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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Continue Electricity Integrated Resource Planning and Related Procurement Processes	Rulemaking 20-05-003 (Filed May 7, 2020)

OPENING COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON THE PROPOSED PREFERRED SYSTEM PLAN

DANIEL S. HASHIMI
TYSON R. SMITH

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (818) 388-1711
Facsimile: (415) 973-5520
E-Mail: Daniel.Hashimi@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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I. INTRODUCTION

Pacific Gas and Electric Company ("PG&E") submits these Opening Comments pursuant to Section 15 of Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Plan ("ALJ Ruling") issued August 17, 2021.

PG&E appreciates the complexity of the task undertaken by the California Public Utilities Commission (the "Commission" or "CPUC") to balance the important goals of achieving a 38 million metric ton ("MMT") greenhouse gas ("GHG") target by 2030 and having sufficient resources online to maintain electric grid operational reliability, all while maintaining costs as low as possible for electric consumers. Striking the appropriate balance on these important goals have presented challenges for the Commission, as well as load serving entities ("LSEs"), which has resulted in out-of-cycle procurement mandates such as the emergency reliability procurement decision ("D.") 19-11-016, which ordered 3,300 Mega Watts ("MW") of additional net qualifying resources ("NQC"), and the midterm reliability ("MTR") procurement D.21-06-035, which ordered an additional incremental 11,500 MW of NQC to add to the 3,300 MW of NQC previously ordered.

PG&E understands that striking the appropriate balance between these important, and at times competing, goals is no small task especially given the need to incorporate the contributions of 41 different LSE integrated resource plans ("IRPs') in the process. As such, PG&E is prepared to serve as a partner with the Commission and other LSEs to ensure that through the collective effort of the entire group the IRP process is improved with improved analytics to better inform future procurements aligned with the IRP process and to avoid other out-of-cycle procurement requirements.

Currently, PG&E, like other LSEs, are focused on developing and executing plans to ensure sufficient qualifying procurements of their proportionate share of the 11,500 MW of NQC. In addition to collectively focusing on improved analytics, it is critical that any decision adopted pursuant to the ALJ Ruling, that will establish the preferred system plan ("PSP"), should closely reflect the portfolio of resources required to be procured by the MTR decision, which the LSEs have been mandated and are currently in the process of procuring. This will ensure that the PSP will be designed to achieve the important goals set out earlier in this section, while also being aligned with the recent Commission procurement mandates.

Additionally, as the collective group works to improve the analytics in the IRP process, it is important to give special attention to establishing the appropriate planning standard and the appropriate planning reserve margin ("PRM") and other metrics used to achieve the proper level of reliability standard. Further discussion on this specific issue is offered in response to Question 4 below.

The balance of these comments are structured as follows: in Section II PG&E provides a brief summary and overview of its comments and recommendations, in Section III PG&E provides responses to the questions set forth in the ALJ Ruling in the order in which they appear in that ALJ Ruling, and in Section IV PG&E provides additional comments on topics not covered by the ALJ Ruling.

II. SUMMARY OF COMMENTS AND RECOMMENDATIONS

1. PG&E supports the environmental goal of achieving a 38 MMT GHG target in 2030 and having sufficient resources on the electric grid to operate reliably. Operational reliability assessment is a critical next step to ensure that the planned resources will adequately address all aspects of reliability.
2. PG&E proposes an alternative PSP that more closely reflects LSE's baseline resources and the MTR procurement for the 2022–23 transmission planning process and to inform any future procurement decision. Individual LSE plans are now outdated and do not

adequately address location specific resource requirements. PG&E offers an alternate portfolio for use as the PSP in response to Questions 3 and 5.

3. PG&E recommends the Commission initiate a process now to determine the correct level of PRM to achieve reliability and avoid over procurement that will burden consumers with excess costs. The current Commission staff analysis of 38 MMT Core Portfolio with enforcement of a 22.5 PRM results in a loss of load expectation ("LOLE") of 0.064 and 0.054 in 2026 and 2030, respectively, both much lower than the typical electric planning standard of 0.1 LOLE the established industry standard nationwide. Reliance on a non-standard and unsupported PRM without proper analysis will likely lead to higher energy rates for consumers than necessary.
4. PG&E does not support further acceleration of the MTR procurement as the current procurement timelines are already compressed; Moreover, PG&E does not support assessment of penalties for LSEs' inability to procure sufficient resources in such a compressed timeline despite reasonable efforts. Instead PG&E recommends that the Commission adopt an incentive mechanism as proposed in response to Question 15 to encourage LSEs to bring resources online sooner.
5. The Commission should address near-term reliability needs in the resource adequacy ("RA") proceeding—not in this proceeding. See Section IV for a detailed discussion on this issue.
6. The Commission should conduct a thorough analysis to properly plan for location-specific resource needs. Resources must be procured in the right locations to address the local and zonal needs of the electric grid. See response to question 2 for details.

III. RESPONSES TO ALJ RULING QUESTIONS

Q1. Please comment on the individual IRP portfolio aggregation performed by Commission staff.

PG&E does not support the use of aggregated LSE portfolios from the 2020 IRP filings for use in developing the PSP. The 2020 aggregated portfolios are outdated. Since the September 2020 LSE IRP filings, changes have occurred that substantially affect individual and aggregate LSE portfolio needs. First, the Power Charge Indifference Adjustment ("PCIA") Working Group 3 decision[1/] allocates procured resource attributes to departing bundled customers, fundamentally altering LSE bundled portfolio needs over the IRP planning horizon. Second, the MTR procurement order directs CPUC-jurisdictional LSEs to procure 11,500 MW of new resources.[2/] These among other changes since the 2020 IRP portfolio filings demonstrate

1/ D.21-05-030.

2/ D.21-06-035.

that the LSE portfolios and portfolio needs have changed significantly. A final adopted PSP relying on such outdated information will not lead to improved reliability or lowered emissions.

Third, the methodology of creating the PSP and assumptions used resulted in a 2030 portfolio greater than needed to meet reliability requirements and is misaligned with the MTR decision. For example, the RESOLVE model uses a simplified approach (22.5% PRM) for modeling the MTR procurement. Although the MTR decision used 22.5% PRM to arrive at the 11,500 MW of NQC capacity requirements, the decision includes very prescriptive language for the characteristics of the different categories of resources.[3/] In addition, a key modelling assumption for the MTR procurement, marginal ELCC values, are significantly different in the RESOLVE model compared to the incremental ELCC values required to be used by the LSEs for the MTR procurement. A more accurate representation of the MTR procurement will lead to a different PSP as confirmed by independently conducted PG&E analysis.

Q2. Comment on the reliability analysis of the aggregated 38 MMT LSE plans.

