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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 and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020 (Filed September 28, 2017)

NRG ENERGY, INC. OPENING COMMENTS ON TRACK 3 PROPOSALS

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In accordance with Assigned Commissioner Liane Randolph's January 29, 2019 *Amended Scoping Ruling and Ruling of Assigned Commissioner* ("Amended Scoping Memo"), NRG Energy, Inc.[1] ("NRG") hereby submits these opening comments on Track 3 proposals.

I. INTRODUCTION AND SUMMARY

In NRG's opening comments, NRG:

- Supports the adoption of Energy Division's most recent Effective Load Carrying Capability-Based ("ELCC") Qualifying Capacity ("QC") values for wind and solar values (while expressing some concern about how the diversity adjustment was allocated);

[1] NRG Energy, Inc. is the parent of NRG Power Marketing LLC, Sunrise Power Company, LLC, and Long Beach Generation LLC, each of which owns and operates or markets generating resources in California. Because the focus of this proceeding is on California issues, NRG Energy, Inc. appears on behalf of these entities.

- Supports increasing the local waiver trigger price;
- Discusses a Pacific Gas and Electric Company ("PG&E") proposal for changing the basis for Resource Adequacy ("RA") requirements from metered load to end-use consumption and supports accounting for Behind-the-Meter ("BTM") resources as supply-side resources in RA analyses;
- Supports deferring action on "fast flexible" proposals pending the results of additional work underway by the California Independent System Operator Corporation ("CAISO");
- Urges caution with regards to considering proposals to expand waivers;
- Opposes PG&E's proposal to adopt seasonal Local Capacity Requirements ("LCR");
- Questions a San Diego Gas & Electric Company ("SDG&E") proposal for deriving an equivalent annual offer price from sub-annual offers for the purpose of considering local waivers and offers an alternative;
- Supports moving forward with some proposals advanced by CPower, ENEL X North America, Inc. and Energy Hub (collectively, the "Joint DR Parties") and supports a Southern California Edison Company ("SCE") proposal to consider a way to evaluate the capacity value of third-party demand response ("DR") by using contract value and back-end controls and testing; and
- Supports deferring action on proposals from Sunrun and the Center for Energy Efficiency and Renewable Technologies ("CEERT");

NRG respectfully reserves the right to submit reply comments on any other proposals on which it did not provide opening comment.

II. COMMENTS

1. The Commission Should Focus Its Attention on Near-Term Problems and Recognize that Track 3 is Already Weighted with Significant Issues When Deciding Which Track 3 Proposals to Adopt or Direct Additional Work Towards

More than a dozen parties submitted a relatively large number of Track 3 proposals. Some of the proposals touch on issues that have been previously considered, but not yet resolved, in this and prior RA proceedings. Other proposals deal with complexities that have long existed but have recently become more affecting, such as the challenging process for forecasting demand and then allocating RA requirements to an increasing number of load-serving entities.

