STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

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

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Ratesetting

TO PARTIES OF RECORD IN RULEMAKING 25-06-019:

This is the proposed decision of Administrative Law Judge Julie A. Fitch. 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 February 26, 2026 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 to the proceeding may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure (Rules).

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:nd3
Attachment

Decision **PROPOSED DECISION OF ALJ FITCH (Mailed 1/14/2026)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Oversight of Electric Integrated Resource Planning and Procurement Processes.	Rulemaking 25-06-019

DECISION REQUIRING 2029-2032 ELECTRIC RESOURCE PROCUREMENT AND TRANSMITTING PORTFOLIOS FOR 2026-2027 TRANSMISSION PLANNING PROCESS

TABLE OF CONTENTS

DECISION REQUIRING 2029-2032 ELECTRIC RESOURCE PROCUREMENT AND TRANSMITTING PORTFOLIOS FOR 2026-2027 TRANSMISSION PLANNING PROCESS

Summary

This decision requires load-serving entities under the California Public Utilities Commission's (Commission) integrated resource planning purview to undertake additional reliability procurement between 2029 and 2032, to pursue any viable projects that can still qualify for Federal tax credits or other incentives, as well as to continue the momentum of annual procurement activity that began under the Mid-Term Reliability (MTR) and supplemental MTR requirements in Decision (D.) 21-06-035 and D.23-02-040, respectively. The new procurement required is 2,000 megawatts (MW) of net qualifying capacity (NQC) by 2030 and an additional 4,000 MW NQC by 2032, with no more than half of the total NQC per tranche eligible to come from storage resources. This procurement will be generally subject to the same compliance and enforcement requirements as the prior MTR orders, except D.25-09-007 provisions will not apply.

This decision also transmits a reliability and policy-driven base case electricity portfolio and a sensitivity portfolio to the California Independent System Operator (CAISO) for analysis in its 2026-2027 Transmission Planning Process (TPP). The recommended base case portfolio is consistent with the 2025-2026 TPP base case portfolio, which was designed to meet a 25 million metric ton greenhouse gas emissions target for the electric sector by 2035. This target is consistent with both the statewide electricity sector emissions trajectory set by the California Air Resources Board in its 2022 Scoping Plan for Achieving Carbon Neutrality, as well as the 2035 emissions requirements set by Senate Bill 1020 (Stats. 2022, Ch. 361). The recommended base case portfolio differs from the 2025-2026 TPP base case by extending the online dates for some offshore

wind resources by up to six years, and recommending up to a two-year extension to the in-service dates for the transmission to support North Coast offshore wind. The recommended sensitivity portfolio tests a low-wind development scenario, and represents an opportunity to identify other transmission development that could be needed under a worst-case scenario slowdown in wind development. This information may be used to inform future TPP base case portfolios.

This proceeding remains open.

1. Background

This section presents both a brief factual background on the issues covered in this decision, as well as a summary of the procedural steps that have led to this decision.

1.1. Factual Background

As part of the longstanding coordination formalized through the memorandum of understanding between the California Energy Commission (CEC), California Independent System Operator (CAISO), and the California Public Utilities Commission (Commission) to collaborate on electricity resource and transmission planning, every year Commission staff develops a recommended set of portfolios for the CAISO to use in its annual Transmission Planning Process (TPP).

Generally, in each TPP cycle, the CAISO evaluates a reliability and/or policy-driven base case portfolio. Under the CAISO tariff adopted by the Federal Energy Regulatory Commission (FERC), if the results of the base case analysis show the need for additional transmission development, the transmission projects are brought to the CAISO Board for approval in the spring of the second year of the TPP. If approved by the CAISO Board, under the FERC tariff, the project would receive cost recovery through the transmission access charge.

Along with the base case analysis that generally leads directly to transmission project approval, in each TPP cycle the CAISO typically analyzes a sensitivity portfolio. The purpose of the sensitivity portfolio analysis is to assist in future planning by identifying relevant transmission needs and potential costs.

Decision (D.) 25-02-026 included both a base case and a sensitivity portfolio that the CAISO is in the process of analyzing for the 2025-2026 TPP cycle. The base case portfolio was based on the scenario that achieves at 25 million metric ton (MMT) statewide greenhouse gas (GHG) emission target in 2035, and includes the resources online, under contract, or planned in the individual load-serving entity (LSE) integrated resource plans (IRPs) submitted in November 2022, including 4.5 gigawatts (GW) of offshore wind that is currently included in the 2025-2026 TPP base case.

The 2025-2026 TPP sensitivity portfolio currently being studied by the CAISO is a long lead-time (LLT) resource sensitivity. This sensitivity is based on the upper bounds of the need determination analysis of LLT resource volumes that the Department of Water Resources (DWR), as a central procurement entity (CPE), could potentially procure, as reflected in the Commission's adopted decision (D.24-08-064), pursuant to Assembly Bill (AB) 1373 (Stats. 2023, Ch. 367). The need determination in D.24-08-064 included geothermal, long-duration energy storage (LDES) with specified durations, and offshore wind resources.

In D.21-06-035, also known as the Mid-Term Reliability (MTR) decision, the Commission required LSEs to procure 11,500 megawatts (MW) of net qualifying capacity (NQC) between 2023 and 2026.[1] Subsequently, in D.23-02-040 (also known as the Supplemental MTR decision), the Commission required LSEs to procure an additional 4,000 MW of NQC by 2028, using the same basic framework established in D.21-06-035. In addition, D.23-02-040 postponed the requirements for LSEs to procure 2,000 MW NQC of LLT resources, as defined in the MTR decision, until 2028, with the potential for a further extension to 2031, while allowing LSEs to cover any delays with generic capacity resources to cover the delayed NQC from MTR's LLT resources.

In Rulemaking (R.) 20-05-003, the prior IRP proceeding, a Staff Proposal for the Reliable and Clean Power Procurement Program (RCPPP) is under consideration. Parties have filed opening comments and reply comments on the content of the RCPPP Staff Proposal in R.20-05-003 and the details of RCPPP will continue to be addressed in that rulemaking. However, some parties, in commenting on the timing of the potential for an RCPPP to be adopted, have commented that the Commission should consider another interim procurement order, to maintain electric system reliability during the time period while the RCPPP framework is considered. In response to the RCPPP Staff Proposal, approximately twenty parties commented on near-term reliability needs, generally for the period 2028-2032. Numerous parties generally recommended that the Commission conduct a near-term reliability need determination and issue an interim procurement order if a system reliability need was found.

[1] NQC for each tranche of procurement required from LSEs is based on vintaged marginal effective load carrying capability (ELCC) values available on the IRP Procurement Track website at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track.

Separately, also in R.20-05-003, American Clean Power — California (ACP-CA) filed the *Motion to Amend the Amended Scoping Memo to Include an Additional Track for Expedited Procurement.* Parties filed responses to the ACP-CA Motion on August 5, 2025 in R.20-05-003. Similar to the RCPPP Staff Proposal, the ACP-CA motion will be addressed in R.20-05-003. However, elements of the ACP-CA motion and its rationale are relevant to the near-term need determination considerations in this decision.

1.2. Procedural Background

An Administrative Law Judge (ALJ) Ruling (Ruling) was issued in this proceeding on September 30, 2025 seeking comments on the recommended electricity portfolios to be transmitted to the CAISO to use in its 2026-2027 TPP, as well as on whether there is a need for additional reliability procurement during the period 2029-2032.

Opening comments in response to the ALJ Ruling were filed by the following parties: Alliance for Retail Energy Markets (AReM); ACP-CA; Bioenergy Association of California (BAC); California Coalition of Large Energy Users; California Community Choice Association (CalCCA); California Energy Storage Alliance (CESA); California Environmental Justice Alliance (CEJA) and Sierra Club, jointly; California Grid Holdings, LLC (CalGrid); CAISO; California Resources Corporation (CRC); California Wind Energy Association (CalWEA); Calpine, Inc. (Calpine); Clean Power Alliance (CPA); Coalition for Community Solar Access (CCSA), Coalition of California Union Employees (CUE), and California Unions for Renewable Energy (CURE), collectively; Defenders of Wildlife (DOW); EDF Power Solutions, North America (EDF-NA); ENGIE North America, Inc. (ENGIE); Environmental Defense Fund (EDF); Environmental Protection Information Center (EPIC); esVolta, Inc. (esVolta); Fervo Energy

Company (Fervo); Form Energy, Inc. (Form); Golden State Clean Energy (GSCE); Golden State Renewable Energy, LLC; GreenGen Storage, LLC (GreenGen); GridLiance West, LLC (GridLiance); Hydrostor, Inc.; Independent Energy Producers Association (IEP); Invenergy California Offshore, LLC (Invenergy), Invenergy Geothermal, LLC, and Maravillosa Solar Energy, LLC, collectively; L. Jan Reid (Reid); Long Duration Energy Storage Council (LDES Council); Mainspring Energy, Inc. (Mainspring); Middle River Power, LLC (MRP); Mussey Grade Road Alliance (MGRA); Natural Resources Defense Council (NRDC); NextEra Energy Resources, LLC (NextEra); Oceantic Network, Inc. (Oceantic); Offshore Wind California (OWC); Pacific Gas and Electric Company (PG&E); Peninsula Clean Energy (PCE); Pioneer Community Energy; PivotGen; the Public Advocates Office at the California Public Utilities Commission (Cal Advocates); Redwood Coast Energy Authority (RCEA) and Humboldt County, jointly; REV Renewables, LLC (REV); rPlus Hydro, LLC; San Diego Gas & Electric Company (SDG&E); Shell Energy North America (Shell); Solar Energy Industries Association (SEIA) and Large-Scale Solar Association (LSA), jointly; Sonoma Clean Power Authority (SCPA) and PCE, jointly; Southern California Edison Company (SCE); Southern California Gas Company (SoCalGas); Terra-Gen, LLC (Terra-Gen); The Nature Conservancy (TNC); The Utility Reform Network (TURN); Union of Concerned Scientists (UCS); Vineyard Offshore, LLC (Vineyard); Vote Solar; Western Power Trading Forum (WPTF); and XGS Energy, Inc. (XGS).

Reply comments in response to the ALJ Ruling were filed by the following parties: ACP-CA; AReM; CAISO; CalCCA; CalGrid; Calpine; CalWEA; Center for Biological Diversity (CBD); CEJA and Sierra Club, jointly; CESA; DOW; EDF; EPIC; Fervo; GreenGen; GridLiance; Hydrostor; Invenergy; LDES Council; LSA and SEIA, jointly; Marin Clean Energy (MCE); Mainspring; MRP; RCEA and Humboldt County, jointly; Reid; Small Business Utility Advocates (SBUA); SCE; SCPA; SDG&E; Shell; San Jose Clean Energy (SJCE); SoCalGas; UCS; Vineyard; Vote Solar; WPTF; and XGS.

On November 3, 2025, an ALJ Ruling was issued seeking comments on the preliminary mapping of energy and storage resources to transmission busbars for purposes of the TPP portfolios (Busbar Ruling). Comments in response to the Busbar Ruling were filed on November 21, 2025 by the following parties: ACP-CA; Bay Area Transmission Group (BAMx); Cal Advocates; Calpine; CalWEA; CEJA and Sierra Club, jointly; CRC; DOW; EDF; Fervo; GreenGen; GridLiance; GSCE; Invenergy; LSA; LS Power; MGRA; NextEra; Ormat Technologies, Inc. (Ormat); Pattern Energy Group, LP (Pattern); PG&E; SBUA; SCPA; TNC; and Vineyard.

1.3. Submission Date

This portion of the proceeding was submitted on November 21, 2025 upon filing of parties' comments on the Busbar Ruling.

2. Procurement Issues

The ALJ Ruling included staff analysis of reliability needs on the electric system between 2028 and 2032. The analysis was conducted in response to the increase in the load forecast in the 2024 Integrated Energy Policy Report (IEPR) of the CEC, comments on the RCPPP from parties in the previous IRP rulemaking (R.20-05-003), as well as the ACP-CA Motion to Amend the Scoping Memo in R.20-05-003.

The analysis noted that several critical things have changed since the Commission last issued an LSE procurement order in D.23-02-040 (as modified by D.24-02-047). First, relative to prior forecasts, significant load growth is now being forecasted in 2028-2032 in the CEC's 2024 IEPR demand forecast, much of it related to data centers, continuing vehicle and building electrification, and lower adoption of and lower capacity factors for behind-the-meter (BTM) solar and storage. In addition, Federal tax credit benefits are being rapidly phased out over the next few years. Other federal actions include executive orders imposing tariffs and limiting or delaying siting on federal lands for some types of renewable resources.

Second, as noted in the ALJ Ruling, as part of the CAISO interconnection queue in Cluster 14 and 15, many more projects are available than have been procured by LSEs. Some of these projects, in addition to being able to meet any identified need, may also be at a point in their development timelines where they could still take advantage of Federal tax benefits, potentially saving California ratepayers money.

In addition, the resource adequacy program routinely studies reliability needs, and recently increased the planning reserve margin (PRM) in light of loss-of-load-expectation (LOLE) studies in R.23-10-011. The Commission recently adopted an 18 percent PRM in the resource adequacy program for years 2026 and 2027, while also extending the effective PRM of 3-5.5 percent, in addition to the binding PRM, for those same years.

To assess whether these changes resulted in the need for another Commission order for capacity procurement in advance of consideration of the adoption of a programmatic framework for the RCPPP, Commission staff undertook a reliability analysis that was presented in the ALJ Ruling.

The analysis began with the following basic assumptions:

- The load forecast was updated based on the 2024 IEPR assumptions.

- A number of key supply assumptions were reviewed, including assumptions related to the realization of LLT resources and Diablo Canyon Power Plant (DCPP) status.
- The 2,000 MW NQC of LLT resources, as defined specifically and required by D.21-06-035 and D.23-02-040 (and further defined by D.25-06-005) to be online in 2028, but with the potential for an extension to 2031, are modeled as online in either 2028 or 2031, according to projected online data in the June 2025 IRP compliance filings of LSEs. In addition, based on the proposed decision in R.20-05-003 in response to the SCE Petition for Modification (PFM) of D.23-02-040 and D.24-02-047 dated August 13, 2025,[2] generic capacity was assumed to have been procured to replace any LLT capacity delayed to 2031 and is still online in 2032. This is likely an optimistic assumption, as further described below.
- Compliance with MTR obligations, across all LSEs collectively, was assumed. Staff analyzed the Commission's existing modeling baseline plus the LSEs' June 2025 compliance filings and removed solar and storage contracts in excess of minimum MTR requirements.
- No additional resources, beyond those included in LSE June 2025 IRP compliance filings, were added to meet long-term GHG goals, even though some LSEs are likely planning to procure additional resources to meet these goals.
- DCPP was modeled as offline in all years.[3]

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[2] Available at the following link: https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=575603716.

[3] Public Utilities Code Section 454.52(f)(1) states: "The commission shall not include the energy, capacity, or any attribute from Diablo Canyon Unit 1 beyond November 1, 2024, or Unit 2 beyond August 26, 2025, in the adopted integrated resource plan portfolios, resource stacks, or preferred system plans." *See* also Senate Bill (SB) 846 (Stats. 2022, Ch. 239), which added Public Utilities Code Section 712.8(q), which states: "the continued operation of Diablo Canyon Units 1 and 2 beyond their current expiration dates shall not be factored into the analyses used by the commission or by load-serving entities not subject to the commission's jurisdiction when

Footnote continued on next page.

- Electricity demand was updated to reflect the 2024 IEPR "Planning" demand forecast, including the amount of BTM rooftop photovoltaics assumed.
- Combined heat and power (CHP) plants were not assumed to be phased out.
- Path 26 transmission was not assumed to be expanded.
- Natural gas units were not assumed to retire on any set timetable.
- No resources from the Strategic Reliability Reserve were included in the analysis.

