STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

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PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

Date **Agenda ID #23020**
**Ratesetting**

TO PARTIES OF RECORD IN RULEMAKING 23-10-011:

This is the proposed decision of Administrative Law Judge Debbie Chiv. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's 12/5/2024 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, *ex parte* communications are prohibited pursuant to Rule 8.2(c)(4).

/s/ MICHELLE COOKE
Michelle Cooke
Chief Administrative Law Judge

MLC:smt

Attachment

Decision **PROPOSED DECISION OF ALJ CHIV (Mailed 10/29/2024)**

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

| | |
|---|---|
| Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations. | Rulemaking 23-10-011 |

# DECISION ON TRACK 2 ISSUES

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## DECISION ON TRACK 2 ISSUES

### Summary

This decision addresses issues scoped as Track 2 of this proceeding, including adopting modifications to the central procurement entity (CPE) framework, such as eliminating the non-compensated self-show option of the CPE framework and locking in CPE allocations to load-serving entities one year earlier.

This proceeding remains open.

### 1. Procedural History

A Scoping Memo and Ruling (Scoping Memo) for this proceeding was issued on December 18, 2023. The Scoping Memo set forth a scope of issues divided into three tracks (Track 1, 2, and 3). Track 1 issues were addressed in Decision (D.) 24-06-004, issued by the Commission on June 26, 2024. Track 2 issues will be considered in this decision, including issues related to the central procurement entity (CPE) framework and the revised Loss of Load Expectation (LOLE) study and Planning Reserve Margin (PRM) for the 2026 and 2027 Resource Adequacy (RA) compliance years.

On March 15, 2024, Energy Division issued its Proposed Inputs and Assumptions, which was attached to an Administrative Law Judge's (ALJ) ruling on March 18, 2024. Energy Division issued a report on the CPE framework on May 31, 2024, titled Report on the 2021-2023 Central Procurement Entity Framework, and issued a revised version of the report on June 4, 2023. On June 5, 2024, an ALJ ruling attached Energy Division's report.

Proposals on Track 2 issues were filed on June 14, 2024 by: American Clean Power – California (ACP-CA); Alliance for Retail Energy Markets (AReM); California Community Choice Association (CalCCA); California Environmental

Justice Alliance (CEJA) and Sierra Club (collectively, CEJA/Sierra Club); California Energy Storage Alliance (CESA); Middle River Power, LLC (MRP); Pacific Gas and Electric Company (PG&E); Southern California Edison Company (SCE); Vistra Corp. (Vistra); and Western Power Trading Forum (WPTF).

Energy Division issued the LOLE Study for 2026 (including Slice of Day Tool Analysis) (LOLE study) on July 19, 2024. On July 22, 2024, the ALJ's ruling attached Energy Division's LOLE study. Workshops on Track 2 proposals and the LOLE study were held on July 25 and July 26, 2024.

Opening comments on Track 2 proposals were filed on August 9, 2024 by: ACP-CA; AReM; California Independent System Operator (CAISO); CalCCA; Public Advocates Office at the Public Utilities Commission (Cal Advocates); California Wind Energy Association (CalWEA); Calpine Corporation (Calpine); CEJA/Sierra Club; CESA; California Efficiency + Demand Management Council (Council) and OhmConnect, Inc. (OhmConnect) (collectively, Council/OhmConnect); Department of Market Monitoring of CAISO (DMM), Leapfrog Power, Inc. (Leap); Microsoft Corporation (Microsoft); MRP; New Leaf Energy, Inc. (New Leaf Energy); NextEra Energy Resources, LLC (NEER); Protect Our Communities Foundation (PCF); PG&E; San Diego Gas & Electric Company (SDG&E); SCE; and WPTF.

Reply comments on Track 2 proposals were filed on August 23, 2024 by: AReM; CalCCA; Cal Advocates; CEJA/Sierra Club; Central Coast Community Energy (3CE); CESA; Council/OhmConnect; Large-Scale Solar Association (LSA); PCF; PG&E; REV Renewables, LLC (REV); and SCE. MRP was granted leave to late-file reply comments on August 26, 2024.

On August 30, 2024, Energy Division issued Appendix A: Revised Slice Of Day (SOD) Tool Analysis and the SOD calibration tool. An ALJ's ruling attached Appendix A.

On September 9, opening comments on the revised SOD PRM calibration tool were filed by: AReM, Ava Community Energy (Ava), CAISO, Cal Advocates, CalCCA, Calpine, CEJA/Sierra Club, California Municipal Utilities Association (CMUA), MRP, PCF, PG&E, SCE, SDG&E, and WPTF. On September 16, reply comments on the revised SOD PRM calibration tool were filed by ACP-CA, AReM, CAISO, Cal Advocates, CalCCA, Microsoft, MRP, PCF, PG&E, SCE, SDG&E, Shell Energy North America (US), L.P. (Shell Energy), and WPTF.

All rulings by the assigned Commissioner and the assigned Administrative Law Judge are affirmed. Any pending motions are denied.

## 2. Submission Date

This matter was submitted on September 16, 2024 upon the submission of reply comments on the revised SOD PRM calibration tool.

## 3. Issues Before the Commission

The scope of Track 2, as adopted in the December 18, 2023 Scoping Memo, is summarized below:

1. Structural modifications and/or refinements to the CPE framework. Energy Division will issue a report on the CPE framework in the 1st Quarter of 2024, as directed by Decision (D.) 22-03-034. The Commission will consider proposals on structural modifications and/or refinements to the CPE framework.
2. LOLE Study and PRM. The Commission will consider modifications to the PRM for compliance years 2026 and 2027, including the results of Energy Division's annual LOLE study. The Commission will consider party input in

developing the study inputs and assumptions, including consideration of Path 26 and the treatment of Diablo Canyon Nuclear Generating Facility pending the outcome of Rulemaking (R.) 23-01-007.

3. Coordination with the Integrated Resource Planning (IRP) Proceeding. This will include the appropriate PRM requirements for short-term planning compared with the longer timeframe for the IRP proceeding, and coordination with the IRP proceeding's development of a programmatic approach to procurement being considered in the IRP proceeding as the Reliable and Clean Power Procurement Program (RCPPP).

On June 4, 2024, an ALJ's ruling was issued that stated that based on the adopted schedule for RCPPP development in the IRP proceeding, "it is necessary to defer consideration of the Track 2 topic 'Coordination with the IRP Proceeding' until after the RCPPP proposal has been considered in the IRP proceeding."[1] As such, Issue 3 above has been deferred until after the Commission issues a decision on the RCPPP proposal in R.20-05-033.

## 4. Discussion

### 4.1. 2026 LOLE Study and PRM Process

On July 19, 2024, Energy Division issued its 2026 LOLE study that establishes a PRM and supports the translation of resource needs in the SOD framework.[2] Compared to previous years, Energy Division's LOLE analysis utilized the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) California Energy Demand Forecast managed peak, rather than the consumption peak.

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1 ALJ's Ruling Deferring Track 2 Issue on Coordination with the Integrated Resource Planning Proceeding, issued June 4, 2024, at 2.

2 Energy Division's 2026 LOLE Study, July 19, 2024, at 4.

Energy Division states that after extensive analysis, it determined that the 2023 IEPR CAISO coincident managed peak forecast appeared more consistent with historical trends than the consumption forecast. Energy Division determined that "[t]he 2023 IEPR, more so than previous years, reflects a large gap between the CAISO coincident consumption and managed peaks largely driven by different hourly profiles of consumption demand resulting from the different demand models used for the LOLE study and the IEPR."[3] Therefore, "[b]y tuning the median managed peak in the LOLE model to match the IEPR managed peak, staff confirmed that the model met the target reliability of 1 day in 10 years (0.1 LOLE) using the updated Baseline set of resources and evening peak hours CAISO simultaneous imports constrained to 2,500 MW rather than the prior assumption of 4,000 MW." In the study, Energy Division Staff stated that "[t]he results of this study show that with the baseline including existing resources and expected resource additions based on LSE contracting and development milestones, RA obligations can be met while allowing for some uncertainty or delay in resource development."[4]

Energy Division then implemented the resource portfolio from the LOLE study in the SOD PRM tool and calculated the required PRM in all 12 months. After calculating initial PRMs, Staff performed stress tests on varying levels of PRM needed to meet the target reliability level. Given the results of this analysis, Energy Division proposed a 18.5 percent PRM on top of the 2023 IEPR CAISO coincident managed peak demand forecast for all 12 months.

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3 *Id.*

4 *Id.* at 5.

On August 30, 2024, Energy Division issued a revised SOD tool analysis, titled Appendix A to Loss of Load Expectation Study for 2026: Slice of Day Tool Analysis (revised analysis). In the revised analysis, Energy Division states that "Staff identified errors in exceedance calculations, and in accounting for storage charging in the SOD tool. To resolve these errors Staff changed the objective function in the SOD tool for storage dispatch, updated the exceedance values and recalculated PRM levels based on the LOLE study."[5] Energy Division further states that "Staff recalculated both the SOD equivalent of the initial LOLE study (which was not rerun) then based on those initial LOLE SOD results, Staff redid the stress tests (including a revised SERVM LOLE run) to determine the required PRM values in each month."[6] Energy Division notes that the underlying LOLE study is unchanged.

Based on the revised analysis, Staff recommends adopting a 26.5 percent PRM on top of the CAISO coincident managed peak demand forecast in months January – May, and a 23.5 percent PRM in June – December. Energy Division states that the underlying resource fleet remains sufficient to meet reliability targets with the baseline set of resources only, with no additional generic resources added.

#### 4.1.1. Comments on Energy Division's Analysis

The below summary of comments primarily focus on Energy Division's revised SOD PRM calibration results.

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5 Appendix A to Loss of Load Expectation Study for 2026: Revised Slice of Day Tool Analysis (Appendix A to LOLE Study), at 2.

6 *Id.*

CAISO, Calpine, MRP, and WPTF support the updated 23.5 percent and 26.5 percent PRM.[7] CAISO states that the updated PRM reflects PRM levels required to meet a 0.1 LOLE across the year and better align with the 0.1 LOLE target in the IRP proceeding.

Numerous parties oppose adopting the 23.5 percent and 26.5 percent PRM, including AReM, Ava, CalCCA, Cal Advocates, CEJA/Sierra Club, PG&E, PCF, SCE, and Shell Energy.[8] These parties generally state that the updated PRM is significantly higher than the 17 percent PRM in 2025 (and the PRM from the initial analysis), is not adequately justified by Energy Division's revised analysis, and will likely have downstream impacts that result in substantially higher costs to ratepayers and higher market prices as LSEs need to procure more resources to meet these requirements.

SCE states that the revised results indicate there are serious design or translation flaws in the modeling.[9] SCE identifies that the CAISO load profiles in the revised analysis do not appear to match the latest 2023 IEPR planning forecast and that several categories of resources in the revised analysis are questionable, such as including more combined cycle net qualifying capacity (NQC) than the total of all CAISO combined cycle plants. PG&E expresses concern about the demand response (DR) value that is significantly higher than

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[7] CAISO Comments on Appendix A to LOLE Study at 2, Calpine Comments on Appendix A to LOLE Study at 1, MRP Comments on Appendix A to LOLE Study at 2, WPTF Comments on Appendix A to LOLE Study at 2.

[8] AReM Comments on Appendix A to LOLE Study at 2, Ava Comments on Appendix A to LOLE Study at 2, Cal Advocates Comments on Appendix A to LOLE Study at 1, CalCCA Comments on Appendix A to LOLE Study at 8, CEJA/Sierra Club Comments on Appendix A to LOLE Study at 1, SCE Comments on Appendix A to LOLE Study at 2, PCF Comments on Appendix A to LOLE Study at 3, PG&E Reply Comments on Appendix A to LOLE Study at 2, Shell Energy Reply Comments on Appendix A to LOLE Study at 3.

[9] SCE Comments on Appendix A to LOLE Study at 6.

amounts used in prior studies and a lack of transparency regarding what resources are being used in the SOD tool.[10] CalCCA observes that the load shapes appear to have peaks shifted later in the day relative to the actual load shapes observed at CAISO, and that forced outages rates of storage and thermal generators are uncertain and may be too high in SERVM.[11] CalCCA, Cal Advocates, CEJA/Sierra Club, and SCE express concern that calibrating LOLE by adding blocks of load may have material impacts in the SOD framework.[12] Other parties, such an CEJA/Sierra Club, PCF, and Microsoft, express concern with artificially limiting the available imports in the translation, which appears to have artificially increased the PRM.[13]

AReM, Cal Advocates, CalCCA, and MRP seek an explanation of why two PRMs are needed, why the results for February were anomalous, and why a LOLE higher than 0.1 was targeted.[14] MRP and Cal Advocates also seek an explanation as to why the revised SOD values are derived not from the peak hour but from the most constrained hour in each month. CMUA states that the updated PRM does not account for factors other than the LOLE study, such as

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10 PG&E Comments on Appendix A to LOLE Study at 2.