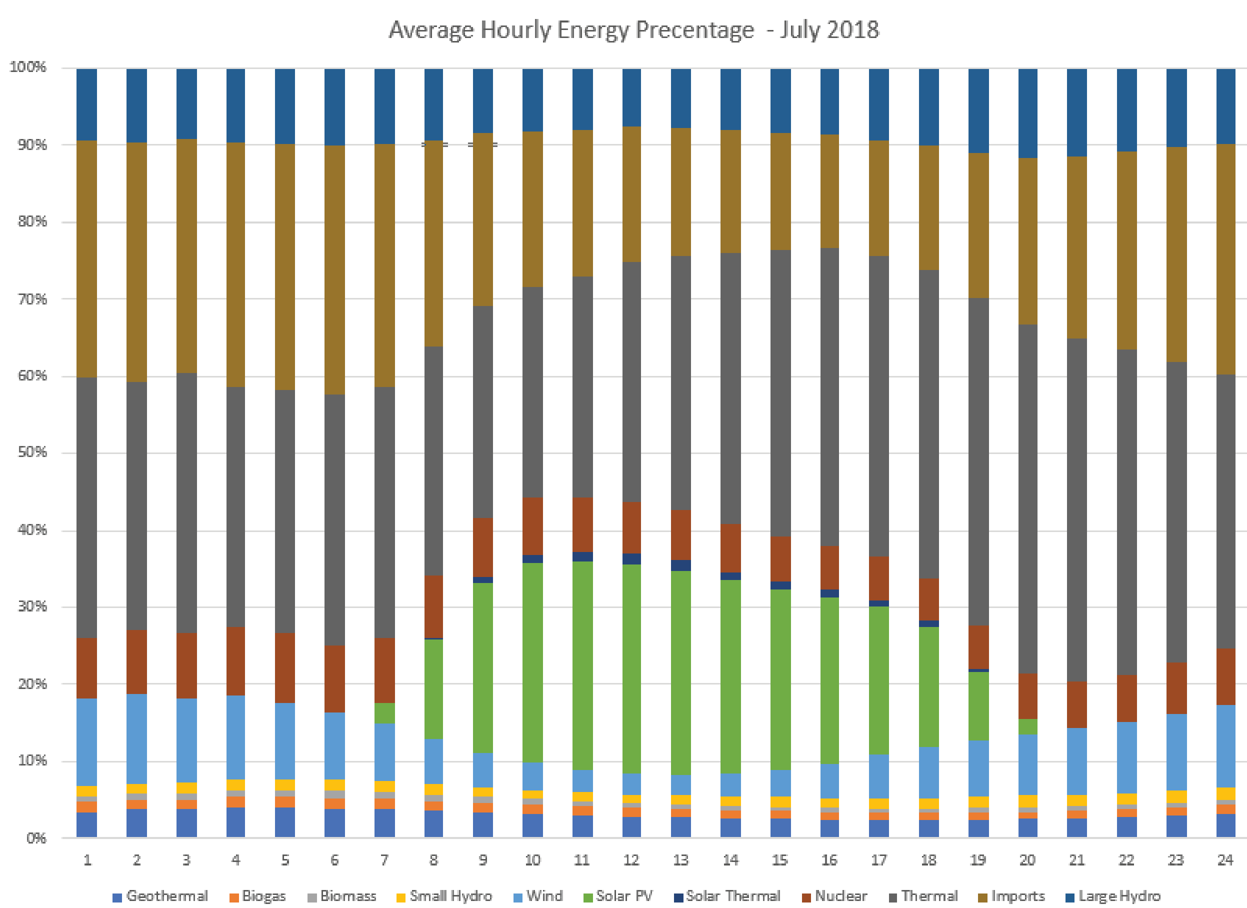
As the Commission considers the large number of Track 3 proposals, NRG respectfully encourages the Commission to bear in mind the limited bandwidth that Energy Division staff and many of the participating parties can bring to bear on these issues. The Commission's deliberations as to which Track 3 proposals it can consider, act upon and set for future action should account for the fact that a significant part of that available bandwidth will be occupied with the central buyer consideration process directed in Decision ("D.") 19-02-022. The Commission should focus its, and the parties', attention and energy on the issues that have significant bearing on the reliability foundation of the RA program and must be addressed in the near term, not on the aspirational proposals that, while interesting, do not need to be solved on the same time frame as the more affecting issues.

2. Energy Division's Proposed Effective Load Carrying Capability-Based RA Capacity Values for Wind and Solar Resource Should Be Adopted

Administrative Law Judge Peter Allen's February 13, 2019 *Administrative Law Judge's Ruling on Effective Load Carrying Capacity* transmitted an updated Energy Division proposal for using ELCC analysis to derive QC values for wind and solar resources.

Energy Division's updated proposal caps the ELCC of energy storage at 100% and proposes to allocate the "diversity benefit" created by storage to solar resources on the presumption that energy storage is primarily being charged by solar resources.