Using this updated baseline and set of assumptions, Commission staff conducted modeling runs for the years 2028 through 2032 using the Strategic Energy and Risk Valuation Model (SERVM), which is the Loss-of-Load-Probability (LOLP) production cost modeling software regularly used in resource adequacy and IRP reliability analyses. Commission staff performed iterative model runs to try to achieve the reliability planning standard of 0.1 LOLE, which means an expectation of one day with loss of load in ten years.[4] Except for study years in which the base portfolio was modeled to be already over-reliable, Commission staff added perfect capacity[5] (PCAP) MWs, which are equivalent to effective load carrying capability (ELCC) MW), to the model until the LOLE result was sufficiently close to 0.1 LOLE.[6]

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determining future generation and transmission needs to ensure electrical grid reliability and to meet the state's greenhouse gas emissions reduction goals."

[4] D.24-02-047 adopted the 0.1 LOLE standard as the key input for determining reliability need and this is consistent with previous modeling efforts in IRP.

[5] Within SERVM, "perfect capacity" is a modeling construct to represent a perfect resource with no operating constraints, no outages, and priced to dispatch only as a last resort, to avoid unserved energy.

[6] Commission staff conducted iterative SERVM modeling runs to get to within 0.02 of the 0.1 LOLE target.

Commission staff followed these basic steps to complete the analysis:

- Step 1: Create a 2025 Need Determination Analysis baseline, which assumes full compliance with the IRP procurement orders.[7]
  - o Calculate the capacity of LSE contracts as of the June 2025 IRP procurement compliance filings (no incremental RESOLVE-selected resources to meet reliability or GHG-reduction targets were included, only existing resources plus LSE-reported contracted resources);
  - o Evaluate the total MTR procurement claimed by LSEs as incremental contracts beyond the MTR baseline; and
  - o Calibrate to the exact minimum compliance MTR NQC MW ordered by adding or subtracting capacity to establish the 2025 Need Determination Analysis baseline.
- Step 2: Analyze the 2025 Need Determination Analysis baseline with an LOLP model (SERVM) to determine incremental need.
  - o Enter the portfolio determined in the step above into SERVM;
  - o For each study year, iteratively add increasing amounts of PCAP until the resulting LOLE is approximately 0.1 (equating to one day in ten years); and
  - o The PCAP added in each study year is equivalent to the ELCC MW need.
- Step 3: Analyze the impact of changes in supply or load through post-processing sensitivities.
  - o Sensitivities were created after SERVM modeling by changing the PCAP MW need by the change in firm

[7] D.21-06-035 and D.23-02-040, as modified by D.24-02-047. This assumption includes 100 percent compliance with those orders, which may or may not actually occur.

capacity or by the change in managed peak (plus a 6 percent operating reserve margin).

Unlike for the development of the TPP portfolios described in Section 2 above, the need determination analysis did not involve running RESOLVE to generate an incremental build of resources to meet reliability and emissions targets at lowest cost. The study simply gathered data on the capacity associated with existing contracts as of the June 2025 IRP procurement compliance filings, adjusted for minimum compliance with MTR requirements, and analyzed the reliability of that portfolio in SERVM, relative to a 0.1 LOLE planning standard.

Of note during the analysis of the MTR baseline used in this analysis is the fact that LSEs have reported 16.3 GW NQC (ELCC) of signed contracts, as of June 2025, to meet MTR requirements by 2028, which exceeds the 15.5 GW NQC requirement in aggregate. This quantity may not represent all LSEs being in full compliance with their IRP procurement obligations, because some LSEs have procured more than their minimum MTR requirements. LSEs may be procuring (*i.e.*, signing contracts) with resources in excess of current compliance requirements for a variety of reasons, including anticipation of resource development delays or failures, anticipation of resource adequacy requirements, assessment of resource value, anticipation of renewables portfolio standard (RPS) requirements, LSE-specific portfolio objectives, or anticipation of future needs. The Commission has several times indicated that LSEs that procure in excess of their MTR requirements should expect to be able to count incremental additional resources towards any future needs without regards to a baseline update,[8] and the ALJ Ruling proposed to continue that principle. In the staff analysis, no

[8] *See*, for example, D.23-02-040, Conclusion of Law 7, and D.25-09-007 at 35.

failure rate for contracts and no assumptions for delays were used, aside from not counting contracts above the minimum level of required MTR procurement.

Subsequent to the modeling analysis, the proposed decision in response to the SCE PFM of D.23-02-040 and D.24-02-047 was revised and finalized, removing the proposed requirement in the original proposed decision for LSEs to be required to replace the delayed LLT resources with generic resources between 2028 and 2031.[9] Due to this change, the model's assumption that capacity from delayed LLT resources will be replaced with generic capacity is no longer correct. Thus, the analysis overstates resources by the amount of replacement capacity added, or approximately 367 MW, for all years in the analysis. In addition, if LLT resources currently expected to come online in 2028 are delayed until 2031, the analysis also overstates available resources (up to 1,633 MW) for the 2028-2030 period. As described further below, Commission staff developed a "Delayed LLT" sensitivity scenario to account for these estimated deviations.

Table 1 below shows the results of the Commission staff analysis in SERVM for the original set of assumptions, referred to as the "Base Portfolio." Table 2 then displays the modeling results, adjusted by staff to reflect a minimum compliance scenario under the terms of D.25-09-007, in which all LSEs have signed contracts to satisfy their LLT resource obligations, LLT resource online dates are delayed from 2028 to 2031, and all LSEs are compliant with their system resource adequacy month-ahead requirements. Under these assumptions, 13,500 MW NQC would be assumed to come online through 2027, in accordance with D.21-06-035 and D.23-02-040 (as modified by D.24-02-047). Then, all

[9] The final version of the decision adopted by the Commission is D.25-09-007.

2,000 MW NQC of LLT resources would be assumed to come online in 2031, leading to a modeled resource build of 15,500 MW NQC. Because many LSEs have requested LLT resource extensions, the ALJ Ruling proposed requiring procurement based on Table 2 below, rather than based on the originally-modeled Base Portfolio in Table 1.

Table 1. Cumulative SERVM PCAP Need Results for 2028-2032, Base Portfolio

Study Year	LOLE	Expected Unserved Energy (EUE)	Cumulative Added PCAP
Year	Days/Year	MWh[10]	ELCC MW
2028	0.043	254	NA
2029	0.115	850	1,200
2030	0.117	755	2,300
2031	0.111	619	4,000
2032	0.098	525	5,900

Table 2. Cumulative SERVM PCAP Need Results for 2028-2032, Delayed LLT Scenario

Study Year	LOLE	Cumulative Added PCAP	Estimated Adjustment for Delayed LLTs	Cumulative Added PCAP, Adjusted
Year	Days/Year	ELCC MW	ELCC MW	ELCC MW
2028	0.043	NA	2,000	NA
2029	0.115	1,200	2,000	3,200
2030	0.117	2,300	2,000	4,300
2031	0.111	4,000	367	4,367
2032	0.098	5,900	367	6,267

10 Megawatt-hour.

Note that in years 2029-2031, as Commission staff only conducted SERVM modeling to get close to the 0.1 LOLE target but not achieve it precisely, a small amount of additional PCAP is likely needed in order to meet the standard. For 2028, staff originally found the existing resource build to be over-reliable compared to 0.1 LOLE. However, the surplus magnitude was not estimated as part of the staff analysis. Therefore, the estimate for the surplus or deficit in 2028 in the Delayed LLT Scenario adjustment is also undefined.

Commission staff also conducted post-processing sensitivity analysis by looking at three changes in assumptions and analyzing each using a heuristic approach, by manually adding or subtracting PCAP from the results, corresponding to the change in forecasted managed peak MW or firm MW available in each sensitivity. In assessing peak MW changes on PCAP need, an additional 6 percent operating reserves were assumed, instead of the load variability of the full PRM, since most of the load changes are not expected to have significant weather-driven variation. These scenarios were not analyzed in SERVM. Staff looked at the following sensitivity scenarios:

1. **Continued DCPP operations**: In this scenario, 2,200 MW was removed from the PCAP shortfall, using the assumption that DCPP would stay online through its current approved timeframe, which would retire Unit 1 on October 31, 2029 and Unit 2 on October 31, 2030.
    - It was assumed that both units would be available for the 2028 and 2029 peak periods;
    - Unit 2 (1,100 MW) would be available for the 2030 peak period; and
    - Neither unit would be available for 2031 or 2032.
2. **Increased data center load**: In this scenario, a managed peak change, plus 6 percent operating reserves, was added to the PCAP shortfall. The managed peak change was

calculated by substituting in the data center load modifier from the 2024 IEPR "Local Reliability" scenario, instead of from the 2024 IEPR "Planning" scenario. No other changes from the 2024 IEPR "Local Reliability" scenario were used.

3. **Reduced load from electrification and data centers**: In this scenario, a managed peak change, plus 6 percent operating reserves, was removed from the PCAP shortfall. This sensitivity was designed to reflect potential impacts of recent policy changes, including the One Big Beautiful Bill Act (OBBBA), potential repeal of the Environmental Protection Agency Waiver from the Clean Air Act potentially influencing electric vehicle adoption, and uncertainty in building electrification and data center load. Potential impacts of federal import tariffs were not included. Details of how Commission staff adjusted load components to reflect the policy changes and uncertainty are described in the slide deck available at: https://www.cpuc.ca.gov/irp_procurement. Note that this heuristic method is less reflective of assumed load behavior, since the load components are more varied compared to the flat data center load changes in Sensitivity 2 above, which is more akin to a PCAP resource as modeled in SERVM.

Sensitivities 1 and 3 above reduce the PCAP need, while Sensitivity 2 increases it.

Tables 3 and 4 below summarize the results of the sensitivity analyses for the Base Portfolio and the Delayed LLT Portfolio, respectively. In the Delayed LLT Scenario, upon which the ALJ Ruling proposed to base a need determination, the current DCPP continued operations schedule would substantially reduce the reliability need in 2029, but the statutory directives prohibiting consideration of DCPP extensions are important and likely render this scenario not actionable at this time. Increased data center load modestly increases the need. Reduced load may substantially reduce need in all years.

Table 3. PCAP Need Results for Sensitivities Compared to Base Portfolio (in MW)

Study Year	Base Scenario	Increased Data Center Load	Reduced Load	Continued DCPP Operations
2028	NA	0	0	NA
2029	1,200	1,301	0	0
2030	2,300	2,544	0	1,200
2031	4,000	4,306	301	4,000
2032	5,900	6,295	1,645	5,900

Table 4. PCAP Need Results for Sensitivities Compared to Delayed LLT Portfolio (in MW)

Study Year	Delayed LLT Scenario	Increased Data Center Load	Reduced Load	Continued DCPP Operations
2028	NA	0	0	NA
2029	3,200	3,301	1,014	1,000
2030	4,300	4,544	1,347	3,200
2031	4,367	4,673	668	4,367
2032	6,267	6,662	2,012	6,267

2.1. 2029-2032 Procurement Need

Based on the Commission staff analysis presented in the ALJ Ruling and summarized above, the ALJ Ruling proposed that the Commission order additional procurement during the years 2029-2032 in the amounts shown in Table 5 below.

Table 5. Proposed Procurement to be Required from LSEs Collectively (in ELCC MW)

Year	Cumulative Procurement Required in Model (rounded to nearest 500 MW)	Incremental Procurement Recommended
2029	3,000	1,500
2030	4,500	1,500
2031	4,500	1,500
2032	6,000	1,500

The ALJ Ruling also proposed that the compliance baseline for these procurement amounts would continue to be the one utilized in D.21-06-035. In D.21-06-035, the Commission required that any procurement that was intended to count towards the required amounts needed to be incremental relative to the existing resources and/or the resources already under contract at that time. To extend that concept to this new potential requirement would mean that any procurement already undertaken by an LSE that exceeds its obligations from D.21-06-035 and D.23-02-040 (as modified by D.24-02-047) would be applied to the LSE's supplemental obligation, derived from the amounts in the final column of Table 5 above.[11] Likewise, any procurement undertaken in response to this order would also be counted toward RCPPP requirements, if a program is ultimately adopted by the Commission.

2.1.1. Comments of Parties

The majority of parties commenting on the analysis of procurement need supported the Commission ordering some procurement as a result. A total of 26 parties supported the proposed order in the ALJ Ruling in some form, with some

[11] This is consistent with D.23-02-040, Conclusion of Law 7, which states: "If an LSE already has procured its share of capacity for one compliance period, it may count any excess procurement from that compliance period in future compliance periods."

parties preferring a slightly reduced magnitude or duration of procurement requirements, and others preferring a longer or larger order. ACP-CA argues that the need determination analysis may understate the need due to anticipated future import constraints, and would prefer an order requiring 2,500 MW of procurement per year. GreenGen argues that a longer order would be better for more diverse resource development beyond solar and storage.

Meanwhile, SDG&E and Cal Advocates supported an order covering only 2029 and 2030, for a total of 3,000 MW of procurement. They both cite to high forecast uncertainty and the potential for RCPPP to be implemented beginning in 2031. CalCCA and SCPA/PCE recommended a two-tranche order of 2,000 MW for the 2029-2030 period and another 2,000 MW for the 2031-2032 period, with a reassessment in 2027 for the later period.

Approximately ten parties indicated neutrality toward the proposed procurement or did not express an opinion about it in comments. Nine additional parties were opposed to the Commission ordering procurement at this time, including AReM, Calpine, CLEU, Reid, MRP, Shell, WPTF, SJCE, and MCE. Generally, the arguments against an order were that a procurement need does not imply that a procurement order is necessary, the 2024 IEPR load forecast is highly uncertain, these types of procurement orders erode LSE negotiating leverage with developers in a market with fixed supply, different compliance rules create administrative complexity, and an order spanning to 2032 would interfere with RCPPP implementation.

CLEU argued that the staff need determination analysis was by itself an insufficient factual record to justify a procurement order and requested workshops on the assumptions to build a more robust record. AReM expressed some support for a shorter procurement order that is based on the reduced load sensitivity, and Calpine and MRP also supported other parties' comments in their replies that argued for a shorter order.

PG&E, SDG&E, and CCSA suggested mechanisms to effectively reduce an order's size, given certain conditions are met. PG&E and SDG&E suggest amending the Public Utilities Code to clearly allow the Commission to account for DCPP's attributes. Then they argue that the procurement need would clearly be reduced. PG&E also argues that any incremental procurement conducted by PG&E and SCE in their roles as the local CPE for resource adequacy should be eligible to reduce procurement obligations. CCSA argues that in the event that front-of-the-meter (FTM) distributed energy resources (DERs) are modeled as load modifiers by CEC in a future IEPR, the LSEs should be able to count load-modifying FTM DERs in their compliance filings as reductions to their need allocations.

Several parties recommended alternative analyses for determining a procurement need. Calpine recommends basing an order on a combination of the reduced load sensitivity and the DCPP operations sensitivity. CLEU also suggests that the Commission is obligated by law (specifically, Public Utilities Code 454.52(a)(1)(E)) to consider DCPP capacity through 2030, as the need determination is a "midterm" analysis. CalCCA reports that its results were similar to the Commission's when using the same assumptions, but cautions that the assumptions may not actually occur, and therefore recommends a set of "lighter" assumptions. ACP-CA and Hydrostor, on the other hand, recommend more generous assumptions about need, with Hydrostor suggesting that data center load may be higher than anticipated. CCSA and CBD recommend supplementing the staff analysis with the Aurora study, which supports a greater role for FTM solar development. MGRA cited a Form study on 100-hour batteries. Finally, Shell recommends that the Commission undertake a joint analysis with the CAISO to determine reliability needs, rather than relying on the analysis presented in the ALJ Ruling.

Parties' comments were also concerned with the potential impacts of a procurement order from the Commission on the market for clean energy and capacity. Several parties argue that an order would likely lead to more adverse conditions for LSEs in the market, including price increases. AReM argues that after D.21-06-035 there was so much procurement activity by LSEs attempting to meet those requirements that the LSEs scrambled to secure contracts, which drove up prices due to the scarcity of compliant resources. SCE and MCE argue this was particular true for battery storage projects. SDG&E and MCE also argue this caused resource adequacy price volatility as well.