11 CalCCA Comments on Appendix A to LOLE Study at 8.

12 Cal Advocates Comments on Appendix A to LOLE Study at 4, CalCCA Comments on Track 2 Proposals, CEJA/Sierra Club Comments on Appendix A to LOLE at 1, SCE Comments on Appendix A to LOLE Study at 6.

13 CEJA/Sierra Club Comments on Appendix A to LOLE Study at 1, PCF Comments on Appendix A to LOLE Study at 4, Microsoft Reply Comments on Appendix A to LOLE Study at 7.

14 AReM Comments on Appendix A to LOLE Study at 2, CalCCA Reply Comments on Appendix A to LOLE Study at 4, MRP Comments on Appendix A to LOLE Study at 4.

affordability or feasibility, and that it may not be practical for non-Commission jurisdictional LSEs to adopt the PRM evenly.[15]

Numerous parties recommend deferring adoption of the 2026 PRM until further analysis can be completed and the PRM results can be vetted, including ACP-CA, AReM, CalCCA, Cal Advocates, Microsoft, PG&E, and SCE.[16] Some parties recommend considering the 2026 PRM in Track 3, while CalCCA recommends a decision in March 2025. CAISO, MRP, and WPTF support the requests for additional time to review the LOLE study and impacts, with WPTF and MRP recommending that a decision on the 2026 PRM still be issued in November 2024.[17] 3CE recommends retaining the current 17 percent PRM and not adopting a 2026 PRM until after the SOD framework has been implemented.[18]

#### 4.1.2. Discussion

In D.22-06-050, the Commission adopted a minimum 17 percent PRM for the 2024 RA year. In D.23-06-029, the Commission adopted a 17 percent PRM for 2025, stating that "[g]iven the realities of available RA supply and persistent delays in development projects, it is prudent to retain the status quo 17 percent PRM for the 2024 and 2025 RA years. Increasing the PRM without greater

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15 CMUA Comments on Appendix A to LOLE Study at 4.

16 ACP-CA Comments on Appendix A to LOLE Study at 1, AReM Comments on Appendix A to LOLE Study at 2, CalCCA Comments on Appendix A to LOLE Study at 8, Cal Advocates Comments on Appendix A to LOLE Study at 4, Microsoft Reply Comments on Appendix A to LOLE Study at 7, PG&E Comments on Appendix A to LOLE Study at 2, SCE Comments on Appendix A to LOLE Study at 2.

17 CAISO Reply Comments on Appendix A to LOLE Study at 3, MRP Reply Comments on Appendix A to LOLE Study at 5, WPTF Reply Comments on Appendix A to LOLE Study at 1.

18 3CE Reply Comments on Track 2 Proposals at 2.

certainty about installed RA resources for 2024 and 2025 is not appropriate at this time."[19] The decision further stated that "[t]he Commission will continue to monitor market conditions and impacts of the adopted PRM framework and will reevaluate the PRM requirements for the 2026 RA year in 2024."[20]

A broad range of parties recommend further analysis and vetting of Energy Division's revised analysis and raise numerous potential issues and errors with the revised analysis. The majority of parties recommend deferring adoption of the 2026 PRM to Track 3 of this proceeding, and seek additional data and information regarding the inputs used in the SOD tool.

The Commission agrees that additional vetting and further analysis of the issues raised by parties is needed. Energy Division is authorized to undertake a further revision of the 2026 PRM analysis to correct identified errors raised in comments, and distribute it to the service list in this proceeding in early December 2024. Following the release of the revised PRM analysis, Energy Division will conduct workshops to explain the analysis and supporting data. Energy Division may solicit informal comments on the analysis and parties will have an opportunity to submit formal comments. Following that process, the Commission will consider the revised PRM analysis in Track 3 of this proceeding.

Lastly, we note that some parties appear to misunderstand the definition and use of the LOLE metric and the mechanisms of the stress test. To enhance learnings of these concepts, Energy Division Staff should include additional clarifications in future LOLE reports.

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19 D.23-06-029 at Finding of Fact 4.

20 *Id*. at 25.

### 4.2. Additional LOLE and PRM Proposals

MRP recommends adopting a standard annual process to develop the PRM for the upcoming compliance year.[21] The proposed process would include Energy Division working with parties to develop inputs and assumptions for the LOLE studies, publication of a preliminary and final LOLE study with an opportunity to comment on each, and submission of proposals based on the final study results.

WPTF proposes adopting a 0.1 LOLE as the reliability standard in the RA program, as also used for IRP modeling.[22] WPTF also recommends specifying the stress test that Energy Division will be conducting as part of the LOLE study to establish the 2027 PRM. WPTF recommends that a regular LOLE study and PRM development process be established, including development of inputs and assumptions for each study and an opportunity to submit alternative LOLE studies.

AReM recommends a process to set a single PRM, as outlined in WPTF's Track 1 PRM proposal.[23] AReM states that the process is comparable to Energy Division Staff's Stress Test 3[24] and notes that if the process leads to an infeasible solution (i.e., greater capacity need in the peak month than can be supplied by available resources), AReM agrees with Energy Division's recommendation for a

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21 MRP Track 2 Proposals at 18.

22 WPTF Track 2 Proposal at 2.

23 AReM Track 2 Proposal at 7.

24 Energy Division, Slice of Day – Load Forecast Process Update and Loss of Load Studies Translation for RA proceeding Update, October 6, 2022, www.cpuc.ca.gov/-/media/cpucwebsite/divisions/energydivision/documents/resource-adequacy-homepage/resource-adequacycompliance-materials/resourceadequacy-history/10-6-2022-wrap-up/workshop-10_energydivision_221006.pdf.

"optional stress test" to set two PRMs, one for the peak month and one for other months.

Vistra recommends adopting a seasonal PRM for peak months and a different PRM value for non-peak months based on recurring probabilistic annual LOLE to ensure accurate assumptions for forced outages.[25] Vistra proposes that seasonal PRMs be updated beginning in 2026 by leveraging the LOLE studies and stress tests and that Energy Division update an annual LOLE study each February beginning in 2025 and every year after. Vistra also recommends that the LOLE study incorporate advanced notice and short notice forced outages to ensure that months with a possibility of unforeseen advanced notice forced outages are incorporated into generation availability assumptions. Vistra believes advanced notice forced outages are not reflected in the Generator Availability Data System (GADS) forced outage rates used in the current LOLE inputs and assumptions.

ACP-CA recommends aligning the SOD framework with probabilistic PRM calibration (as it previously proposed in Track 1).[26] ACP-CA recommends revisiting resource counting and accreditation for wind and solar resources to align with probabilistic modeling methods. ACP-CA contends that resource accreditation should align with expected contributions of a resource during critical reliability periods across a range of conditions and more sophisticated weather modeling programs should be evaluated to understand patterns outside the state. ACP-CA states that the current exceedance methodology approximates

[25] Vistra Track 2 Proposal at 4.

[26] ACP-CA Track 2 Proposal at 4.

this result but does not reflect expected values during critical periods, which is problematic for resources in developing regions without operations data.

#### 4.2.1. Comments on Proposals

Several parties support a regular schedule for LOLE studies and PRM updates with stakeholder participation, including CAISO, CalCCA, SCE, SDG&E, PG&E, and WPTF.[27] CAISO states that while an annual LOLE study would be ideal, a schedule that balances the benefits of updated inputs with staff resource demands should be considered. SDG&E states that a standard process would give certainty to LSEs and the market and allow the LOLE study/PRM to incorporate market changes over time. CEJA/Sierra Club oppose locking in an annual LOLE process before evaluating the proper reliability metric.[28]

SCE supports moving from a single PRM to seasonal, monthly, or peak/non-peak month PRMs and states that Energy Division should conduct more granular analyses to determine the best PRMs.[29] SCE supports adopting the Natural Resources Defense Council's LOLE Informed Intermittent Resource Counting proposal for LOLE modeling which would reduce errors, fairly compensate resources, and provide certainty in counting rules. CalCCA supports a single, annual PRM until the study methodology is sufficient to evaluate monthly or seasonal PRMs.[30] CalCCA states that the current methodology lacks variability that would warrant monthly or seasonal variation,

[27] CAISO Comments on Track 2 Proposals at 3, CalCCA Reply Comments on Track 2 Proposals at 3, SCE Comments on Track 2 Proposals at 6, SDG&E Comments on Track 2 Proposals at 2, PG&E Reply Comments on Appendix A to LOLE Study at 5, WPTF Comments on Track 2 Proposals at 4.

[28] CEJA/Sierra Club Comments on Track 2 Proposals at 18.

[29] SCE Comments on Track 2 Proposals at 6.

[30] CalCCA Comments on Track 2 Proposals at 5.

as compared to the annual PRM. Microsoft supports Vistra's proposal and agrees that Energy Division should refine modeling to support seasonal PRMs.[31]

CAISO, MRP, Microsoft, and SDG&E support adopting a 0.1 LOLE reliability target for the RA program, as it is a general industry standard and can better align the RA requirements with the IRP proceeding.[32] CAISO recommends stress testing the PRM to ensure it meets a 0.1 LOLE across the year and to adopt stress testing as part of the PRM-setting process. WPTF comments that monthly stress tests should be conducted for future LOLE studies, as this can identify month-specific PRMs, can be used as a starting point for seasonal PRMs, and can identify a single PRM that achieves 0.1 LOLE reliability.[33]

Cal Advocates argues that there is no reason to formally adopt the 0.1 LOLE standard since the RA program already targets that standard and adoption may make the 0.1 LOLE standard binding, hampering the Commission's ability to adjust RA requirements and the PRM as issues arise.[34] Cal Advocates points to recent examples where the Commission declined to adopt a PRM based on the 0.1 LOLE study or when the Commission extended the effective PRM program. CalCCA states that while the industry definition of a reliable system is one that meets a 0.1 LOLE, the focus on reliability should not lose sight of implications on affordability.[35]

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31 Microsoft Comments on Track 2 Proposals at 5.

32 CAISO Comments on Track 2 Proposals at 2, Microsoft Comments on Track 2 Proposals at 2, MRP Comments on Track 2 Proposals at 6, SDG&E Comments on Track 2 Proposals at 4.

33 WPTF Comments on Track 2 Proposals at 3.

34 Cal Advocates Reply Comments on Track 2 Proposals at 2.

35 CalCCA Comments on Track 2 Proposals at 4.

CEJA/Sierra Club oppose a 0.1 LOLE standard and recommend analyzing a reliability definition based on loss of load hours (LOLH) and unserved energy.[36] CEJA/Sierra Club state that there is no consistent way to apply the 0.1 LOLE standard, though it is widely used, and that other methods for defining the 1-in-10 standard is one day every ten years, which translates into 2.4 hours of outage a year, or based on the examination of unserved energy. Microsoft agrees that parties would benefit from understanding the volumetric effect of outages using a LOLH metric.[37] SDG&E opposes a 2.4 hours per year relaxed standard as leading to decreased reliability because it would be a lower standard that would require fewer resources to be procured.[38] SDG&E points out that the study cited by CEJA/Sierra Club to conclude the 2.4 hours per year would result in a small reliability impact was from 2011 and the reliability challenges facing the grid have changed significantly.

CalWEA and PG&E support ACP-CA's proposal to remove the exceedance step in developing QC values for wind and solar.[39] CalWEA states that ACP-CA's analysis shows how translation of historical benchmarks into exceedance values arbitrarily drives overcounting and undercounting of solar values and undercounting of wind values. PG&E supports using the worst day benchmark and removing the exceedance step but notes that exceedance can still be used in development of the worst day benchmark, which would provide greater benchmark flexibility. PG&E supports further exploration of the methodologies.

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36 CEJA/Sierra Club Comments on Track 2 Proposals at 15.