PG&E appreciates the Commission's efforts to complete a LOLE study to validate that the proposed PSP meets a 0.1 LOLE target. While the LOLE study is a step in the right direction to confirm adequacy of resources, more work is needed to ensure that the California Independent System Operator ("CAISO") system will have the right mix of resources to operate reliably. PG&E recommends the following additional steps to validate that the PSP portfolio of resources will adequately support the CAISO system reliability:

- *Ensure operational reliability* – confirm the CAISO system can maintain operational reliability under different operating conditions after the retirement of the once-through-cooling ("OTC") resources and with the increased levels of intermittent and inverter-

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3/ E.g., the MTR decision requires 2500 MW of DCPP retirement to be replaced "zero-emitting resources". This zero-emitting capacity "(a) Be from a generation resource, a generation resource paired with storage (physically or contractually), or a demand response resource; (b) Be available every day from 5 p.m. to 10 p.m. (the beginning of hour ending 1800 through the end of hour ending 2200), Pacific Time, at a minimum; and (c) Be able to deliver at least 5 megawatt-hours of energy during each of these daily periods for every megawatt of incremental capacity claimed."

based resources. This analysis will be a part of the 2022-23 CAISO Transmission Planning Process ("TPP") analysis. In the TPP analysis, the CAISO performs a NERC reliability assessment to confirm that the CAISO system meets all NERC reliability requirements. In addition, for past several TPP cycles, the CAISO has been working on improving its models for validating that the inverter-based resource portfolios can adequately address the frequency response requirements of the CAISO system. In the "Frequency Response Assessment" chapter of the 2020–21 Transmission Plan, the CAISO points out that, "[g]iven the materially different operating characteristics of renewable generation, this necessitates broader consideration of a range of issues in managing system dispatch and maintaining reliable service across the range of operating conditions."[4/] PG&E agrees and appreciates CAISO's ongoing efforts to improve transmission models to understand the system performance with increased levels of renewable penetration. CAISO's operational reliability assessment, including the frequency response analysis, is a key next step to confirm that the PSP portfolio of resources will not adversely impact operational reliability.

- *Ensure locational resource needs to maintain reliability* – PG&E is concerned that the IRP process has not addressed location specific resource needs (zonal and local) to support and maintain reliability, a critical element for the state to meet its GHG reduction goals.
    - For the zonal requirements, the CPUC SERVM model and the simplified stack analysis approach used in the CPUC RESOLVE model could provide a planning level estimate of zonal capacity needs to address zonal resource requirements due to transmission limitations. The CPUC SERVM model, once calibrated to reflect the major TAC area transmission interconnections constraint, can provide insights into whether the transmission interconnections within the TAC areas are limiting the

4/ 2020-2021 Transmission Plan (March 24, 2021) (CAISO 2020-2021 Transmission Plan), page 382, Section 6.3, http://www.caiso.com/Documents/BoardApproved2020-2021TransmissionPlan.pdf (accessed Sept. 27, 2021).

transfer of resources between the zones to address CAISO system reliability. In addition, a simple zonal stack analysis could provide an indication on whether TAC areas have sufficient capacity physically available to address the demand and operating reserve requirements in the TAC areas, given limited transfer capability between different TAC areas.[5/]

- For the local resource needs, in the 2020-21 TPP, the CAISO included local capacity requirements for years 2021, 2025, and 2030.[6/] Although these requirements don't reflect the latest Integrated energy policy report ("IEPR") forecast and the expected growth in the electric vehicle ("EV") load, the results are indicative of the increasing local capacity requirement in many areas. PG&E appreciates CPUC's and CEC's collaborative effort to develop a location specific EV demand forecast. Once the location specific forecast is ready, PG&E asks the CAISO to revise its local capacity requirements. The revised requirement should be used as inputs in the IPR process to ensure that the RESOLVE model develops a portfolio that incorporates location specific resource requirements.

Maintaining reliability is depended on appropriately located resources throughout the state to meet the local and zonal needs of the electric grid and ensuring the right mix of resources to address operation reliability requirements. Otherwise, the reliability analysis is incomplete.

Q3. Comment on the appropriateness of the scenarios and sensitivities developed in RESOLVE to be considered as the preferred portfolio. Suggest any alternative sensitivities or changes to the analysis

The CPUC has proposed the "38 MMT Core Portfolio" scenario as the PSP. This scenario uses "a 38 MMT GHG target in 2030 with LSE plans incorporated, along with the MTR

5/ For e.g., Path 26 (interconnection between PG&E and SCE) has a North to South rating of 4000 MW, limiting only 4000 MW of northern California resources to be available to meet load and operating reserve requirement of loads south of Path 26.

6/ CAISO 2020-2021 Transmission Plan, page 375, Section 6.1, http://www.caiso.com/Documents/BoardApproved2020-2021TransmissionPlan.pdf (accessed Sept. 27, 2021).

resources of 11,500 MW."[7] The proposed scenario and the resulting portfolio have the following primary issues:

- The aggregated LSE plans are outdated. See response to Question 1.
- The methodology used to develop the PSP results in a portfolio that is larger than needed to meet reliability requirements and is misaligned with the MTR procurement decision.[8]
- The IEPR forecast used for the core scenario is outdated and the mid- EV forecast underestimates the expected level of EV penetration by 2030. See response to Question 6.
- Zonal and local resource requirements have not been sufficiently considered for identifying the appropriate location for additional resources. See response to Question 2.

PG&E recommends the following core scenario updates for use as the PSP to address these issues:

1. Update the load forecast to reflect the most recent California Energy Commission ("CEC") 2020 IEPR forecast and 2020 IEPR high EV scenario;[9]
2. Remove incremental resource additions from the 2020 LSE aggregated plans;
3. Update resources related to MTR procurement to better align with the MTR decision; and
4. Add additional resources if the SERVM results demonstrate that reliability is less than 0.1 or GHG emissions are above the targeted 38 MMT.

7/ ALJ Ruling, p. 14, Attachment A, p. 33.

8/ E.g., the MTR decision requires 2500 MW of DCPP retirement to be replaced "zero-emitting resources". This zero-emitting capacity "(a) Be from a generation resource, a generation resource paired with storage (physically or contractually), or a demand response resource; (b) Be available every day from 5 p.m. to 10 p.m. (the beginning of hour ending 1800 through the end of hour ending 2200), Pacific Time, at a minimum; and (c) Be able to deliver at least 5 megawatt-hours of energy during each of these daily periods for every megawatt of incremental capacity claimed."

9/ Additional details in response to question 6.

Using the approach described above, PG&E developed an alternative PSP to reflect the MTR decision ("MTR Portfolio"). (See appendix A for PG&E's recommended resource portfolio.)

PG&E's MTR Portfolio[10/] includes a nameplate capacity of 97,814 MW in 2030. By comparison, the 2030 PSP portfolio modeled by the CPUC is 108,129 MW (nameplate). The MTR Portfolio reflects LSE baseline resources and the MTR procurement decision. As expected, the capacity of the MTR portfolio is lower than the CPUC's 38 MMT Core Portfolio. This is an artifact of the methodology and the ELCC values used by the CPUC in selecting additional resources to meet the 22.5% PRM.

Comparison of CAISO Name Plate Capacity for year 2030

Study Year	MTR Portfolio	38 MMT Core	38 MMT Aggregated LSE Plan
2030	97,814 MW	108,129 MW	91,995 MW

PG&E tested this portfolio using PG&E's SERVM model and CEC 2020 IEPR forecast.[11/] The result of the SERVM analysis shows that with the MTR procurement, the CAISO system is on track to achieve its share of 38 MMT target (i.e., 31.1 MMT) and will achieve an LOLE of at least 0.1.

Comparison of LOLE and GHG Emission Results

2030 Metric	MTR Portfolio[12/]	CPUC 38 MMT Core	Target
LOLE	0.04	0.05	0.1

10/ The details included in this section and Appendix A present PG&E's preliminary analysis to inform PSP. PG&E plans to use time between opening and reply comments to refine its analysis. Any updates to PG&E's analysis presented here will be include in our reply comments.

