carve-Out**

EnerNOC supports the inclusion of a Low-Income Sector Carve-Out. It is important to make sure that all Pennsylvania ratepayers, including low-income customers, benefit from the program. As stated above, all customers benefit from lower energy and capacity prices when DR reduces peak load. However, low-income customers can benefit even more if they participate in EE and DR programs and there is no technical reason why they cannot. However, traditionally programs aimed at these customers have not been as cost-effective as other programs, due to their generally low consumption and the difficulty sometimes of reaching them. Therefore it is important to have a carve-out to ensure the widest possible participation among Pennsylvanians.

7. Transition Issues

EnerNOC does not object to allowing an EDC that surpasses its Energy Efficiency reduction targets in Phase One to credit the surplus reduction amount to Phase Two target requirements. However, EnerNOC does not recommend reducing the budget for demand response or other programs during Phase Two. EnerNOC also believes any additional funding not used in Phase One that was allocated to the demand response programs should carry over and be allowed to be used during Phase Two.

8. Other Act 129 Program Design Issues

Act 129 is long on "sticks" for EDCs who do not comply (up to $20 million fine) but short on "carrots." EnerNOC would like to support the comments of OPower in this proceeding that encourage the Commission to use its rate setting authority to consider financial incentives for EDCs who not only do a good job of implementing Act 129 but for implementing all demand-side activities. As OPower points out, there are a number of ways to do this and a number of states have already taken such action.

Conclusion

EnerNOC appreciates the opportunity to comment on Phase Two of the Energy Efficiency and Conservation Programs. EnerNOC believes that demand response programs are necessary to include in Phase Two of the program and will be beneficial to Pennsylvania electric customers. EnerNOC urges the Commission to adopt the process described in these comments to ensure that there are no gaps in the program that would compromise achieving reduction goals, hinder customer participation and reduce benefits to all Pennsylvanians.

WHEREFORE, EnerNOC, Inc. respectfully requests that the Pennsylvania Public Utility Commission enter these Comments to the March 1, 2012 Secretarial Letter in this proceeding into the record. We look forward to participating in the process going forward and contributing our experience and expertise. Thank you again for the opportunity to comment on this important matter.

Respectfully submitted,

By: ______________________

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DATED: APRIL 17, 2012

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COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION

ACT 129 ENERGY EFFICIENCY AND CONSERVATION PROGRAM PHASE TWO	DOCKET NO. M-2012-2289411

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document "**Comments on behalf of EnerNOC, Inc. in Response to the Act 129 Energy Efficiency and Conservation Program Phase Two Secretarial Letter**" in hand to the Commission and electronically to Megan Good at megagood@pa.gov.

Dated: **April 17, 2012**

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