37 Microsoft Comments on Track 2 Proposals at 9.

38 SDG&E Comments on Track 2 Proposals at 4.

39 CalWEA Comments on Track 2 Proposals at 1, PG&E Reply Comments on Track 2 Proposals at 9.

LSA is open to considering elimination of the exceedance step but states that the worst day approach must be equally transparent so that resources can determine what their RA value will be.[40] MRP is concerned that removing the exceedance step may lead to volatile and unreliable RA values but agrees that the methodology should be revisited.[41]

SCE supports aligning the process for RA resource counting with IRP and recommends moving the resource profile process to the IRP proceeding to align RA accreditation with capacity profiles used in the IRP and SERVM LOLE modeling.[42] SCE states that the advantages of this include consolidating focus to a single set of resource profiles and the availability of funding for third-party vendor IRP work. CalCCA supports consistency between data used in SERVM modeling, the SOD PRM translation, and resource accreditation.[43]

#### 4.2.2. Discussion

The Commission highlights that the data gathering and reconciliation process for the inputs and assumptions that underlie the LOLE study is very time-consuming and resource intensive. The Commission therefore determines that it is not feasible to run an updated LOLE study each year. It is more realistic and reasonable for Energy Division Staff to update an RA LOLE study every two years. Accordingly, Energy Division is authorized to update the LOLE study every two years for consideration in the RA proceeding.

The Commission recognizes that a schedule for developing and discussing the LOLE study would be beneficial to stakeholders for understanding the LOLE

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40 LSA Reply Comments on Track 2 Proposals at 2.

41 MRP Reply Comments on Track 2 Proposals at 5.

42 SCE Comments on Track 2 Proposals at 6.

43 CalCCA Reply Comments on Track 2 Proposals at 8.

study inputs and process. We note, however, that any timeline must revolve around the availability of data inputs, notably including any revised IEPR data which is typically published in February of each year. Ahead of its expected biannual RA LOLE study, Energy Division is encouraged to develop and distribute a schedule that provides for necessary updates of data in the LOLE model, publication of an inputs and assumptions document, processing of inputs and assumptions into the SERVM model, completion of the LOLE study and stress tests, and opportunity for party comments.

As noted above, data gathering and reconciliation for the LOLE modeling process is a time-intensive, significant undertaking for Commission Staff. We underscore that Commission Staff is gaining experience as to how long the data development and modeling process will take for the new SOD framework, and we appreciate parties' patience as Staff develops and refines the modeling timelines.

The Commission sees merit in modifying the QC values for wind and solar resources using SERVM weather profiles, rather than using exceedance profiles, as this would better align SOD RA values with how SERVM stochastic datasets are used in the RA LOLE studies. However, we find that there is insufficient record at this time to consider this change and that more analysis is needed. In D.24-06-004, the Commission determined that "the exceedance levels for wind and solar resources will be adjusted to monthly levels, with the next update to occur in 2024 and subsequent updates every three years thereafter."[44] As such, the current exceedance levels for wind and solar resources have been locked in for three years. The Commission authorizes Energy Division to conduct an

[44] D.24-06-004 at Ordering Paragraph 8.

analysis comparing exceedance profiles for wind and solar resource against SERVM weather profiles to be considered in Phase 3 of this proceeding.

Regarding the 0.1 LOLE reliability standard, the Commission notes that Assembly Bill 2368 was recently passed, which provides that the Commission shall determine the most efficient and equitable means to "[e]nsuring that the resource adequacy program can reasonably maintain a standard measure of reliability, such as a one-day-in-10-year loss-of-load expectation or a similarly robust reliability metric adopted by the commission, and use it for planning purposes."[45] We agree with parties that state that a 0.1 LOLE reliability target is the general industry standard and use of the standard can better align the RA requirements with the IRP program. The 0.1 LOLE reliability standard is currently used by Energy Division in the RA LOLE modeling and we plan to continue to use that standard going forward.

Regarding AReM's proposal, we note that Energy Division conducted its LOLE study using Stress Test 3. For future RA LOLE studies, Energy Division should continue to perform similar stress tests to ensure monthly reliability levels. In D.24-06-005, the Commission "determined that a single PRM will apply to all hours of the year for initial implementation of the SOD framework."[46] However, following the initial implementation of the SOD framework, we recognize that a single PRM may not be appropriate for all hours of the year. As Energy Division conducts its PRM calibration analyses, Energy Division is authorized to conduct an optional stress test analysis to set a single annual or multiple PRMs, as necessary.

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[45] Public Utilities Code Section 380(h)(4).

[46] D.24-06-005 at Finding of Fact 3.

### 4.3. Unforced Capacity (UCAP) Methodology

Vistra recommends the Commission direct a UCAP working group to provide CAISO, Energy Division, and stakeholders with a venue to develop a UCAP methodology and submit a proposal in early 2026 to be adopted for the 2028 compliance year.[47] Vistra proposes that between Q3 2026 – Q3 2027, implementation efforts would include suppliers reviewing RA contracts to confirm NQC reductions, LSEs reviewing portfolios and procuring additional RA capacity, and suppliers appealing initial UCAP value. Vistra recommends that in August 2027, CAISO publish the draft and final NQC, which will include NQC values based on UCAP for the 2028 NQC list.

CESA supports Vistra's proposal for resource-specific UCAP accreditation in 2028 and for storage UCAP values to be calculated only after sufficient, consistent historical outage data is available from CAISO.[48] SDG&E generally supports UCAP implementation and argues that adoption earlier than 2028 would be difficult in potentially forcing LSEs to make solicitation decisions without full information.[49]

CAISO states that it will begin a stakeholder process to consider a UCAP framework, which will provide a venue for stakeholders, Energy Division, and other local regulatory authorities in the CAISO balancing authority area.[50] CAISO states that if Vistra's proposal is adopted, the Commission should ensure close coordination with CAISO's stakeholder process and that CAISO will work with Energy Division to align a potential UCAP framework.

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47 Vistra Track 2 Proposal at 7.

48 CESA Comments on Track 2 Proposals at 5.

49 SDG&E Comments on Track 2 Proposals at 6.

50 CAISO Comments on Track 2 Proposals at 6.

PG&E states that it is premature to determine that 2028 is the appropriate implementation year and notes that because Energy Division has been working on UCAP for some time, earlier implementation is possible.[51] PG&E states that the timing of UCAP should be aligned with PRM changes, which does not have an established cadence. PG&E supports the principles it raised in Track 1 for a UCAP methodology but notes that it may not be feasible for a final methodology to be at the resource-specific level, which should be further explored.

#### 4.3.1. Discussion

In D.24-06-004, the Commission stated that:

> The Commission observes that a broad range of parties agree that further discussion is needed to develop a UCAP methodology for thermal and storage resources. As such, we decline to adopt a UCAP methodology at this time. We note the UCAP framework is being further developed in Track 2, as a UCAP framework is intended to be used for 2026 RA LOLE modeling efforts and for developing forced and ambient outage derates for the 2026 compliance year at the earliest.[52]

The Commission agrees with PG&E that it is premature to determine that 2028 is the appropriate implementation year for a UCAP methodology. We note that Energy Division has been working on a UCAP methodology for over a year and CAISO will be initiating a stakeholder process on a UCAP methodology. As such, Energy Division should coordinate with CAISO to develop a UCAP accreditation methodology for thermal power plants and battery electric storage systems for consideration in advance of the 2028 RA compliance year and to submit a revised UCAP proposal in Track 3 of this proceeding.

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[51] PG&E Comments on Track 2 Proposals at 6.

[52] D.24-06-004 at 63.

Due to the work already underway towards a proposed UCAP methodology, an additional working group process is unnecessary; rather, we encourage parties to participate in CAISO's stakeholder process and/or submit proposals or evaluate Energy Division's proposal in Track 3 of the proceeding. Energy Division should harmonize its UCAP proposal with CAISO, to the extent possible, and coordinate on critical issues, including: (1) identifying one source of data; (2) identifying the correct treatment of nature of work codes; (3) specifying how to determine UCAP for new resources; (4) determining the appropriate level of aggregation/disaggregation of similar resources; (5) determining how to accommodate for different outage types, such as maintenance and thermal ambient derates in addition to pure equipment failure curtailments; and (6) determining a protocol for outliers and missing data.

The Commission notes that only curtailments and outages will be assessed for the UCAP methodology. We agree with CalCCA that forced outage rates for storage resources should reflect plant failures but not state-of-charge, as the model used in SERVM already accounts for state-of-charge when dispatching storage.[53] A battery resource's state-of-charge is somewhat analogous to onsite fuel storage and somewhat analogous to resources with long start-up times, neither of which are incorporated into UCAP for conventional resources. While a grid resource's interactions with other resources (including a storage resource's ability to be charged and ready when needed) are important to overall reliability, these interactions are modeled separately from the forced outage events outside the control of resource operators, which UCAP is intended to address. The

53 _CalCCA Reply Comments on Track 2 Proposals at 6

UCAP methodology for battery storage should therefore incorporate forced outages due to equipment failures, but not state-of-charge.

The Commission further notes that Energy Division's Track 1 UCAP proposal provided that Energy Division does not support resource-specific accreditation "in large part due to the confidential nature of the GADS data from which we source EFORd values, necessitating aggregation such that they cannot be attributed to individual resources."[54] Even if data is sourced from public sources, there is also the issue of data quality and completeness. The Commission notes that it may not be feasible for a final UCAP methodology to be at a resource-specific level unless a procedure is developed to correct anomalous or missing data from specific plants, and therefore, additional class groupings should be considered. We encourage Energy Division to coordinate with CAISO to develop data acquisition and analysis procedures using alternative public sources, to the extent possible, for a UCAP methodology and to develop a protocol with CAISO to account for missing or outlier data.

### 4.4. Major Reforms to the CPE Framework

AReM, CESA, and MRP put forth proposals to eliminate the CPE framework and/or eliminate the local RA requirements, as summarized below.

AReM states that the current CPE framework has resulted in inefficiencies in the RA market and has been unsuccessful in procuring the required local RA capacity. AReM thus proposes to eliminate the CPE framework and the local RA requirements, and instead allow LSEs to procure system RA obligations with the expectation that resources needed for local reliability will be procured and

54 Energy Division's Track 1 Proposal, January 19, 2024, at 17.

shown to meet system RA requirements.[55] AReM states that if specific resources needed for local reliability are not procured, they can be procured through CAISO's Capacity Procurement Mechanism (CPM) authority or using the Cost Allocation Mechanism (CAM). AReM argues that this proposal would reduce the complexities of procurement with little or no detriment to local reliability because local resources are expected to be procured with system resources. AReM adds that this proposal allows the impacts of IRP procurement to be considered alongside the impacts of SOD procurement.

CESA recommends reverting to the former local RA program if the CPE framework is dismantled.[56] CESA contends that eliminating the local RA program entirely is shortsighted and that the local RA requirements are valuable in resolving defined local reliability issues. CESA posits that in future years, it may not be the case that LSEs will procure local resources to meet overall system requirements.

MRP recommends eliminating the CPE framework because more mature procurement by LSEs has reduced the need for CPEs to procure on LSEs' behalf and the CPE framework rules impede longer-term cost-effective contracts needed to retain existing resources and to develop new resources.[57] MRP proposes a new track in 2025 to discuss dismantling the CPE framework for 2026.

#### 4.4.1. Comments on Proposals

Calpine supports dismantling the CPE structure and reverting back to the former local RA rules.[58]

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55 AReM Track 2 Proposal at 7.

56 CESA Track 2 Proposal at 3.

57 MRP Track 2 Proposal at 4.

58 Calpine Comments on Track 2 Proposals at 5.

Cal Advocates, CalCCA, and PG&E oppose eliminating the CPE framework.[59] CalCCA argues that significant changes to the RA program should not be considered until after the SOD program has been implemented and tested. CalCCA states that constant shifting of the compliance framework and rules of the RA program makes it challenging for the market to adjust and could be harmful to the market. PG&E likewise objects to a major overhaul of the CPE framework and notes that while in a tight system RA market, resources needed for local reliability will be contracted to provide system and flexible RA, this may not be the case with excess RA resources. PG&E states that eliminating the CPE framework would be disruptive and likely result in a less reliable grid and potentially higher prices.[60]

Cal Advocates asserts that the CPE's targeted procurement of local resources is important to provide reliability benefits, and a deficient sub-area may lead to immediate load shed after a single contingency. Cal Advocates states that the CPEs' market power mitigation tools, including deferring procurement for high priced offers, are critical during periods of elevated RA prices.

CAISO, MRP, and SCE oppose eliminating the local RA requirements.[61] CAISO argues that system RA requirements do not have enough geographic granularity to ensure sufficient resources are available in local capacity areas. CAISO states that local requirements are needed to ensure adequate capacity to

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59 CalCCA Comments on Track 2 Proposals at 9, Cal Advocates Comments on Track 2 Proposals at 11, PG&E Comments on Track 2 Proposals at 5.