Discussion at the workshop noted: (1) that the ELCC calculations for solar did not include any assumed forced outages rate for solar resources and (2) that the diversity benefit need not be assigned solely to solar resources, because other resources were operating across the hours during which storage was charging. While NRG does not know exactly when the ELCC analysis assumed that solar was charging, NRG provides a graph below that shows the average percentage of energy output from various kinds of resources across each hour of the day for July 2018, the month for which Energy Division assigned the highest ELCC-based QC value for solar:



This graph shows that, during the hours in which it would be reasonable to assume that storage was charging (hours 10-16), solar provided a relatively modest amount of total energy (in the range of 20-25%) relative to total energy production. Energy Division's proposal to assign all the diversity benefit to solar should be viewed in this light.

The concerns about the lack of forced outage rate modeling for solar (and, perhaps for wind as well) and how to allocate storage's diversity benefit notwithstanding, NRG respectfully urges the Commission to adopt Energy Division's proposed updated ELCC-based QC values for wind and solar. As with Energy Division's initial implementation of ELCC-based QC values for wind and solar, Energy Division's updated proposal reflects substantial progress towards the goal of having reasonable ELCC-based QC values for these variable resources. Given that the parties have not reached consensus as to how to deal with other important issues regarding using ELCC analysis to assign QC values to wind and solar resources, such as whether to average new ELCC-based numbers across the entire fleet or to "vintage" existing resources and assign the lower incremental ELCC values to new resources, there remains plenty of opportunity to further refine the ELCC analysis. Instead, given the general agreement that RA margins are tightening, it is more important to implement the updated QC values sooner rather than later to ensure that variable resources are not unduly relied upon to ensure reliability.

NRG's final comment on Energy Division's ELCC analysis is an observation that ELCC analysis produces average capacity values across a period (in Energy Division's analysis, across a month). Such values reflect a statistical probability that the variable resources will produce energy at their ELCC-assigned capacity values when the peak demand of the month occurs. There is no guarantee that any resource, variable of otherwise, will perform at its QC value when the peak demand occurs. For resources that are presumed to be fuel-unlimited, however, the likelihood that the resource will not be able to produce at its maximum value has more to do with the resource's forced outage rate than any other factor. This difference is not trivial. The CAISO's recent draft 2020 LCR analysis, for example, projects that the peak demand in the San Diego-Imperial Valley local capacity area will occur at 8 PM – a time when solar resources are producing no output. While the ELCC analysis should and will evolve, it will not and cannot evolve to a point that it produces capacity values that guarantees variable resources will be producing energy at that capacity value when the peak demand, or peak reliability need, is occurring.

3. The Local Waiver Trigger Price Should Be Increased

Energy Division proposed increasing the local waiver trigger price from the current value of $40/kW-year to $51/kW-year.[2] NRG agrees that the $40/kW-year local waiver trigger price, established in 2006, is stale and should be updated. Despite the somewhat artificial precision of the waiver trigger price having to be a particular number, the waiver trigger price is a subjective value, and either the $51/kW-year price proposed by Energy Division or the suggestion made by Calpine's representative at the March 13 workshop to set the waiver trigger price at the Capacity Procurement Mechanism ("CPM") soft-offer cap price should be adopted.

4. Discussion on PG&E's Load Forecasting Proposal

PG&E proposes a modification to how BTM resources are treated in setting RA requirements. To account for large potential drops in output from BTM resources, PG&E proposes to change the basis of system RA requirements from metered load (i.e., the

[2] *Energy Division Proposal for Proceeding 17-09-020, Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years* ("Energy Division RA Proposals") *Staff Proposal B: Updates to the Resource Adequacy Enforcement and Waiver Processes*, at page 24. The proposed $51/kW-year price is the 85th percentile price for monthly SP26 capacity from the 2017 Resource Adequacy Report.

measurement of how much energy is drawn from the bulk power system to serve load) to end-use consumption (which also accounts for how much load is being served by BTM resources.[3]

PG&E's concern about the potential for a swing in BTM production leading to an increase in demand from the bulk power system is reasonable. However, the efficacy of PG&E's proposed multi-step method to base RA requirements on end-use consumption instead of metered load hinges on the viability of several of the proposed steps, including imputing the self-supply of BTM photovoltaic resources (step 2) and developing a meaningful QC value for BTM resources (step 4). These are important steps whose viability is not yet clear.