ACP-CA and REV, on the other hand, argue that a procurement order on the order contemplated in the ALJ Ruling would not likely increase prices in the market. ACP-CA states that the quantity of uncontracted projects in the current interconnection queue suggests that LSEs maintain a strong position in negotiations. REV argues that the longer timeframe, with the first need being four years out, aligns very well with development timelines and should make the market competitive.

2.1.2. Discussion

As a starting point, we are always concerned about the impact that our procurement decisions have on the market. As we have since our first IRP procurement order in 2019,[12] we expect the LSEs generally to be in the market with solicitations regularly, as they should be planning for load growth and

[12] D.19-11-016.

future resource needs in advance. Therefore, we expect that the Commission's consideration of requiring additional procurement after the expiration of the current MTR requirements should not come as a complete surprise to the LSEs or other market actors. LSEs have also been on notice that the Commission is considering approaching ongoing procurement needs with a programmatic approach, in the form of the RCPPP proposal under development in R.20-05-003. The adoption of some form of programmatic requirement will also impose ongoing procurement requirements on LSEs. In general, the proposed new resource requirement of 1,500 MW NQC annually in the ALJ Ruling does not seem unreasonable or particularly burdensome in light of the size of the resource need when considering the magnitude of California's GHG goals out through 2045.

We are also persuaded that there may still be some projects without contracts that can take advantage of remaining Federal tax credits, and if those are available, it would be to the benefit of ratepayers for the projects to be contracted, assuming other reasonable terms.

In addition, we note that the timing of this order allows for more procurement lead time than has often been the case with past IRP procurement orders. On this, we agree with the argument made by REV that the longer lead time we are planning for here is likely to dampen negative market effects.

At the same time, we are concerned about impacts on ratepayer costs. While it is likely that DCPP will be online through 2030 in reality, the Commission models its impact pursuant to SB 846 requirements.

Further, we are aware that having annual procurement requirements can have a burdensome impact on both LSEs and Commission staff assessing compliance requirements. In addition, contracts and project investments are often lumpy and do not fit neatly into annual tranches.

In light of all of the above factors, this order modifies the proposal in the ALJ Ruling to require the same total amount of procurement, but in two specific years instead of annually for four. We adopt a requirement for 2,000 MW NQC total procurement online by June 1, 2030, with an additional 4,000 MW NQC online by June 1, 2032.

This timing will allow for a smooth transition to the potential adoption of an RCPPP framework, along with implementation details, in a timeframe that is realistic and should not cause market disruption regardless of the form the RCPPP may ultimately take.

2.2. Resource Eligibility

The ALJ Ruling proposed that qualifying resources to meet the procurement requirements would be the same as under D.21-06-035 and D.23-02-040. Namely, the resources would be required to be non-GHG-emitting and/or eligible for the RPS program. Only new resources (online after January 1, 2020[13]) would qualify. The rules around baseline swaps,[14] baseline waivers,[15] and obligations swaps[16] would also be extended. Resources fueled by natural gas or any other fossil fuel would not qualify to meet the procurement requirements.

Most prior decisions did not allow the repowering of existing clean energy or natural gas resources to qualify to meet the procurement requirements. Given that there are resources that will enter retirement age in the late 2020s and early

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[13] *See* D.23-02-040 at 21.

[14] *See* D.23-02-040, Ordering Paragraph 13.

[15] *See* D.23-02-040 at 19.

[16] *See* D.23-02-040, Ordering Paragraph 10.

2030s, parties were also asked to comment specifically on whether repowering should be eligible to count toward "new" resources requirements, including recommendations for how such resources should be verified (given that the CAISO rarely reissues new resource identifications or updates commercial online dates for repowering, which could make compliance verification challenging).

2.2.1. Comments of Parties

In general, most of the CCAs advocate for a technology-agnostic order, as does Calpine, esVolta, EDF, CESA, AReM, ACP-CA, CalWEA, and SCE. Parties also argue that the resource adequacy slice-of-day (SOD) requirements will drive procurement that is aligned with load.

EDF argues that the Commission should specify the need for clean firm resource procurement, particularly those resources which provide consistent output, including geothermal. Fervo agrees. BAC argues that the Commission should order firm and dispatchable procurement. CLEU argues for at least ten percent DERs, whereas GreenGen argues for resources that can provide output over many hours/days.

Ultimately, CAISO, NextEra, IEP, CEJA/Sierra Club, REV, GreenGen, and PG&E all advocate that this procurement order should have the same resource requirements as the MTR requirements.

Several parties also commented on whether resources with energy-only deliverability status should be eligible to count toward any requirements. SCE, AReM, SCPA, TNC, and CEJA/Sierra Club advocate for allowing energy-only resources to count if they are co-located with storage.

LSA/SEIA and SCPA advocate for broader eligibility of energy-only resources in the resource adequacy SOD framework to more realistically represent their ability to meet charging sufficiency requirements across the system. LSA/SEIA and SDG&E also advocate that the Commission work with CAISO to study the resource adequacy program's charging sufficiency requirement, with the goal of allowing energy-only solar to count towards charging sufficiency for storage within the local capacity or transmission zone where the solar is located, and not just for a co-located storage facility.

REV advocates that energy and storage that are contractually paired should be allowed to count towards the requirements in this order. SCPA/PCE and ACP-CA advocate for general eligibility of energy-only resources in the order, without requirements for co-location. CalWEA and LSA/SEIA suggest allowing interconnection customers that fail to obtain deliverability to convert to energy-only status, rather than being eliminated from the queue. CalWEA and NextEra note that there is currently not much demand for energy-only resources because of program and eligibility rules. UCS argues that resources with deliverability status should continue to be required to meet any capacity component of a procurement order, but energy-only resources could help meet any energy component. CAISO and Fervo emphasize a general need for an order to ensure charging sufficiency.

On eligibility of repowering, AReM and ACP-CA advocate for incremental repowers to count. SDG&E also advocates for repowering, and SoCalGas advocates for the eligibility of gas repowers and gas resources overall.

2.2.2. Discussion

In general, we do not find justification to deviate from the previous MTR procurement resource eligibility requirements, which include that the resources must be zero-emitting and/or RPS-eligible. Only new resources (online after

January 1, 2020[17]) will qualify to meet the procurement requirements in this order. The rules around baseline swaps,[18] baseline waivers,[19] and obligation swaps[20] will also be extended. Resources fueled by natural gas or any other fossil fuel will not qualify for the procurement required in this decision.

For repowering, we will also leave the rules in place that govern MTR procurement, because no party provided a compelling justification to change the rules. Thus, a resource may be repowered, but only the incremental capacity that is added over and above the original resource capacity will count towards the procurement requirements herein. This also applies to modifications or upgrades to baseline resources, where only capacity added over and above the original baseline value will be eligible to be counted toward procurement required in this decision.

As to energy-only contracts, we find justification to allow hybrid projects and limited additional eligibility for projects where the generation and the storage are co-located and the storage is fully deliverable. This means that multiple separate resources with distinct CAISO identification numbers may qualify as long as they have the same point of interconnection on the CAISO system. This definition also aligns with the resource adequacy program eligibility under SOD requirements. Other arrangements that are otherwise contractually paired will not be eligible, largely due to the difficulty involved in verifying deliverability and charging sufficiency, for purposes of attributing increased reliability benefits.

[17] *See* D.23-02-040 at 21.

[18] *See* D.23-02-040, Ordering Paragraph 13.

[19] *See* D.23-02-040 at 19.

[20] *See* D.23-02-040, Ordering Paragraph 10.

2.3. Energy Procurement (instead of, or in addition to, Capacity)

In the ALJ Ruling, the required procurement amounts were also proposed as effective capacity amounts, in units of NQC-ELCC, consistent with past orders. Also in past orders, the Commission required staff to post the MTR-ELCC valuations for each technology type. Similarly for this decision, Commission staff proposed in the ALJ Ruling to determine the ELCC valuation for each technology and each tranche of procurement. It is important to note, for example, that as additional storage is added to the system, there may be a question about the need for energy resources to generate sufficient additional electricity to charge the storage. Parties were thus specifically requested to comment on whether generic capacity requirements would be sufficient or whether there should be a required energy component of the procurement. Further, parties were asked to weigh in on whether energy procurement, if required, would be best accomplished through the RPS program or a separate IRP requirement.

2.3.1. Comments of Parties

More than twenty parties commented on this issue in their response to the ALJ Ruling. About half of the parties support focusing on capacity procurement requirements only and not requiring an energy component. Many of those parties suggest that a capacity framework provides LSEs with necessary flexibility to procure the least-cost, best-fit resources tailored to their specific resource needs. CalCCA, SDG&E, and SCE add that the RPS and resource adequacy programs already drive procurement of clean energy generation. CalCCA explains that the SOD framework requires LSEs to meet a charging sufficiency requirement to demonstrate that energy storage resources can be fully charged and discharged to meet the resource adequacy program's planning standards.

CESA argues that a separate energy-based requirement would be redundant because the marginal ELCC values inherently capture both capacity and energy constraints. REV argues that there is insufficient evidence of a system-wide shortfall of energy. Thus, a capacity-only target maps cleanly to reliability modeling and avoids pre-selecting technologies. CAISO, IEP, and SDG&E all argue that it is important to stay consistent with prior MTR orders.

These parties who are against requiring a separate energy procurement requirement also largely argue that the SOD framework better captures both capacity and energy needs, ensures alignment between IRP and resource adequacy programs, and provides more accurate, long-term planning signals than marginal ELCCs, which are very volatile. These arguments were made by, among others, CalCCA, AReM, Calpine, and LSA/SEIA.

Roughly the other half of parties commenting on this issue support including an energy component to the requirements for various reasons and to varying degrees. Most of these parties are concerned about the decline in ELCC values of stand-alone storage. PG&E, ENGIE, and CalWEA argue that heavy reliance on storage without sufficient renewable generation threatens energy availability during critical hours. ACP, Vote Solar, LSA, and SEIA argue that including an energy component would ensure that storage has adequate charging energy, especially from zero-carbon sources. ACP-CA concurs in reply comments, explaining that the entire rationale for a procurement order is to address the risk that there may not be sufficient signals to LSEs to procure necessary resources.

Further, ENGIE, CEJA/Sierra Club, and UCS argue that without explicit energy targets, LSEs may under-procure renewables because the RPS requirements have largely already been met. CEJA/Sierra Club and MGRA argue that an energy component connects procurement directly to GHG reduction goals and reliability needs, which is important.

Parties in support of including an energy procurement requirement generally argue that the SOD framework is incomplete, untested, and costly. These parties generally prefer the ELCC framework or a traditional resource adequacy approach, which provides clearer market signals and better manages existing resources. SDG&E also argues that updated incremental ELCCs will reflect reliability contributions accurately, whereas SOD is duplicative of resource adequacy functions and unnecessary in the IRP context.

PG&E argues that any procurement requirements should have an energy component and suggests that the procurement order should include a requirement for at least 50 percent of the capacity come from generating resources, to mitigate energy insufficiency risks and stabilize ELCCs.

Parties also commented on the idea of ordering energy procurement through the RPS program, instead of in this proceeding. Supporters of this idea believe that adjusting RPS program requirements would be the simplest and fairest way to spur an accelerated buildout of clean energy, but close coordination with IRP would be required. UCS emphasizes that the LSEs are collectively behind on clean energy procurement and that accelerating RPS requirements would be simple and fair, recommending increasing RPS targets to 60 percent by 2028, 70 percent by 2029, and 80 percent by 2030, to allow LSEs to adjust, while bridging gaps until other programs, including RCPPP, are fully implemented. Reid also supports using the RPS mechanism.

Most other parties opposed ordering additional energy procurement through the RPS program. PG&E argues that relying on the RPS program does not necessarily incentivize projects to achieve CAISO deliverability status, and thus could negatively impact reliability. Calpine, CEJA/Sierra Club, GreenGen, ICP, and AReM variously argue that the RPS framework is too narrowly focused and cannot adequately capture the capacity, duration, and flexibility contributions from non-RPS resources such as pumped storage hydro (PSH), compressed air energy storage, and other clean-firm technologies.

GreenGen further argues that the IRP is the only proceeding capable of addressing system reliability, resource adequacy, and portfolio diversity on a technology-neutral basis, while specifying the deliverability requirements of new resources. CalCCA, ACP-CA, Vote Solar, PG&E, and SDG&E concur. CalCCA also argues that to the extent that an LSE needs to procure additional clean energy to achieve RPS compliance, the Commission can presume that the LSEs will seek to satisfy its RPS needs and IRP procurement order needs by procuring a new clean energy resource that satisfies both requirements. CalCCA states that there is no need to place an entity under "double jeopardy" by issuing multiple penalties for the same deficiency.

TURN argues that the RPS program should not be relied on for near-term incremental energy needs because there is no guarantee that such an approach would yield additional resources, meaning that increased RPS obligations could be met by banked or existing procurement rather than through the addition of new generation. MRP agrees, as do LSA/SEIA, ACP-CA, and PG&E in reply comments. ACP-CA also mentions the risk of multi-year delays, due to the RPS program timeline. SCE, SDG&E, CalCCA, and CalWEA also argue that expanding RPS at this time could also conflict with ongoing RCPPP development, or lead to potential duplication or misaligned incentives, procurement inefficiencies, or unintended market consequences.

Finally, CalCCA, MRP, and AReM argue that an RPS-based allocation approach may not align with individual LSE portfolio needs, whereas the IRP framework allows for tailored, system-aligned procurement.

2.3.2. Discussion

On the question of whether to require energy procurement along with capacity procurement, the Commission encourages LSEs to procure a balanced portfolio and avoid an over-reliance on any one technology. In recent procurement, we observe that LSEs found battery storage to be a very attractive resource, both because of its declining costs, as well as its modular nature and ability to be developed and brought online quickly. However, we caution against overreliance on battery storage or any other particular technology. Federal tariff policy may be having a negative impact on the battery storage market, due to the rising cost of components. In addition, the resource adequacy SOD requirements and the other RPS requirements would tend to encourage LSEs to procure more energy-generating resources naturally instead of more battery storage. However, because all of these changes are occurring relatively recently, it is not entirely clear how solicitations and procurement will play out in light of new market trends.

To help avoid over-reliance on storage and support developing the resources that can adequately charge the storage on the system for reliability purposes, we will adopt a variation on the proposal PG&E put forward in its comments in response to the ALJ Ruling. Instead of requiring 50 percent of the resources procured to meet the requirements of this order to be energy-generating, we will instead cap the amount of capacity that can come from storage resources at 50 percent. This will achieve the same purpose, but will have an easier verification process. Thus, the procurement requirements of this order will still be expressed in capacity terms (MW or GW), but only 50 percent or less of the allocated proportional share of capacity, per procurement tranche, may be from energy storage projects.

Having determined that we will not require a specific amount of energy generation to comply with this order, we do not need to conclude whether to use an RPS mechanism or a regular IRP procurement order to requiring energy generation. Parties' comments remain instructive for our deliberations on the nature of the long-term procurement obligations as we move forward.

2.4. Local Procurement

The ALJ Ruling did not propose any requirements for local reliability procurement, but some parties requested this in their comments.

2.4.1. Comments of Parties

CCSA, CEJA/Sierra Club, REV, Vote Solar, EDF, and LSA/SEIA, argue for local capacity area procurement requirements to be included in any procurement order. Specifically, CEJA/Sierra Club suggest prioritizing areas with disadvantaged communities and where storage can replace the need for natural gas plants on a one-to-one basis. CEJA and Sierra Club suggest that at least 1,000 MW of energy storage and 1,000 MW of clean energy generation should be targeted to local areas.

CalCCA and SCE argue against a local capacity requirement, stating that it will drive up costs. Calpine also states that a local procurement requirement should not be assigned without a demonstration of need. AReM similarly argues that more study would be needed before requiring local procurement. Finally, ACP-CA argues that the resource adequacy central procurement entities should be the ones doing local procurement.

2.4.2. Discussion

On this issue, given the timeframe in which we are considering this procurement, we agree with CalCCA and SCE that it would be ill-advised to adopt a specific local procurement requirement in this context because it would likely increase costs and make procurement more difficult. However, we encourage LSEs to pursue procurement in local areas where it makes sense for their portfolios. We also intend to continue to evaluate the need for local solutions in IRP planning and procurement in general, as well as in the context of local capacity need evaluation in the resource adequacy proceeding.

