BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 13-12-010 (Filed December 19, 2013)

COMMENTS OF ENERNOC, INC. ON DECEMBER 18, 2013 WORKSHOP MATERIALS

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EnerNOC, Inc. (EnerNOC) respectfully submits these Comments on the December 18, 2013 Workshop Materials identified in the Administrative Law Judge's (ALJ's) Ruling served by electronic mail to the service list in the prior Long Term Procurement Plan (LTPP) Rulemaking (R.) 12-03-014 on December 19, 2013 (12-19-13 ALJ's Ruling). These Comments are filed and served pursuant to the Commission's Rules of Practice and Procedure and the 12-19-13 ALJ's Ruling, which included the direction to file these Comments in R.13-12-010, the "successor proceeding" to R.12-03-014.

I.
INTRODUCTION

On December 18, 2013, the Commission held a Workshop during which the staffs of this Commission, the California Energy Commission (CEC), and the California Independent System Operator (CAISO) introduced a proposed joint CPUC-CEC-CAISO planning assumptions, scenarios, and renewable portfolios to be used in the 2014 CPUC LTPP and the 2014-2015 CAISO Transmission Planning Process (TPP) cycles. By the 12-19-13 ALJ's Ruling, parties have been given the opportunity to comment on these proposals and the related materials distributed and discussed at the December 18 Workshop, including offering responses to an attachment listing "Key Technical Questions."

EnerNOC attended and actively participated at the December 18 Workshop. EnerNOC has also reviewed the materials and questions distributed with the 12-19-13 ALJ's Ruling.

Based on that review and its responses to the "Key Technical Questions" (included in Section II below), it is EnerNOC's position that the planning assumptions and scenarios have significant shortcomings. Specifically, the assumptions and scenarios fail to adequately represent demand response (DR) potential; fail to incorporate any growth over current levels of DR, including the Expanded Preferred Resources Scenario; leave the determination of efficacy of DR resources for local reliability purposes to the discretion of the CAISO and the project team; and fail to adequately consider non-dispatchable DR as a modification to the load forecast as small commercial customers and residential customers are exposed to time variant pricing.

As a result, EnerNOC recommends that the Commission require that the LTPP Team adjust their assumptions to provide a range of potential DR scenarios, including a high, mid-range, and low forecast, as was done in the 2012 LTPP. The mid-range would assume a 20% increase over current levels, the low forecast would assume existing DR capacity through 2024, and the high forecast would assume a 30% increase over current DR levels. These assumptions, as explained further below, are still conservative and will provide a range of resource needs depending upon the DR scenario assumptions. The high forecast should be used in the Expanded Preferred Resources Scenario.

II.
RESPONSES TO KEY TECHNICAL QUESTIONS

With respect to the "Key Technical Questions," attached to the 12-19-13 ALJ's Ruling, EnerNOC does not believe that these questions address its concerns with the planning assumptions with respect to demand response, other than the broadly worded Question 1. EnerNOC, therefore, offers its responses and concerns on the planning assumptions and issues in response to Question 1. EnerNOC also offers limited responses to two other questions, but reserves the right to respond further on each of the Key Technical Questions in its Reply Comments.

QUESTION #1: *Is the current range of scenarios sufficient to cover current policy issues facing the CPUC?*

RESPONSE TO QUESTION #1: The direct answer to this question is "No." The current range of scenarios assumes a static DR value, no growth, over the 10-year planning horizon. The assumption that DR will not grow over the next 10 years is directly counter to several key policy objectives of the state.

