**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.	R.17-09-020 (Filed September 28, 2017)

TRACK 3 PROPOSALS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

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I. INTRODUCTION

Pursuant to the schedule set forth in the *Amended Scoping Memo and Ruling of Assigned Commissioner*, dated January 29, 2019, as amended by the February 22, 2019 *E-Mail Ruling Extending Track 3 Proposal Deadline* of Administrative Law Judge Debbie Chiv, which extended the deadline for submission of Track 3 proposals from February 25, 2019 to March 4, 2019, Pacific Gas and Electric Company ("PG&E") hereby provides its Track 3 proposals in this proceeding.

PG&E's Track 3 proposals are summarized as follows and discussed in more detail in the body of this pleading:

- PG&E proposes that the California Public Utilities Commission ("Commission"), in the calculation of effective load carrying capacity-based qualifying capacity ("QC") values for solar resources, treat behind-the-meter ("BTM") solar photovoltaic ("PV") resources the same as solar resources in front of the meter.

- PG&E proposes that the Commission establish end-use consumption, rather than traditional metered load, as the proper metric upon which to base the resource adequacy ("RA") program requirements.

- PG&E proposes that the combining of traditional demand response ("DR") (i.e., load drop) and energy storage (i.e., discharge) should be measured in aggregate using relevant methodologies.

- PG&E proposes that, consistent with all other resources, the QC for third-party DR provider resources be based on observable and verifiable event performance data.

- PG&E proposes that the Commission adopt a multi-year load forecast to be submitted by all Commission-jurisdictional load serving entities ("LSEs") to be used in determining the local RA requirements for each of the three forward years.
- PG&E proposes that seasonally varying local capacity requirements be established beginning with the 2021 RA compliance year.
- PG&E proposes that the conditions for local RA penalty waivers should be expanded to include good faith participation in sellers' solicitations, including those offered by other LSEs.
- PG&E proposes that the Commission revisit the current methodologies for hydro resource counting through a workshop process and develop an approach that more accurately reflects the benefits that hydro resources can provide vis-à-vis system and local reliability.

II. DISCUSSION

A. Further Refinements to the Resource Adequacy Program

1. Revisions to the load forecast methodology

PG&E proposes that the Commission adopt modifications to the RA program regarding the treatment of BTM PV resources and the methodology by which the RA requirements are established for Commission-jurisdictional LSEs. In its Track 2 Opening Testimony, PG&E proposed that the load forecast used to set RA requirements should be adjusted to reflect end-use consumption of power, instead of metered load and that BTM PV resources should be treated the same as PV resources in front of the meter in the calculation of RA requirements.[1] By this filing, PG&E re-introduces this proposal in Track 3 of this proceeding to be adopted this year and implemented for the 2021 RA compliance year.

First, PG&E encourages the Commission to treat BTM PV resources the same as in front of the meter resources, rather than load modifying resources, because the location of a resource vis-à-vis the customer's meter does not change the impact of solar resources on system reliability. Second, with increasing adoption of BTM PV resources by end-use customers,

[1] *Pacific Gas and Electric Company Generation Resource Adequacy Program Prepared Testimony*, dated July 10, 2018 ("Track 2 Opening Testimony"), pp. 3-2 - 3-6.

PG&E believes that a change in the basis used for determining the system RA requirements for LSEs is warranted. Specifically, PG&E believes that the Commission should change the basis of the system RA requirements for LSEs from traditional metered load (i.e., the amount of energy being provided by the bulk energy system) to end-use consumption. This is because the wide-spread adoption of BTM resources has resulted in a distinction between metered load and the amount of energy consumption by end-use customers that creates significant problems for the RA program and the determination of the RA requirements. While BTM resources can reduce the amount of power drawn from the grid, the change in location of the customer meter does not reduce the overall consumption and reliability needs of the system on a consistent basis throughout the year, month, day or hour.