In any case, NRG agrees with PG&E's proposal to treat BTM resources as supply-side resources rather than load-modifying resources, and respectfully urges the Commission to incorporate supply-side treatment of BTM resources in future ELCC analyses.

5. Work on Fast Flexible RA Products Should Be Deferred

Two parties propose changes to the RA program that would emphasize the need for, and value of, "fast" ramping capability. The California Energy Storage Alliance ("CESA") proposed basing Effective Flexible Capacity ("EFC") values on sub-hourly, "15-minute trough-to-peak ramp-ability".[4] Citing the fact that the CAISO's Flexible Resource Adequacy Criteria and Must-Offer Obligation Phase 2 ("FRACMOO2") stakeholder initiative has not adequately assessed or addressed the need for faster ramping, Wellhead Electric Company, Inc. ("Wellhead") proposed

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[3] Track 3 Proposals of Pacific Gas & Electric Company (U 39 E) ("PG&E Proposals") at pages 2-3.

[4] *Track 3 Proposal of the California Energy Storage Alliance in Response to the Amended Scoping Memo and Ruling of Assigned Commissioner* ("CESA Proposals") at page 6.

that the Commission take the lead on developing a "Fast Flex RA product" with minimum performance standards.[5]

While NRG understands Wellhead's frustration with the lack of progress towards a durable flexible capacity regime and agrees that the increasingly steeper one-hour net load ramps are not adequately addressed by the current flexibility requirements, which are based on three-hour net load ramps, the CAISO needs to complete the comprehensive re-assessment of flexible capacity requirements in FRACMOO2 before modifications to the flexible capacity requirements in the RA program can be meaningfully considered and implemented. While ramping speed may become an increasingly important consideration, the growing three-hour net load ramp still requires securing sufficient ramping capability across a longer duration.[6] Focusing on "fast" ramping will not create a comprehensive durable flexible capacity framework. While the delays in moving forward with the FRACMOO2 initiative are unfortunate, implementing significant changes to the RA program's flexible capacity framework without the benefit of the FRACMOO2 investigation would be premature.

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[5] *Wellhead Electric Company, Inc.'s Track 3 Proposal* at pages 3-6. The performance standards proposed by Wellhead include: going from off-line to Pmax in 15 minutes or less; four hours of sustained energy duration; two daily ramps to Pmax and the ability to shut down in 15 minutes or less.

[6] For example, on Sunday, March 17, the CAISO experienced a net load ramp (based on five-minute data) of 15,018 MW – the second time this year that it experienced a three-hour net load ramp greater than 15,000 MW, the first being on New Year's Day – and a one-hour net load ramp of 7,513 MW.

6. **The Commission Should Carefully Consider Waivers for System and Flexible Capacity**

SCE proposed that a waiver process should be established for system and flexible RA capacity. SCE proposes that the threshold for system and flexible waiver requests be set at the CPM soft-offer cap price of $75.68/kW-year.[7]

There is general agreement that the RA market is tightening – and a tightening market *should* produce higher prices. To NRG's knowledge, however, there has not yet been any factual demonstration that the ability to exercise market power for system or flexible capacity exists. On the contrary, there is at least anecdotal evidence that the prevailing incremental value for flexible capacity remains at or near $0/MW – hardly a sign of impending market power. Absent any conclusive demonstration of the ability to exercise market power for system and flexible capacity, NRG respectfully urges the Commission to exercise great care when considering whether to implement a waiver process for system and flexible capacity. The CAISO has indicated that it intends to open an initiative to examine the capacity to exert market power on a system basis in March 2019.[8] Rather than overreacting to appropriately increasing prices, the Commission should at least allow the CAISO's examination of system market power to play out before considering any new waiver processes.