2.5. Need Allocation

The ALJ Ruling proposed that the allocation of need to each LSE should be based on each LSE's share of the managed peak on the electric system as of the resource adequacy program year 2026 and the energy load forecasts for IOUs and CCAs, in the same basic manner as the procurement requirements were allocated under the MTR and Supplemental MTR orders. LSE requirements were proposed to be based on each LSE's year-ahead resource adequacy forecasts for 2026.

The ALJ Ruling also described other options that could be considered, including requiring procurement by the investor-owned utilities (IOUs) on behalf of all LSEs, with costs allocated via the Cost Allocation Mechanism (CAM). An argument for this approach could be to maximize the opportunities to take advantage of expiring tax credits. In addition, an argument could be made that having a smaller number of LSEs in the market to procure could simplify the task.

Parties were asked to comment on the centralized procurement approach in response to the ALJ Ruling.

2.5.1. Comments of Parties

Very few parties commented on the proposed primary allocation method in the ALJ Ruling, based on load forecasts and resource adequacy peak load. Shell specifically takes issue with allocating any procurement requirements to the ESPs until the cap on direct access load is lifted. AReM argues that allocation should be determined through a workshop followed by public comments. CESA argues for allocation based on a "contract baseline method" rather than using the MTR baseline, which would give credit for past procurement progress. CalCCA and MRP generally argue for share of peak load, which is an element of the ALJ Ruling proposal.

On the concept of having IOUs centrally procure on behalf of all LSEs, around twenty parties commented on this, with most parties opposing the idea. Most parties argue that LSEs should procure their own resources individually, for a variety of reasons. Calpine argues that most of the available resources are easy to contract in small increments, and therefore do not require centralized procurement. CPA and MGRA argue that central procurement could result in inconsistency with LSE portfolio needs, leading to market inefficiencies. MRP and MGRA argue that central procurement would hinder the ability of LSEs to tailor their portfolios to their customers' needs. CalCCA similarly argues that central procurement would lead to non-optimization of LSE portfolios.

CalWEA and EDF both simply state that centralized procurement is not necessary to achieve the proposed resource procurement. PG&E fears that central procurement could hinder progress and undermine the reliability goal of the order in the first place. Shell argues that central procurement has not been shown to reduce costs or improve reliability. REV also argues that individual LSE procurement creates more market competition, which can improve cost efficiency.

A few parties supported the idea of central procurement in their comments. LDES Council argues for central procurement for the technologies included under AB 1373. AReM argues that LSEs should be allowed to voluntarily opt in to centralized procurement by DWR as the backstop entity for LLT procurement. AReM also argues that central procurement is reasonable because it mitigates equity issues in spreading procurement responsibility for load growth, allows for allocation of procurement costs to new large loads via CAM, and avoids leaving out LSEs who may endeavor to procure as ordered but are unable to due to market unavailability. GreenGen suggests that any central procurement structure should be voluntary and transparent, functioning to facilitate options for resources that cannot otherwise aggregate sufficient offtake through bilateral or joint solicitations. Vote Solar argues that there should be backstop procurement authorized if it becomes apparent that some LSEs cannot meet their obligations. Reid suggests that LSEs should be allowed to opt out of central procurement, if it is ordered. SCE argues that for MTR procurement, the Commission required all LSEs to procure their proportional share and did not allow opting out. SCE supports this logic for any additional procurement.

2.5.2. Discussion

We generally support the principle that each LSE should be responsible for procuring electricity resources to serve its own load, unless there is a compelling reason to order centralized procurement for logistical or cost reasons. In the case of the need found for LLT resources in D.24-08-064, there was a compelling rationale for LSEs taking a collective risk on new resources that may be more costly or difficult to develop than standard already-commercialized resources. In the case of the procurement required by this decision, we are expecting generally available and commercialized technologies to be procured. LSEs always have the option to jointly procure, if the amounts necessary for each individual LSE are small and easily aggregated. Thus, we do not see the need for the Commission to require centralized procurement for the capacity need identified in this decision. Instead, we will allocate this procurement responsibility to each LSE.

We understand the point made by Shell and others that the direct access percentage of load is capped as a proportion of the total load. However, that does not mean that load served by ESPs is not also growing, like the load of LSEs in total. Thus, we decline to exempt ESPs from the need to procure their proportional share of the additional capacity found to be needed in this order.

As proposed in the ALJ Ruling, we will allocate LSE procurement responsibility for the 6,000 MW NQC on the basis of each LSE's share of the managed peak on the electric system as of the resource adequacy program year 2026, and taking into account the energy load forecasts for the IOUs and CCAs, in the same basic manner as the procurement requirements were allocated under the MTR and Supplemental MTR orders. The proportional allocations will be rounded to the nearest whole MW amount.

Attachment A to this decision contains the allocation (rounded to the nearest whole MW) of procurement responsibility to each LSE for each tranche (2030 and 2032), except that the ESPs are shown collectively. Individual ESP assignments are to be kept confidential and will be transmitted individually by Commission staff to each ESP within two weeks of the effective date of this decision.

The ESP allocations are calculated by dividing the individual ESP's year-ahead adjusted peak resource adequacy forecast for 2026 (for month 9) by the total/aggregate year-ahead adjusted peak resource adequacy forecasts for 2026 (for month 9) for all Commission-jurisdictional LSEs.

2.6. Compliance and Enforcement

The ALJ Ruling proposed that compliance and enforcement processes mirror those under the MTR and Supplemental MTR orders. First, new resources to meet the compliance requirements would be required to be online by June 1 of each year where procurement is required, via an annual tranche, and under long-term contracts of at least ten years in length. Second, the baseline would be identical to the original baseline for D.21-06-035, which builds upon the baseline originally set in D.19-11-016. Third, resources would be counted based on a set of incremental ELCC values to be published by Commission staff. Alternatively, the ALJ Ruling noted that the Commission could extend the existing ELCC values from 2028-2032, though they may overstate the value of four-hour storage, but compliance obligation simplicity could offset the lost precision in ELCC valuation. Next, the ALJ Ruling proposed that any excess procurement in response to the MTR and Supplemental MTR requirements would count toward any additional procurement required by this decision. Finally, the ALJ Ruling proposed that non-compliance would be penalized at the net cost of new entry (CONE) for any amount of ELCC MW that an LSE is short in a given year. Compliance was proposed to be assessed on an annual basis.

The ALJ Ruling noted that even if the Commission orders procurement with a certain compliance regimen, other programs, including resource adequacy, RPS, and a potential RCPPP, could end up being more binding constraints on LSE procurement.

2.6.1. Comments of Parties

Every party making comments agreed that any excess MTR or Supplemental MTR procurement by an LSE should count toward the LSE's requirements from this decision requiring new procurement. Most parties did not comment on the ten-year contracting proposal. REV and Hydrostor do request that the Commission make it clear that this requirement is still in place, to give developers confidence and the ability to bring the resources online by the deadlines.

A number of parties were concerned with the way capacity accreditation would work under a procurement requirement. Generally, MRP, SoCalGas, Calpine, CAISO, CEJA/Sierra Club, PG&E, SCE ACP-CA, EDF-NA, CESA, REV, and GreenGen were in favor of using ELCCs to accredit resources for compliance purposes. ACP-CA specifically argues for "firm" ELCCs that the market can plan around. CAISO supports using marginal ELCCs and states that an effective PRM does not incentivize LSEs to acquire new capacity. SCE supports using the 2028 ELCCs already produced; REV prefers an updated ELCC analysis. PG&E supports using marginal ELCCs only for this order, and thereafter using the SOD framework as part of an adopted RCPPP framework.

CalCCA, AReM, and the Joint Solar Parties (in reply comments) prefer using the SOD framework to count for compliance with the procurement in this decision. CalCCA states that if the decision adopts an ELCC framework instead, it should account for charging sufficiency for storage and fix ELCCs in advance, to optimize procurement.

Separately, CalCCA specifically requests that the compliance flexibility rules in D.25-09-007 apply to any procurement ordered in response to the ALJ Ruling. This effectively would mean LSEs would have up to three years of flexibility to bring resources online after the due date, if LSEs have signed contracts and are otherwise compliant with their resource adequacy obligations.

2.6.2. Discussion

In this decision in general, we intend to keep compliance as simple as possible by remaining consistent, wherever possible, with MTR and Supplemental MTR requirements already in place and familiar to LSEs and stakeholders. Thus, we will continue to require that the new resources come online by June 1 in the year in which they are required (this means contracted to begin deliveries and actually delivering energy to the grid) and that they be under a contract that is a minimum of ten years in length. Any LSEs with excess resources procured to meet MTR or Supplemental MTR requirements may use them to satisfy the requirements of this decision, as long as they otherwise meet the criteria specified herein.

On the issue of resource accreditation, we will use a marginal ELCC approach for accreditation of resources for compliance with the procurement required herein. This should not be read as any indication of the direction the Commission may take with the design of the RCPPP, if adopted in R.20-05-003. That consideration is independent of the requirements of this order, and the Commission will fully weigh the pros and cons of a marginal ELCC approach compared to using the resource adequacy SOD framework for resource accreditation under RCPPP. However, for purposes of the procurement required by this order, resources will be counted using marginal ELCCs, in the same manner as for the MTR and Supplemental MTR procurement.

We are not convinced that the 2028 marginal ELCCs already published will be appropriate to use for procurement due in 2030 and 2032, however. It seems likely that the values will be outdated, but without conducting a new study, we will not know by how much. Therefore, we will ask Commission staff to complete a new ELCC study to develop values for 2030 and publish it in final form by no later than July 31, 2026. Then, for the second 4,000 MW tranche of procurement required to be online by June 1, 2032, Commission staff will complete and publish a new ELCC study for the year 2032 by no later than December 31, 2027. The timing of these two ELCC studies should give LSEs sufficient time to procure and develop resources before the June 1, 2030 and June 1, 2032 deadlines for the first and second set of resource procurement deadlines under this decision.

Because the procurement required in this decision will be in two tranches over a period of between five and seven years from now, we will not extend the compliance flexibility offered in D.25-09-007 to the procurement required herein. That is, there will be no three-year flexibility for bringing resources online by showing resource adequacy compliance and executed contracts, in order to be deemed compliant with the 2030 and 2032 procurement requirements. The total 2,000 MW NQC due in 2030 and the 4,000 MW NQC due in 2032 will be assessed based on whether the resources are online, contracted to begin deliveries, and delivering to the grid as of those dates, with no further grace period or other alternative compliance mechanisms, except that LSEs may use the baseline swap, baseline waiver, and/or obligation swap processes laid out in D.23-02-040, if applicable to their particular circumstance and approved by the Commission in the required advice letters applicable to the processes.

Thus, any LSE that fails to deliver the requisite new capacity by June 1, 2030 and June 1, 2032 will be found non-compliant and subject to a financial penalty of the net CONE value. Compliance will be assessed separately for the 2030 requirements and the 2032 requirements.

We will also maintain the backstop procurement mechanism option associated with D.21-06-035 and D.23-02-040. The Commission will assess the need for backstop procurement based on the compliance filings on June 1, 2030 and June 1, 2032.

Finally, we will maintain the semi-annual procurement compliance filing deadlines articulated in D.23-02-040. The compliance filings will continue to be due on June 1 and December 1 of each year between now and June 1, 2032, unless otherwise modified by the Commission.

3. California Independent System Operator Transmission Planning Process Recommendations

This section discusses the staff recommendations for electricity resource portfolios to be transmitted to the CAISO for their annual TPP that were contained in the ALJ Ruling, parties' comments on those recommendations, and the final recommendations to be transmitted to the CAISO for the 2026-2027 TPP.

3.1. Modeling Assumptions

Prior to recommending a base case portfolio, as well as any sensitivity portfolios, every year Commission staff update numerous assumptions on which the analysis of the portfolios is based. Since releasing the Draft 2025 Inputs and Assumptions document,[21] there were several high-level policy changes, in addition to various changes to resource-specific assumptions.

First, the modeling takes into account the impacts of recent Federal action, including:

[21] The Draft 2025 Inputs and Assumptions document is available at the following link: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/2025_draft_inputs_and_assumptions_doc_20250220.pdf.

- The FY 2025 Congressional Reconciliation Bill (also referred to as the One Big Beautiful Bill Act (or OBBBA) that has impacted tax credit assumptions for impacted technologies, including wind, solar, and other resources; and
- The introduction of wide-ranging tariffs, applying across numerous trading partners, impacting every technology, with special impact on technologies dependent on imports from China and Southeast Asia.

Not included in the changed assumptions used for the analysis presented in this ruling, but on the horizon and being monitored are impacts related to:

- Anti-Dumping and Countervailing Duties (AD/CVD); and
- Foreign Entities of Concern (FEOC).

Guidance from the Treasury Department and Department of Energy, respectively, were not published in time to ensure sufficient review and incorporation of these issues into the updated modeling inputs.

For the updates to the tax credit assumptions, the model assumptions include ending tax credits for wind and solar projects that fail to commence construction by July 4, 2026. Energy storage and clean-firm technologies retain tax credit eligibility through 2032, as well as safe-harboring provisions and the three-year phase-out previously established in the Inflation Reduction Act of 2022.

For the tariff assumption changes, current tariff policy is assumed to last through 2029, reflecting historical precedent and maintaining consistency with how IRP modeling has treated similar assumptions in previous modeling efforts. U.S. trade policy impacts by technology were estimated by assessing the supply chains of imported components by country and applying the latest tariff rates (as of July 2025) to the proportions of projects' capital expenditures attributed to those imports, with the awareness that many of the assumptions are likely fluid.

The analysis concludes that tariff impacts are largest for solar and lithium-ion battery storage, which source most of their components from China and Southeast Asia. The analysis also assumes that solar developers will be able to adapt their supply chains to avoid AD/CVD penalties. The staff analysis also notes that the battery energy storage supply chain is uniquely dependent on imports from China, which is subject to some of the highest tariffs overall under current policy.

The resulting weighted average tariff for onshore wind is 29 percent, utility-scale solar photovoltaics is 70 percent, and battery storage (lithium-ion) is 122 percent. As noted earlier, this impact on battery storage costs does not consider the fact that China has been flagged as a FEOC. Under preliminary guidance, battery storage developers will need to demonstrate that the majority of their capital expenditures are not sourced from Chinese suppliers, or else risk forfeiture of federal tax credits. These impacts were not yet captured in the analysis presented in the ALJ Ruling.

In addition, wind resources are also affected by recent federal policies delaying or cancelling projects sited on federal land or seeking federal permits. The near-term onshore wind pressures are factored into the base case onshore wind development, but some consideration of impacts on extended offshore wind development timelines are also included in the recommendations for the base case portfolio. The recommended 2026-2027 TPP sensitivity portfolio considers the impact that federal policy could have on both onshore and offshore wind development. Regardless of federal policy changes, it is important to note that offshore wind is not optimally selected in least-cost modeling and its inclusion in recent TPP portfolios relies on previously-planned LSE resources included in their individual IRPs filed in 2022. In addition, the supply chain for wind turbines is assumed to be relatively insulated from many of the recent federal policy measures.

Other updates to the RESOLVE inputs for the 2026-2027 TPP include:

- Updates to the solar, wind, and near-field enhanced geothermal systems (EGS) resource potential;
- New transmission cost adders for out-of-CAISO wind and geothermal resources in Northeast California and the Imperial Valley;
- Full representation of Deep EGS on CAISO transmission deliverability constraints; changes to the retention costs of existing thermal units; and
- Corrections to the offshore wind hourly generation profiles.

3.1.1. Comments of Parties

Numerous parties made specific comments about the modeling assumptions, including about the RESOLVE model itself, transmission constraints, load forecasts, build limits, cost assumptions, and resource-specific assumptions.