To avoid associated RA program problems, the planning standard by which the Commission ensures that consumers are protected from service interruption should account for large potential drops in output from BTM resources. To that end, PG&E believes the Commission should change the basis of the system RA requirements for LSEs from metered load to end-use consumption. PG&E proposes that the Commission take the following steps in the process of determining RA requirements to account for BTM PV resources:

- Require all Commission-jurisdictional LSEs to report BTM PV resources as well as sales;
- Impute self-supply done by BTM PV resources for each LSE;
- Calculate an estimate of total end-use consumption by adding sales to imputed self-supply;
- In determining system RA requirements, use total consumption as a starting point and net off the QC value of BTM PV resources to calculate the total system RA requirement;
- Apply the current planning reserve margin of 15% to the total system RA requirement; and
- In allocating system RA requirements to LSEs, base LSE responsibility on an LSE's share of end-use consumption, less the QC, for LSE BTM PV resources.

2. Consideration of how storage and combined resources should be counted for RA credit

For BTM resources, PG&E supports the measurement of overall performance at the retail premise meter, which captures all load activity occurring behind the retail meter as observed by Southern California Edison's Testimony.[2] As such, the combining of traditional DR (i.e., load drop) and energy storage (i.e., discharge) should be measured in aggregate using the relevant methodologies, which can be metering and/or the use of baselines. PG&E cautions, however, that any discussions of alternative metering configuration and performance evaluation (e.g., California Independent System Operator Corporation's ("CAISO") Metering Generator Output)[3] should be subject to guidance provided in the DR proceeding (Application ("A.") 17-01-012 et al. or successor) regarding the applicability and use of such configurations.[4]

3. Refinements to the third-party demand response qualifying capacity methodology

As a matter of principle third-party DR Providers ("DRPs") should be held to the same standards, protocols and processes approved by the Commission for determining the =QC of DR resources provided through investor-owned utility ("IOU") programs. Currently, the QC for an IOU DR resource is based on Commission-approved load impact evaluation protocols that require use of observed and verified past event performance data. In contrast, the current QC for

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[2] *See Southern California Edison Company's Track 2 Testimony in Rulemaking 17-09-020*, dated July 10, 2018, p. 29 lines 19-24.

[3] The Metering Generator Output ("MGO") is a performance evaluation methodology that can utilize a combination of meters and baselines to measure the performance of distribution energy resources behind the retail premise meter, which can include settlement at the device level. This methodology was originally adopted by the CAISO in 2016 through Phase 1 of its Energy Storage and Distributed Energy Resources stakeholder process. For more information, see *Memorandum Re: Decision on energy storage and distributed energy resources proposal*, dated January 27, 2016, *available at* https://www.caiso.com/Documents/Decision_EnergyStorage_DistributedEnergyResourcesProposal-Memo-Feb2016.pdf (last visited February 26, 2019).

[4] *Pacific Gas and Electric Company's Prehearing Conference Statement and Responses to ALJ Questions*, dated January 3, 2019 and filed in A.17-01-012 et al., proposed a procedural pathway to address MGO issues. This was clarified at the Prehearing Conference in A.17-01-012 et al. held on January 10, 2019 and could be scoped into an upcoming workshop in A.17-01-012 et al. on March 22, 2019.

third-party DRP resources is based on contracted capacity which is not supported by observed and verified event performance data.

PG&E believes that the current methodology of determining the QC for third-party DRP resources based on contracted capacity is: (1) inherently flawed for resource planning purposes, (2) intended to be an interim methodology approved through 2019 because it was believed that penalties under the CAISO tariff (including the Resource Adequacy Availability Incentive Mechanism ("RAAIM")) and contract provisions are adequate incentives for DRPs to correctly state the QC of their resources, which the Energy Division's final evaluation report contradicts,[5] (3) inconsistent with the standards by which the IOUs are being held, and (4) creating an unlevel playing field between IOU DR resources and third-party DRP resources. For those reasons, PG&E proposes that, consistent with all other resources (including IOU DR resources), the QC for third-party DRP resources be based on observable and verifiable event performance data.