11/ PG&E's load assumption did not include the 2020 IEPR high EV load forecast.

12/ These results represent the impact of 2,172 MW lower solar name plate capacity and 21 MW higher Biomass name plate capacity compared to the MTR Portfolio capacity shown.

GHG Emissions	31.6	34.7	31.1[13/]

As shown in the above table, the MTR Portfolio results in a CAISO system LOLE of 0.04 and GHG emissions of 31.6 MMT. Since the PG&E portfolio does not include resources that will be procured by public owned utilities ("POUs") (app.10% of CAISO), addition of any planned procurement by non-CPUC jurisdictional entities will results in even lower LOLE and GHG emission.

PG&E recognizes that more work is required to develop an acceptable reliability planning metric ("RPM") for resource adequacy planning. In the absence of an acceptable replacement of the current RPM, PG&E recommends that the Commission adopt PG&E's proposed MTR Portfolio as the PSP. To account for uncertainties related to frequency of extreme weather conditions, it may be reasonable to add additional capacity for planning purposes.

PG&E performed an additional 2030 sensitivity to reflect an extreme weather year. The preliminary analysis shows an additional 2,000 MW NQC may be required to meet a 0.1 LOLE planning standard under extreme weather conditions.[14/]

The MTR Portfolio has the same shortcoming as the 38 MMT Core Portfolio, because it too does not include location specific requirements. Recognizing that the zonal and local capacity requirements will not be available from the CAISO before the schedule for finalizing the PSP, and given the uncertainties associated with the types and the locations of new resources, PG&E recommends the following two MTR portfolios for use in the CAISO TPP to identify the transmission upgrades driven by resource locations and help identify "least regret" transmission upgrades.

13/ CAISO share of Statewide 38 MMT GHG emission = 31.1 MMT emission.

14/ Addition of any planned procurement by non-CPUC jurisdictional entities (POUs) could fill-in some or all of incremental resources required to address reliability needs under extreme weather conditions.

i. MTR portfolio 1: RESOLVE model identifies location of resources to achieve the MTR portfolio total nameplate capacity by technology type. This approach will be similar to how the 38 MMT Aggregated LSE Portfolio was enforced in the portfolio to address location.

ii. MTR portfolio 2: Split incremental resources in CAISO transmission access charge ("TAC") areas based on load ratio share.

Use of the above proposed portfolios will not only inform the "least regret" transmission upgrade decision, it will also provide useful insight into the next IRP cycle about the impact of the location of the resources on transmission congestion and additional transmission costs.

Q4. Comment on the SERVM analysis and results of the 38 MMT Core Portfolio

PG&E urges the Commission to initiate a process in 2021 to update the target LOLE for consumers (and the resulting PRM) pursuant a thorough process vetted by stakeholders. The Commission Staff's analysis of the 38 MMT Core Portfolio with the enforcement of a 22.5 percent PRM results in a LOLE of 0.064 and 0.054 in 2026 and 2030 respectively, much lower than a typical electric planning standard of 0.1 LOLE that is industry standard nationwide.

PG&E is concerned that the use of a 22.5 percent PRM assumption and the absence of a defined LOLE target in this proceeding sets a precedent without sufficient analytical rigor. The Commission's own decision requiring procurement to address MTR needs recognizes that "[m]ore analysis is needed before revising the planning reserve margin for long-term planning in the IRP proceeding on a permanent basis."[15/] The Commission Staff's SERVM analysis of the 38 MMT Core Portfolio further heightens the urgency for the CPUC to initiate a process to update the target LOLE (and the resulting PRM) to ensure that procurement targets do not burden consumers with excessive costs.

15/ See D.21-06-035, page 86, Findings of Fact (FOF) 1.

Q5. Comment on the appropriateness of the 38 MMT Core Portfolio as the PSP.

PG&E proposes an alternative PSP (2030 nameplate capacity of about 98,000 MW) that more closely reflects LSE's baseline resources and the MTR procurement. To account for uncertainties related to account for extreme weather conditions, it may be reasonable to add additional capacity for planning purposes. See response to Question 3 for more detail regarding PG&E's recommendations for the PSP.

The amalgamation of individual LSE portfolio plans along with the CPUC's methodology of adding resources on top of the aggregated plans has created a misalignment with the MTR procurement and fails to reflect the resulting changed portfolio needs of individual LSEs resulting from Commission-ordered procurement.

As indicated earlier, the 2020 aggregated LSE portfolio is an outdated measure of current LSE needs and portfolio composition. For example, in PG&E's 2020 IRP LSE Plan, PG&E identified a need to procure 748 MW of wind resources in the 38 MMT target scenario.[16/] Now however, the MTR procurement directs PG&E to procure 2,302 MW of new resources (including 900 MWs of criteria-specific capacity). As PG&E works to fulfill this ordered procurement, the assumptions used in the development of its plan are outdated given the MTR order, and the resources that it will add to its portfolio will likely be different that those envisioned in its IRP (in short, the IRP is now outdated).

Q6. Comment on whether the load forecast assumptions should be adjusted to include higher load, particularly related to EV adoption or high electrification more broadly.

PG&E supports adjusting load assumptions for the PSP to reflect higher EV load. PG&E understands this ruling suggests the CPUC adopt the 2020 IEPR high EV load forecast.[17/] PG&E believes that all 2020 IEPR EV scenarios materially underestimate the likely EV load by the year 2030. For example, in PG&E's service area, PG&E forecasts 2.3 million light-duty EVs on the road in 2030, compared to the 1.8 million light-duty EVs projected in the 2020 IEPR high

16/ PG&E LSE Plan, filed September 1, 2020, at page 5.

17/ ALJ Ruling, at page 22.

EV scenario. The 2020 IEPR scenarios underestimate EV load because they do not anticipate future policy changes that will likely accelerate EV adoption. For example, Governor Newsom's 2020 Executive Order N-79-20 sets EV adoption targets substantially higher than the EV adoption suggested by the 2020 IEPR scenarios.[18/] If the PSP must rely on a 2020 IEPR EV scenario, PG&E supports the use of the high scenario rather than the mid scenario.

Q7. Comment on the proposal to use the 38 MMT Core Portfolio as the reliability and policy-driven base case in the TPP.

PG&E does not support the proposed 38 MMT Core Portfolio for use as the reliability and policy-driven base case for the 2022–23 CAISO TPP (See response to Question 3).

The 38 MMT Core Portfolio does not reflect resources that must be procured to meet local reliability or zonal transmission needs. As in the past, PG&E again here emphasizes the need for robustness in the CPUC's IRP analysis to account for local and zonal needs critical for overall system reliability. The 38 MMT Core Portfolio unfortunately falls short on these critical aspects of resource planning, because the 38 MMT Core Portfolio, selected by RESOLVE, selects the majority of new resources (30,265 MW of the total 36,085 MW)[19/] in Southern California. This is not realistic. LSEs will procure resources across the CAISO system to meet local and zonal needs. Resource procurements must be aligned with locational resource needs. The Commission must conduct a study with use of at least two sensitivities—with a more balanced selection of resources between Northern and Southern California—to help remove the risk for approving transmission upgrades that may not be required if the location specific resource requirements are incorporated in the IRP.

