BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements and Establish Annual Local Procurement Obligations	R.11-10-023 (Filed October 20, 2011)

COMMENTS OF NRG ENERGY, INC. ON PHASE 3 WORKSHOP TOPICS

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For
NRG ENERGY, INC.

February 18, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider Annual Revisions to Local Procurement Obligations and Refinements to the Resource Adequacy Program.	R.11-10-023 (Filed October 20, 2011)

COMMENTS OF NRG ENERGY, INC.
ON PHASE 3 WORKSHOP TOPICS

In accordance with the August 2, 2013 *Phase 3 Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge* ("August 2 Scoping Memo"),[1] NRG Energy, Inc.[2] ("NRG") hereby submits these comments on (1) the January 16, 2014 Energy Division Staff ("ED Staff") Proposal regarding *Effective Load Capacity and Qualifying Capacity Calculation Methodology for Wind and Solar Resources* ("Wind and Solar QC Proposal"); (2) the January 16, 2014 Staff Proposal Outline regarding *Qualifying Capacity and Effective Flexible Capacity Calculation Methodologies for Energy Storage and Supply-Side Demand Response Resources*[3] ("Storage and DR QC and EFC Proposal"); and (3) the January 16, 2014 *RA Implementation Staff Proposals* ("Implementation Proposals"); as discussed in the January 27, 2014 workshop.

[1] The August 2 Scoping Memo set February 17, 2014 as the comment due date; Administrative Law Judge David Gamson's February 4, 2014 e-mail, noting that February 17 was a state holiday, moved that due date to February 18, 2014.

[2] NRG Energy, Inc. is the parent of NRG Power Marketing LLC, GenOn Energy Management, LLC, Cabrillo Power I LLC, Cabrillo Power II LLC, El Segundo Power LLC, GenOn Delta, LLC, GenOn Marsh Landing, LLC, GenOn West, LP, High Plains Ranch II, LLC, Long Beach Generation LLC, NRG Solar Alpine LLC, NRG Solar Borrego I LLC, NRG Solar Blythe LLC, NRG Solar Roadrunner LLC and Avenal Solar Holdings LLC, each of which owns and operates generating resources in California. Because the focus of this proceeding is on California market issues, NRG Energy, Inc. appears on behalf of these entities.

[3] The date on this proposal was mis-labeled as January 16, 2013.

I. COMMENTS

A. Determining Qualifying Capacity For Wind and Solar Resources Through Effective Load Carrying Capability ("ELCC") Analysis

As ED staff note: the requirement to determine QC values through ELCC analysis is codified in legislation.[4] As such, the question of whether ELCC analysis should be used to determine RA QC values is largely moot. However, the question of whether QC values that are derived through the ELCC analysis methodology set forth by ED staff align with the purposes of the RA program under its current design is pertinent.

The RA program currently has two components:

(1) ensure adequate capacity to meet monthly peak demand needs during the five peak demand months of May through September; and

(2) ensure adequate capacity to meet local capacity needs. While these local capacity needs are determined by studies conducted at annual peak demands, the local capacity requirements determined are enforced for the entire year.

The wind and solar QC methodology using ELCC analysis proposed by ED staff has these characteristics:

- It categorizes wind and solar resources into five technology types. NRG agrees with using separate technology categories. However, it is not clear whether the five technology categories proposed are the "right five" technology categories. For example, within one category (solar thermal) the technologies used could be substantially different (*e.g.,* power tower and solar trough).
- It further categorizes a resource's location into one of 18 areas, eight of which are within California and ten of which are outside California. While providing for

[4] Wind and Solar QC Proposal at 1.

geographic differences is rational, NRG does not know whether the proposed geographic breakdown most efficiently follows the natural geographic difference in the performance of these resources. The more regions, the more accurate the QC values, as long as there is sufficient data to perform a robust analysis.

- It determines an "aggregate" QC value for a resource type and region and then allocates that aggregate QC to all same-type resources within that region based on each resource's Pmax. ED staff propose this particular method to avoid creating "winners" and "losers" by vintage, as it is expected that the aggregate QC of solar PV resources will decrease as the penetration of those resources increases. The purported equity of this proposal notwithstanding, this proposal would ensure that solar PV resources' current QC values will change, almost certainly decrease, as additional solar PV resources come on-line. If RA buyers provide for such a future downward trajectory in their RA agreements, such a mechanism could prove both equitable and workable. However, if suppliers are held to constant RA values in their power purchase agreements, the proposed "vintage-indifferent" allocation methodology, while equitable to future developers, exposes current solar PV suppliers to risk. Inasmuch as the drop in QC values for PV solar resources with increased solar PV penetration is to be expected, this dynamic should not unduly impact existing suppliers. The primary value of solar resources – of all intermittent resources, for that matter – is their energy value, not their capacity value. While it is reasonable to expect renewable resources to provide some RA capacity contribution, capacity value is not their most valuable attribute. This reality should be reflected in the LSE buyers' contracting practices.