Concerns about the RESOLVE model include AReM advocating to use the SERVM model to investigate whether RESOLVE's low marginal ELCCs are accurate. EDF-NA suggests constraining RESOLVE and SERVM assumptions to align with current resource adequacy rules. NextEra supports the RESOLVE model updates to disaggregate zonal topology and match RESOLVE zones to CAISO study areas.

On the topic of transmission constraint assumptions, AReM comments that the level of new-resource build within the base case is infeasible due to transmission constraints and would strain ratepayer affordability. AReM also argues that imports during peak demand hours should be based on an analysis of available imports, not an arbitrary 4,000 MW cap.

NextEra is particularly concerned with the East of Pisgah area, arguing that transmission constraints there are unreasonable and inconsistent with busbar mapping principles. They recommend forcing in a new 500 kilovolt (kV) line to be built in the 2036 timeframe, along with assuming that the new 500 kV Lugo-Victorville line is built by 2036. NextEra urges the Commission to work closely with the CAISO to accelerate the transmission solutions for Path 15 and Path 26 and to incorporate advanced grid technologies as part of the optimal long-term strategy.

SCE supports the addition of Path 26 upgrades as candidate resources in RESOLVE. SCE also recommends additional potential transmission corridor upgrades, expansions, and new build be included in future iterations of RESOLVE. PG&E agrees and specifically requests that Path 15 upgrades be considered for future iterations. Vineyard agrees, and is specifically concerned that Central Coast wind is being overvalued compared to North Coast offshore wind, because of the lack of modeling of the Path 15 South-to-North constraints. Invenergy disagrees with this, however, arguing that any potential limitations imposed on Central Coast resources by the Path 15 constraint will also limit North Coast transmissibility to any load centers below the constraint.

Several other parties had specific comments on load forecasts and the availability of imports. ACP-CA argues that maximum import capability requests from LSEs should be incorporated into modeling earlier. ACP-CA also argues that the availability of uncontracted/unspecified imports should be reduced or eliminated. VoteSolar further explains that data centers could locate in lower-cost states such as Oregon and Arizona, plus hydroelectric availability is impacted by drought conditions; both situations would reduce the availability of surplus generation to export to California from those states.

AReM states that the demand forecast reflects too high an estimate of data center load growth. Shell also suggests that the load forecast is uncertain and reliance on it is flawed.

Other parties comment on build rate assumptions. Fervo states that geothermal build limits should align with commercial development and build limits on out-of-state Deep EGS should be removed. NextEra comments that annual build limits on in-state wind through 2030 are a reasonable proxy, but post-2030 build limits are still too high and unsupported. NextEra includes discussion of local moratoria, California condor protections, fire threats, and military training routes. CalWEA disagrees, focusing on the fact that several wind developments are currently in progress, including fully contracted projects, demonstrating market viability. CalWEA also specifically refutes NextEra's comments point by point, arguing that NextEra's conflict maps are overly broad. CalWEA also notes that out-of-state wind projects face similar hurdles in terms of Federal policy changes compared to California wind projects. PG&E, SCE, and GreenGen all state that build rates in general are overstated and should be better grounded in historical performance and market data.

On the topic of portfolio cost assumptions, several parties had specific comments. EDF suggests that the forthcoming Western regional electricity market is likely to result in a reduction in the cost of out-of-state generation. GreenGen suggests that certain key assumptions are optimistic and risk overstating the near-term build feasibility and understating the costs of the portfolios. OWC suggests that the offshore wind cost assumptions should include a greater anticipated reduction as deployment increases globally. Fervo points to the NREL ATB binary advanced case as the correct source for EGS cost assumptions.

Several parties also commented on assumptions related to solar and storage resources. Form requests that we more specifically analyze the transmission-related benefits of LDES and multi-day storage, guided by updated marginal ELCCs. LDES Council also states that the modeling did not include the full benefits of multi-day LDES. NextEra recommends that resource selection be geographically diverse and robust to changes in solar cost and resource performance assumptions, noting potential changes in cost assumptions that could drive major portfolio differences.

Some parties also expressed concerns about the wind resource assumptions. CalWEA states that the complex approach used by staff underestimates capacity factors of wind in at least some areas. CalWEA argues that the net capacity factor for Northern California wind resources should be 30-35 percent, instead of the staff-calculated 26 percent. Invenergy suggests using the existing offshore wind leases in the planning assumptions. Vineyard is also concerned about the reduction in capacity factors for offshore wind on the North Coast. SCE agrees with extending the online date assumptions for offshore wind, but urges annual reexamination of these assumptions.

Other parties commented on the assumptions related to natural gas capacity retention. CRC suggests adding 1-2.5 GW of carbon capture and storage (CCS) projects to the portfolio, given that retrofits are easy, quick, affordable, mature, and scalable to meet GHG goals. Calpine and PG&E also suggest modeling CCS projects as candidate resources. IEP agrees, and comments that the Commission should not assume that all MTR procurement is achieved. CEJA and Sierra Club argue that natural gas cost assumptions should be updated to reflect the increased costs of contracting seen in the resource adequacy benchmark data, reliability must-run contract expenses, increasing methane fuel costs, and non-energy costs. CRC disagrees with CEJA and Sierra Club, arguing that the resource adequacy prices do not reflect underlying cost increases, but rather market supply and demand.

Numerous parties also commented on the impact of Federal policy on the assumptions. CalWEA suggest that we should assume that wind and solar tax credits will be restored by 2029, noting that Congress has retroactively restored tax credits many times in the past. Invenergy agrees and would prefer that assumptions about federal tax policy not be embedded in modeling beyond 2028. DOW recommends planning for low-conflict siting of renewables to avoid potential federal conflicts. MGRA recommends frequent re-assessment of assumptions based on changing Federal policy.

3.1.2. Discussion

As is typical in each annual TPP cycle, parties have suggested numerous changes and improvements that are not feasible to be implemented in the timeframe available to us before transmitting the TPP portfolios to the CAISO for analysis, based on their tariff deadlines. However, also as in previous years, we intend to take into account parties' constructive suggestions for use in future TPP cycles and other analyses.

The particular suggestions we are interested in exploring for next year's TPP include the addition of Path 15 upgrades to be considered in future iterations of RESOLVE, similar to the addition of Path 26 upgrades this year. This is a critical transmission corridor that has large impacts on the ability to transfer electricity between the Northern and Southern parts of the state. Thus, we will ask staff to work on this improvement.

We also continuously evaluate our import assumptions to take into account changing conditions relative to historical patterns. We generally agree with AReM that the import assumptions should be based on recent patterns in imports, but would not go so far as ACP-CA suggests to eliminate availability of imports for modeling purposes. Similarly, we will continuously update our assumptions relative to load growth projections, particularly as they relate to data center development and electrification. In addition, we also agree with PG&E, SCE, and GreenGen who suggest historical analysis of build rates for various types of resources, to inform those limits in the modeling. We will reevaluate those assumptions for next year's TPP as well. Also in the category of ongoing evaluation will be assessment of Federal policy impacts on the portfolio in general.

With respect to specific resource assumptions, there are two in particular to which we will pay close attention. The first is the capacity factor for onshore wind. In addition, we will ask staff to prioritize modeling CCS projects as candidate resources for the next TPP cycle, as this technology appears to be becoming a more viable option that should be modeled and evaluated.

Finally, we will continue monitoring progress toward MTR requirements, in order to ensure that future TPP portfolios reflect the reality of LSE procurement as much as possible.

3.2. Base Case Portfolio

The ALJ Ruling presented a proposed base case portfolio for the 2026-2027 TPP that includes approximately half of the upper bound of the LLT resources considered for central procurement by DWR in the need determination adopted in D.24-08-064, per AB 1373 (Stats. 2023, Ch. 367). The proposed base case in the ALJ Ruling included the new resource amounts shown below in Table 6. Table 6 includes values for model years 2031 and 2045, even though those results are not required for CAISO TPP analysis. The proposed base case also retains the amount of offshore wind that LSEs reported in their November 2022 individual IRPs and as was included in the 2025-2026 TPP base case portfolio. However, the proposed 2026-2027 TPP base case assumes that the 2.9 GW of offshore wind in Morro Bay would come online by no later than 2036 rather than 2032, and that the 1.6 GW in Humboldt would come online by no later than 2041, rather than by 2035.

The recommended base case portfolio intends to provide the CAISO information it needs to study the transmission needed for the other non-offshore-wind resources that are needed in the nearer term in California.

Table 6. New Resources Included in 2026-272 TPP Proposed Base Case (in GW)

Resource Type	2031	2036	2041	2045
Natural Gas	-	-	-	-
Geothermal	1.2	3.4	3.4	3.4
Enhanced Geothermal	-	1.7	1.7	1.7
Biomass	-	-	-	-
In-State Wind	2.0	2.6	4.8	7.7
Out-of-State Wind	5.5	7.0	17.0	19.0
Offshore Wind	-	2.9	4.5	4.5
Solar	35.9	47.5	53.7	68.5
Li-ion Battery (4-hr)	6.8	6.8	6.8	6.8
Li-ion Battery (8-hr)	10.0	13.2	13.2	18.6
Location-Constrained Storage (12-hr)	1.6	5.4	5.4	5.4
Generic LDES (12-hr)	-	-	-	-
Generic LDES (24-hr)	-	0.5	0.5	0.5

Resource Type	2031	2036	2041	2045
Generic LDES (100-hr)	-	-	-	-
Shed Demand Response	-	-	-	-
Gas Capacity Not Retained	(1.7)	(1.7)	(1.7)	(1.7)

3.2.1. Comments of Parties

In comments in response to the base case portfolio recommendation, numerous parties showed general support in their comments, including CAISO, GSCE, EDF-NA, CEJA/Sierra Club, REV, GreenGen, SCE, SDG&E, GridLiance, and LSA/SEIA. CEJA and Sierra Club generally support the base case recommendation, particularly the decision to model the possibility that half of the LLT capacity is delayed to 2031. GridLiance agrees with the Commission's assessment of the limited in-state wind buildout in the base case portfolio. GreenGen supports the adoption of the recommended base case, but recommends incorporating into the base case transmission deliverability for LLT resources that is freed up from the delay of offshore wind development. SCE agrees with extending the online date assumptions, but urges Commission staff to update the assumptions annually. CalWEA, in reply comments, agrees with CEJA and Sierra Club support of the base case, but points out that onshore wind energy, even without tax credits, has been and continues to be one of the most affordable clean energy resources.

Numerous parties disagree with the idea of delaying transmission planning to support offshore wind on the North Coast beyond 2036. CalCCA suggests maintaining the amount of in-state and offshore wind in previous TPP portfolios to maintain consistency and limiting out-of-state wind in the base case to the amounts supported by the SWIP-North, TransWest Express, and Sunzia transmission lines. EPIC suggests that North Coast and Central Coast offshore wind should be projected to come online at the same time.

OWC states that delaying online dates for transmission planning could jeopardize timeline-specific offshore wind goals; OWC suggests that federal permits could be delayed for several years but the online dates in 2035 could still be achievable. Vineyard is concerned that pushing back the offshore wind online dates sends mixed signals to the market about the Commission's commitment to clean energy and incorporating offshore wind in the portfolio. EDF is also concerned that the offshore wind industry is at an inflection point, and the change in assumptions for online dates could cause a significant chilling effect that would not be in the interest of ratepayers. CalGrid also argues against pushing back the online dates for offshore wind, in part due to the need for other resources, including geothermal and in-state wind, to utilize the transmission being developed to serve the offshore wind projects. Vineyard argues that the shift in the online date for North Coast wind fails to capture the Humboldt (transmission) Projects' timeline, which are on track to begin delivering power in the mid-2030s.

CalGrid also argues that the CAISO agreements for the Humboldt Projects include provisions not to incur any major costs in connection with the transmission development without the express written approval of the CAISO, which CalGrid states will ensure that the transmission facilities can continue to move forward, with protections in place for ratepayers before major expenditures are made.

ACP-CA and Oceantic also want to keep the North Coast wind assumption to being online by 2036, while Invenergy, in reply comments, argues that North Coast wind cannot feasibly come online in the mid-2030s. RCEA and

Humboldt County question why North Coast offshore wind development is delayed by six years, while Central Coast is delayed only by four years.

CalWEA states that planning for only 4.5 GW of offshore wind by 2041 leaves no room for additional development by 2045 in order to achieve economies of scale on cost. NRDC is concerned that changing the assumptions is premature and unsupported.

Several parties argue for alternative treatment of offshore wind in the 2026-2027 base case portfolio. CUE and CURE suggest retaining the online dates used in the 2025-2026 base, but planning for various resource options to ensure that California has the necessary resources and transmission infrastructure to get the resources online no matter the uncertainty, including development of the Valley Clean Infrastructure Plan.

Several parties argue that the base case should include even higher penetrations of various LLT resources, including offshore wind and multi-day storage, including NRDC, Oceantic, EDF, LDES Council, Invenergy, Mainspring, and SBUA. NRDC would include the full amount of LLT resources in the D.24-08-064 need determination, because the first tranche of procurement will be more expensive on a per-unit basis than subsequent tranches, and the full amount is needed to bring about economies of scale and cost reductions. EDF agrees in reply comments. Also in reply comments, SBUA suggests that this is important also for purposes of making optimal use of transmission and port investments.

Oceantic also suggests that including the full amount of the D.24-08-064 need determination in the base case is important to maintain a signal of continuity. Invenergy suggests that the Commission retain the full need determination of 7.6 GW of LLT resources in D.24-08-064 in the base case, or the potential for up to 10 GW of offshore wind.

On the opposite end of the spectrum, some parties argue that there should not be any resources forced into the RESOLVE model. WPTF recommends excluding any planned DWR procurement, as no such procurement has yet taken place. CESA suggests that the base case should align with the least-cost comparison portfolio or, at a minimum, one that avoids forcing in the offshore wind volumes. PG&E prefers that the base case be based on the least-cost portfolio. In reply comments, CalWEA agrees with PG&E and CESA about the realistic ability of offshore wind to come online in the previous timeframes, and recommends that the Commission postpone the decision for at least a year on this question.

A number of parties proposed alternative portfolios to use as the base case portfolio. CalCCA recommends modifying the base case portfolio to use a more conservative forecast of data center load, to minimize the risk of building transmission for load that may not materialize. Vote Solar disagrees in reply comments, noting that there are countervailing trends that suggest that the proposed base case portfolio may actually underestimate the need for new reliability resources.

CalCCA also suggests maintaining the amount of in-state and offshore wind included in the previous TPP base case, but limiting out-of-state wind due to the CAISO's stated challenges with out-of-state wind integration. CalWEA would replace the offshore wind capacity with in-state, onshore wind capacity, to maintain the resource diversity provided by wind energy without excessive reliance on out-of-state wind.

CalGrid recommends distributing the offshore wind resources more evenly across the North Coast and Central Coast areas in 2036, given that the Humboldt Projects have already been approved in the CAISO's previous TPP. They argue this would also provide optionality in the event that DCPP remains operational, thereby reducing transmission capacity available for Morro Bay offshore wind.

SCPA and PCE suggest adopting the Limited-Wind Sensitivity portfolio as the base case, because the proposed base case relies too heavily on both out-of-state and offshore wind resources that are highly speculative. Reid agrees, and both EPIC and ACP-CA disagree, in reply comments.

CEJA and Sierra Club argue that the base case portfolio should include significant reductions in natural gas generation to comply with SB 887 (Stats. 2022, Ch. 358). CalWEA agrees in reply comments.

AReM generally argues that the Commission should model and adopt portfolios with reasonable levels of resource build to reduce the cost of the portfolios for consumers.

Several parties also argue that the GHG emissions targets should be altered in the base case. Cal Advocates argues that the Commission should model a new portfolio with a GHG emissions target of 30 MMT by 2035 en route to an 8 MMT target by 2045. Further, Cal Advocates would test the reliability of that portfolio in SERVM and add resources, if necessary, to meet the 0.1 LOLE target.

AReM suggests that the base case should not have more aggressive GHG emissions reduction targets than current legislative requirements. PG&E suggests that the Commission reconsider whether the rationales underlying the 30 MMT target in 2030 continue to hold. SCE supports this view in reply comments. SDG&E also states, in reply comments, that the Commission should adjust the GHG target to 38 MMT in 2035 to mitigate the need for an improbably high solar buildout.