B. Track 2-Related Refinements

1. Basis for 2021 and 2022 allocation of requirements

Decision 19-02-022 regarding multi-year local RA requirements does not adequately consider foreseeable load migration in setting individual LSE local RA requirements for the 2021 and 2022 compliance years. The Decision states:

> As the Commission is unable to anticipate when new LSEs will form or how load will migrate among LSEs beyond the one-year timeframe, at this point, all LSEs will be allocated local requirements for each of the three forward years based on their

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[5] This methodology was approved in Decision 16-06-045, pp. 41-42, which states that the exemption should be reviewed based on the findings of the Energy Division's final evaluation report. Energy Division's final evaluation report was issued on January 4, 2019 in A.17-01-012 et al., in the *Administrative Law Judge's Ruling Issuing Evaluation Report of the Demand Response Auction Mechanism Pilot, Noticing January 16, 2019 Workshop, and Denying Motion to Require Audit Reports in the Evaluation Report*. Specifically, the report states on p. 109: "During the DRAM pilot, CAISO RAAIM penalties and replacement capacity requirements under the CPUC's RA program have not effectively incentivized performance." In addition, p. 78 of the report states: "IOU DRAM contracts with DRPs did not include explicit, universal penalties for non-compliance with contract obligations, although there was some discretion available to IOUs to impose penalties in certain cases."

> load share in the first year resulting from the adopted California Energy Commission (CEC) load forecasting process.[6]

The proposed approach by the Commission to allocate local RA requirements based on a single year's load forecast for multiple forward years is ineffective and likely to result in (1) cost shifting, (2) inequities in RA obligations that occur as load shifts from IOUs such as PG&E to community choice aggregators ("CCAs"), and (3) potential over-procurement. This approach raises topics similar to those the Commission addressed in Resolution E-4907.

Therefore, PG&E proposes that the Commission adopt a multi-year load forecast to be submitted by all Commission-jurisdictional LSEs and used in determining the local RA requirements for each of the three forward years. Based on the timing and schedule of Track 3 in this proceeding, PG&E is proposing that LSEs be required to submit their three-year load forecast as part of the August mandatory load forecasting update for the 2020-2022 local RA requirements only. On a going forward basis, if needed, LSEs should be required to submit their multi-year load forecasts in the month of April as part of the existing RA timeline and serve only the load they have planned for.

Given the anticipated load shifting landscape of the near future, with multiple LSEs expanding their service, the introduction of a multi-year load forecast to capture load migration among LSEs is a critical component to minimize inequitable RA procurement obligations between an IOU and a new or expanding CCA.

2. Refinements to Local Area Rules

a. Seasonally varying Local Capacity Requirements

PG&E proposes that seasonally varying local capacity requirements be established beginning with the 2021 RA compliance year. Currently, the local RA requirements are set on an annual basis, specifically based on the respective year's August peak load in each local area.[7] There have been discussions in the past–most recently in 2017–on changing the local RA

[6] Decision 19-02-022, p. 28.
[7] This is true for all local areas except for Humboldt where the January peak load is used. This is because the Humboldt region is winter peaking and not summer peaking like the rest of the local areas.

requirements to a seasonal or even monthly basis, but, until now, no change has been adopted. During the October 23, 2017 Commission workshop in this proceeding, the CAISO identified concerns with establishing a seasonal local RA requirement, as follows:

> Generators have raised the concern that if they are only needed for the summer season, they would seek to recover all of their costs during this period. However, if CAISO needs these resource during non-summer months (as may happen during maintenance periods, abnormal system conditions etc.), then backstop may be needed, even though the local RA program was designed to eliminate the need for the CAISO to enter into RMR contracts for resources needed to meet the LCR criteria.[8]

PG&E understands the concerns raised by CAISO and the potential complexities in determining monthly local RA requirements. As a result, PG&E proposes that local requirements in each month be set based on the ratio of the local requirement to the peak demand during the peak month of the year in each region. Namely, if the local requirement in a region is X and the peak demand in the peak month is Y, the local requirement would be X/Y of the peak in each month. This would provide monthly varying local requirements.

PG&E notes that the Commission has already adjusted the monthly local requirements for some local areas by capping the local requirement at the system requirements.[9] Seasonal local RA requirements would allow generators and LSEs to better optimize outage schedules with the procured local RA resources, especially in winter load months, which typically have lower load needs. Additionally, seasonal summer and winter local RA requirements could better integrate preferred resources, including solar, wind, run-of-river hydroelectric resources and DR resources, whose net QCs ("NQCs") vary throughout the year based on fuel availability and event dispatchability. Because these resources' NQCs are generally higher during summer load months, a seasonal local RA requirement could maximize their value to customers.