- It develops monthly QC values.[5] NRG agrees that this or any other QC methodology should determine monthly QC values. However, the discussion on page 7 of the Wind and Solar QC Proposal which suggests that ELCC analysis will consider all 8760 hours is confusing.

Whether the proposed ELCC methodology develops reasonable QC values cannot be determined until the QC values this methodology produces are fully evaluated. The experience of Rulemaking R.08-04-012, in which complex probabilistic analysis was explored to try to assess the reasonableness of the 15-17% Planning Reserve Margin ("PRM"), should inform these probabilistic study efforts as well. In that proceeding, the initial results, which were based on a particular set of assumptions, were deemed to be fatally flawed, and the use of probabilistic techniques to validate the PRM – or determine a different PRM – was ultimately scrapped. The ELCC methodology requires complex, data-intensive, assumption-driven analysis. The QC values that result from this analysis must be fully evaluated, including comparing those values with the QC values that are derived through the current methodology. ELCC QC values that vary sharply from the current QC values could introduce unwelcome and unhelpful dislocations in current contracting practices or outcomes. Consequently, the reasonableness of using ELCC analysis that is based on a particular set of assumptions and methods to derive QC must be informed by the results of that analysis.

[5] See Wind and Solar QC Proposal at 3, which mentions monthly ELCC values; at 8, which discusses determining monthly Loss of Load Expectation values (and, presumably, monthly QC values); at 10, which discusses calculating a monthly ELCC across all facilities of a given type within a region.

B. Allocating the RA Benefits of Combined Heat and Power ("CHP") and Cost Allocation Mechanism ("CAM") Resources Within the Transmission Access Charge ("TAC") Area

ED Staff propose to limit the allocation of RA benefits from CAM and CHP resources to the TAC area in which the CAM or CHP resource is located.[6] This would mean that if an IOU procured a CHP or CAM resource outside of its TAC area, it would not receive RA credit for that CHP or CAM resource outside of its TAC area. The proposal, however, makes clear that the purchasing IOU still would be able to allocate the costs of the resource outside its TAC to customers within its TAC.

Staff proposes this treatment for three reasons:

> Allocating CHP RA credit to LSEs in one TAC area for resources procured in another TAC area can be problematic for the following reasons: 1) it does not consider the Path-26 system constraint, 2) local costs are not equitably allocated, in that customers in one TAC area (that of the IOU conducting the RFP) are paying for reliability benefits in another area (the TAC area in which the CHP is located), and 3) It creates another level of complexity in procurement planning that is not transparent to LSEs that service DA and CCA load.[7]

The proposal to not allow IOUs to count the RA benefits of CHP or CAM resources procured outside their service area is problematic. Doing so reduces the number of potential buyers for such resources, and, in so doing, could have the effect of imbuing the purchasing IOU within the same service area with monopsony power, as the loss of the RA value to other potential buyers may diminish their interest in that resource.

NRG does not dispute the third problem, namely, the increase in complexity of procurement planning. That increase in complexity is a direct result of procurement mechanisms that allow IOUs to allocate certain procurement costs to all customers, not just their bundled customers. However, the proposal to limit the allocation of RA benefits from CHP and CAM resources will not, in and of itself, reduce the current complexity of the procurement process.

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[6] Implementation Proposals at 3-4.
[7] Implementation Proposals at 3-4.

If CHP and CAM resources are shown on RA plans, as proposed in another part of the Implementation Proposals, this should allow the Path 26 counting constraint to be considered.

Finally, the second objection – that customers in one TAC area are paying for reliability benefits in another TAC area – would apply to any resources, CAM, CHP, or otherwise, that is procured outside the IOU's TAC area. To the extent that such resources are counting for system RA, this objection is largely invalid, as that amount of system benefit should be location-indifferent.

For all of these reasons, NRG does not support this proposal.