7. **PG&E's Proposed Seasonal LCR Should Not Be Adopted**

PG&E proposes that "seasonally-varying" LCR be established beginning with the 2021 RA compliance year.[9] PG&E further proposes that the local requirements "in each month" be set

[7] *Southern California Edison Company's (U 338-E) Track 3 Proposals* ("SCE Proposals") at pages 15-17.
[8] See CAISO February 20, 2019 Market Performance and Planning Forum presentation (available at http://www.caiso.com/Documents/Presentation-MarketPerformanceandPlanningForum-Feb202019.pdf), at slide 67.
[9] PG&E Proposals at pages 6-8.

based on the ratio of the local requirement to the peak demand during the peak month of the peak month of the year.[10]

NRG continues to object to LCR enforced on anything other than a full-year duration. When the Commission established LCR in 2006, it set those requirements to be in place across all months of the year. The approach, in contrast to the monthly approach adopted for system RA requirements, ensures there is adequate local generation to prudently allow for generating units and transmission equipment to be properly maintained at non-peak times across the year. Additionally, the annual fixed revenue requirement of a generating unit does not vary whether the unit is operated one month or twelve months out of the year. If a generating unit requires $X to cover its fixed costs, it will still have to recover $X to remain in operation whether it is contracted for one month or for twelve.

If the Commission were to adopt LCR across other than a full-year period, the CAISO would have to factor generator and transmission maintenance requests and schedules into its studies to set seasonal or monthly LCRs, either greatly complicating these studies, or putting the ability to take necessary outages. Further, LCRs may or may not scale linearly to the peak demand in the affected area; if the LCRs relate to reactive power support, they certainly will not scale linearly with area demand.

Proposals to implement LCRs over a shorter time frame than annually have been regularly proffered since the current LCR paradigm was implemented in 2006. Over that time, the Commission has heard no evidence compelling enough to cause it to change the way it implements and enforces LCR. While PG&E's proposal to linearly scale LCR on a monthly

[10] *Id.* As an example, PG&E proposes that if the LCR for a given area is X and the peak demand in the peak month is Y, in each month apart from the peak month the local requirement would be X/Y times the peak demand in that month.

basis is novel, PG&E does not demonstrate that it would result in cost savings sufficient to justify its adoption.

8. SDG&E'S Proposal to Extrapolate an Equivalent Annual Offer from Shorter Offers Should Not Be Adopted As Is

SDG&E proposes a method for extrapolating an equivalent annual "per kW-year" offer from an "per kW-month" offer shorter than for a full year for the purposes of applying the $40/kW-year local waiver trigger.[11] SDG&E proposes to determine this equivalent annual offer by adding the relevant monthly weighted average price from the most recent RA report for the months not offered by the seller to the sum of the monthly prices for the months offered by the seller.[12]

SDG&E's proposal to "fill in" the missing months might produce a rational "equivalent annual offer" that could be used to assess the possible exercise of market power if the seller sold RA capacity to another buyer during the months in which it did not offer to the initial buyer, but would not make sense if the seller could not contract the resource in other months. As noted above, a seller must recover its annual fixed costs across a year regardless of how many months it is contracted for. If a seller had fixed costs of $50/kW-year and recovered those costs by selling RA capacity at $10/kW-month across five months and being unable to sell RA capacity in all other months, adding the monthly weighted price to that seller's offer in the months in which they had not sold RA would result in an equivalent annual offer far above what the resource owner stood to earn.

[11] *San Diego Gas & Electric Company (U 902 E) Track 3 Proposal* at pages 2-5.
[12] *Id.*

SDG&E does not explain why a seller of local RA capacity would not offer local RA in all months. A resource owner that must staff and maintain its unit for the entire year has no incentive to offer that unit in only a few months of the year.

Because it is based on the presumption that a seller will earn at least the average price for local capacity in all other months in which it does not sell to the initial buyer, NRG does not support SDG&E's proposal. If the Commission is inclined to adopt SDG&E's proposal, it should not impute an annual price to assess a seller's attempt to exercise market power against one buyer by filling in the "missing" months with the average local capacity price, a price which the seller may not receive. Instead, the Commission should only fill in missing months with actual capacity prices that the seller is earning from another buyer.

9. Comments on Demand Response Proposals

A few parties offer several DR-specific proposals.