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[8] *See CAISO Resource Adequacy Working Group on Path 26, Seasonal Local Requirements and Dispatchability (R.14-10-010)*, dated October 23, 2017, p. 6.
[9] "The local RA requirement is higher than needed for non-summer months." Decision 15-06-063, p. 54.

PG&E understands that, given the timing of the 2020 local capacity technical study being performed by the CAISO, it is not feasible to set summer and winter seasonal local RA requirements for the 2020 RA compliance year. Therefore, PG&E proposes that the requirement to set local RA needs on a summer and winter basis be adopted this year, to be implemented for the 2021 RA compliance year.

The local RA requirement has been in place since 2007. With the adoption of multi-year local RA requirements and the potential adoption of a central procurement structure for local RA in the fourth quarter of 2019, it is now an appropriate time to re-visit the local RA requirements so that they are set on a summer and winter seasonal basis. At this point, there is sufficient information and time for the Commission and the CAISO to determine that a summer and winter demarcation for local RA requirement is a more cost-effective and efficient approach and how its use could be applied in the multi-year local RA requirements and central procurement structures for local RA while maintaining the goals of system and local reliability.

b. Local penalty waiver requirement

Currently, the Commission has instituted the ability for an individual LSEs to be granted a waiver from meeting its local RA requirements under specific circumstances. In Decision 19-02-022, the Commission indicated that it would continue the waiver process.[10] This process is focused on the individual LSE holding a solicitation to purchase local RA capacity and the outcome of the responses to that solicitation. PG&E notes, however, that sellers of RA capacity also hold solicitations to sell local RA capacity in which market participants may be able to purchase RA capacity. The necessary conditions for a waiver are only based on a buyer holding solicitations, not on an LSE's participation in sellers' solicitations. PG&E proposes that the conditions for a waiver should be expanded to include participation in sellers' solicitations, with a similar requirement that any LSE seeking a waiver participated in good faith in sellers'

[10] "Accordingly, we apply the local penalty and waiver process instituted on a one-year basis, pursuant to D.06-06-064 and D.07-06-029, to apply to the three-year forward requirement for LSEs." Decision 19-02-022, p. 29.

solicitations to sell RA capacity and confirmation of bid levels and rejections from sellers as to those bid values. These conditions can be easily added to the criteria for waiver qualification.

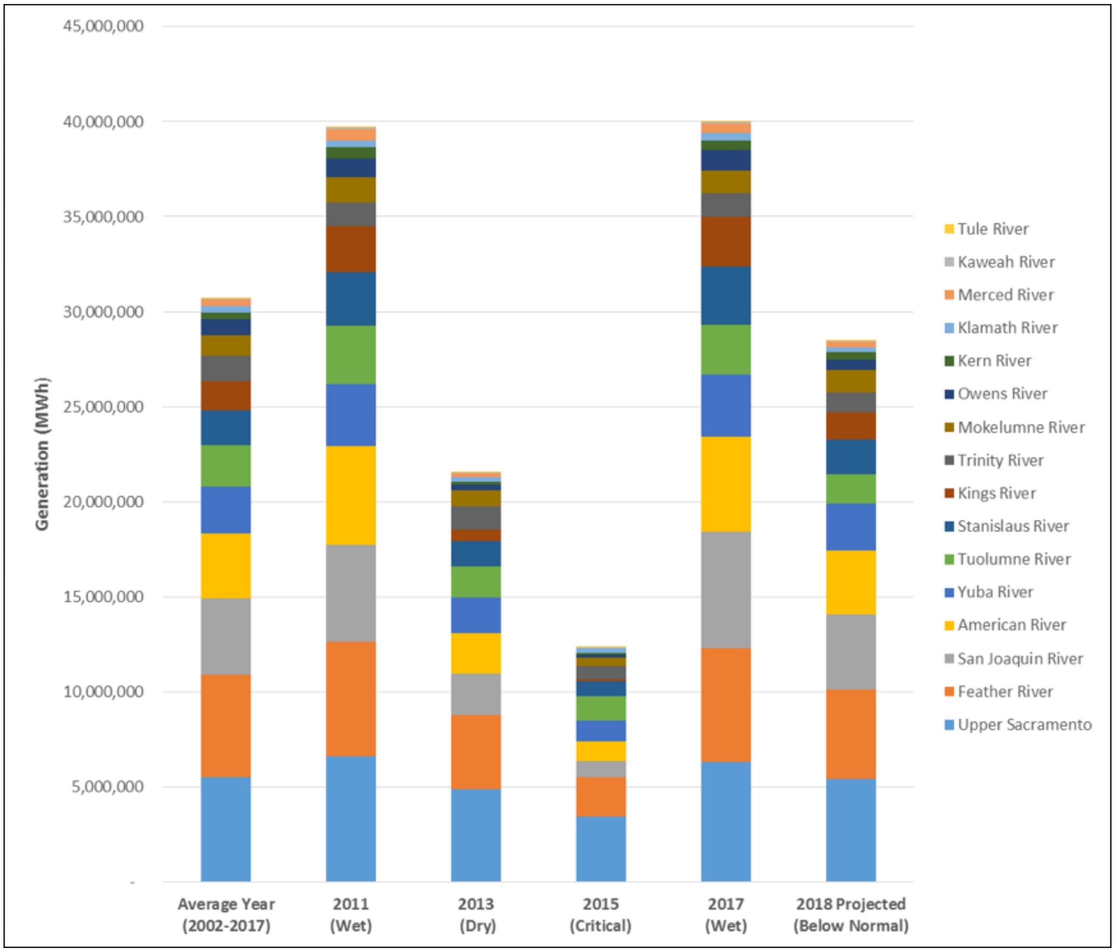
In accordance with the foregoing, in addition to the current description of the conditions for waiver in the QC manual, the following condition should be added:

> a demonstration that the LSE reasonably and in good faith provided bids in solicitations to sell capacity that would meet its RAR capacity needs along with accompanying information about the terms and conditions of solicitation, the level of its bid, and rejection notice from the selling party that the bid was not accepted.

C. Refinements to QC Counting Rules for Hydro Resources

Hydro resources have historically been and will continue to be a significant source of clean and reliable power and play an important role meeting system and local needs of the grid. Hydro resources, which are classified as use-limited, are highly dependent on hydrological conditions, weather patterns, Federal Energy Regulatory Commission ("FERC") licensing, storage levels and upstream and downstream powerhouses; and the changing landscape of the grid (e.g., higher penetration of renewables) is changing the dispatchability and optimal time to provide capacity to the market and/or generate energy from these resources. Under the current QC methodology, dispatchable hydro resources have a QC based on the resource's PMax while non-dispatchable hydro resources have a QC based on the rolling average of the previous three year's generation output during the Commission's RA measurement hours. The current QC methodologies for dispatchable and non-dispatchable hydro resources have inherent challenges and it is important to accurately assess the reliability contribution (or QC) of hydro resources.

As illustrated by the California Energy Commission data copied below,[11] the total generation provided by a portfolio of hydro resources in the state of California varied significantly over the last several years.



Given the inherent challenges with establishing QC values for hydro resources, it is timely to revisit the current methodologies and develop an approach that more accurately reflects the benefits that hydro resources can provide vis-à-vis system and local reliability. PG&E therefore proposes that the Commission convene a workshop in Track 3 of this proceeding so that interested parties may work to develop a comprehensive approach for hydro resources that balances hydrological conditions, weather patterns, FERC licensing, storage levels and upstream

[11] *Hydroelectric Power in California*, Figure 2 – May 2018 Version: Statewide Hydroelectric Generation by Watershed, *available at* https://www.energy.ca.gov/hydroelectric/ (last visited March 4, 2019).

and downstream powerhouses to develop respective QC values. Any approach must realize two goals. It must account for the variability that is inherent in hydro resources, while also creating the certainty that is necessary for long term planning. Adjusting the counting rules would increase certainty that a given hydro resource would be able to provide capacity at its QC value in any given year. PG&E looks forward to further developing this proposal in the workshop process.

III. CONCLUSION

PG&E appreciates this opportunity to present its Track 3 proposals and looks forward to working with the Commission and all parties to expeditiously resolve all remaining issues in this proceeding.

Respectfully Submitted,

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