18/ Governor Newsom's Zero-Emission by 2035 Executive Order (N-79-20) (Sept. 23, 2020), at page 2.

19/ 17,637 MW of the total 20,999 MW of selected renewables and 12,627 MW of the total 15,086 MW selected storage.

Q8. Comment on the proposed policy-driven sensitivity portfolio for the TPP based on the 30 MMT GHG limit in 2030 with the high electrification load assumptions. Suggest any additional or alternative scenarios that should be analyzed as policy-driven sensitivities.

While PG&E does not have a concern with the use of a 30 MMT GHG target as a policy-driven sensitivity, PG&E believes that the effort would be better spent in addressing the missing pieces required for a robust and integrated resource planning:

i. *Establish a new Planning Metric for Resource Adequacy Planning:* As stated above, PG&E recommends the Commission initiate a process now to determine the correct level of PRM to achieve reliability and avoid over procurement that will burden consumers with excess costs. The current Commission staff analysis of 38 MMT Core Portfolio with enforcement of a 22.5 PRM results in LOLE of 0.064 and 0.054 in 2026 and 2030, respectively, both are much lower than the typical electric planning standard of 0.1 LOLE that is the established industry standard nationwide. Reliance on a non-standard and unsupported PRM without proper analysis will likely lead to higher energy rates for consumers than necessary.

ii. *Location specific resource requirements (zonal and local):* PG&E expects higher electrification load will have an impact on location specific resource requirement. Resource requirements due to transmission limitations need to be identified as soon as possible for the IRP process to be successful. See response to Q2 for additional details.

iii. *Estimated cost of new transmission*: If the Base Case or the Policy-Driven Sensitivity Portfolios require additional transmission investments to maintain reliability or for resource deliverability, estimated cost of new transmission investment as an input to the RESOLVE model will support the IRP's objective to identify a least-cost portfolio and better estimate the customer rate impact.

iv. *Magnitude of renewable generation curtailment due to transmission congestion*: Since the CPUC's RESOLVE model does not include a detailed transmission representation, magnitude of transmission congestion related curtailment from the CAISO TPP will help fine-tune the RESOLVE model GHG emission estimates and SERVM model reliability assessment. The CAISO has modified its Deliverability Assessment and now uses Off-peak Deliverability Status ("OPDS") for resources. The CPUC-transmitted portfolios will be assessed using the new OPDS for resources. The use of the modified Deliverability Assessment may significantly increase congestion and curtailment risk for both new and existing resources.

v. *Guidance on gas-fired resource retention and retirement*: The majority of the existing thermal generation is retained through 2030, there is an opportunity to develop a process to identify the optimal level of existing resources that should be retained to maintain system reliability. Currently the CAISO relies on its Reliability Must-Run ("RMR") process to retain resources required for reliability. Use of RMR process is a sign that planning efforts are not adequately addressing reliability needs of the system.

vi. *Minimum generation requirement for local areas, sub-regional level (e.g., Bay Area or North and South of Path 26)*: If the TPP studies indicate there is a need for minimum generation requirement for transmission reliability, the information should be used to refine IRP modelling to ensure that the dispatch of resources reflect how they will be operated by the CAISO and planned at the right location.

Q9. Comment on whether and how the Commission should act to encourage specific non-transmission alternatives to be built, if identified as part of the CAISO TPP process, both for the two specific projects identified in the 2020-2021 TPP, as well as in general for future such opportunities.

PG&E here focuses on its assessment of the effectiveness of the two specific projects identified in the 2020–21 TPP in PG&E's service area and a high level recommendation for the process to be used for encouraging non-transmission alternatives in future. A discussion on the more general issues is provided in the response to Question 10.

PG&E's assessment of the Effectiveness of the two storage projects in its Service area

1. *The 95MW energy storage resource on the Kern-Lamont 115 kilovolt ("kV") system:* This project will be located in a local area and will adequately address the identified reliability issues on the 115 kV system and replace the need for transmission upgrades. However, the CAISO's cost-effectiveness assessment is incomplete as only a portion of a hypothetical energy storage project's cost was included in the analysis (e.g., any energy storage deliverability related cost is excluded from the analysis).[20/] Since this project is in a local area, PG&E supports using the central procurement entity ("CPE") to conduct solicitations for non-transmission alternatives at the Kern-Lamont 115kV location, as further described in response to Question 10 below. The attributes of the CPE procured resource should then be allocated to all LSEs sharing the procurement cost.
2. *The 50-MW 4-hour energy storage resource at the Mesa 115 kV substation:* This project on the other hand will only partially address the reliability issues and will not replace the need for transmission upgrades. While the energy storage resource may result in meeting the North American Electric Reliability Corporation ("NERC") reliability criteria, PG&E recommends that reliability issues beyond the reliability criteria should still be considered. The transmission upgrades (e.g., the wires solution) should be authorized in order to address all the reliability issues.

PG&E's recommendation for the process to encourage non-transmission alternatives in the future

PG&E supports the best fit and most cost-effective solution to maintaining system reliability for the future. PG&E supports a holistic consideration of non-transmission alternatives in the CAISO TPP process. The current TPP process is already setup to evaluate the effectiveness of non-wire alternatives to mitigate identified reliability issues. As soon as the

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20/ See CAISO 2020–2021 Transmission Plan, p. 114, available at http://www.caiso.com/Documents/BoardApproved 2020-2021TransmissionPlan.pdf (accessed Sept. 27, 2021).

uncertainty associated with the process for cost recovery of transmission alternatives is resolved (see additional details in response to Question 10), PG&E believes that the non-transmission alternative will become a part of integrated transmission and generation planning.

Q10. Comment on the options raised in Section 7.2 of this ruling to address procurement for system benefit more broadly. Suggest whether and how a particular cost recovery framework can be adopted quickly or discuss additional considerations that should be explored.

In response to this question PG&E (i) offers a recommendation for long-term solution for cost-recovery of transmission alternatives, (ii) offers an interim solution for procurement of storage options identified by the CAISO in the 2020-21 TPP process, and (iii) raises issue with the option presented in Section 7.2 that any LSE could apply to conduct such procurement on behalf of all LSEs.

Recommendation for long-term solution: PG&E recommends cost recovery through the TAC rate for asset (e.g., generation or transmission) procurement to address transmission constraints. All LSEs and their customers, regardless of CPUC jurisdiction, benefit from transmission-related solutions. The adoption of a storage as transmission asset ("SATA") framework by CAISO is an equitable means for recovering the respective costs from all benefitting market participants. A comprehensive approach enabling energy storage facilities to provide transmission services has the potential to generate additional cost benefits and provide greater flexibility to the grid.

PG&E urges the CAISO to restart its SATA initiative either within the Energy Storage Enhancements ("ESE") initiative or as a standalone initiative. CAISO's SATA is the appropriate place to encourage non-transmission alternatives that are identified as part of the CAISO TPP process. However, until the CAISO adopts a SATA framework, the Commission appropriately can explore alternative pathways for non-transmission alternatives. The most reasonable (interim) near-term solution for SATA investments for local capacity requirements is for the Commission to order the investor owned utilities ("IOUs") as the CPEs in their respective distribution service territories to run solicitations to determine if energy storage can cost-effectively defer transmission investments.