Parties also raised various resource-specific concerns. Calpine argues generally that the base case portfolio should include a more diverse set of resources.

CalWEA argues that the 2.6 GW of in-state wind in 2036, down from 7.9 GW in 2035 in the 2025-2026 TPP base case is too low. Meanwhile, CalWEA suggests that the Humboldt Projects for transmission should be put on hold because the likelihood of achieving even 2.9 GW of offshore wind by 2036 is low.

BAC points out that there is no biomass capacity included in any of the portfolios, even though biomass is required by multiple state laws. RCEA and Humboldt County point out that biomass capacity should be included to help mitigate wildfire risk, especially in Humboldt County, where biomass is abundant. CalGrid, in reply comments, further argues that biomass facilities could use the transmission that will be made available by the Humboldt Projects.

In reply comments, Mainspring argues that the base case should include "firm zero-emitting ready" generation like green hydrogen resources.

Several parties also express concern about assumptions including high penetrations of solar resources in Arizona. DOW argues that the base case is overly-reliant on Arizona solar and there should be greater emphasis on in-state solar in the San Joaquin Valley. TNC and Cal Advocates make similar arguments, and CBD agrees, in reply comments. Also in reply comments, DOW argues that heavy reliance on out-of-state resources defers approval of needed in-state infrastructure that will be critically needed should out-of-state resources fail to materialize and meet expectations.

GridLiance also questions an "unreasonably" high concentration of solar in Arizona. PG&E recommends that the Commission cap the amount of Arizona solar at an amount that can be feasibly imported into the CAISO system, given that new out-of-state transmission is considerably more challenging to plan for than in-state transmission. CalWEA agrees in reply comments and notes that in-state wind is an important resource to meet GHG targets.

3.2.2. Discussion

To begin our consideration of the appropriate base case portfolio, we emphasize that the purpose of this scenario is for prudent transmission planning. Each year, the Commission studies a portfolio of resource attributes that the state could develop to cost-effectively and reliably serve load and meet state GHG emissions reduction goals, which the CAISO studies in its annual TPP cycle for least-cost system planning for incremental transmission needs. For this cycle, we choose this base case portfolio as a realistic portfolio for purposes of transmission studies.

In light of recent changes in Federal policy, the Commission's TPP portfolio will reflect some extensions to resources, including for offshore wind, compared to our expectations last year. The assumptions proposed in the ALJ Ruling included Central Coast offshore wind coming online by no later than 2036, and North Coast offshore wind by 2041. It is important to note that this does not mean the entire volumes in each location would be delayed completely until those dates. Rather, the projects, or a portion of them, may come online on the Central Coast during the period 2032 through 2036, with North Coast projects taking slightly longer and coming online between 2036 and 2041. We note that CAISO's latest analysis states that, even with DCPP online, approximately 3,000 MW of Central Coast offshore wind could be accommodated using current transmission capacity.[22] The longer timeline for the North Coast is due primarily to the transmission upgrades needed to deliver those projects to load.

We note that parties provided a number of generally conflicting comments about the proposed base case. There are inherent tradeoffs no matter which base case we choose. In general, we do not wish to make changes to the load forecast assumptions for the base case, because it is important to maintain continuity and the principle that we base our load assumptions on the most recent IEPR load forecast. Since the load forecast is updated every year, this is an assumption that is under constant reevaluation, but we will not further deviate from it in choosing a base case. Consistent with SB 350 (Stats. 2015, Ch. 547), the Commission uses the GHG reduction targets established by the California Air Resources Board (CARB) in our IRP processes. Thus, we will stay the course with the 25 MMT target in 2035 and 8 MMT by 2045, as the emissions reduction trajectory.

Thus, we find that the proposed base case in the ALJ Ruling that includes approximately half of the AB 1373 LLT resources for which need was found in D.24-08-064, achieves a reasonable balance among the various options recommended by parties, and will result in usable transmission planning information, which is the ultimate purpose of the base case.

This leaves the situation where offshore wind on the Central Coast is assumed to come online between 2032 and 2036, with North Coast offshore wind expected to arrive between 2036 and 2041. The Humboldt transmission projects currently have in-service dates of June 1, 2034, and some parties have suggested

[22] CAISO 2024-2025 Transmission Plan at 19.

that if the offshore wind generation projects come online later, the transmission potentially could or should also be delayed. After consideration of the generation timelines in the base case, we agree that extending the in-service date for the Humboldt transmission projects is reasonable and would still have transmission available for when offshore wind generation is anticipated to begin to become available. Thus, we recommend to the CAISO that they allow the potential in-service dates for the Humboldt transmission projects to extend out to June 1, 2036.

There are several types of ratepayer protections proposed for the Humboldt transmission projects, as explained in the CAISO's public selection reports identifying CalGrid, a wholly-owned subsidiary of Viridon Holdings, LLC, as the approved project sponsor for both projects. We also expect there will be additional opportunities to reevaluate the transmission projects before construction commences, after at least one solicitation has been held for offshore wind generation projects, as called for in D.24-08-064.

In addition, in D.25-02-026, our decision recommending the 2025-2026 TPP portfolios, for the first time we recommended that the CAISO reserve transmission deliverability for several types of LLT resources, including geothermal, biomass, offshore wind, out-of-state wind, in-state wind and non-battery LDES. The CAISO largely implemented these recommendations, with two exceptions. First, biomass was assessed to be too locationally diffuse for deliverability to be specifically reserved. Second, in-state wind was not deemed to have a long lead time by the CAISO.

In comments, stakeholders have expressed difficulty in bringing locationally-sensitive technologies online and argue that many LLT resources benefit from deliverability reservations. The CAISO has also demonstrated willingness to include technologies for deliverability due to the lack of presence in the queue and their importance to meet reliability and resource diversity needs. Thus, for the most part, we will continue our recommendations for transmission deliverability to be reserved in this year's TPP. Specifically, we recommend that deliverability be reserved for all of the in-state geothermal resources selected in the base case, as well as all of the non-lithium-ion-baterry LDES. For out-of-state wind and offshore wind, we request that the amount of deliverability for these resources be reserved based on last year's final reservations made by the CAISO, rather than the amounts selected this year in the base case. This is mainly to preserve some optionality for other resources to achieve deliverability in the event that not all of the out-of-state and offshore wind resources materialize. We will maintain the prior TPP's recommended reservation levels to support consistency and signal resource interest, without locking out other potential resources entirely. The recommended levels, compared to previous recommendations, are shown in Table 7 below. In addition, we note that out-of-state wind transmission needs, in particular, are still undergoing additional analysis from last year's TPP.

Table 7. Recommended Transmission Deliverability Reservations by Year (in MW)

Resource Type	2024-2025 TPP (2034) Reserved	2025-2026 TPP (2035) Recommended	2025-2026 (2035) TPP Reserved	2026-2027 (2036) TPP Mapped	2026-2027 TPP (2036) Recommended
Biomass	-	171	-	-	-
Geothermal	950	1,639	1,639	5,105	2,265
LDES	-	1,264	1,264	5,448	5,448
In-state wind	-	5,589	-	1,743	-
Out-of-state wind	6,096	5,700	6,096	7,036	6,096

Resource Type	2024-2025 TPP (2034) Reserved	2025-2026 TPP (2035) Recommended	2025-2026 (2035) TPP Reserved	2026-2027 (2036) TPP Mapped	2026-2027 TPP (2036) Recommended
Offshore wind	3,855	4,531	4,531	2,924	4,531

Finally, returning to the selection of the base case, we note some parties' concerns about specific resource issues and assumptions. The issue we are most concerned about is the assumed solar build rate to achieve the base case. We also understand the concerns about the concentration of resources, particularly solar, outside of California and agree with parties who point out that those resources may be more difficult to develop, particularly because they require additional transmission development. Planning for those transmission resources is already underway with the results of past TPP analyses, and adopting this base case for 2026-2027 will maintain continuity and hopefully continue to move those transmission planning efforts forward.

3.3. Sensitivity Portfolio

The ALJ Ruling recommended that the Commission transmit one sensitivity portfolio to the CAISO for study in the 2026-2027 TPP. The recommended sensitivity portfolio is a Limited Wind Sensitivity, designed to reflect the recent increased difficulty of permitting wind projects in California and the recent changes in Federal policy toward wind projects. The sensitivity is intended to study how transmission needs would differ if recent PSP portfolios and prior TPP portfolios change over time to include fewer wind resources for reasons generally outside of California's control. Table 8 summarizes the new resource buildout results for the recommended sensitivity portfolio, including forced-in, LSE-planned, and RESOLVE-selected resources, above and beyond the RESOLVE modeling resource baseline.

In the recommended sensitivity portfolio, in-state wind development is limited to 2.5 GW, out-of-state wind is limited to the amount available on existing transmission where the CAISO has rights, and offshore wind is excluded. These assumptions result in the portfolio selecting all of the conventional geothermal potential, as well as a significant amount of EGS. Solar and storage resources are also selected at very high levels, and the portfolio includes a smaller amount of natural gas retirement.

Also included in the ALJ Ruling were two other potential sensitivity portfolios that were evaluated but not recommended. The first was a DCPP Extension Sensitivity, which modeled DCPP as receiving a 20-year extension through 2045. The second alternative sensitivity portfolio set GHG reductions to 25 MMT of emissions in 2035, and then held the target constant until 2045.

Table 8. New Resources Included in Proposed 2026-2027 TPP Sensitivity Case (in GW)

Resource Type	2031	2036	2041	2045
Natural Gas	-	-	-	-
Geothermal	1.2	3.4	4.7	5.6
Geothermal (enhanced)		3.6	3.6	3.6
Biomass				
In-State Wind				
Out-of-State Wind	4.0	4.0	5.1	5.1
Offshore Wind	-	-	-	-
Solar	37.5	48.6	67.6	83.2
Li-ion Battery (4-hr)	6.8	6.8	6.8	6.8
Li-ion Battery (8-hr)	12.1	17.7	17.7	26.9
Location-Constrained Storage (12-hr)	1.6	5.7	7.5	7.5
Generic LDES (12-hr)	-	-	-	-

Resource Type	2031	2036	2041	2045
Generic LDES (24-hr)	-	-	-	-
Generic LDES (100-hr)	-	-	-	-
Shed Demand Response	-	-	-	-
Gas Capacity Not Retained	(1.2)	(1.2)	(1.2)	(1.2)

3.3.1. Comments of Parties

Many parties either support or do not object to the proposed Limited Wind Sensitivity portfolio. GreenGen, GSCE, SDG&E, and EDF-NA support the proposed sensitivity portfolio. CAISO also supports the recommendation, stating that it will ensure system reliability and alignment with state goals, if increased solar, storage, and geothermal development is required. MRP supports the intent of the sensitivity portfolio, but notes the unrealistic build rates for other resources caused by the lack of wind development. AReM does not object, but is also concerned about the total resource build being potentially unreasonable.

TNC, VoteSolar, and DOW support the analysis of the Limited Wind Sensitivity, in light of recent Federal policy shifts.

SCE supports the development of the Limited Wind Sensitivity portfolio, but is concerned about the significant difference in the post-2035 out-of-state wind buildout between the proposed base case and sensitivity cases.

SCPA and PCE suggest that in addition to assessing the limited wind availability in the sensitivity portfolio, the portfolio should also be tested for increased load, limited geothermal and PSH availability, and higher resource costs.

GridLiance supports conveying a sensitivity portfolio to the CAISO with limited wind development, in part because it would substantiate what

GridLiance characterizes as the critical need to address transmission constraints in the Victor-Lugo corridor.

LSA and SEIA endorse the characterization of the Limited Wind Sensitivity as a plausible alternative to the base case scenario and encourage the CAISO to approve no-regrets transmission upgrades that can serve both portfolios.

In contrast, several other parties do not support the Limited Wind Sensitivity. EPIC does not believe it is a realistic alternative portfolio and therefore does not support studying it. OWC states that the Limited Wind Sensitivity contradicts state policy, is not a "least regrets" strategy, and is flawed because RESOLVE has faulty cost assumptions for offshore wind, failing to account for anticipated long-term cost reductions in the coming decade as more offshore wind is deployed.

Invenergy argues that the portfolio is not reasonable and the impacts to the portfolio due to Federal policy are not durable and planning for them to be so will prevent the selection of necessary transmission upgrades.

Calpine does not support the sensitivity recommendation, instead arguing that the Commission should study limited amounts of wind, solar, and storage to better understand how other resource types could meet clean energy goals. PG&E also does not support the sensitivity portfolio, because the increased solar build rates in it are even less feasible than the current base case.

ACP-CA states that it cannot support either a Limited Wind Sensitivity or the Diablo Canyon Sensitivity that was also considered but not recommended by Commission staff.

CalWEA strongly opposes the proposed Limited Wind Sensitivity, arguing that the analytical basis for it is entirely lacking and that it would add almost

$11 billion in costs by 2045 at a time when electricity affordability is already a major state concern.

CEJA and Sierra Club suggest that the Commission work to remove obstacles to wind development rather than plan for its failure. They argue that wind is still more affordable than other resources and the capacity is valuable. Rather than running the Limited Wind Sensitivity, CEJA and Sierra Club recommend studying another sensitivity with high natural gas retirements. EDF agrees in reply comments, though does not oppose the Limited Wind Sensitivity. They also suggest running such a scenario, with updated assumptions, every 2-3 years, incorporating results from previous "high gas retirement" portfolio analysis.

Several other parties suggested alternative lower-cost sensitivity portfolios to be studied instead of the recommended Limited Wind Sensitivity. MGRA suggests simply studying the least-cost portfolio. CalWEA recommends a sensitivity where Federal tax credits are restored in 2029, to inform whether to include higher levels of in-state wind in the 2036 portfolio.

TNC supports west-wide energy resource sharing and regionalization, and suggests studying a scenario where regional renewable investments are pursued.

CalCCA suggests studying a scenario that has a combination of high wind penetration and high data center load. PCE recommends studying a high distributed energy resource (DER) scenario, to determine how much it could lower portfolio and transmission costs. CCSA agrees in reply comments.

CRC recommends including carbon capture and sequestration in the portfolio instead of studying the scenario where GHG targets are relaxed after 2035, in order to lower costs while still achieving GHG goals.

PG&E disagrees with the assertion that the Diablo Canyon extension sensitivity portfolio would not be useful for the CAISO or the Commission. They argue that the results of modeling this scenario would be informative to understand the reduction in transmission upgrades required as compared to the base case portfolio. Calpine supports this viewpoint in reply comments. ACP-CA responds to these comments by suggesting that there be a sensitivity portfolio that examines the transmission upgrades necessary to accommodate both DCPP remaining online through 2045 and the addition of the clean energy resources included in the base case, particularly Central Coast offshore wind.

3.3.2. Discussion

One of the most important reasons to ask the CAISO to study a sensitivity portfolio is to learn information about the transmission needs of the portfolio that would otherwise go unidentified in studying the base case portfolio. In the past few years, the Commission has asked the CAISO to study portfolios that explore transmission needs both in the absence of certain resources (*e.g.*, natural gas generation) as well as in the event of an abundance of certain resources (*e.g.*, offshore wind).

The staff-recommended Limited Wind Sensitivity under consideration for the 2026-2027 TPP is another portfolio that would study the absence of a certain resource (wind energy generally) with the purpose of understanding the transmission needs that would arise in that circumstance. Of the potential sensitivity portfolios evaluated, the Limited Wind Sensitivity represents the portfolio that would provide the most information about transmission needs. The Diablo Canyon scenario is not as helpful for transmission planning as it is for creating an opportunity to compare the mix of resource attributes that would be selected with extended inclusion of an existing, clean, firm resource that utilizes existing transmission. In addition, the alternative sensitivity portfolio where the GHG target would be held steady after 2035 would also not tell us a great deal about transmission needs.