60 PG&E Reply Comments on Track 2 Proposals at 2.

61 CAISO Comments on Track 2 Proposals at 6, MRP Comments on Track 2 Proposals at 10, SCE Comments on Track 2 Proposals at 8.

meet reliability needs in local areas and encourage new development in local areas. MRP states that the local requirements represent requirements that must be satisfied by CAISO to comply with adopted reliability criteria. SCE does not support removing local requirements if the CPE framework is dismantled and states that LSEs can use local load shares to inform their system RA procurements on a yearly basis.

#### 4.4.2. Discussion

The Commission declines to dismantle the CPE framework or eliminate the local RA requirements. Energy Division's May 2024 Report on the 2021-2023 CPE Framework (CPE Report) was the Commission's first comprehensive review of the CPE framework and we find it premature and unnecessary to dismantle the CPE framework at this time without further discussion and a more developed record. The Commission agrees with parties that such a drastic change would be greatly disruptive to the RA program, particularly as the program is transitioning to full implementation of the SOD program in 2025.

Further, we agree that system RA requirements alone cannot target local reliability areas with the same granularity as local RA requirements, and thus cannot ensure that sufficient resources are procured in local areas. While parties' proposals focus on the current tight RA market conditions in which local RA resources are being contracted for system RA needs, we caution that these market conditions could evolve as newer resources are built, potentially resulting in system RA requirements being inadequate to meet local RA needs. In addition, one of the CPEs' key tools is to defer to backstop procurement (i.e., decline to procure) to mitigate market power when prices are too high. A CPE's decision to decline to procure is analogous to the local RA waiver process that allows for an LSE to receive a waiver if local RA prices were above a certain threshold, among other requirements. For these reasons, we decline to dismantle the CPE framework or eliminate the local RA requirements. We next consider parties' proposals to refine the existing CPE framework.

### 4.5. Refinements to the CPE Framework

#### 4.5.1. Soft-Offer Price Cap Proposal

CESA and WPTF propose a soft-offer price cap for CPE procurement that would approximate the opportunity cost to LSEs of not procuring sufficient resources to meet RA requirements.[62] The proposed price cap would be based on the sum of CAISO's CPM soft-offer cap and the higher of the system or local RA penalty price.

CESA recommends that if an offer exceeds the price cap, the CPE is not obligated to accept the offer but has discretion to procure above the price cap if it determines the offer is in the best interest of ratepayers, subject to Commission approval. CESA states that this formalizes a process so that the CPE has clarity from regulators on whether an offer that exceeds the price cap is in the best interest of ratepayers before deferring to CAISO's backstop mechanism.

WPTF recommends that the CPE have discretion to accept bids above the price cap if it is in the best interest of ratepayers, but the CPE would not have discretion to reject bids below the price cap if the resources are needed to meet the CPE's procurement requirements in that local area. Both parties note that the Commission has previously stated that the CPE has discretion to defer procurement of local resources to CAISO's backstop mechanism "if bid costs are deemed unreasonably high" but has not provided guidance on what constitutes unreasonably high prices.

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62 CESA Track 2 Proposal at 10, WPTF Track 2 Proposal at 6.

#### 4.5.1.1. Comments on Proposal

Several parties oppose the proposal, including AReM, Cal Advocates, DMM, PG&E, and SCE.[63] These parties generally state that a public soft-offer price cap is harmful to competition as capacity owners will bid up to the price cap, rather than bid competitively, and potentially raise costs for customers.

Cal Advocates argues that CPEs' discretion to defer procurement based on price is an important market power mitigation tool, especially when local capacity requirements are near or at the level of available capacity in a local area and there is a greater potential for market power. SCE notes that the Commission gave the CPE discretion to determine what "unreasonably high" bid costs are because the CPE's assessment is informed by several qualitative and quantitative factors that are not compatible with one definition. PG&E opposes the proposal because the CPEs already have authority to determine whether competitive offers are priced too high using public RA pricing information, competitive offers are evaluated against several criteria that influence whether or not to accept an offer, and the CAM procurement review group (PRG) and independent evaluator (IE) provide oversight of the process. DMM states that the price cap would far exceed the going-forward fixed costs and allow for local RA sellers to exert market power within that price range.

AReM contends that the proposal appears to be more about circumventing CAISO's soft-offer cap in the backstop procurement process than protecting reliability.[64] If the proposal was adopted for the 2023 and 2024 RA years, AReM

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63 Cal Advocates Comments on Track 2 Proposals at 18, DMM Comments on Track 2 Proposals at 3, PG&E Comments on Track 2 Proposals at 3, SCE Comments on Track 2 Proposals at 9.

64 AReM Comments on Track 2 Proposals at 4.

notes that the CPE may have procured more local resources at higher prices but that would not have impacted reliability, as CAISO did not need to perform backstop procurement despite PG&E's CPE being deficient. AReM posits that the proposal would raise costs for customers with no clear benefit for reliability when a lower cost backstop mechanism is available.

##### 4.5.1.2. Discussion

The Commission finds that a soft-offer price cap has the potential to reduce competition and increase market power in exactly those locations where generation is controlled by few suppliers. We concur with parties that state that a public soft-offer price cap will quickly become a price floor as bidders are not incentivized to submit competitive bids below the price cap. This will drive up market prices and costs for all ratepayers, including unbundled customers that absorb prices through the CAM.

We also find that obligating CPEs to execute any contracts below the price cap will negate the CPEs' ability to procure local resources using least cost, best fit and other qualitative metrics, as the CPEs have been directed to do by the Commission in D.20-06-002. CPE procurements are subject to the oversight and review by the IE and CAM PRG, which ensures that solicitations and transactions are consistent with the Commission's directives and selection criteria. For these reasons, we decline to adopt a soft-offer price cap as part of the CPE framework.

#### 4.5.2. Contract Transfer Proposal

MRP states that in its experience, once a CPE has procured capacity, the CPE is reluctant to change the transaction to allow LSEs to procure that capacity from the resource owner due to uncertainty about the CPE's ability to allow it, even if doing so would facilitate LSEs self-procuring their own local resource and reducing CPE procurement costs. MRP asserts that some LSEs seek longer-term system RA contracts, but those resources may be in local areas and have already been contracted by the CPE.

MRP proposes that the CPEs be authorized to allow capacity that was procured by the CPE to be later transferred to another LSE when the LSE elects to procure directly with the resource owner for a long-term contract (of 5 years or more) and the contract has an overlapping delivery period with the existing CPE contract.[65] The new LSE must self-show that capacity to the CPE for the initial delivery term with the CPE. MRP recognizes that this would impact other LSEs due to affected CAM credits but notes that there are multiple factors (*e.g.*, load forecast, NQC methodology) that also affect CAM credits.

Microsoft, Calpine, and WPTF support the proposal.[66] Microsoft states that LSEs should be encouraged to sign long-term contracts for local RA, at least until a comprehensive solution is developed between the IRP and RA proceedings. WPTF states that the proposal would result in LSEs receiving fewer system RA credits from the CPEs but would reduce overall CPE procurement costs allocated to LSEs.

CalCCA opposes the proposal and argues that it would exacerbate existing challenges LSEs face with predicting CPE RA allocations, as LSE allocations after CPE procurement could decrease or be eliminated entirely.[67] CalCCA notes that transferring CPE procurement does not increase the amount of capacity under contract but transfers the costs and benefits LSEs would already collectively pay

[65] MRP Track 2 Proposal at 16.

[66] Microsoft Comments on Track 2 Proposals at 15, Calpine Comments on Track 2 Proposals at 7, WPTF Comments on Track 2 Proposals at 12.

[67] CalCCA Comments on Track 2 Proposals at 11.

to an individual LSE. CalCCA states that the proposal allows lower-priced contracts with the CPE to be abandoned for higher-priced ones with LSEs, and LSEs cannot defer to backstop procurement if prices are too high. PG&E opposes the proposal and agrees with CalCCA that the proposal would result in significant contracting uncertainty.[68]

The Commission declines to allow the transfer of CPE procurement contracts to individual LSEs. While the proposal may help one or more LSEs to secure a longer-term contract than the CPE may be willing to secure, we note that LSEs are currently able to engage in longer-term contract negotiations, regardless of the CPEs' positions or available solicitations. We agree with CalCCA that the proposal allows generators to abandon existing lower-price contracts with the CPEs, while the costs of that transfer are borne on deficient LSEs that cannot defer to backstop procurement if prices are too high. We also agree that this proposal will lead to greater uncertainty for LSEs in accounting for CPE allocations, and the proposal does not increase the amount of available RA capacity to contract. For these reasons, we decline to adopt MRP's proposal.

#### 4.5.3. Proposals to Eliminate the Self-Showing Option

PG&E asserts that the PG&E CPE continues to face challenges procuring local RA capacity due primarily to an overall lack of participation, as a significant amount of local capacity is held by LSEs for system RA requirements and is not shown to the CPE.[69] PG&E states that this is further demonstrated by the fact that despite the CPE's deficiencies, CAISO has not undertaken backstop procurement designations after the CPE's annual local RA showing. PG&E

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[68] PG&E Reply Comments on Track 2 Proposals at 8.

[69] PG&E Track 2 Proposal at 2.

states that due to this lack of participation, the CPE has incomplete information before the annual solicitation as to what local RA capacity is under contract by LSEs. Therefore, the CPE cannot make the best procurement decisions on behalf of customers, cannot secure the most effective local resources needed, and cannot mitigate backstop procurement.

PG&E states that the non-compensated self-showing process does not incentivize LSEs to self-show local resources for the three-year compliance period. PG&E proposes to eliminate the non-compensated self-showing process and instead have Energy Division collect local RA contracting information from LSEs to then distribute to the CPEs. PG&E states that removing the self-show process will eliminate the administrative work associated with self-showing and close the information gap CPEs need to inform procurement decisions.

PG&E recommends Energy Division include a modified template in the annual RA compliance process that requests information, including: Resource ID, local area, contract start/end date, technology type, and contracted monthly MW capacity for the three-year forward period. PG&E states that the information would not include LSE-identifying information and proposes a reporting deadline of January 31, 2025, as the information would not be used until after the annual RA compliance process. PG&E recommends that the CPEs send a letter to all LSEs with an existing and/or active attestation within 30 days of this decision to nullify remaining self-show commitments.

SCE recommends counting all shown system resources in local areas towards the CPEs' local RA obligation.[70] Because CPEs must file Annual Compliance Reports in September, LSEs that plan to include system RA in local

[70] SCE Track 2 Proposal at 3.

areas towards their system requirements would have to self-show the resource earlier than the October year-ahead filing deadline. This would force LSEs to self-show all resources in a local area and if the resource is shown on the supply plan as a system resource, it would equally count as a system and local resource and reduce the amount of local RA the CPE must procure.

WPTF proposes to refocus the CPEs' role on procuring resources to meet local requirements that have not been contracted by LSEs to meet system requirements.[71] WTPF recommends the CPE's role be limited to a backstop procurement with the self-showing option terminated and the Local Capacity Requirement Reduction Compensation Mechanism (LCR-RCM) discontinued. The CPEs would consult with the Commission and CAISO to determine whether there is a need to procure local RA based on the year-ahead RA compliance showing and RA plans. WPTF notes that the effectiveness of this proposal would depend in part on the adoption of multi-year forward system requirements and should be considered in alignment with the RCPPP.

#### 4.5.3.1. Comments on Proposals

Calpine supports removing the uncompensated showing option, as it does not seem to be serving its function, and seeking information through Commission reporting will be more reliable and less cumbersome.[72] CEJA/Sierra Club support PG&E's proposal with the modification that the information reported to Energy Division should be aggregated by type of resource and be made public, as this would be important for determining what procurement gaps exist for phasing out reliance on gas plants.[73] CEJA/Sierra

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71 WPTF Track 2 Proposal at 10.

72 Calpine Comments on Track 2 Proposals at 7.

73 CEJA/Sierra Club Comments on Track 2 Proposals at 18.

Club support SCE's proposal as important to ensuring all local resources are counted towards phasing out reliance on gas plants.