Interim solution for procurement of energy storage resource on the Kern-Lamont 115 kV system: Since the 95MW energy storage resource on the Kern-Lamont 115 kV system is in a local area, PG&E supports the use of a CPE to conduct solicitations for non-transmission alternatives. The CPE is already authorized by the Commission to make procurements and allocate costs using CAM for other LSEs. The use of CAM would still result in cost shifting among customers since some customers that benefit from the procurement made by the CPE will not pay its proportionate share of CAM costs. As such, CAM should only be authorized for recovery of costs for the Kern-Lamont project[21/] until the CAISO's SATA framework can be finalized. Therefore, PG&E recommends that the CPE be authorized to run a solicitation for cost-effective non-wires alternative for the Kern-Lamont location, with costs recovered using existing CPE methodologies (i.e., using the CAM).

The CPE presents the CPUC with an existing cost recovery mechanism for SATAs. Use of the CPE would ensure that CPUC can use an existing cost recovery mechanism using existing mechanisms, rather than create a mechanism from scratch. As the Commission found in D.19-02-022 and affirmed in D.20-06-002, "designating the distribution utilities as the CPEs for their respective TAC areas is the most practical, feasible solution"[22/] because the IOUs "are the candidates with 'the resources, knowledge and experience' to procure local reliability resources on behalf of all LSEs without excessive delay."[23/]

Utility-owned solutions should be permitted under a CPE framework to maximize the pool of competitive projects and deliver the best SATA solution for all LSE customers. Prior

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21/ As stated in Q9, for the Mesa Project PG&E recommends that procurement of a non-wires alternative should be put on hold until PG&E can revisit with the CAISO their recommendation for the Mesa project to ensure all reliability issues are addressed.

22/ D.19-02-022, at page 14. D.20-06-002, at page 33.

23/ D.19-02-022, at page 14.

competitive solicitations under the CPE framework have allowed utility-owned solutions to compete and have shown this can be done fairly.

Issues with the option raised in Section 7.2 where any LSE could apply to conduct such procurement on behalf of all LSEs: In the ALJ Ruling, the Commission has offered an option where "any LSE could apply to conduct such procurement on behalf of all LSEs and be granted conditional approval by the Commission for cost recovery." PG&E has significant concerns with the proposal to allow any LSE to use a new non-by-passable charge as a cost recovery mechanism without also establishing clear and upfront standards for approval. The CPUC will need cost oversight of LSEs procurement activities. The contract management activities will need to be reviewed every year in compliance review process (similar to the IOU's ERRA Compliance Proceeding), subjecting the LSE to disallowances for cost recovery if it is determined that the LSE was not prudent in its contract management activities. To the extent that some LSEs will be able to charge other LSEs for their costs, all parties should have a similar opportunity to review their contract management activities for prudency and disallow cost recovery for unreasonable actions. Establishing upfront and achievable standards and a compliance review process for more than 40 LSEs would likely be administratively burdensome and highly litigious. The Commission should fully consider the challenges of this responsibility before assuming it.

Q11. Comment on the busbar mapping approach.

PG&E does not have comments on the busbar mapping approach at this time.

Q12. Comment on whether the Commission should require the procurement of resources contained in the individual IRP filings and have LSEs face penalties and/or backstop procurement requirements with cost allocation arrangements, similar to those for D.19-11-016 and D.21-06-035.

The Commission should not require individual LSEs to procure the specific resources included in their IRP filings, nor assess penalties and/or order backstop procurement for IRP procurement 'noncompliance.' For many reasons, PG&E opposes requiring procurement of IRP-specific resources for individual LSEs though the IRP submittals themselves.

First, the LSEs prepare their IRP filings based on the best available information at the time of its preparation, but the plans can quickly become outdated due to CPUC procurement orders requiring acquisition of resources with certain operating characteristics (e.g., D.21-06-035) or due to other CPUC decisions affecting LSE portfolio plans (e.g., D.21-05-030).[24/] An LSE that showed a certain MW need for a specific resource may no longer need to procure that resource given a subsequent procurement order that requires other resources be brought online that meet both the operating characteristic and GHG emissions need previously identified.

Second, the resource portfolios contained in LSE plans contain a mix of resources based on currently available technologies and their relative costs compared to other technologies with similar operating characteristics and GHG emissions. However, the IRP structure of planning for a time period of a decade or more in advance must also account for technological breakthroughs in existing, as well as, new technology resources that have significant potential for lowered costs and improved efficiencies. Adopting these new technological developments to enhance efficiency and cost effectiveness may result in resource selections different than those shown in previously filed IRPs. LSEs should be able to take advantage of these opportunities over a long horizon planning process as long as the new/different resources procured have similar operating characteristics to meet the defined need in LSE IRPs.

Third, the IRP planning track, which includes the filing of individual LSE IRPs, is a *non-binding planning process*. The IRP is designed to 1) ensure that there are sufficient resources available to maintain grid reliability; 2) cost effectively meet California's GHG emission reduction goals for the electricity sector; and 3) take into account the resource preferences of

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24/ CPUC guidance Q&A on 2020 IRP Filings instructed "[Q] What assumptions for departing load should be used by all LSEs to allocate costs and resources? Should all LSEs apply existing PCIA rules? [A] LSEs should not deviate from their assigned load forecast in preparing their proposed resource portfolios. LSEs may describe in their narrative (Study Results and Action Plan sections) how PCIA rules may affect their costs and planned resources." See response to Question 9, p. 13, available at ftp://ftp.cpuc.ca.gov/energy/modeling/Filling%20Requirement%20QA%20_%20Aug.pdf individual LSEs.[25/] This process was never intended to lock in LSEs to specific procurement obligation that would be the subject of an enforcement mechanism for procurement based on LSE IRP submittals.

In addition to the above, it is important to acknowledge that the Commission has other, more appropriate mechanisms for ensuring that LSEs meet their procurement obligations, including through the RA and renewable portfolio standard ("RPS") programs. If the Commission were to adopt resource-specific procurement requirements with associated noncompliance penalties in the IRP proceeding, this would create a potential mismatch across other programs with existing procurement enforcement components.

Q13. Comment on whether you would prefer an approach where the Commission determines procurement need for GHG-free resources or the GHG-free attributes of resources at the system level and then uses a need allocation methodology to assign procurement to individual LSEs.

As a standard for assigning any resource procurement, PG&E strongly supports the CPUC allocating such procurement using need-based allocation methodologies in order to ensure that procurement is equitably allocated across LSEs. For GHG emissions planning purposes, PG&E supports the CPUC establishing an annual GHG emissions planning target trajectory with corresponding annual LSE targets. The CPUC should consider adopting the following LSE IRP planning requirements to ensure that the State is on a path to achieving its adopted GHG-emissions target goals for the electric sector:

- For each LSE IRP, LSEs must file plans demonstrating that the GHG emissions from their portfolio of contracted and owned resources, if applicable, do not exceed their established annual GHG target for the following two years (e.g., 2023 and 2024 for the 2022 LSE IRP filings);

25/ *Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes*, (Issued May 14, 2021).

- In addition to the above, LSE plans must include proposed commercial activity, if applicable, for meeting established annual GHG targets for years three and four (e.g., 2025 and 2026 for the 2022 LSE IRP filings); and
- LSE plans must receive CPUC approval for reasonably demonstrating plans to meet annual GHG targets, as well as other compliance positions, for all additional plan years.