The Joint DR Parties propose, among other things, to:

> (1) adopt a process for showing DR resources year-ahead that is consistent with the methodology proposed by the utilities last July and create a placeholder for a discussion on how to demonstrate DR resources multiple years in advance now that the Commission has adopted multi-year forward local RA requirements;[13]
>
> (2) coordinate with the CAISO Energy Storage and Distributed Energy Resource (ESDER) Phase 4 initiative regarding protocols for weather-sensitive DR and create a placeholder for a discussion of weather-sensitive DR in Track 3 until the fate of the Demand Response Auction Mechanism becomes clearer;[14] and

[13] Joint Track 3 Proposals of CPower, ENEL X North America, Inc. and Energy Hub ("Joint DR Parties") ("Joint DR Parties Proposals") at pages 2-4.
[14] *Id.* at pages 7-8.

(3) address the use of “slow DR” for meeting Local Capacity Requirements in Track 3.[15]

NRG agrees with the Joint DR parties that adopting multi-year local capacity requirements creates the potential for a severe misalignment with third-party DR programs, which are currently awarded on a one-year basis, and that the Commission should begin working in Track 3 to address the misalignment.

NRG notes that topics (3) and (4) are under consideration in ESDER 4. While the Commission cannot dictate the pace or schedule of CAISO stakeholder processes, NRG expects that it may be difficult for the Commission to incorporate resolutions to these issues in the RA program until ESDER 4’s consideration of these issues is more advanced, if not completed.

PG&E and SCE propose ways for assigning RA capacity value to third-party DR resources. PG&E proposes that the RA capacity value for third-party DR resources be developed only through the use of the Load Impact Protocols (LIPs) currently applied to utility DR programs.[16] SCE also proposes to use the LIPs to set third-party DR RA values, but alternatively expressed an openness to allowing the RA value for third-party DR to be set as the DRAM contract value, subject to demonstration of that value through test or dispatch.[17] NRG appreciates SCE’s openness to a process for assigning RA capacity to third-party DR programs that could allow for those values to be set as the agreed-upon contract value, subject to verification, and urges the Commission to consider that approach.

[15] *Id.* at pages 8-10.
[16] PG&E Proposals at pages 4-5.
[17] SCE Proposals at page 9.

10. **Sunrun's Proposals Should be Deferred**

Sunrun offered a number of proposals intended to further the ability of BTM resources to count towards meeting RA requirements.[18] Without question, the estimated nearly seven (7) GW of rooftop solar has changed the operations of the bulk power system, and BTM resources are a growing part of California's resource mix. Nevertheless, the implications of assigning RA capacity value to Net-Energy-Metered resources are significant (not only for the RA program, but for NEM resources), and warrant greater consideration than can happen in Track 3.

11. **CEERT's Portfolio Proposal Should be Deferred**

Anticipating the not-yet-released results of SCE's Request For Offers for preferred resources in the Moorpark and Goleta sub-areas, and citing the Oakland Clean Energy Project and the recent procurement of storage to eliminate the need to contract with gas-fired generation (even though such need had already been eliminated by a series of transmission upgrades), CEERT proposes to develop a "portfolio NQC" approach to assessing how these resources can count towards meeting LCR, with the details to be fleshed out in subsequent Commission workshop or through a CAISO stakeholder initiative, through which the needed CAISO tariff, RA counting rules and RA guide revisions would be made.[19]

It is critically important to accurately and reliably determine how preferred resources can count towards meeting local capacity requirements. A portfolio approach, which assumes resources can perform in a complementary way, depends on those resources actually performing in that complementary way on the day that they are needed to perform. Further, as CEERT acknowledges, fleshing out its proposed approach would require much additional work on

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[18] *Track 3 Proposal of Sunrun Inc.*

[19] *Track 3 Proposals of the Center for Energy Efficiency and Renewable Technologies* at pages 4-5.

details. Given this, and given the myriad other things competing for parties' and the Commission's time and resources, NRG suggests consideration of CEERT's portfolio approach be put off to a future proceeding or track of this proceeding.

III. CONCLUSION

NRG appreciates the opportunity to provide these opening comments on Track 3 proposals.

Respectfully submitted,

By *<u>/s/ Brian D. Theaker</u>*
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