First, DR is a preferred resource at the top of the loading order and all cost-effective DR and energy efficiency should be procured first before all other resource types.[1] The Energy Action Plan II also states that demand response should be incorporated "appropriately and consistently into the planning protocols of the CPUC, the CEC, and the CAISO."[2] The top of the loading order is codified into the Public Utilities Code and requires the electrical corporation to "first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible."[3]

Assembly Bill 32, The California Global Warming Solutions Act, 2006, requires a 20% reduction in greenhouse gas (GHG) emissions by 2020 relative to 1990 levels. The California Air Resources Board (CARB) 2008 Scoping Plan relies upon a high concentration of renewable resources alongside aggressive implementation of energy efficiency including "innovative strategies above traditional utility programs."[4] One of the "innovative strategies" includes "[p]roviding real time energy information technologies to help consumers conserve

[1] EAP II, at p. 2.
[2] EAP II, at p. 7.
[3] California PU Code §454.5 (b)(9)(C).
[4] CARB Scoping Plan, at p. 41.

and optimize energy performance".[5] The effort to provide real-time energy information to consumers, or their service providers, is underway through the smart grid deployment plans in the Smart Grid Rulemaking (R.08-12-009) and should increase both DR and EE as a result.[6]

In its Decision (D.) 13-02-015 in Track 1 (Local Reliability) of the 2012 LTPP (R.12-03-014), the Commission provided explicit direction to Southern California Edison Company (SCE) as to the amount and type of procurement they were authorized to pursue, with as much as 800 MW of the maximum 1,800 MW procurement authorization to come from preferred resources.[7] The new DR Rulemaking (R.) 13-09-011 states that one goal of this proceeding is to "increase the penetration of demand response programs."[8] The CEC's 2013 Integrated Energy Policy Report (IEPR) states that "[t]here is an urgency to expand DR as a frontline resource for maintaining system reliability and taking full advantage of the contributions of low - carbon renewable generation. "[9] The Preliminary Reliability Plan for LA Basin and San Diego, prepared by Staff of this Commission, the CEC, and CAISO on August 30, 2013, in relation to the permanent retirement of the San Onofre Nuclear Generating Station (SONGS), identifies its first key action to be development of 3,250 MW of preferred resources to meet 50% of the identified resource needs resulting from the SONGS closure.[10]

Yet, despite all of this direction that would support at least some expected increase in DR over the study horizon, *none* was assumed in the December 18 Workshop assumptions

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[5] CARB Scoping Plan, at p. 42.
[6] R.08-12-009 (Smart Grid) Annual Smart Grid Reports filed by PG&E, SCE and SDG&E on October 1, 2013.
[7] D.13-02-015, at pp. 10-11.
[8] R.13-09-011, Order Instituting Rulemaking (September 25, 2013), at p. 15.
[9] CEC 2013 IEPR, at p. 40.
[10] The Preliminary Reliability Plan, at p. 2.

and scenarios. In addition, not only is using the current levels of DR for planning resource needs over the next 10 years an extremely conservative assumption, that level of DR can be further, subjectively reduced by the CAISO for uncertainty of local effectiveness in Trajectory Scenario 1.a.[11] In fact, CAISO exercised its discretion in its analysis of the 2012 LTPP Track 4 needs in the absence of SONGS by disregarding the *clear directive* of the Commission that CAISO was to assume 183 MW of DR for a post-first contingency and 997 MW of DR for a post-second contingency in that analysis.[12] CAISO, instead, considered only the post-first contingency DR and none of the post-second contingency DR.[13] However, to this date, CAISO has not specified the DR resource requirements in order for DR to be recognized as a local capacity resource.[14]

It is unconscionable to continue to espouse support for DR resource development in a policy context and to ignore the existence of DR resources for planning purposes. It gives the appearance of a lack of internal coordination among the agencies and their staffs conducting the studies, including those that enforce the State's policies and laws. It is an abundant waste of parties' time and resources to have to continually advocate for inclusion of preferred resources into planning scenarios, when that should be occurring without question. Instead, parties have to expend tremendous effort to "undo" the results that are based on assumptions that are squarely in opposition to Commission policies.