Each LSE must demonstrate that its portfolio meets its respective LSE-GHG emissions target by submitting a Clean System Power ("CSP") workbook, or its identified successor, based on the underlying portfolio assumptions that satisfy the portfolio requirements described above. If the CPUC determines an LSE's plan is deficient in meeting the described GHG emission planning requirements, or any other plan requirements established by the CPUC, LSEs should have an opportunity to cure any such deficiencies by submitting revised plans no later than 60 days upon receiving notification of a deficiency. If the CPUC determines that revised plans are still deficient, then LSEs should be subject to reasonable fines or penalties.

Regarding cost allocation, given that the proposed requirements above are based on LSEs meeting their respective load forecasts, no additional cost recovery mechanism need be developed. IOUs can use the established PCIA cost recovery mechanism and associated vintaging rules for recovering resource procurement costs. If the CPUC orders IOUs to act as backstop procurers for deficient LSEs or procurers of large long-lead time resources, the CPUC should allow IOUs to bill deficient LSEs directly for costs incurred or recover costs through the established CAM.

Q14. If you believe the Commission should take more of a programmatic approach to GHG-beneficial procurement, explain the process you recommend and your rationale.

The CPUC need not develop an additional programmatic approach to GHG-beneficial procurement in addition to what PG&E has proposed in response to Question 13.

Q15. Comment on whether and how much procurement required in D.21-06-035 should be accelerated to 2023 and/or suggest additional actions to facilitate additional resources in response to the Governor's Proclamation from July 30, 2021.

PG&E supports the ambitious goals of the proposed PSP, however PG&E is not in favor of accelerating procurement required in D.21-06-035 to 2023, as suggested in Question 15. The CEC's needs analysis on IRP MTR procurement highlights that accelerating procurement for 2023 is not needed, assuming the 2019 IRP ordered resources come online on time in 2022 and 2023.[26/] In addition to a lack of need for accelerated procurement, motivation already exists for LSEs to bring resources online faster, such as the opportunity to earn higher revenues in a tight market and the use of higher marginal effective load carrying capability ("ELCC") values. For these aforementioned reasons, PG&E does not support an explicit requirement by the Commission to accelerate D.21-06-035 procurement, however it does recommend that the Commission encourage LSEs to exceed their procurement targets, as feasible, to help facilitate additional resources in response to the Governor's Proclamation.[27/] Specifically, PG&E suggests that in order to further encourage LSEs to procure in excess of their requirements, the Commission should consider an incentive mechanism for LSEs that exceed their IRP MTR procurement target online dates from D.21-06-035.

PG&E has historically expressed concerns with expedited procurement due to compressed timelines and resource development challenges. However, PG&E believes that an incentive mechanism for resources brought online early (e.g., 2023 resources coming online by summer 2022) could be paid. An incentive for exceeding compliance (an Incentive Mechanism for Procurement Exceedance ("IMPE")) has realistic application for near-term resource procurement, would fairly compensate LSEs for expediting resources to come online, and is equitable in terms of approach and distribution of benefits among the various LSEs.

26/ California Energy Commission, Presentation for August 30 Lead Commissioner Workshop on Midterm Reliability Analysis, (Aug. 30, 2021).

27/ Proclamation of a State of Emergency by California Governor Gavin Newsome (July 30, 2021).

PG&E has developed an initial proposal for the IMPE that self-funds incentive payments for LSEs that surpass their procurement target online dates early from penalties assessed based on the structure adopted in D.21-06-035 on LSEs that miss their respective procurement target online dates. This incentive mechanism is similar to the CAISO's Resource Adequacy Availability Incentive Mechanism ("RAAIM")[28/]—that is, any penalties assessed on LSEs for missing their respective procurement target online dates will be used to provide an incentive payment to LSEs that exceed their procurement target online dates.

Like the RAAIM, the IMPE funds itself and does not require additional external financial resources beyond the program because the incentive payment is paid for entirely through the delayed procurement penalties that are assessed on noncompliant LSEs. The IMPE likely will not add additional payments or encourage LSEs to renegotiate existing contracts to bring resources online faster. It is specifically for new resources exceeding 2022 and 2023 targets. Instead, the IMPE spurs LSEs to bring on more resources than required with the potential opportunity to receive incentives, as available.

The IMPE follows this rationale: When an LSE fails to bring a required resource online in a timely manner, then collectively the system is short. If another LSE can make up that shortage, then the LSE should receive an incentive payment equivalent to the penalty that was assessed for the noncompliant LSE. For example, if LSE A is assessed a 50 MW penalty while LSE B exceeds its target by 50 MW, then LSE B would be provided an incentive for "making up the difference." Like RAAIM, each MW of noncompliant procurement is charged a penalty price. These penalty charges are then pooled and ultimately divided among LSEs that exceed their procurement targets on a per-MW basis during the given compliance period.

The IMPE is intentionally structured to be flexible to evolve with changing procurement requirements and timelines. The amount of incentive payment is not set. It is dependent upon the pool of penalty payments during a given compliance period, avoiding any exercise of market

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28/ California Independent System Operator Corporation FERC Docket No. ER15-1825-000 Tariff Amendment to Implement Phase 1A of Reliability Services Initiative, (May 29, 2015), pp. 60-63.

power. The IMPE is not intended to provide a fixed revenue stream for LSEs or developers. The IMPE aims to incentivize LSEs to go beyond their procurement requirement.

Q16. Comment on the CEC's MTR reliability analysis, the determinations regarding the need for fossil-fueled generation resources, and the actions, if any, that the Commission should take as a result.

PG&E continues to review the CEC's MTR Analysis conclusion that a portfolio of preferred resources can provide equivalent system reliability, despite the retirement of approximately 4 gigawatts ("GW") of OTC resources and without the addition of new thermal resources. Both the CEC's MTR analysis and the CPUC's proposed PSP will require an extraordinarily large volume of new nameplate capacity from preferred resources to avoid the addition of non-preferred (i.e., thermal) generation.

PG&E encourages the CPUC to review the procurement assumption in D.21-06-035 to more accurately capture the requirements put forth in the decision for MTR procurement. PG&E's proposed MTR Portfolio is based on the details prescribed in the MTR decision (See Appendix A for additional details.)

Notwithstanding the CEC's MTR analysis conclusion, if the Commission deems that new thermal resources are needed for system reliability, PG&E recommends that LSEs not be required to enter into long-term contracts for these resource types. If the IOUs are required to procure these resources on behalf of all customers, any associated emissions should be allocated to all LSEs for planning and CEC reporting purposes.

Q17. Comment on the definition of eligible renewable hydrogen proposed in this ruling.

PG&E does not oppose using the self-generation incentive program ("SGIP") renewable hydrogen definition proposed by the ruling on an interim basis, pending further clarification.[29/] If the proposal proves unworkable that a generating facility need document renewable energy credit ("REC") retirement for energy used to produce the hydrogen fuels, a REC-like market

[29/] The CPUC is considering defining renewable hydrogen in R.13-02-008, and there is ongoing policy activity in the State Legislature.

would need to be developed to tag the renewable hydrogen fuel to tie the fuel used for production to the commodity.

Q18. Comment on the percentage of renewable hydrogen facilities that should be required, if any, and the timing of the transition from a blend to full renewable hydrogen combustion, including the option for inclusion of fuel cells. Discuss the feasibility and cost of achieving a 100 percent renewable hydrogen blend by 2036 in your comments.