Thus, for this year, we find it reasonable to ask the CAISO to study the Limited Wind Sensitivity portfolio. This represents a portfolio that could result from recent Federal policy changes. We note that a better outcome would be continued robust development of all types of cost-effective wind resources that are needed to serve load and meet state goals, especially since wind can provide resource diversity and provide a higher capacity resource to meet increasing winter loads in the outer years of the planning horizon. We also note CalWEA's comments that the Limited Wind Sensitivity portfolio is estimated to be a lot more expensive than the base case, but we are recommending it for study by the CAISO because it is a useful portfolio to analyze potential transmission planning needs.

It is important to understand how even near-term policy changes at the Federal level could slow wind deployment and result in the need for contingency planning. We agree with LSA and SEIA that it will be interesting to evaluate the transmission resources that are identified both for the base case and for the Limited Wind Sensitivity portfolios, and we encourage the CAISO to place increased emphasis on developing any transmission projects identified that are needed for both portfolios.

For transmission planning beyond the 2026-2027 TPP, we will consider other parties' recommendations for other sensitivity portfolios to be analyzed.

3.4. Addressing High Solar and Storage Build Rates Implied in Base Case and Sensitivity Portfolios

The ALJ Ruling noted that both the recommended Base Case and Sensitivity portfolios include a massive amount of solar, and to some degree storage, buildout between now and 2045. Given recent development pace, it could take extraordinary efforts to achieve the build rates implied in both portfolios. Numerous parties addressed this challenge in their comments and had suggestions for how to approach it.

3.4.1. Comments of Parties

More than 25 parties addressed this issue in their comments and presented a diverse set of potential actions that could be taken. We have grouped the potential solutions into eleven different categories described below.

The first set of actions relates to reforming and expediting transmission, interconnection, and permitting processes. The majority of parties commenting in this category suggest simply approving more transmission development. SCPA and PCE request more expansive transmission investments from the CAISO through robust portfolios and "right-sizing" that allows more flexibility for resources to interconnect. GSCE recommends approving the solar capacity amounts identified in the ALJ Ruling and relaying to the CAISO the need to approve the associated transmission. LSA and SEIA recommend that the Commission and CAISO establish a process allowing CAISO to conditionally approve transmission upgrades based on the highest projected resource buildout levels, to the extent allowed by the CAISO tariff. Terra-Gen recommends increasing deliverability to the East of Pisgah area and promoting projects with shorter development timelines. CalWEA agrees in reply comments. TNC suggests evaluating expanding existing transmission capacity with advanced transmission technologies, in addition to building new lines, particularly when planning projects connecting Southern California solar to Northern California load. TNC focuses on studying where transmission can be upgraded to make use of existing and future solar resources. ACP-CA states that the high solar build rate is achievable and emphasizes that timely transmission development is key for achieving it.

For the second set of actions, many parties comment in favor of selecting more distributed solar rather than utility-scale solar. CCSA recommends studying a new sensitivity portfolio that includes dispatchable FTM load-modifying solar and storage projects connected to the distribution grid, to more fully examine the extent to which load-modifying DERs, inclusive of their avoided transmission and distribution benefits, can be part of a least-cost portfolio. CEJA and Sierra Club suggest a high DER sensitivity to identify potential tradeoffs between distributed solar deployment and associated demand-side tools compared to utility-scale resources, due to permitting uncertainty associated with utility-scale resources. DOW similarly urges the forced selection of distribution-connection solar, arguing that it would mitigate land-use limitations and avoid transmission and interconnection delays. VoteSolar brings up the role that virtual power plants and hybrid solar and storage projects interconnected to the distribution grid can play in meeting GHG emissions reduction targets. LSA and SEIA point out the additional benefits of reduced congestion, reduced curtailment, and resource adequacy, particularly with respect to hybrid projects with solar and storage on the same site. TNC generally supports continued study of how to accelerate and maximize deployment of solar on developed land, including distributed solar, in a cost-effective manner. GSCE specifically urges support for the Valley Clean

Infrastructure Plan for 20 GW of solar, up to 20 GW of battery storage, and a new 500 kV transmission project in Fresno County.

The third set of actions generally involves selecting a more diverse portfolio. Form emphasizes that high solar build rates reflect the need for better modeling of long-duration and multi-day storage to turn intermittent solar into dispatchable energy and capacity. NextEra argues for greater portfolio diversity across regions and resource types. Calpine argues that CCS retrofits and other clean firm resources should be incorporated into the portfolio. CalWEA seeks to ensure that the 1.6 GW of wind capacity planned for development in the Baja California area by 2032 is included in the base case analysis. Several parties also note concerns with relying so heavily on an out-of-state solar buildout when in-state resources, such as offshore wind, would be preferable.

For the next set of actions, some parties suggest relaxing the GHG targets, while other parties oppose this idea in reply comments. Cal Advocates suggests redesigning the base case portfolio to focus on a GHG emissions reduction to 30 MMT by 2035 rather than 25 MMT. PG&E suggests assuming a feasible build rate for solar (based on historic levels) and then relaxing the GHG constraint, to determine what emissions levels would result. In reply comments, SCE opposes these suggestions, because they would delay necessary infrastructure investments that are necessary for future reliability and climate goals. SCP also argues that backing off of GHG targets now will only make future portfolios even less achievable. SDG&E generally argues that the Commission has the discretion to select a higher GHG target that would result in a less costly buildout, but DOW opposes this and urges the Commission to stay the course, while utilizing more distributed generation and storage solutions.

A few parties suggest managing and/or reexamining load growth in order to reduce the need for so much resource procurement. AReM suggests using a reduced load scenario while also reassessing the availability of imports to meet needs. AReM would prefer that the GHG targets not go beyond statutory requirements. CEJA and Sierra Club suggest managing data center load growth through large load tariffs. Calpine recommends not relying on a potentially "inflated" load forecast and an "unlikely" DCPP retirement assumption.

Two parties suggest increasing the procurement of storage with energy-only deliverability status, as one potential solution. LSA and SEIA argue that energy-only solar is quicker to develop and less transmission-constrained. They suggest that the Commission work with the CAISO to allow interconnection projects that fail to achieve full deliverability to be converted to energy-only status, to avoid being eliminated from the interconnection queue. LSA and SEIA also suggest working with the CAISO to study the resource adequacy program's charge sufficiency requirement, with the goal of allowing energy-only solar to count towards charging sufficiency for storage within the local capacity area or transmission zone where the solar is located, not just for co-located facilities. GreenGen makes this same point in its comments. In addition, LSA and SEIA suggest bridging the gap between transmission development and offshore wind operations and avoiding stranded transmission assets by allocating energy-only resources to areas where transmission was approved for offshore wind, to address the uncertainty around solar build rates and advance transmission upgrades.

LSA and SEIA also support PG&E's observation that the Diablo Canyon Extension sensitivity is the only portfolio which includes a solar build rate from 2028-2031 that falls within the historic range, demonstrating that DCPP's extension to 2045 would not only solve high near-term solar build rates, but also reduce reliance on out-of-state wind and eight-hour storage, reduce emissions from natural gas, and potentially allow for retirement of additional natural gas units.

LSA and SEIA also suggest prioritizing projects for expedited development that can take advantage of expiring Federal tax credits.

IEP suggests that the Commission and other state agencies coordinate their efforts and increase staffing to meet statutory times for processing.

Finally, a number of parties suggest addressing the short-term build rates of solar by issuing a procurement order to procure more resources sooner. MGRA suggests that the staff analysis shows a need for a procurement order in the near term. EDF-NA suggests that the 6,000 MW need shown in the ALJ Ruling, if ordered for procurement, would be a step toward long-term confidence. SCPA and PCE recommend ordering procurement that allows energy-only projects to contribute to the need and to SOD resource adequacy requirements. UCS recommends raising the RPS requirement higher in the near term.

3.4.2. Discussion

The numerous suggestions of parties described above lead us to consider a number of potential portfolio configurations that could be evaluated in future TPP cycles.

With the exception of the Diablo Canyon extension and relaxed GHG emission targets scenarios, which we evaluated above and have decided not to recommend for the 2026-2027 TPP, many other scenarios are not feasible to create in the time left for this year’s portfolio recommendations. However, we intend to consider many of the portfolios that parties recommended, and potentially other scenarios, for the 2027-2028 TPP and/or 2027 Preferred System Plan sensitivity analyses.

We also note that there is a lack of consensus among parties suggesting solutions this year, making it difficult to narrow the options further to one or two portfolios. Next year, we will make efforts to engage parties earlier in the portfolio development process, particularly for sensitivities, because parties continue to raise helpful perspectives that may help inform future portfolio development.

Parties' comments also stressed the importance of several ongoing priorities. The first is continued efforts to reform the transmission, interconnection, and permitting processes, in concert with the CAISO. This includes efforts to expedite the interconnection of projects that qualify for expiring Federal tax credits. Second is reexamining the modeling assumptions that lead to high selection of solar resources (as we do every IRP cycle).

3.5. Busbar Mapping Methodology

Each year, Commission staff build on the methodology used in the previous year to map generation and storage resources to busbars on the transmission system. This locational analysis helps the CAISO, in its TPP analysis, understand the locations needed for potential expanded and/or upgraded transmission. This year, the following methodology updates were recommended in the ALJ Ruling:

Substation-level interconnection criteria

- Integrating Participating Transmission Owner (PTO) feedback and per-unit cost guide data to estimate the economic feasibility to interconnect at individual busbars. Commission staff coordinated with the PTOs to collect and synthesize interconnection data and feedback on:

  - Existing headroom (before transmission plan deliverability (TPD) allocation);
  - Number of available interconnection positions;
  - Upgrade condition; and
  - Available area within the fence line.
- New criteria are initially used for a subset of busbars that have high demonstrated commercial interest and/or have had large mapped total resources from previously-adopted TPPs.
- Data collected from the PTOs is used to estimate interconnection cost for each busbar as a function of PTO, tie-in voltage, and feasibility.
- Substations with higher interconnection costs, including those that would require extensive upgrades or entire substations to facilitate new projects, will be de-prioritized over less expensive alternatives.
- Cost estimates across all busbars are categorized to define thresholds for criteria alignments scores.

<u>Land-use and environmental criteria</u>

- Replacing the Commission's High Fire Threat Districts (HFTD) dataset which is no longer being updated, with the U.S. Department of Agriculture Forest Service (USFS) Wildfire Risk to Communities dataset. To assess the fire threat to resources and transmission:
  - The NFTD maps are outdated and will not be maintained going forward, which makes them poor candidates for use in future busbar mapping cycles.
  - Among the alternative data sources reviewed, the 2024 USFS Wildfire Risk maps are a newly-published dataset from a federal agency with nationwide coverage, making it a viable option to replace the current data source.

   - Commission staff classified USFS burn probability data to align with the busbar mapping criteria alignment levels of 1-5.

<u>CEC land-use screens development and implementation</u>

- Updated methodology and sources of land-use and environmental criteria that information environmental evaluation:
   - The CEC Protected Area Layer, one component of the Land-Use Screens, was expanded to include coverage for CAISO-interconnecting regions of Southern Nevada and Western Arizona.

<u>Commercial development interest</u>

- No specific changes. Commission staff are adding clarification in the methodology document for how interconnection quantity data from neighboring balancing authority areas (BAAs) is used in the commercial interest criteria, due to confusion evidenced in stakeholder comments.

<u>Gas capacity not retained</u>

- Generators located within disadvantaged communities will no longer receive a blanket exemption from non-retention decisions for being among the youngest and/or most reliable units.
- Generators without any local effectiveness factor data from the CAISO Local Capacity Technical Report are now assigned the quartile scoring aligned with the lowest priority for non-retention.

3.5.1. Comments of Parties

Fourteen parties filed comments related to the recommended busbar mapping methodology updates. TNC generally recommends that the interagency busbar mapping working group maintain a public web viewer that displays draft busbar mapping results in their spatial form and allows for the downloading of the same spatial data.

GSCE recommends focusing on in-state transmission development and therefore consider shifting RESOLVE-selected solar from South of Path 26 to the Fresno area.

Several parties expressed specific concerns with the fire threat maps. CalWEA recommends not screening out high-quality wind resource areas based on the updated fire threat maps, because the maps cover too much area to serve as a meaningful screening tool and will de-prioritize most wind resource areas. BAC suggests relying on Cal Fire's fire hazard maps in addition to, or instead of, the U.S. Forest Service maps. NextEra comments that the fire threat maps should be used to assess resource potential and select mapped resources for not only the project site, but also the necessary gen-tie and new transmission sites. TNC supports the use of the U.S. Department of Agriculture Wildfire Risk to Communities dataset to model fire threats, but notes its coarse resolution and suggests that Commission staff review the latest and best available data as part of the next planning cycle, to ensure that the most recent fires and disturbances are taken into account.

Several parties are also concerned about the land-use criteria. CalWEA recommends not screening out high-wind-speed areas where development is legally permissible based on discretionary GIS layers in the CEC's Core Land-Use Screen. CalWEA also provides statistics on how many existing projects would have been screened out by using these GIS layers.

GridLiance and NextEra comment that the effects of the U.S. Bureau of Land Management's (BLM's) Western Solar Plan in Southern Nevada should not be overstated in the land-use screens.

GridLiance generally states that despite recent news suggesting that solar projects on federal lands may face permitting challenges, GridLiance ultimately believes that a development path on federal lands will be found by the 2036 timeframe of this TPP. In the meantime, GridLiance recommends refining land-use screening to align with actual BLM implementation, recognizing partially exempt and variance-eligible projects, and integrating GridLiance's granular mapping into IRP modeling and busbar mapping.

TNC is generally in favor of extending the CEC's land-use screens to areas in Arizona and Nevada. TNC requests that staff include and publish latitude and longitude values in the land-use evaluations spreadsheet provided by the CEC and make available environmental layers, specifically Areas of Conservation Emphasis layers, in the Data Viewer tool for the 2025 Draft Updates of Data for CEC Busbar Mapping Assessment. TNC would also like to reshare the geospatial tool that TNC created to better understand various potential resource and transmission scenarios from a land-use and environmental perspective.

Invenergy and SCE express differing views on the interconnection criteria included in the busbar mapping methodology. Invenergy does not support the change in the substation interconnection ease and feasibility analysis that ties the alignment levels to estimated cost ranges, as it may impose a one-size-fits-all process for evaluating substation interconnection viability, resulting in projects being mis-classified. SCE supports the updates, particularly the integration of PTO feedback and use of per-unit cost guide data. SCE also recommends evaluating new substations and demonstrating how consideration of both existing substation and new greenfield infrastructure upgrades, including assumptions and estimates, was incorporated, to ensure a comprehensive review and mapping process.

Several parties express concerns about the busbar mapping criteria's impact on gas retirement and disadvantaged communities. Calpine supports not including the U.S. Energy Information Administration data major maintenance to prioritize gas retirement. CEJA and Sierra Club recommend eliminating the local effectiveness factors from the gas plant retirement criteria, and strongly agree with eliminating exemptions for gas plants in disadvantaged communities that are in the youngest quartile and the highest effectiveness quartile. In addition, CEJA and Sierra Club suggest including the gas retirements modeled in busbar mapping in the TPP base case or at least the sensitivity case transmitted to the CAISO. CEJA and Sierra Club also support the busbar mapping guidance that biomass and biogas should avoid disadvantaged communities and air quality non-attainment areas. Finally, EDF supports the staff-proposed modifications and also recommends eliminating the blanket exemption for all gas plants, not just those in disadvantaged communities.

Several parties also expressly commented on how the busbar mapping methodology evaluates geothermal and PSH resources. Invenergy generally supports the new criteria. TNC also supports the criteria and encourages staff to resume this work in the next TPP cycle. GreenGen supports the new methodology, with the following recommendations: (1) adopting PSH-specific environmental and commercial-interest screens, (2) linking busbar mapping with deliverability pathways for LLT substitutions, and (3) enabling either-or mapping where PSH can compete directly with eight-hour batteries at specific nodes.

A number of parties also comment on the criteria to inform mapping of geothermal resources, and EGS in particular. SCPA and PCE argue that the RESOLVE model only selected near-field EGS and the Commission should honor that selection by mapping EGS only to nearby known geothermal resource areas. Conversely, XGS argues that the Commission should consider expanding the locations for EGS and use the Stanford Thermal Model to assess resource potential. SCPA and PCE also recommend that the Commission strive to maintain the total capacity of EGS on each side of Path 15 and Path 26.

