CAISO Draft 2014-2015 Transmission Study Plan

Submitted by	Company	Date Submitted
Melanie Gillette Director, Western Regulatory Affairs EnerNOC, Inc. 916-671-2456	EnerNOC, Inc.	3/13/14

EnerNOC appreciates the opportunity to provide these comments on the February 20, 2014 *Draft 2014-2015 Transmission Planning Process Unified Planning Assumptions and Study Plan* (2014-2015 Study Plan). We continue to support the California Independent System Operator (CAISO) for attempting to integrate existing and authorized preferred resources into its reliability assessments and to consider them as mitigation alternatives for identified reliability concerns in support of California's policy emphasis on the use of preferred resources—specifically demand response and energy efficiency, which are at the top of the state's loading order. EnerNOC believes it is critical to incorporate these preferred resources into the planning assumptions to meet local reliability needs in order to appropriately represent the current and future potential of these resources.

As we have stated in previous comments on the 2013-2014 Transmission Plan, EnerNOC's overarching concern is that the planning assumptions and scenarios being used by the California Public Utilities Commission (CPUC), the California Energy Commission (CEC) and CAISO do not adequately represent the demand potential. For example, they fail to incorporate any growth over current levels of demand response; do not include modifications to the load forecast to reflect increasing customer exposure to time-variant rates; do not include any demand response resources for local reliability purposes; and fail to define the attributes that would allow preferred resources to be included for local reliability going forward.[1]

[1] February 26, 2014 *Comments of EnerNOC on CAISO Draft 2013-2014 Transmission Plan*, at pp. 1-2.

Demand response is one of the preferred resources being promoted in the state's policy context; however, it is being virtually ignored for planning purposes. This apparent lack of coordination among the agencies and their staffs conducting the studies is leading to an untenable situation. Parties, including EnerNOC, have to devote significant time and resources to continually advocate for the inclusion of preferred resources into planning scenarios, when they should be included automatically, consistent with state policy.

The 2014-2015 Study Plan includes one short page explaining how "fast-response" demand response programs will be considered to mitigate first contingencies under an N-1-1 condition. However there is not sufficient detail in this brief paragraph to understand how demand response programs were identified as "an acceptable assumption for local area studies." The only definitions that are included are that the resources must be "fast-response" and located in the most effective areas for mitigating first contingencies under an N-1-1 condition.[2] "Fast-response" is defined as having an expectation that demand response would be "able to respond in sufficiently less time than 30 minutes from the CAISO dispatch, to allow ISO operators enough time to detect a non-response and dispatch an alternative resource if needed to mitigate a contingency."[3] The only additional detail about demand response included in the 2014-2015 Study Plan is a table that identifies the demand response programs for each investor-owned utility (IOU) that meet the "fast response" criteria.[4] The demand response programs that are included in this table are BIP, API and AC Cycling.

While EnerNOC is encouraged to see demand response included for local reliability in the Study Plan, it is unclear why these DR programs were selected for the study while other "Fast-Response" resources were not included. The February 27 presentation included additional slides for each of the three IOUs that included additional descriptors such as "advanced notification," "frequency limitations,"

[2] *Draft 2014-2015 Transmission Planning Process Unified Planning Assumptions and Study Plan,* at p. 28
[3] *Id.*
[4] Id, at Table 4-11, p. 28

and "duration limitations." The "Fast Response DR Programs" included in the table had 30 minute advance notification, with the exception of SCE BIP, which indicates 15 or 30 minutes advance notification, and varied in their frequency limitation and duration limitations by IOU. In addition to the Base Interruptible Program, several supply-side demand response resources, including Aggregator-Managed Contracts, the Capacity Bidding Program, and the Demand Bidding Program are dispatchable by either local capacity area or sub-load aggregation point. However, this capability does not appear to be captured in the Transmission Plan's scenarios.

It is our understanding that CAISO requires that demand response resources must be fast response curtailment (20 minutes) in addition to meeting the resource adequacy requirement for four hour duration.[5] Presumably this requirement is related to CAISO's need to stabilize the system within 30 minutes after a contingency event. CAISO interprets that requirement to suggest that demand response resources would need to be dispatched in advance of that 30 minute timeframe. To our knowledge this is not a requirement in other markets, however. The reality is that with 30 minute notification of an event, customers do start to drop load, so there is some amount of load drop that would definitely occur within the 20 minute window. However, resources that come on line within the 20-30 minute window still have some value for restoring the system, especially considering that most generation in a local capacity area cannot respond to a 30 minute dispatch signal and yet still counts toward meeting local reliability. The value for the 30 minute demand response is certainly not zero!

It would be very helpful if the 2014-2015 Study Plan would address the issues outlined above. It is important for parties to have clear definitions of what qualifies for a resource to be considered to mitigate a local reliability constraint. It is also important that CAISO help stakeholders understand why there is a "California-specific" requirement for demand response to be considered to satisfy a NERC

[5] Draft 2013-2014 Transmission Plan, at p. 92.

requirement. This is puzzling and challenging. EnerNOC appreciates the opportunity to provide these comments and respectfully requests CAISO's consideration.