As stated elsewhere, PG&E supports procurement targets that designate certain resource attributes, rather than carveouts for specific resource types. However, PG&E recognizes that the CPUC should also set standards and guidelines for resources like renewable hydrogen. Currently, PG&E is aware that turbine manufacturers recommend no more than a 45-percent blend of hydrogen with natural gas to ensure safe operation. Manufacturers are working toward developing turbines that can accommodate 100-percent hydrogen fuels within the next decade, but it is not clear when the technology will be approved and safe to use.

PG&E notes that its existing portfolio of thermal resources would require extensive modifications to be able to use up to 45-percent hydrogen-blended fuels, and further modifications (which are not yet available) to use 100-percent hydrogen fuels.

For resources that do not have access to on-site hydrogen fuel production, fuel transportation will need to be considered. Technical studies are underway to determine what level of hydrogen can be blended with natural gas while safely transported in current natural gas pipeline infrastructure.[30/]

Q19. Comment on proposed measures regarding NOx emissions from facilities using renewable hydrogen.

The proposal seems reasonable to PG&E.

30/ For some current research on transporting hydrogen blends with natural gas in pipeline infrastructure, see for example: DOE Hydrogen H2@Scale initiative, DOE Earthshot Hydrogen Shot, Pipeline Research Council International (PRCI) State of the Art Hydrogen Blending Study, NREL Hyblend, IEA study.

Q20. Comment on whether the Commission should take any initial actions on geographically-targeted procurement, particularly with respect to Aliso Canyon, or more broadly, and respond to the factors discussed in Section 12 of this ruling.

While PG&E appreciates the opportunity to comment on geographically-targeted procurement in the Los Angeles basin with respect to Aliso Canyon, any major proposals should come after the FTI Consulting analysis due to the complexities described in the ruling. The complex interplay between the electric and gas systems in the region means that it is difficult to target least-regret actions. PG&E recommends that the FTI Consulting analysis be completed and released before the CPUC recommends any course of action. Additionally, the ruling raises multiple potential concerns about the interplay between closure of the Aliso Canyon facility and natural gas generation but does not indicate which of those potential impacts are a serious concern, if any.

If the CPUC seeks least-regret options, PG&E recommends renewables integrated with storage without the capability to charge from the grid, with an emphasis on long-duration storage. While the ruling speculates that storage alone may inadvertently increase emissions from fossil-fuel generators, renewables paired with long-duration storage may be the best option until the FTI Consulting's analysis is complete.

Q21. Comment on whether and how the Commission should act to preserve transmission deliverability rights in the central coast area that could be utilized for offshore wind or other resources.

As CAISO's 2020–21 Transmission Plan notes, the owners of the Diablo Canyon Power Plant retain certain deliverability retention options for repowering that can remain in effect for up to three years following the retirement of the plant.[31/] PG&E has not yet made its decision on which of the scenarios described in the CAISO's tariff[32/] and Business Practice Manual[33/] it

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31/ CAISO 2020-2021 Transmission Plan, at page 28.

32/ CAISO Fifth Replacement FERC Electric Tariff, Effective August 4, 2021.

33/ http://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx (accessed Sept. 27, 2021).

will pursue for the transmission deliverability rights. PG&E welcomes Commission input on this matter that impacts the central coast area.

Q22. Comment on the amount of offshore wind, if any, that should be included in the 2022-2023 TPP base case. Comment on how the results of the 2021-2022 TPP offshore wind sensitivity case should influence this issue.

PG&E supports least-cost, best-fit resource procurement as a foundational aspect of cost-effective, reliable resource planning. Offshore wind and out-of-state renewable resources may present an attractive value for California energy consumers. PG&E supports policy action to advance transmission development for access to high-capacity factor diverse resources (e.g., out of state and offshore wind). In the past, California successfully developed renewable energy zones (i.e., CREZs) through systematic planning. Similarly, the Commission should adopt a similar zone approach to plan for and develop transmission for offshore and out-of-state wind resources.

Q23. Comment on whether and how the Commission should act to support the development of OOS renewables/wind and the transmission to deliver it. Be as concrete and specific as possible in your recommendations.

See response to Question 22.

Q24. Comment on specific actions the Commission can take to ensure retention of existing resources needed both for reliability and/or GHG emissions purposes.

PG&E supports a systematic approach to ensure retention of existing resources needed both for reliability and GHG emissions purposes. This task can only be accomplished after the completion of an operational reliability assessment. As noted in response to Question 2, the CAISO is working on validating its transmission models required for frequency response assessment to ensure that the portfolio of intermittent and inverter-based resources can provide an acceptable level of frequency response for additional details about the need for completing operational reliability assessment. In addition, and since a large number of existing resources support local reliability, it is extremely important that the local and zonal requirements are a part of this assessment to ensure that a decision for retention or retirement of an existing resource accounts for the impact on locational reliability. In the absence of a robust reliability assessment (operational reliability and local/zonal resource requirements), there is a risk that existing resources may retire due to economic reasons, even though these resources (or cost effective alternatives) are required for reliability, or some resources are retained using an emergency RMR mechanism. Either of these outcomes will result in uneconomic emergency procurement decisions.

If the reliability assessment finds the need to retain existing resources and the IOUs are required to contact with these resources, PG&E recommends use of CAM cost recovery and fair allocation of emission attributes, if any.

Q25. For any of the potential procurement requirements discussed in this ruling, allocation of need to LSEs is a required step. Comment on how the methodologies should account for in-CAISO POU load and what steps the Commission should take to ensure those POUs bear their share of responsibility for reliability and GHG impacts.

PG&E appreciates the Commission's consideration of this important matter of procurement responsibility across all benefitting LSEs and their customers across the CAISO balancing authority area.

PG&E recognizes that current legislative language in Section 454.51 does not explicitly distinguish procurement responsibility among Commission-jurisdictional LSEs and POUs and, thus, changes in legislative language are warranted to ensure procurement responsibility is appropriately allocated, including those to POUs.

PG&E highlights that there is a current framework that could be leveraged—SB 859 (BioRAM) recognized the importance of all LSEs, IOUs as well as POUs, contributing to broader state goals. In Senate Bill 859, POUs were assigned a proportional share to procure resources in response to the Governor's state of emergency on tree mortality. Similarly, the RPS program requires all LSEs, IOUs as well as POUs, pursuant to a series of legislation the most recent of which was Senate Bill 100 that requires retail sales to achieve carbon neutrality by 2045. The requirements of Senate Bill 100 and other predecessor RPS legislation applies equally to IOUs as well as POUs.

A similar path and framework could be pursued for procurement needs identified and established in the IRP. This would require coordination among the legislature, CPUC and CEC.

IV. ADDITIONAL COMMENTS ON TOPICS NOT COVERED BY THE ALJ RULING

A. The Commission should consider extending system RA requirements across multiple years and utilize that framework as the procurement enforcement mechanism

The Commission should address near-term reliability in the RA proceeding—not in the IRP proceeding—by considering the extension of system RA requirements on a multi-year forward basis, similar to local RA requirements. As referenced in Question 12 above, PG&E opposes requiring the procurement of resources identified in the individual IRP filings and subjecting LSEs to associated penalties. Instead, PG&E proposes that the Commission develop and implement a multi-year RA framework in the RA proceeding and utilize this more appropriate venue as a mechanism to enforce procurement compliance. This approach will clearly delineate the planning process from procurement enforcement, avoid duplication of efforts and confusion with potential various penalty structures, and provide an already established enforcement mechanism for procurement responsibility. It will also ensure near-term reliability and help to minimize rushed emergency procurement.