SCE generally supports PG&E's proposal but states that the information for year-ahead requests for offers (RFO) could be outdated because the CPE will receive the current year's local capacity information in January and the proposal assumes local capacity data from the Commission will remain the same for two years.[74]

CalCCA opposes PG&E's proposal, arguing that it is unclear why CPEs need the proposed information and that the information cannot be used to understand what may be bid or shown, as resources that are not contracted with an LSE may be contracted by a non-jurisdictional LSE or out-of-state entity.[75] If the purpose is to determine which resources are unavailable for CPE procurement, CalCCA states that the CPE would know this after those resources are not offered into the solicitation. CalCCA claims that existing firewalls to separate an investor-owned utility's (IOU) CPE functions and its LSE functions may not be sufficient to ensure IOUs do not have a competitive advantage over other LSEs. PG&E responds that it is not proposing changes to the solicitation process that would allow the CPE to eliminate a resource from consideration simply because it is under contract to an LSE.[76] PG&E asserts that CalCCA provides no basis to question whether the CPEs' existing firewalls are sufficient.

74 SCE Comments on Track 2 Proposals at 11.

75 CalCCA Comments on Track 2 Proposals at 13.

76 PG&E Reply Comments on Track 2 Proposals at 5.

CalCCA and AReM oppose SCE's proposal.[77] CalCCA states that the proposal turns the CPE into a backstop entity, ignores the risks of self-showing by forcing LSEs to self-show (such as reducing flexibility to sell parts of a portfolio), and requires procurement decisions before the current deadlines. AReM agrees with CalCCA that it is unclear how much capacity is under contract and not self-shown by the year-ahead deadline and forcing self-showing will not result in a substantial benefit. AReM states that the market would be better served by Energy Division Staff contacting LSEs to encourage them to self-show and provide assistance with the self-showing process.

PG&E asserts that WPTF's proposal assumes resources needed for local reliability will be contracted to provide system and flexible RA.[78] PG&E states that substantial local reliability risks may result in a system RA market with excess resources, as the Commission and CAISO would need to ensure local resources are contracted through other means like the CPM. CalCCA agrees that WTPF's proposal should be considered in parallel with the RCPPP to ensure a coordinated approach to ensuring retention of existing resources needed for reliability.[79]

#### 4.5.3.2. Discussion

In D.20-06-002, the Commission adopted a "hybrid" CPE framework, which allowed LSEs to procure local resources to meet their system and flexible RA requirements and voluntarily "show" their procured local capacity to the

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77 CalCCA Comments on Track 2 Proposals at 13, AReM Reply Comments on Track 2 Proposals at 5.

78 PG&E Comments on Track 2 Proposals at 5.

79 CalCCA Comments on Track 2 Proposals at 10.

CPE to count the capacity towards the CPE's collective RA requirements.[80] The Commission determined that the hybrid framework, as opposed to a full or residual procurement model, "allows a CPE to secure a portfolio of the most effective local resources, use its purchasing power in constrained local areas, mitigate the need for costly backstop procurement in certain local areas, and ensure a least cost solution for customers and equitable cost allocation."[81] LSEs' option to voluntarily show their procured local capacity to the CPE has since been referred to as the non-compensated self-showing option (as compared to self-showing for compensation via the LCR-RCM).

Since the implementation of the CPE framework, however, the lack of participation in the non-compensated self-showing option by LSEs has been well-documented, particularly in the PG&E CPE's service territory. In D.22-03-034, the Commission stated that "a limited amount of local resources were self-shown to the PG&E CPE for no compensation" in the 2021 RFO solicitation.[82] The Commission noted that "[b]y self-showing local resources, LSEs can lower the overall amount of the CPE's local RA obligation, which reduces the amount of local resources the CPE must procure and thus lowers procurement costs for ratepayers in the CPE's service area."[83]

To encourage greater self-showing by LSEs, several modifications were adopted in D.22-03-034, including (1) requiring an attestation for self-showing rather than a binding contractual agreement;
(2) revising the CPE procurement timeline to give LSEs and CPEs a similar

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80 D.20-06-002 at 24.

81 *Id*.

82 D.22-03-034 at 13.

83 *Id*.

amount of time for procurement; and (3) requiring an LSE that declined to self-show or bid into the CPE solicitation to explain why it declined to self-show or bid.[84] In D.23-06-029, the Commission further modified the self-showing process to allow an LSE that self-shows to the CPE to sell the self-shown capacity to other LSEs, which we stated "may increase the amount of self-shown resources by removing a potential disincentive for self-showing and provide additional opportunities for LSEs to procure system and/or flexible RA."[85] The Commission also ordered the CPEs to report on resources that were not offered to the CPE in deficient areas and resources where an agreement could not be reached, to help LSEs manage upfront system RA procurement and understand the inventory of available resources.[86]

Despite multiple efforts over the last few years to increase LSEs' participation in the non-compensated self-showing option, there was continued lack of - and even decreasing – participation in self-showing in the PG&E CPE's 2021, 2022, and 2023 RFO solicitations.[87] Because of this, the Commission is concerned that the CPEs do not have access to critical information before initiating the CPE solicitation as to what local resources are under contract by LSEs, what the most effective local resources are to secure, and what the true needs are in designated local areas. Without this information, the CPEs cannot make effective procurement decisions and may under- or over-procure in local capacity areas, which increases costs to ratepayers and in the case of under-procurement, may result in backstop procurement.

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[84] *Id*. at Ordering Paragraph (OP) 1, OP 2, OP 3, 14.

[85] D.23-06-029 at OP 14, 49.

[86] *Id*. at 46.

[87] Energy Division's CPE Report at 47, PG&E Track 2 Proposal at 2.

The Commission agrees that the current non-compensated self-showing construct has been ineffective, as there is no binding commitment on LSEs to self-show and LSEs have clearly elected not to self-show despite numerous attempts to incentivize participation. Further, the self-showing attestation only requires that LSEs state their intention at the time of the self-showing. Because non-performance of self-shown local resources does not result in the allocation of a larger share of backstop costs, LSEs have little incentive to perform according to their attestation.

The Commission is persuaded that PG&E's proposal may provide a much more reliable, efficient way for the CPEs to obtain information about what local resources are under contract by LSEs, along with their expiration date. The information would be provided to the CPEs to better assess the state of the overall local portfolio before initiating the CPEs' annual solicitations and would include information on existing and new build resources under contract with LSEs. The CPEs would use this information to better assess the actual needs for short-term and long-term procurement for the three-year forward requirements and beyond. We find that PG&E's proposal will allow CPEs to better fulfill the role designated to them in D.20-06-002: to secure a portfolio of the most effective local resources, use purchasing power in constrained local areas, mitigate the need for backstop procurement, and ensure a least cost solution for customers and equitable cost allocation.[88] For these reasons, we adopt PG&E's proposal.

The Commission acknowledges CalCCA's concerns about retaining the option to sell or self-show a local resource for compensation if the CPEs obtain information about what local resources are under contract. We note, however,

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[88] *See* D.20-06-002 at 24.

because CPE procurements are monitored and overseen by the IE and CAM PRG, bid review and selection processes are already required to follow fair and equal consideration.

Accordingly, the non-compensated self-showing option of the CPE framework is eliminated, effective 30 days from the issuance date of this decision. For self-shown capacity that has been committed to the CPEs, the CPEs shall send a letter to LSEs with an existing and/or active attestation within 30 days of the issuance of this decision, nullifying any remaining commitments and stating that the commitments shall no longer be relied on for purposes of satisfying the CPE's compliance obligations. A template for the CPEs' letter is attached to this decision as Appendix A.

Energy Division is instead authorized to collect additional information from LSEs regarding local RA capacity that is under contract in an LSE's portfolio. Energy Division is authorized to collect the following information from each LSE about its local RA capacity under contract:

(1) Resource ID

(2) Local Area

(3) Contract Start/End Date

(4) Resource Technology Type

(5) Contracted Monthly MW Capacity for the 3-Year Forward Period

For the 2026 RA compliance year, Energy Division is authorized to send data requests in January 2025, with responses to be submitted by the LSE by February 1, 2025. Energy Division will aggregate and anonymize the information and provide the data to the CPEs for use in the CPEs' annual solicitation and procurement process. The Commission notes that the IRP Resource Data Template is already used to collect information on what resources are under contract with LSEs. The Commission requests that parties submit proposals in Track 3 on how to synchronize the existing IRP data collection process with the data requirements adopted here for the CPE framework, in order to minimize duplication and administrative burden on Commission Staff.

#### 4.5.4. Proposal to Adjust CPE Timeline

CalCCA proposes to modify the CPE procurement timeline to move the CPE's final showing requirements up by one year.[89] CalCCA states that under the current rules about when LSEs are notified of CPE credits, the CPEs are permitted to procure up to two months prior to LSEs submitting year-ahead RA showings, which leaves LSEs with uncertainty about their system and flexible RA requirements. Further, CalCCA states that LSEs cannot assume the amount of CPE allocations and once allocations are issued, LSEs have little time to adjust procurement. CalCCA argues that because the local RA program has three-year forward requirements, the requirements generally do not change drastically from Year 2 (Y-2) to Year One (Y-1).

CalCCA recommends that the CPEs make their final showing one year in advance of LSEs' year-ahead showings, consistent with the 100 percent local RA requirement for Y-2. The deadline would apply regardless of whether the CPEs met their RA obligations so that even if a CPE did not meet its Y-2 obligation by October 31, the CPE's procurement efforts would conclude at that time. CalCCA states that if a CPE does not meet its RA obligation, CAISO would make any CPM designations (as it currently does) following LSE showings in October for Y-1. CalCCA adds that if the local RA need increases after Y-2, the CPE could procure only for the incremental need.

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89 CalCCA Track 2 Proposal at 8.

#### 4.5.4.1. Comments on Proposal

AReM, Calpine, Microsoft, and New Leaf support CalCCA's proposal.[90] AReM agrees that uncertainty regarding CPE CAM credits, especially in the PG&E CPE's service territory, gives LSEs little time to procure. Calpine states that local capacity that the CPE is unable to secure in Y-2 is unlikely to be available in the Y-1 timeframe and so there is no need for an additional round of procurement. Microsoft states that the proposal allows LSEs to manage portfolios more effectively and avoid over-procurement from uncertainty about CPE procurement.

Cal Advocates, MRP, PG&E, and SCE oppose the proposal. Cal Advocates argues that under the proposal, CPEs would procure to meet targets two years before the compliance year, creating risks that CPE procurement may not account for variables affecting year-over-year targets, such as changes to the local requirements, LSE load migration, and other RA credits.[91] Cal Advocates states that allowing incremental procurement to address changes in the local requirements could cause significant changes to CPE credits and fail to mitigate credit uncertainty. Cal Advocates states that the CPEs use CAISO's LCR technical studies to procure for the upcoming compliance year and non-technical estimates to procure two years forward. Based on its own analysis, Cal Advocates finds that needs in the year-ahead timeframe were higher than non-technical needs in the two-year-ahead timeframe and would require the CPEs to undertake incremental procurement.

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[90] AReM Comments on Track 2 Proposals at 3, Calpine Comments on Track 2 Proposals at 7, Microsoft Comments on Track 2 Proposals at 13, New Leap Comments on Track 2 Proposals at 4.

[91] Cal Advocates Comments on Track 2 Proposals at 15.

MRP points out that some LSEs do not wait on CPE procurement before making system procurement decisions, as some LSEs procure via long-term contracts.[92] Even if some LSEs wait for CPE allocations, MRP states that this does not warrant the CPEs having to stop procurement two years before the compliance year, increasing the potential for the CPEs to fail to meet their local capacity requirements.

SCE argues that the proposal will not accomplish the intended objective because it discourages LSEs from timely self-showing resources.[93] SCE states that without an incentive to show resources two years out, LSEs will self-show even fewer resources to the CPE. CalCCA responds that in moving the timing up, there is no reason an LSE that has a local resource multiple years forward would not be willing to self-show.[94] PG&E states that the proposal should be considered in a later phase, as it does not address visibility challenges experienced by the CPE.[95] CalCCA responds that concerns about over-procurement risk are due to allocations not being made sufficiently in advance and if LSEs receive allocations in advance, LSEs will have time to adjust procurement plans, including selling off excess RA if needed.[96]

#### 4.5.4.2. Discussion

Under CalCCA's proposal, the CPEs would cease local procurement in October of each year and submit their RA showings two years prior to the RA compliance year (Y-2). For example, for the 2027 RA compliance year, the CPEs

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92 MRP Comments on Track 2 Proposals at 14.

93 SCE Comments on Track 2 Proposals at 10.

94 CalCCA Reply Comments on Track 2 Proposals at 14.

95 PG&E Comments on Track 2 Proposals at 2.

96 CalCCA Reply Comments on Track 2 Proposals at 14.

would submit local RA showings in October 2025. We agree that the timeframe for LSEs to receive CPM credits, if provided, is often even tighter than the local CPE timeframe. The Commission also agrees with CalCCA that locking in CPE allocations more than one year in advance – as compared to two months - would be beneficial in that it would give LSEs more time for procurement and to negotiate favorable RA contracts on behalf of customers. We also agree that locking in CPE allocations earlier will increase certainty for LSEs to understand how much system and flexible RA they may need to procure.