C. Subjecting CAM and CHP Resources to the Scheduled Outage Replacement Requirement and Standard Capacity Product (SCP) Mechanisms

ED Staff propose that CAM and CHP resources would be subject to both the Scheduled Outage Replacement requirements and SCP mechanisms. To facilitate this, ED staff propose that CAM and CHP resources would be shown on RA – and, presumably, supply - plans.[8] ED Staff indicate that, currently, CAM and CHP resources are not shown as physical resources on RA plans.[9]

Given the growing number of CAM resources, not listing CAM resources as physical resources on RA plans is neither a prudent nor sustainable course of action. However, breaking down CAM and CHP resources into smaller allocated pieces among a number of LSEs and expecting all of those LSEs to bear some substitution or replacement obligation when that CAM resource is forced out, or scheduled out and must be replaced, would seem to be unworkable.

In this light, ED Staff's proposal to require the IOU to show the full value of the CAM or CHP resource in their supply plans, and directs them to manage the replacement or substitution

[8] LSEs submit RA plans to demonstrate that they have procured sufficient resources to meet RA obligations. The suppliers of that RA capacity submit supply plans to the CAISO indicating which resources have RA obligations.
[9] Implementation Proposals at 5.

obligation, seems reasonable. Similarly, the scheduling coordinator for the CAM or CHP resource (if not the LSE buyer) also should be permitted to show the resource as fully committed to the IOU on its supply plan.

D. Local Area Aggregation

ED Staff propose to allows Load Serving Entities (LSEs) whose local RA obligation net of CAM allocations is less than five (5) MW to aggregate their local requirements within a single Investor-Owned Utility ("IOU") Service Area.[10] ED staff cite two primary motivations behind this proposal: (1) reducing the administrative burdens associated with procuring local capacity and (2) the need to provide additional local market power mitigation.

NRG does not have any experience with acquiring small amounts of local capacity and cannot speak directly to the administrative burden associated with doing so. However, NRG will comment on two aspects of this proposal: (1) the technical merits of aggregating local procurement and (2) the alleged market power motivation behind allowing aggregation.

With regards to the technical merits of aggregating local procurement – there are none. Local capacity procurement obligations were established to ensure that the capacity needed to ensure reliability within a local area was procured within that local area. Deeming that capacity procured in a one local area can somehow meet local capacity requirements in another area is not technically supportable.

With regards to the second motivation, ED Staff note:

> Another key reason is to provide additional local market power mitigation. Allowing the aggregation of local area requirements for LSEs that serve a small amount of load (LSEs that have less than a 5 MW local requirement in the local area) will give generation owners in local areas less market power over small LSEs.[11]

[10] Implementation Proposals at 9-10.
[11] Implementation Proposals at 9-10.

The waiver threshold trigger implemented in D.06-06-064 exists to provide local market power mitigation.[12] The Commission later allowed LSEs to aggregate local capacity within the PG&E service area because large LSEs, either in the role of generation owners as original owners of the local area generation or due to their procurement activities, controlled most or all of the local capacity within a single local area.

ED staff ask whether the proposed five MW threshold is the right threshold. It is difficult to quantify what threshold appropriately balances the reliability risk of allowing local capacity procured in one local area against the purported administrative ease of allowing aggregation. Rather than offering a specific number, NRG offers that one way to determine the threshold would be to set it as (1) the smallest backstop procurement designation the CAISO would realistically make in the local area divided by (2) the number of LSEs minus one (the dominant LSE controlling supply). In this way, if all non-dominant LSEs met their local capacity requirements by procuring local capacity outside of that local area, doing so would not trigger backstop procurement.

From a reliability standpoint, allowing local capacity procured in one area to count towards meeting local capacity requirements in another area is not technically defensible. Rather than expanding the use of aggregation, NRG respectfully encourages ED staff to explore other ways to deal with local market power due to concentration.

E. Topics For Which NRG Offers No Initial Comments

NRG offers no initial comments with regards to ED Staff's proposals regarding timing of local RA adjustments, using ELCC analysis to derive QC values for energy storage and supply-side demand response, and allocating flexibility associated with CAM and CHP capacity, but

[12] See D.06-06-064 at 70 ("The waiver trigger that we adopt in the following section is the means by which this [local] market power mitigation is accomplished.").

reserves the right to respond in reply comments on these topics.

II. CONCLUSION

NRG thanks the Commission for this opportunity to submit these comments and respectfully asks the Commission to consider these comments in making its decisions on these matters.

Respectfully submitted,

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