Parties in the RA proceeding have expressed similar sentiments—namely, that the IRP proceeding is a tool to plan for and order procurement, while the RA filings function as the enforcement mechanism for near-term reliability. For example, the CAISO noted in its revised RA Track 3B.2 proposal that multi-year system RA requirements are important to ensuring "near-term reliability and [to] ensure continued operation of existing generation resources."[34/] The Western Power Trading Forum ("WPTF") and the Independent Energy Producers Association ("IEPA") submitted initial proposals on a multi-year RA requirement on August 7, 2020, with WPTF noting in its revised proposal that multi-year system RA requirements provide

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34/ R.19-11-009, *Comments of Pacific Gas and Electric Company on Revised Track 3b.2 Proposals*, (Jan. 15, 2021) at page 5.

several benefits, including: revenue certainty needed for long-cycle maintenance costs for generators, support for capacity upgrades to facilities, more rational cost recovery, and reduced transaction costs for LSEs.

PG&E acknowledges that multi-year system RA requirements could provide benefits, but also recognizes that there are important conceptual concerns as well as implementation details that need to be resolved before adopting such multi-year RA requirements. PG&E recommends that multi-year requirement issues be discussed in the RA proceeding, with a focus on identifying durable solutions to these issues. Utilizing the RA program for procurement compliance, including the adoption of a multi-year RA framework, would provide multiple benefits, including an expanded time horizon for mandated procurement across multiple years, and would incorporate an already-adopted tiered penalty structure for noncompliance.

V. CONCLUSION

PG&E respectfully requests that the Commission adopt the recommendations herein.

Respectfully Submitted,

DANIEL S. HASHIMI

By: *\/s/ Daniel S. Hashimi*
DANIEL S. HASHIMI

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (818) 388-1711
Facsimile: (415) 973-5520
E-Mail: Daniel.Hashimi@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: September 27, 2021

APPENDIX A – OVERVIEW OF PG&E MODELING (PRELIMINARY)

This appendix provides details of PG&E's preliminary analysis. PG&E plans to use the time between opening and reply comments to refine its analysis. Any updates to PG&E's analysis presented here will be updated and included in PG&E's reply comments.

Study Objective: PG&E's analysis focused on identifying incremental capacity above what was ordered for the MTR procurement and the amount of capacity needed to achieve a CAISO system 0.1 LOLE and the 31.1 MMT GHG emissions target.

Study Approach: The following is a high-level overview of the approach used for developing PG&E's analysis.

Steps to complete LOLE and GHG emission analysis:

1. Develop MTR representative portfolio by taking CPUC's 2030 baseline (assumed to be inclusive of 2019 procurement order) and adding PG&E developed MTR procurement assumption.
2. Run MTR portfolio through PG&E's 2030 SERVM model to identify system LOLE and GHG emissions.
3. Identify incremental capacity needs if the MTR portfolio does not achieve a CAISO system 0.1 LOLE and 31.1 MMT target.

Overview of PG&E's SERVM Model

PG&E created a SERVM model to identify the CAISO resource mix during stressed system conditions using the following approach:

- CPUC 2020 Reference System Plan (RSP) SERVM model used as a starting point
- RSP SERVM model was modified with the following major updates:
  - Load, Solar and wind profiles:
    - Added recent year (2018, 2019, 2020) weather data
    - Calibrated load to 2020 IEPR – inclusive of CEC load climate change adder[35]
    - Calibrated solar and wind profiles using historical production data
  - CAISO Imports fine-tuned to align with 2020 import conditions and CPUC Assumptions:
    - Maximum net imports limited to 4000 MW during peak hours (Months 6-9, HE17-22)

[35] PG&E's load assumption did not include the 2020 IEPR high EV load forecast.

- Other WECC excess capacity (beyond 0.1 LOLE) removed to simulate WECC conditions where excess resources are not readily available for CAISO[36]
- Net import flow to Northern and Southern California calibrated using 2020 historical import split between Northern and Southern California.

- Increased CAISO Operating Reserve Requirements from 4.5% to 6% and enforced separately for Northern and Southern California to account for Path 26 limitation preventing use of reserves.
- Forced and planned outages adjusted to reflect historical forced outage rates from August 2020.
- Updated hydro de-rates, DR performance using historical data

Approach for developing resource portfolio for MTR decision

The MTR Portfolio was developed by using the MTR incremental ELCCs to convert the 11.5 NQC GW into nameplate capacity.

1. Aggregate capacity by resource category from the CPUC staff's 2030 Baseline + Development Resources (assumed to be inclusive of 2019 Procurement Mandate).
2. Add PG&E's MTR procurement estimates summarized in the following table.

Portfolio to Meet MTR Procurement

Technology	Total Nameplate (MW)	Total NQC (MW)
Long Lead Time Resources (assume 80% CF)**		
Geothermal	669	669
Biomass/Wood	331	331
8-hr Storage	1,279	1,000
Sub Total	*2,300*	*2,000*
Zero Emitting Resources***		
Solar	3,937	-
4-hr Storage	3,125	2,500
Sub Total	*7,062*	*2,500*
Remaining Procurement (Any type of Resource)*		
Solar	9,849	673
Wind	4,996	827
4-hr Storage	5,943	5,270
DR	58	58
OOS Wind & Offshore Wind	506	171
Sub Total	*21,352*	*7,000*
Total MTR Procurement	**30,714**	**11,500**

36 The import assumptions represent a stressed system condition for WECC. Import may be higher than PG&E's modelling assumption.

*Allocation of resources is based on ratio shown in the RESOLVE Adjusted 38 MMT Plans

**Zero-emitting generation resources (RPS-qualifying resources and 80% capacity factor) assumed to be split between geothermal and biomass based on the 2022 split (~70%/30%)

*** Nameplate assumption was developed by the Market and Procurement Policy team based on PG&E's current interpretation of the MTR procurement ruling and the 2020 QC manual

Comparison of MTR Portfolio and CPUC 38 MMT Portfolios

The following table shows a comparison of PG&E's MTR Portfolio using the approach described above with the CPUC 38 MMT Core scenario and the 38 MMT Aggregated LSE Plans.

Comparison of MTR Portfolio with 38 MMT Aggregated and Core Portfolios

Technology*	MTR Portfolio	38 MMT Aggregated LSE Plan	38 MMT Core
Nuclear	635	635	635
Thermal	26,952	26,977	26,635
Hydro	6,372	6,004	8,031
PSH	1,599	2,273	2,899
Geothermal	2,301	1,910	2,747
Wind	12,595	11,602	12,219
Solar	30,338	25,944	30,874
Battery Storage	14,056	10,064	17,659
DR	1,804	1,704	2,636
Biomass	1,141	928	942
Hybrid	0**	3,954**	0**
Total**	97,793	91,995	108,129

Technology categories were simplified to ensure consistent accounting. The MTR Portfolio and 38 MMT Aggregated LSE Plan capacities were reported out by SERVM resource categories. The 38 MMT Core capacities were reported out by RESOLVE resource categories.

***Totals are not reflective of actual resource capacity totals. The 38 MMT Aggregated LSE Plan scenario does not have hybrid resources disaggregated.*