Cal Advocates expresses concern that ceasing procurement two years prior to the compliance year may not mitigate credit uncertainty if the CPEs are required to conduct incremental procurement that results in further changes to CPE credit allocations. In the current RA market, the Commission is persuaded by CalCCA that the three-year forward local requirements do not change drastically from Year 2 (with a 100 percent obligation) to Year 1. Under these circumstances, we would not expect that the CPEs would have to conduct a substantial amount of incremental procurement. However, as the current RA market evolves and more system resources come online, it is possible that the CPEs would need to procure local resources that would otherwise be procured for the backstop mechanism by August.

For these reasons, the Commission adopts CalCCA's proposal to lock in CPE allocations to LSEs one year earlier, on an interim basis to be reevaluated by the end of 2027. This will be effective beginning in 2025 for the 2027 RA compliance year. The Commission authorizes Energy Division to monitor the amount of CPEs' incremental procurement, the rate of local RA deficiencies that are deferred to backstop procurement, and whether market power may be exercised by generators.

Accordingly, the following CPE procurement process is adopted (using Y to indicate the compliance year). Local CPE procurement conducted by October 31 of Y-2 for compliance year Y will be considered "locked:" that is, in Y-1, the CPEs will no longer procure for local requirements allocated in Y-2. In Y-1, the CPEs will only conduct procurement for the incremental changes between what was provided in Y-2 and CAISO's updated Local Capacity Technical study for compliance year Y. Any incremental procurement the CPE conducts for compliance year Y will be allocated to LSEs in accordance with the annual CPE and LSE allocation timelines in August and mid-September. Because these incremental needs are expected to be relatively small, LSEs should plan to receive few, if any, procurement allocations in Y-1.

For the 2026 RA compliance year and beyond, we provide the following illustration:

- In 2025, for the 2027 RA compliance year, the CPEs submit their final RA showings to Energy Division in August. Following this showing, Energy Division will allocate CPE credits for the 2026-2028 RA compliance years. The 2027 CPE allocations are "locked" and CPEs will no longer procure local resources to meet the 2027 compliance year local needs allocated to them in 2025.

- In 2026, the CPEs will only be responsible for incremental local requirements for the 2027 RA compliance year based on CAISO's annual Local Capacity Technical study, filed in the RA proceeding. In 2026, procurement conducted for the 2028 compliance year will be "locked" in the same manner as procurements in 2025 for the 2027 compliance year.

#### 4.5.5. Proposals to Repurpose the CPE To Reduce Gas Generation

CEJA/Sierra Club state that based on Energy Division's CPE Report, it is unclear that the CPE has provided any benefit over LSEs conducting their own procurement and the CPE has not generated the competitive conditions needed to reduce prices and meet local RA requirements. CEJA/Sierra Club recommend refocusing the CPE to only procure new clean resources in local areas to plan for the retirement of gas plants. The CPE process would focus on local procurement with key elements, including: (1) need determination (based on need for local procurement using CAISO's most recent LCR study), (2) self-procurement (to allow LSEs to elect to self-procure), (3) types of resources (to only allow procurement of resources consistent with the IRP Preferred System Plan with a focus on local Distributed Energy Resources (DER)), (4) incentives (combination of IRP contractual offerings and local adders based on past local procurement), and (5) reliability metric based on loss of load hours.

PG&E recommends further exploration of a centralized planning and procurement process to reduce the state's reliance on gas generation and to determine if it is more appropriate for planning to be done on a broader basis by a state entity or a modified CPE framework.[97]

Leap, Microsoft, and PCF support CEJA/Sierra Club's proposal.[98] Leap states that it is a reasonable way to incentivize greater deployment of clean resources, including virtual power plants. Microsoft states that the principles of the proposal to create an IRP process for local RA are worth considering and that as long as IRP is not facilitating the development of new renewables and local resources, local reliability will rely on existing generation.

[97] PG&E Track 2 Proposal at 10.

[98] Leap Comments on Track 2 Proposals at 3, Microsoft Comments on Track 2 Proposals at 14, PCF Comments on Track 2 Proposals at 8.

Multiple parties oppose CEJA/Sierra Club's proposal, including Calpine, CalCCA, CESA, MRP, New Leaf, SDG&E, and WPTF.[99] Several parties, such as CalCCA, New Leaf, MRP, and WPTF, oppose refocusing the CPE's role to procure new clean resources as the process of retiring gas generation should be considered within or at least aligned with the IRP proceeding.[100] CalCCA states that repurposing the CPE to procure for gas retirement would require an assessment to determine the best path to reduce gas reliance through development of new clean resources or transmission to reduce local area constraints. CESA contends that refocusing the CPE would change the purpose of the local RA program to a long-term planning and procurement process (rather than for ensuring sufficient local RA is available to CAISO). Calpine disagrees that the goal of CPE procurement should be to displace gas plants in local areas and that consideration of the gas fleet's role should account for the impact on cost and reliability at the system level.

MRP states that the CPEs have failed to promote the development of new clean resources in local areas and there is no reason to rely on them to develop meaningful clean resources. MRP disagrees with CEJA/Sierra Club's comments that state law prohibits new, long-term contracts with gas generation from CPE procurements. Calpine argues that CEJA/Sierra Club misrepresent the impact of gas generation on local air quality and counters that gas plants' impact on air quality has been shown to be generally insignificant. Calpine opposes

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[99] Calpine Comments on Track 2 Proposals at 8, CalCCA Comments on Track 2 Proposals at 8, CESA Comments on Track 2 Proposals at 8, MRP Comments on Track 2 Proposals at 11, New Leap Comments on Track 2 Proposals at 2, SDG&E Comments on Track 2 Proposals at 8, WPTF Comments on Track 2 Proposals at 8.

[100] MRP Comments on Track 2 Proposals at 11, CalCCA Comments on Track 2 Proposals at 8, New Leap Comments on Track 2 Proposals at 2, WPTF Comments on Track 2 Proposals at 8.

administratively determined incentives to procure clean resources, as it is unclear who would pay for the incentive and how the incentive cost would be recovered. SDG&E opposes CEJA/Sierra Club's proposal for DER procurement as outside the scope of the proceeding, lacking necessary details, and potentially double-counting resources.[101] SDG&E states that allowing IOUs to procure DERs where the underlying resource is included in the Preferred System Plan lacks sufficient clarity and cannot be implemented.

The Commission finds that the issues raised by CEJA/Sierra Club's proposal – aligning procurement targets, incentive design, and locational targets – warrant further exploration in a coordinated effort between the IRP and RA proceedings. As the Commission creates a pathway for a programmatic approach for long-term procurement, it is essential that procurement ensures reliability and achieves greenhouse gas reduction goals at least cost. We encourage CEJA/Sierra Club to provide input and recommendations in those efforts, including in response to the upcoming Commission staff proposal on the RCPPP, which is expected to be released in the IRP proceeding in Q4 of 2024.

#### 4.5.6. Expansion of CPE Reporting Proposal

PG&E proposes expanding the publication of certain CPE procurement information that would otherwise qualify as confidential market-sensitive information.[102] PG&E recommends modifying the confidentiality matrix such that the CPEs would publicly provide: (1) the CPEs' local RA capacity procured on a CAISO-defined local capacity area level; (2) the CPEs' net open positions on a CAISO-defined local capacity area level; and (3) capacity purchased by the

[101] SDG&E Comments on Track 2 Proposals at 8.

[102] PG&E Track 2 Proposal at 7.

CPEs on a resource-specific level, which aligns with reporting processes of other CAM-eligible resource procurement. PG&E states that based on the past few years' experience as the CPE, PG&E does not believe that releasing this information will materially affect the competitiveness of the CPE's solicitations and could benefit the overall CPE framework by providing more granular level information to drive regulatory improvements. AReM, WPTF, and CEJA/Sierra Club support this proposal.[103]

The Commission finds PG&E's proposed expansion of the publication of CPE procurement information to be reasonable and agrees that providing additional granular information on the CPEs' procurement process could benefit the CPE framework by giving stakeholders more insight into the procurement process. As such, the Commission directs the CPEs to provide the following additional information in their Annual Compliance Reports: (1) the CPEs' local RA capacity procured on a CAISO-defined local capacity area level; (2) the CPEs' net open positions on a CAISO-defined local capacity area level; and (3) capacity purchased by the CPEs on a resource-specific level, which aligns with reporting processes of other CAM-eligible resource procurement. The Confidentiality Matrix adopted in D.22-03-034 is modified to reflect these changes, and attached to this decision as Appendix B.

### 4.6. Load Impact Protocols Simplification

Pursuant to the Commission's direction in D.23-06-029, on January 19, 2024, PG&E submitted the Load Impact Protocols (LIP) Simplification Working Group Report (LIP WG Report) on behalf of the LIP Simplification Working Group. In D.24-06-004, the Commission noted that no party comments on the

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[103] AReM Reply Comments on Track 2 Proposals at 6, WPTF Comments on Track 2 Proposals at 13, CEJA/Sierra Club Comments on Track 2 Proposals at 18.

LIP Working Group Report in Track 1 of this proceeding and that the Commission would need additional time to consider the recommendations of the LIP Working Group Report.[104] The Commission stated that the LIP Working Group Report recommendations would be addressed in Track 2 of this proceeding. We summarize the LIP WG Report recommendations below.

#### 4.6.1. Proposed Modifications to D.08-04-050

The LIP WG Report makes the following recommendations for the LIP process as adopted in D.08-04-050 (additions are provided in underline and deletions are struck through):[105]

(1) "Third party demand response providers" should be added to Conclusion of Law 6 to read: "6. The DR Load Impact Estimation Protocols in Attachment A should be adopted for use by <u>third party demand response providers</u>, SCE, SDG&E, and PG&E."

(2) "Third party demand response providers" should be added to Ordering Paragraph 1 to read: "1. The Demand Response (DR) Load Impact Estimation Protocols in Attachment A (Adopted Protocols) are adopted for use by <u>Third Party Demand Response Providers</u>, Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), and Pacific Gas and Electric Company (PG&E)."

(3) For Protocols 1 and 3, the LIP WG Report states that a template has been started by the LIP WG Report to replace the evaluation, but the template is incomplete and needs further refinement. The Report recommends starting another Working Group and directing Energy Division or hiring a third-party to complete the template.

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[104] D.24-06-004 at 64.

[105] LIP WG Report at 16.

(4) Protocol 5 should be modified to replace "shall" with "may optionally" as the Report states that the mean change in energy use per year is an efficiency value that shows the total change in energy use per year and per participant, which is not useful for RA qualifying capacity (QC) values. Protocol 5 should be modified to read: "*The mean change in energy use per year may optionally ~~shall~~ be reported for the average across all participants and for the sum of all participants on a DR resource option for each year over which the evaluation is conducted.*"

(5) Protocol 6 should be modified to replace "10th, 30th, 50th, 70th, and 90th" percentiles with "5th, 50th, and 95th" percentiles because the Report states that a 90th percentile uncertainty window (i.e., 5th and 95th) is the standard convention in statistical regression analysis. Protocol 6 should read: "*Estimates shall be provided for the ~~10th, 30th, 50th, 70th, and 90th~~5th, 50th, and 95th percentiles of the change in energy use in each hour, day and year, as described in Protocols 4 and 5, for each day-type and level of aggregation described in Protocol 8.*"

(6) Protocol 7 should be modified to add Table 4-1-1, which would include back-end data informing the table generator in Table 4-1 and be structured in the format defined in Tables 4-1-1 and 4-1-2. The Report states that standardizing the back-end data structure of the table generators will allow Joint Staff to stack data for ease of analysis and verification, greatly lowering review time. The Report includes a sample back-end data table for Table 4-1-1 and Table 4-1-2 but recommends another Working Group be directed to finalize the table.