As such, EnerNOC strongly encourages the use of scenario analysis for supply-side and for non-dispatchable DR in the load forecast. Based on a response to a question

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[11] 12-19-13 ALJ's Ruling Attachment, at p. 23.
[12] R.12-03-014 Assigned Commissioner and ALJ Revised Ruling and Scoping Memo (May 21, 2013), Appendix A, at p. 2.
[13] R.12-03-014 Track 4 Reporter's Transcript (RT) at 1456-1457 (CAISO (Sparks))
[14] R.13-09-011 (DR) EnerNOC and Comverge Joint Reply to Responses to Foundational Questions (December 31, 2013), at pp. 2-3.

EnerNOC asked at the December 18 Workshop, Staff has confirmed that the scenarios do not reflect the potential for an increase in non-dispatchable DR as a result of the implementation of time-variant pricing for residential DR, beginning in 2018. The affect of residential DR, as of 2018, was dismissed as "too in the weeds." It is also reasonable to assume that DR growth will occur as a result of the implementation of default coincident peak pricing (CPP) and peak-day pricing (PDP) for small commercial customers.

Further, the forecast on which the Staff has chosen to rely assumes *no* growth in supply-side DR over the planning period. Further, it is not clear to what extent DR resources will be considered as local capacity resources or solely as system resources, despite the fact that several supply-side DR resources are dispatchable by either local capacity area (LCA) or sub-load aggregation point (LAP).

In the previous LTPP (R.12-03-014), a scenario analysis was performed such that the most likely outcome used the load impact results with a low and a high scenario. EnerNOC protested the use of the load impact protocols as the most likely scenario as too conservative in that instance.[15] However, here, where such scenarios do not exist, EnerNOC recommends that such a scenario analyses be used in the 2014 LTPP, and recommends the use of the high scenario for the "Expanded Preferred Resources Scenario." In terms of framing a scenario analysis, EnerNOC would recommend that the current load impact results would be used for the low scenario, a 20% increase above current load impact levels would reflect the mid-range estimate, and a 30% increase above current load impact levels would reflect the high scenario. These are reasonable ranges considering all of the aforementioned efforts underway to expand DR participation.

[15] R.12-03-014 (LTPP) EnerNOC Opening Comments on the Straw Proposal Assumptions (May 31, 2012), at pp. 2-6.

QUESTION #3: *Should Diablo Canyon be assumed online or retired in the Trajectory case?*

RESPONSE TO QUESTION# 3: Diablo Canyon should be assumed to be "retired" in the Trajectory case.

QUESTION #6: *How should the capacity value of energy storage, demand response, and demand side resources (PV, CHP) be allocated to small geographic regions and/or busbars and how should the capacity value be adjusted to account for locational and operational characteristics uncertainty?*

RESPONSE TO QUESTION #6: A portion of the DR aggregator-managed program (AMP) contracts are dispatchable by either sub-LAP or local capacity area. The capacity bidding program (CBP), demand bidding programs (DBP) and Base Interruptible Program (BIP) all have some level of local dispatch capability. The utilities should know the amount and location, and that data should be reflected in the scenarios here.

III.
CONCLUSION

EnerNOC appreciates the opportunity to provide these comments and respectfully requests that the Commission require that the demand- and supply-side assumptions for DR resources in the 2014 LTPP be modified to reflect the clear objective to expand DR resources over the planning horizon. These include, but are not limited to, including (1) DR reductions as a result of implementing time-variant rates for residential customers beginning in 2018 and small commercial DR as a result of implementing coincident peak or peak day pricing tariffs, and (2) scenarios for DR penetration to include high, mid-range, and low assumptions such that the high scenario is assumed to be 30% higher than the load impact levels for 2013, the mid-range assumes a 20% increase in the load impact levels for 2013, and the low range assumes no growth over the 2013 load impact levels. The CAISO should also be required to disclose the amount of DR assumed in the Trajectory Scenario 1.a. for local capacity purposes.

These changes are required, at a minimum, to ensure that this State's energy policies are being followed by this Commission, the CEC, and CAISO. It is, therefore, essential that those policies be reflected in the planning assumptions used to determine new resource needs.

Respectfully submitted,

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