(7) Protocol 8 should be modified such that the information in Table 4-1 is deemed either required or optional. The Report recommends modifying the "average across participants on average event day" as optional, as this information may be useful for IOU reporting, but modern DR programs are not consistently called with the same number of sensitive customers within the dispatch window. Protocol 8 should be modified to read:

*"The information shown in Table 4-1 shall be provided for each of the following day types and levels of aggregation:*

- *<u>Required</u>: Each day on which an event was called;*
- *<u>Optional</u>: The average event day over the evaluation period;*
- *<u>Required</u>: For the average across all participants notified on each day on which an event was called;*
- *<u>Required</u>: For the total of all participants notified on each day on which an event was called; and*
- *<u>Optional</u>: For the average across all participants notified on the average event day over the evaluation period."*
- *<u>Optional</u>: An average event day is calculated as a day-weighted average of all event days.*

(8) Protocol 10 should be modified to remove the last bullet that is duplicative of the requirements in Protocol 26, and to modify the "variance-covariance matrix" as optional. The Report recommends Protocol 10 statistics should not be reported, as modern regression modeling often creates individual regressions (rather than portfolio-level regressions) which means a large data set would not be useful to the Commission. Rather, the data is recommended to be calculated and stored for a one-year period after the April 1 filing. Protocol 10 should be modified to read:

*"For regression based methods, the following statistics and information shall be calculated and stored by the evaluator for a period of one year after filing date of April 1 ~~reported~~:*

- *Adjusted R-squared or, if R-squared is not provided for the estimation procedure, the log-likelihood of the model;*
- *Total observations, number of cross-sectional units and number of time periods;*
- *Coefficients for each of the parameters of the model;*
- *Standard errors for each of the parameter estimates;*
- *<u>Optional:</u> The variance-covariance matrix for the parameters;*

- *The tests conducted and the specific corrections conducted, if any, to ensure robust standard errors.~~; and~~*
- ~~*How the evaluation assessed the accuracy and stability of the coefficient(s) that represent the load impact.*~~"

(9) In Attachment A at 78, under "5. Ex Post Evaluation for Non-Event Based Resources," the Report recommends modifying to add: "All protocols within this section (protocols 11-16) are only applicable to filers that have non-event based resources. Filers without those resources are exempt."

(10) Protocol 12 should be modified to replace "shall" with "may optionally" to read: "*The mean change in energy use per month and per year <u>may optionally</u> ~~shall~~ be reported for the average across all participants and for the sum of all participants in a DR resource option in each year over which the evaluation is conducted.*"

(11) Protocol 13 should be modified to replace "10th, 30th, 50th, 70th, and 90th" percentiles with "5th, 50th, and 95th" percentiles to read: "*Estimates of the ~~10th, 30th, 50th, 70th, and 90th~~<u>5th, 50th, and 95th</u> percentiles of the change in energy use in each hour, day and year, as described in Protocols 11 and 12, for each day-type and level of aggregation described in Protocol 15, shall ~~to~~ be provided.*"

(12) Protocol 14 should be modified so that uncertainty estimates of 5th and 95th percentiles are presented since these values are required to be calculated in Protocol 13. Protocol 14 should read: "*Impact estimates shall be reported in the format depicted in Table 4-1 for all required day types, as delineated in Protocol 15. <u>In lieu of an average event hour, provide an average hour as applicable to resource. For example, provide the average on-peak window for a non-event based pricing resource like a Time-of-Use (TOU) rate</u>.*"

(13) Protocol 15 should be modified to replace "peak day" to "worst day" to read: "*The information shown in Table 4-1 shall be provided for each of the following day types for the average across all participants sum of all participants:*

- *For the average weekday for each month in which the DR resource is in effect*
- *For the monthly system worst ~~peak~~ day for each month in which the DR resource is in effect*."

"*Monthly System Worst ~~Peak~~ Day for Each Month: The day with the highest system load in each month."*

(14) Protocol 16 should be modified to remove the last bullet, which is duplicative of Protocol 26 requirements, to read:

"*For regression based methods, the following statistics and information shall be calculated and stored by the evaluator for a period of one year after filing date of April 1 ~~reported~~:*

- *Adjusted R-squared or, if R-squared is not provided for the estimation procedure, the log-likelihood of the model*
- *Total observations, number of cross-sectional units and number of time periods*
- *Coefficients for each of the parameters of the model*
- *Standard errors for each of the parameter estimates*
- *Optional: The variance-covariance matrix for the parameters. Must be stored* only if *used to calculate the uncertainty adjusted impact percentiles, and*
- *The tests conducted and the specific corrections conducted, if any, to ensure robust standard errors.~~; and~~*
- *~~How the evaluation assessed the accuracy and stability of the coefficient(s) that represent the load impact~~*."

(15) Protocol 19 should be modified to replace "shall" with "may optionally" to read: "*The mean change in energy use per month may optionally ~~shall~~ be estimated for non-event based resources and the mean change in energy use per year shall be estimated for both event and non-event based resources for the average across all participants and for the sum of all participants on a DR resource option for each year over the forecast horizon*."

(16) Protocol 20 should be modified to replace "10th, 30th, 50th, 70th, and 90th" percentiles with "5th, 50th, and 95th" percentiles to read: "*Estimates of the ~~10th, 30th, 50th, 70th,~~*

*~~and 90th~~5th, 50th, and 95th percentiles of the change in energy use in each hour, day and year, as described in Protocols 17 and 18, for each day-type and level of aggregation described in Protocol 22, shall be provided."*

(17) Protocol 21 should be modified to add Table 6-1-1, which would include back-end data informing the table generator in Table 6-1 and be structured in the format defined in Table 6-1-1 and 6-1-2. This recommendation is to standardize the back-end data structure of the table generators to stack data for ease of analysis and verification. The Report includes a sample back-end data table for Tables 6-1-1 and Table 6-1-2 but recommends another Working Group finalize the table.

(18) Protocol 22 should be modified to include as optional reporting the 1 in 10 weather year, typical event day, and average weekday for each month, as these are not needed for the QC calculation. Protocol 22 should read:

*"The information shown in Table 6-1 shall be provided for each of the following day types using 1-in-2 ~~and 1 in 10~~ weather conditions for the average across participants and for the sum of all participants for each forecast year:*

- *Optional: For a typical event day for a 1-in-2 ~~and for a 1 in 10~~ weather year for event-based resource options.*
- *Optional: For the average weekday for each month in which the resource option is in effect for a 1-in-2 ~~and for a 1 in 10~~ weather year for non-event based resource options.*
- *For the monthly system worst ~~peak~~ day for each month in which the resource option is in effect, for a 1-in-2 ~~and for a 1 in 10~~ weather year for event-based and non-event based resources.*

*Typical Event Day for a 1-in-2 ~~and 1 in 10~~ Weather Year may optionally be reported: This day type requirement applies primarily to event-based resources.*

*Average Week Day for Each Month In A 1-in-2 ~~and for a 1 in 10~~ Weather Year may optionally be reported: This day type requirement applies primarily to non-event based resources.*

*Monthly System* <u>*Worst*</u> ~~*Peak*~~ *Day for Each Month In a 1-in-2* ~~*and for a 1 in 10*~~ *Weather Year: This day type applies to event-based and non-event based resources. It is meant to capture impacts for the day with the highest system load in each month. In addition to reporting all of the information shown in Table 6-1, the following information may be provided:*

- *An explanation of how the weather and any other relevant day-type characteristics were chosen for the typical monthly system* <u>*worst*</u> ~~*peak*~~ *day.*

(19) Protocol 23 should be modified to read: "*All ex ante estimates based on regression methodologies shall* <u>*calculate and store*</u> ~~*report*~~ *the same statistical measures as delineated in Protocols 10 and 16* <u>*for a period of one year from filing date of April 1*</u>*.*"

(20) Protocol 26 should be modified to update Tables 9-1 and 9-3 to indicate which reporting is optional versus required.

(21) Protocol 27 should be modified to read: "*A review and comment process will be used at three stages in the implementation of the Load Impact estimation effort. These stages are:*

1. *The evaluation plan used to develop the research questions to be answered and the corresponding methods to be used to answer them;*
2. *The interim and draft final reports for all load impact studies conducted for demand response resources; and*
3. <u>*Public*</u> *Review of Final Reports to determine how comments were addressed.*

This process protocol is meant to ensure that the products of each of the two stages in the estimation effort benefits from a ~~public~~ review by ~~stakeholders~~, Joint Staff, <u>and the DRMEC</u> ~~and the CAISO (California Independent System Operating)~~. The Demand Response Measurement Evaluation Committee (DRMEC) would be used to initiate evaluation planning, review the final evaluation plan, and review draft load impact reports.

10.1. Evaluation Planning – Review and Comment Process

~~The DRMEC~~ Commission staff will be responsible for working with the utilities (or another identified lead entity) in developing evaluation plans for all statewide or local DR programs that are to have load impacts estimated. ~~The DRMEC will develop a process to determine which demand response programs/activities or tariffs should be evaluated and how frequently meetings should be held. The DRMC is responsible for finalizing the process of deciding which DR programs or tariffs should have impact evaluations within 90 days of this order.~~ The DRMEC will also be responsible for ensuring the issues identified in the evaluation planning sections of the load impact protocols are covered during this planning process. The following actions will be undertaken:

1. DRMEC members will identify utility or state staff leads that will be responsible for developing draft evaluation plans for selected projects. The DRMEC will also review draft and final research plans for local utility programs.

2. The DRMEC is to oversee the drafting of the IOU evaluation plans. These drafts should be sent to CPUC staff and DRMEC for comment. ~~interested utility program managers and/or evaluators and to the service list (preferably the list established for the review and authorization of DR programs in the last round) or for those who want to participate on the DRMEC for comment.~~

3. The ~~Utility or DRMEC~~ member responsible for drafting the evaluation plan is responsible for ensuring that comments are solicited from DRMEC and Joint Staff ~~key stakeholders~~ and publishing a small summary of comments received and how or if they were incorporated into the final evaluation plan for each load impact study. The comment period, including responses to them, will be set by ~~the DRMEC~~ Commission staff, taking into account the complexity and length of the documents. Absent good reason, the

period for comments on evaluation plans will be 15 business days.

4. The final evaluation plan will be made available to Joint Staff and DRMEC members ~~and parties to previous DR proceedings~~ upon request.

5. Responses to the evaluation plan comments are required by filing parties that have received comments from DRMEC, Energy Division, Public Advocates Office, California Energy Commission, or other reviewing party. Updated methods sections specifically addressing the comments made by reviewers are due by the second week of March or as determined by Energy Division.

~~**10.2. Review of Interim and Draft Load Impact Reports**~~

~~The utility or contract manager is responsible for facilitating the production of a readable first draft of the load impact report. There may also be interim reports specified in the evaluation plan that will also be subject to a review and comment process. Interim reports may be useful to the impact estimation effort by ensuring interim work products are to be consistent with the protocols. The review and comment process will consist of:~~

1. ~~The interim or draft load impact report will be sent to both the members of the DRMEC and the service list and Joint Staff with a request for comments in at least 5 business days or more, within the time limit determined by Commission staff the DRMEC. The DRMEC can, at its discretion, choose to meet to discuss any the study or conduct the study review by e-mail.~~

#### 4.6.2. Proposed Modifications to D.10-04-006, Appendix 1

The LIP WG Report next recommends modifications to Appendix 1 of D.10-04-006 because some IOUs' executive summaries are duplicative of information in their LIP reports, while other executive summaries are supplemental to the LIP reports' contents. Appendix 1 is recommended to read:[106]

> "Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company (collectively, the Utilities) may optionally ~~shall~~ prepare the following executive summary and are required to prepare the summary tables described below as a part of their annual load impact reports, and shall file this summary information in R.07-01-041 or its successor proceeding, as long as such a proceeding is open. While the executive summary is not required to be in its own, separate filing, the information required herein is still required in either the individual DR program filings or the executive summary.
>
> The executive summary (if filed separately from individual DR program filings) and the summary table are due three weeks after the individual DR program filings are due. If individual filings are due April 1, the executive summary and summary tables are due April 22.
>
> ***Optional Executive Summary ~~Requirement~~***
>
> Consistent with D.08-04-050, Attachment A, Protocol 26 under item 4, the utilities shall prepare Executive Summaries of their load impact reports. These executive summaries shall include an overview of the evaluation findings and the study's recommendation for changes to the demand response resource. In addition, it should also describe briefly the methodology, the enrollment forecast and the inputs and assumptions used for calculating the ex post and the ex ante load impact estimates. The utilities should also report the regression model specification for each demand response program.
>
> The Executive Summary shall also contain an explanation of how the Monthly System Worst ~~Peak Load~~ Day under the "1-in-2 Weather Conditions" ~~and the "1-in-10 Weather Conditions"~~ were derived and disclose the temperature or

[106] LIP WG Report at 31.

Weather Year used for those conditions. It shall also disclose the assumption used for ex ante "portfolio basis" load impacts.

***Summary Table Requirement***

The Summary Tables to be filed along with the Executive Summary of each utility's load impact reports shall include the aggregate average ex ante load impacts for each Monthly System Worst ~~Peak Load~~ Day under a 1-in-2 Weather Condition ~~and a 1-in-10 Weather Condition~~ for the next 10 years. The average impact shall be based on the hours ~~from 2 p.m.–6 p.m. or other peak hours~~ consistent with the average hours used in calculations in the current Resource Adequacy proceeding, R.23-10-011~~09-10-032~~, or a successor Resource Adequacy proceeding."

#### 4.6.3. Proposed Modifications to D.10-06-036, Appendix B

The LIP WG Report recommends a modification to Appendix B of D.10-06-036 at 21, stating that if a filer is requesting local RA under the Slice of Day methodology, the breakdown at the sub-LAP level for every hour of the RA window is required for all months of the year. Appendix B should read:[107]

"In order for DR programs to receive local capacity credit for RA, the load impact must be broken down by local areas. ~~However, this breakdown is not required for all months – it is only required for August.~~ If a filer is not requesting any local RA, breakdown at the Sub-LAP level in ex ante are not required."

#### 4.6.4. Proposal on Confidentiality

Lastly, the LIP WG Report states that third-party DR providers have been interpreting confidentiality rules differently when filing LIPs, such that information in enrollment projections may be publicly available in some filings

[107] LIP WG Report at 31.

and not others.[108] The Report states that this creates an unfair advantage between third parties. The Report notes that D.20-06-031 only provides that: "The Load Impact Protocol (LIP) reports and qualifying capacity values from a demand response provider's LIP results shall be posted publicly to the maximum extent allowable, while protecting customer privacy and market sensitive information of demand response providers by adhering to the Commission's existing confidentiality practices."[109] The Report contends that Energy Division Staff has authority to determine what the "maximum extent possible" should be and that Energy Division should clarify in the LIP Filing Guide as to expectations.

The Report recommends that the following be kept confidential: (1) customer forecast scenarios, (2) customer forecast rationale, and (3) anything that violates existing Commission confidentiality policies (*e.g.*, 15/15 rule).

#### 4.6.5. Comments on LIP WG Report

Several parties recommend full adoption of the LIP WG Report, including Council/OhmConnect, Leap, PG&E, SCE, and SDG&E.[110] These parties point out that a broad range of stakeholders participated in the WG process and developed consensus recommendations following robust discussion. Council/OhmConnect state that the recommendations will reduce the number of analyses needed and volume of the LIPs reports, but also ensure that Energy Division has sufficient data to make a well-informed determination of DR NQC

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108 LIP WG Report at 33.

109 *Id.* (citing D.20-06-031 at OP 17).

110 Council/OhmConnect Comments on Track 2 Proposals at 2, PG&E Comments on Track 2 Proposals at 11, SCE Comments on Track 2 Proposals at 12, SDG&E Comments on Track 2 Proposals at 9, Leap Comments on Track 2 Proposals at 2.

values. SDG&E urges adoption before December 2024 and states that adopting it after makes incorporations into the 2024 LIP Reports challenging.

CEJA/Sierra Club oppose the proposal to eliminate a public process as some stakeholders may not have the resources to participate in a working group but have an interest in the LIPs determination.[111]

#### 4.6.6. Discussion

The Commission appreciates the thorough discussion and efforts of the LIP Simplification Working Group, as well as stakeholders' submission of additional comments on the LIP WG Report in Track 2. We recognize that the LIP WG Report recommends directing a further Working Group process to address certain issues, particularly for modifications to Protocols 1, 3, 7, and 21. However, due to the staffing and resource constraints, an additional Working Group process is not feasible at this time. Regarding the modifications to Protocols 1 and 3, we encourage any party, the Demand Response Measurement and Evaluation Committee, or Energy Division to submit proposals for consideration in a future phase.

For the proposed modifications to Protocol 7 and 21, as adopted in D.08-04-060, the Report describes Tables 4-1-1, 4-1-2, 6-1-1, and 6-1-2 as a first attempt to create a standardized back-end data structure that requires further development in a Working Group. As there is insufficient record to adopt the modifications to Protocols 7 and 21, we decline to adopt Tables 4-1-1, 4-1-2, 6-1-1, and 6-1-2 as modifications to Protocols 7 and 21. Table 4-1 and Table 6-1, however, are complete and accordingly, we adopt these modifications.

[111] CEJA/Sierra Club Comments on Track 2 Proposals at 19.

With respect to other proposed modifications to D.08-04-050, as discussed above, we recognize that these are consensus recommendations that represent the positions of a broad range of parties and find the recommendations to be reasonable. As such, the other modifications to D.08-04-050 are adopted. The adopted changes are outlined in Appendix C, attached to this decision.

With respect to the proposed modifications to D.10-04-006, Appendix 1, the Commission recognizes that these are consensus recommendations that represent the positions of a broad range of parties and finds the recommendations to be reasonable. As such, the modifications to D.10-04-006, Appendix 1, are adopted. The adopted changes are outlined in Appendix C, attached to this decision.

With respect to the proposed modifications to D.10-06-036, Appendix B, the Commission recognizes that these are consensus recommendations that represent the positions of a broad range of parties and finds the recommendations to be reasonable. As such, the modifications to D.10-06-036, Appendix B, are adopted. The adopted changes are outlined in Appendix C, attached to this decision.

With respect to the confidentiality proposals, the Commission finds that the WG has not put forth a developed proposal for consideration. The WG Report requests that Energy Division clarify which information should be deemed market-sensitive, confidential information and the recommendation lacks sufficient record development. As such, we decline to adopt this recommendation. We note that there is an ongoing Data Working Group in Phase One, Track Two of R.22-11-013, and parties are encouraged to participate in that process.

## 5. Summary of Public Comments

Rule 1.18 allows any member of the public to submit written comment in any Commission proceeding using the "Public Comment" tab of the online Docket Card for that proceeding on the Commission's website. Rule 1.18(b) requires that relevant written comment submitted in a proceeding be summarized in the final decision issued in that proceeding. No public comments were submitted.

## 6. Comments on Proposed Decision

The proposed decision of ALJ Debbie Chiv in this matter was mailed to the parties in accordance with Pub. Util. Code Section 311 and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on __________, and reply comments were filed on _____________ by ________________.

## 7. Assignment of Proceeding

Alice Reynolds is the assigned Commissioner and Debbie Chiv is the assigned Administrative Law Judge in this proceeding.

## Findings of Fact

1. Additional vetting and further analysis of Energy Division's revised PRM analysis is needed. The data gathering and reconciliation for the inputs and assumptions that underlie the LOLE study are time-consuming and resource intensive.

2. Due to a lack of participation by LSEs in the non-compensated self-showing option, CPEs do not have access to critical information before initiating the CPE solicitation as to what local resources are under contract by LSEs, what the most effective local resources are to secure, and what the true needs are in designated local areas.

3. The current non-compensated self-showing construct has been ineffective, as there is no binding commitment on LSEs to self-show and LSEs have elected not to self-show despite numerous attempts to incentivize participation.

4. PG&E's proposal to eliminate and replace the non-compensated self-showing option will allow CPEs to better fulfill the role designated to them in D.20-06-002: to secure a portfolio of the most effective local resources, use purchasing power in constrained local areas, mitigate the need for backstop procurement, and ensure a least cost solution for customers and equitable cost allocation.

5. Locking in CPE allocations more than one year in advance, as compared to two months, would be beneficial in that it would give LSEs more time for procurement and more time to negotiate favorable RA contracts on behalf of customers.

6. Locking in CPE allocations earlier will increase certainty for LSEs to understand how much system and flexible RA they may need to procure.

7. PG&E's proposed expansion of the publication of CPE procurement information would provide additional granular information on the CPEs' procurement process that could benefit the CPE framework by giving stakeholders more insight into the procurement process.

8. The recommendations from the LIP Working Group Report, with some exceptions, represent consensus positions from a broad range of parties.

## Conclusions of Law

1. Energy Division should be authorized to undertake a further revision of the 2026 PRM analysis to correct identified errors and distribute it to the service list in December 2024.

2. Consideration of the revised PRM analysis and the 2026 PRM should be deferred to Track 3 of this proceeding.

3. It is more realistic and reasonable for Energy Division Staff to update the RA LOLE study every two years for consideration in the RA proceeding.

4. PG&E's proposal to eliminate the non-compensated self-showing option may provide a more reliable, efficient way for the CPEs to obtain information about what local resources are under contract by LSEs. PG&E's proposal to eliminate the non-compensated self-showing option should be adopted, with modifications.

5. CalCCA's proposal to lock CPE allocations to LSEs one year in advance is reasonable and should be adopted, with modifications, on an interim basis to be reevaluated at the end of 2027.

6. PG&E's proposal to expand the publication of CPE procurement information is reasonable and should be adopted.

7. The recommendations from the LIP Working Group Report, with some exceptions, are reasonable and should be adopted.

8. All assigned Commissioner and assigned Administrative Law Judge rulings should be affirmed.

9. All pending motions should be denied.

## O R D E R

**IT IS ORDERED** that:

1. Energy Division is authorized to undertake a further revision of the planning reserve margin (PRM) analysis to correct errors identified in comments and to distribute it to the service list in this proceeding in early December 2024. The revised PRM analysis will be considered by the Commission in Track 3 of this proceeding.

2. Energy Division is authorized to update the Resource Adequacy (RA) Loss of Load Expectation study every two years for consideration in the RA proceeding.

3. The non-compensated self-showing option of the central procurement entity (CPE) framework is eliminated, effective 30 days from the issuance date of this decision. For self-shown capacity that has been committed to the CPEs, the CPEs shall send a letter to load-serving entities with an existing and/or active attestation within 30 days of the issuance of this decision, nullifying any remaining commitments and stating that the commitments shall no longer be relied on for purposes of satisfying the CPE's compliance obligations. A template for the CPEs' letter is attached to this decision as Appendix A.

4. Energy Division is authorized to collect additional information from load-serving entities (LSEs) regarding local Resource Adequacy (RA) capacity that is under contract in an LSE's portfolio. Energy Division is authorized to collect the following information from each LSE about its local RA capacity under contract:

    (1) Resource ID
    (2) Local Area
    (3) Contract Start/End Date
    (4) Resource Technology Type

(5) Contracted Monthly Megawatt (MW) Capacity for the 3-Year Forward Period

For the 2026 RA compliance year, Energy Division is authorized to send data requests in January 2025, with responses to be submitted by the LSE by February 1, 2025. Energy Division will aggregate and anonymize the information and provide the data to the CPEs for use in the CPEs' annual solicitation and procurement process.

5. California Community Choice Association's proposal to lock central procurement entity (CPE) allocations to load-serving entities (LSE) one year earlier is adopted, on an interim basis. This will be effective in 2025 for the 2027 Resource Adequacy (RA) compliance year and will be reevaluated by the end of 2027. The following CPE procurement process is adopted (using Y to indicate the compliance year).

(a) Local CPE procurement conducted by October 31 in Y-2 for compliance year Y will be considered "locked:" in Y-1, the CPEs will no longer procure for local requirements allocated in Y-2.

(b) In Y-1, the CPEs will only conduct procurement for the incremental changes between what was provided in Y-2 and the California Independent System Operator's updated Local Capacity Technical study for compliance year Y. Any incremental procurement the CPE conducts for compliance year Y will be allocated to LSEs in accordance with the annual CPE and LSE allocation timelines in August and mid-September.

6. Energy Division is authorized to monitor the amount of CPEs' incremental procurement, the rate of local RA deficiencies that are deferred to backstop procurement, and whether market power may be exercised by generators.

7. The central procurement entities (CPE) shall provide the following additional information in their Annual Compliance Reports: (1) the CPEs' local Resource Adequacy (RA) capacity procured on a California Independent System Operator (CAISO)-defined local capacity area level; (2) the CPEs' net open positions on a CAISO-defined local capacity area level; and (3) capacity purchased by the CPEs on a resource-specific level, which aligns with reporting processes of other Cost Allocation Mechanism (CAM)-eligible resource procurement. The Confidentiality Matrix adopted in Decision (D.) 22-03-034 is modified to reflect these changes, and is attached to this decision as Appendix B.

8. Modifications to the Load Impact Protocols requirements, as outlined in Appendix C attached to this decision, are adopted.

9. All assigned Commissioner and assigned Administrative Law Judge rulings are affirmed.

10. All pending motions are denied.

11. Rulemaking 23-10-011 remains open.

This order is effective today.

Dated _____________, at Sacramento, California.