SCE agrees with the mapping of EGS by Commission staff, but disagrees with the assumption that the EGS capacity potential at each site is the same as the conventional geothermal potential. XGS agrees in reply comments, stating that EGS and next-generation geothermal potential should be higher than conventional geothermal potential.

ACP-CA supports greater inclusion of EGS in TPP modeling and recommends planning for it inside and outside of California. SCE recommends consideration of developing a more detailed sensitivity portfolio for use in a future TPP to explore in-state EGS potential, including potential CAISO transmission upgrades needed to ensure deliverability. XGS agrees in reply comments. Fervo also endorses planning for EGS within California and recommends new data sources.

PG&E also recommends conducting an annual survey among entities with commercial interest in geothermal development to present their new capacity projects for consideration in busbar mapping. Fervo also suggests utilizing the Nevada Power Company interconnection queue, while includes 3.3 GW of geothermal capacity. CEJA and Sierra Club recommend mapping geothermal with community impacts in mind, particularly with respect to earthquakes, water quality, and air quality.

Several parties are concerned with how busbar mapping methodology impacts reserving deliverability on the transmission system. CESA comments that only differentiating between distributed solar and non-distributed solar capacity values prevents distributed storage from receiving deliverability through the CAISO's Distributed Generation Deliverability process, putting it at a severe competitive disadvantage relative to distributed solar. In addition, CESA states that the lack of clarity regarding whether there is, in fact, distributed energy-only capacity at certain substations disqualifies those substations from being assessed in the CAISO's Distributed Generation Deliverability process.

RCEA and Humboldt County argue that North Coast transmission-constrained areas are failing to trigger upgrades necessary to meet local resource development needs. They recommend developing alternative trigger mechanisms to enable deliverability upgrades in underserved areas, especially those regions that are resource rich.

PG&E requests continuing to busbar map PG&E's Helms Uprate Project and continuing to reserve deliverability for the uprate in the 2026-2027 TPP. GreenGen agrees, in reply comments.

Some parties also note concerns with the commercial interest criteria. NextEra recommends commercial viability scores include projects that were withdrawn from the interconnection queue, as well as projects filed but not allowed to enter Cluster 15. PG&E is concerned that primarily using the CAISO transmission interconnection queue as the source of commercial interest relies on circular logic that is not supportable. CalCCA also makes this argument. PG&E suggests finding new ways to forecast commercial interest, particularly in the case of location-constrained generation resources. GreenGen agrees with this in reply comments. GridLiance also points out that reliance on the CAISO interconnection queue is no longer sufficient because of the CAISO's revised study selection criteria, which screen out projects at interconnection points with no deliverability. ACP-CA states that it agrees with parties who identify gaps in the interactions between the CAISO's new interconnection process, the development of TPP portfolios, and associated busbar mapping, which are likely devaluing the development potential and commercial interest in high-quality resource zones.

Several parties also suggest incorporating other data into the commercial interest assessment. NextEra recommends including IRP plan data from the Western Transmission Expansion Coalition and other sources, as well as establishing an open process for developers to assist in addressing any gaps or inconsistencies in the data sets. REV suggests undertaking an annual developer survey to determine areas of interest. GridLiance suggests that site control and interconnection applications (including withdrawn or deferred projects), permitting milestones, offtake discussions or contracts, financing readiness, and development timelines should all be factored into the commercial interest criteria. Fervo also suggests integrating recent Federal permitting timelines, particularly for out-of-state resource assessment. SCE concurs, especially for projects sited partially or fully on BLM land.

GridLiance pushes for greater transparency, arguing that the Commission should work with CAISO to establish a joint process for reporting on constrained regions that reconciles "queue-visible" and "queue-filtered" development activity so that planning signals reflect actual market interest. In addition, GridLiance recommends creating a forward-looking forecast for merchant and zero-deliverability areas that weights documented pipelines and capacity expansions at existing facilities, not just queued projects able to clear the CAISO deliverability gate. GridLiance argues that IRP-mapped resources in areas with zero deliverability should be used as explicit triggers for evaluating cost-effective TPP upgrades.

Finally, MGRA argues that the Commission should evaluate commercial interest in PSH projects based on how far along they are in development. And CEJA and Sierra Club would prefer to prioritize environmental impact criteria over commercial interest.

3.5.2. Discussion

Many of the suggestions in party comments on the busbar mapping methodology represent ongoing areas for improvement and require discussion among the interagency busbar mapping working group. Many of the comments would also require more time to implement than we have available for the 2026-2027 TPP cycle. Several of the suggestions are already under discussion, including the following:

- Creating and maintaining a public viewer that displays draft busbar mapping results in their spatial form and allows for downloading of the data;
- Including the latitude and longitude values in the CEC's land-use evaluations spreadsheet;
- Reviewing and incorporating the most up-to-date, relevant fire threat data available;
- Gathering California and Federal permitting data, particularly in location-constrained areas, to augment the existing commercial interest criteria;
- Revising the geothermal and EGS mapping criteria, to implement better assumptions and data sources, plan for in-state EGS, improve commercial interest assessment, and improve community impact assessment; and
- Continuing improvements to the PSH mapping approach, including additional stakeholder engagement.

Although this work is beginning in the context of the interagency working group, most of these improvements could have impacts in the 2027-2028 TPP cycle and will not be able to be incorporated this year due to time constraints.

Because the TPP process is annual and cyclical, we appreciate parties' ongoing attention to these methodological improvements so that we can continue to improve the process each and every year.

We also intend to ask Commission staff, along with the interagency busbar mapping working group, to devote particular attention to reviewing and refining the commercial interest criteria in time for the 2027-2028 TPP cycle. The Interconnection Process Enhancements that CAISO has made are reducing the number of projects in the interconnection queue, as expected. However, this limits CAISO queue data as a measure of commercial interest. Therefore, the busbar mapping working group is developing new measures of commercial interesting, using California and Federal permitting data, to augment the existing commercial interest criterion. This process began in the 2026-2027 TPP cycle with the analysis of California Environmental Quality Act and National Environmental Policy Act permitting data, and will continue in the 2027-2028 TPP cycle with the implementation of new commercial interest criteria that consider both queue position and permitting data.

We also note that for this year, improvements to the RESOLVE model, in particular to its zonal topology, have lessened the influence of the commercial interest criteria on specific project mapping because resources are optimally selected in regions, instead of needing to be mapped. Trends in the size of the mapped portfolio and the interconnection queue also mean that interagency staff have more ability to allocate capacity for existing commercial interest while also mapping a great deal of capacity to new areas. This year's base case portfolio maps around 50 percent more resources than the 2025-2026 base case. This also means that the amount of capacity informing the commercial interest criteria has fallen and many areas have more resources mapped than currently exist in the interconnection queue. As a consequence, in the 2026-2027 base case, more capacity is being allocated to new areas without existing commercial interest.

3.6. Busbar Mapping Results

Based on the recommended base case portfolio included in the ALJ Ruling, Commission staff undertook a preliminary mapping of the identified generation and storage resources to busbars on the transmission system. This information was presented in a public webinar held on November 12, 2025. A November 3, 2025 ALJ Ruling allowed parties to make specific comments on the preliminary busbar mapping presented by Commission staff.

Parties' comments on the preliminary busbar mapping fell into several categories that are summarized in this section, including: mapping criteria issues; transmission-related issues; volume of resources mapped; offshore-wind-specific issues; import issues; issues related to gas capacity not retained; and specific remapping requests. This section summarizes only those comments where a change was made in response to the party's comment. Other comments will be taken under advisement for future TPP cycles.

3.6.1. Mapping Criteria Issues

Related to mapping criteria, Fervo comments that the commercial interest criteria and analysis should consider more EGS development in Utah and Nevada, because the Nevada Energy queue shows 3.3 GW and Cape Station reports 5 GW. In response, Commission staff initially remapped 290 MW of geothermal from Malin to an alternative tie-in location in Southern California. However, SERVM analysis (discussed further in Section 3.7 below) showed reliability concerns with this remapping, so the resources were moved back to the original location at the Malin substation. Some geothermal was also initially remapped to the Geysers #17 substation due to stakeholder input and the priority of continuing alignment with the 2025-2026 TPP portfolio. However, this created transmission exceedances; therefore, the original mapping was retained.

3.6.2. Transmission-Related Issues

In comments, BAMx suggests providing additional guidance to avoid approving some major transmission upgrades in the 2025-2026 TPP that may not be required based on the proposed 2026-2027 TPP portfolios, specifically the Wilson-Storey-Borden Lines and the Delevan upgrades. In general, we are aiming to be as consistent as possible with prior years' portfolios, and therefore if resources mapped in the 2025-2026 TPP portfolio triggered a transmission upgrade, those resources will likely continue to be mapped this year for consistency. This could include resources that trigger the need for the lines mentioned by BAMx.

SCPA also suggests revisiting the analysis completed in the 2024-2025 TPP to assess the need for mapping additional "unaccounted-for" TPD in Northern California to address the discrepancy between the portfolio's inclusion of new Northern California resources and scarcity of TPD due to the Collinsville-Tesla 500 kV constraint. SCPA suggests not limiting the analysis to TPD related to offshore wind, but also including other resource types including geothermal. "Unaccounted-for TPD" generally refers to TPD that has been awarded by the CAISO to a specific project already in the interconnection queue, but for which there is no corresponding resource in the Commission's portfolio at the same point of interconnection. The busbar mapping process does not include all interconnection requests in the CAISO queue as resources in the portfolio; the queue is used as an indication of commercial interest. TPD is awarded to projects prior to the execution of their generator interconnection agreements. Thus, the projects may not be included in the RESOLVE modeling baseline due to their uncertainty of being developed. This situation may arise when projects lose viability for a variety of reasons, such as inability to secure land.

In response to SCPA's comments, Commission staff are using a new methodology of summing the non-operational prior commitment capacity and the TPD allocated capacity from the TPD report, and then subtracting the mapped FCDS capacities from this sum. Any non-negative deltas from these calculations were identified as unaccounted-for TPD, and this calculation was performed for each transmission constraint involving LLT resources. Commission staff are working with the CAISO to better capture TPD in the busbar mapping dashboard by adding the unaccounted-for TPD across constraints, thus showing the additional transmission upgrades required.

In the 2025-2026 TPP, unaccounted-for TPD was an issue, and we added a certain amount of storage resources with TPD already allocated to the mapped portfolio, to inform necessary transmission capacity to support deliverability of offshore wind resources.[23]

For this year, with respect to transmission needed to ensure deliverability for LLT resources, if the CAISO takes into account all of the storage with TPD and adds LLT transmission needs, there is a risk of overbuilding the transmission system at considerable cost. To avoid this, Commission staff have worked with CAISO staff to identify a preliminary list of constraints where unaccounted-for TPD needs to be incorporated into the 2026-2027 TPP to allow for LLT deliverability reservations. The current analysis on the amount of unaccounted-for TPD needing transmittal to the CAISO is available in the Base Case portfolio tabs labeled "unaccounted for TPD Calculator" and "Unaccounted

[23] *See* D.25-02-026 at 56.

for TPD Summary" and will be included, through further Commission and CAISO staff coordination, in addition to the mapped portfolio resources for study in the 2026-2027 TPP base case at the constraints identified.

Commission staff will continue to work with the CAISO to further refine a standardized policy and methodology for considering unaccounted-for TPD in busbar mapping, as feasible.

3.6.3. Volume of Resources Mapped

Multiple stakeholders, including DOW, GSCE, LSA, and NextEra, advocate for more solar resources to be mapped in the PG&E territory, particularly in the Central Valley. These parties generally assert that true commercial interest for solar is not captured by either the commercial interest or land-use metrics, especially for the PG&E Fresno and Kern study areas. GSCE argues that Fresno is suitable for additional resources due to the lower-implication lands there.

There are two main issues with increasing the amount of solar mapped to the PG&E area, and Fresno in particular. First, mapping more solar causes transmission exceedances due to overlapping constraints in the area. Second, the amount of solar selected by RESOLVE, even without additional remapping requested by stakeholders, already exceeds the amount of commercial interest shown in the dashboard, though in this TPP cycle there are significantly more resources in the base case portfolio than in past cycles, without a corresponding increase in commercial interest. There are several cases in the busbar mapping dashboard where mapping goes beyond identified commercial interest to reach the RESOLVE-selected amount of resources. Mapping at PG&E Fresno goes even further by remapping 2.5 GW of solar resources from SDG&E to PG&E Fresno. This was partially motivated by strong support from multiple stakeholder groups who indicated in their comments that there was solar development interest not captured by the busbar mapping methodology. As noted above, Commission staff are also actively working to improve the commercial interest criteria and hope to introduce these changes in the 2027-2028 TPP, which is intended to increase the amount of commercial interest captured in busbar mapping. Finally, there was stakeholder support for additional solar resources to be mapped to the Central Valley and because PG&E Fresno shows the most transmission upgrades triggered for study by the CAISO compared to the other CAISO study areas, there exists the potential for further solar resource mapping to PG&E Fresno in the future.

NextEra also suggests remapping some of the Arizona solar to East of Pisgah. Commission staff agree with this comment, due to the initial mapping of Arizona solar requiring potentially multi-billion-dollar transmission upgrades.

In response to all of these issues, Commission staff have engaged in strategic remapping of solar resources from the overloaded SDG&E Arizona study area to further optimize the mapping. Accordingly, a total of 8.3 GW of solar from Arizona originally mapped to SDG&E is being reallocated across several areas. Approximately 2.5 GW has been moved to the PG&E Fresno area, 0.5 GW has been moved to the PG&E Greater Bay Area, 3.2 GW has been moved to SCE's area, and 2.13 GW moved to SDG&E Imperial. As part of a transfer of 3.2 GW of SDG&E Arizona solar to the SCE area, 470 MW have been placed in the East of Pisgah area at the Lathrop substation.

This remapping results in ultimately mapping a total of 6.4 GW of solar to PG&E Fresno in 2036 and 7.5 GW in 2041, with 8.0 GW mapped to PG&E Kern in 2036 and 8.5 GW in 2041.

Invenergy also questions the reduction in geothermal capacity mapped to the SCE Eastern study area. A small adjustment has been made in response to this comment by adding 70 MW back to Mirage substation. However, remapping 500 MW, consistent with the 2025-2026 TPP, would set off several transmission exceedances in the area, necessitating further upgrades. Staff did not see those transmission upgrades as critical for investment, given the lack of commercial interest so far at the substation. Geothermal was instead moved to other locations showing more commercial interest and which did not require transmission upgrades. As discussed above, Commission staff will continue to evaluate and update the commercial interest criteria and we encourage stakeholders to submit comments in the next TPP cycle with additional insights. For this cycle, the geothermal resources in Imperial Valley are mapped either to SCE or SDG&E Imperial areas, and staff have ensured that the geothermal totals across both areas are consistent with past TPP base cases.

3.6.4. Offshore-Wind-Specific Issues

Vineyard suggests mapping Humboldt offshore wind only in 2036, or at least clearly directing CAISO to continue advancing the North Coast transmission lines without delay, so that the offshore wind can begin coming online as soon as 2036. This comment has been addressed earlier in this decision in Section 3.2.

3.6.5. Import Issues

LSA suggests remapping resources more evenly among the Arizona solar substations to avoid unintended consequences. As described above, approximately 8.3 GW of solar has been remapped from the Arizona area importing into SDG&E, to avoid unstudied upgrades that are potentially multi-billion-dollar investments. Around 5.5 GW remains in the SDG&E Arizona import area, which is in line with CAISO estimates of current line carrying capabilities. The latest mapping reduces the solar initially mapped to the three Arizona substations by between 60-80 percent, leaving only 500 MW at North Gila. This addresses the point raised by LSA that the amount initially mapped to North Gila far exceeded the amount of available "low implication" land at that substation. The sensitivity portfolio, which contains more solar than the base case portfolio, will restore significant amounts of solar to SDG&E to encourage the CAISO to study the transmission constraints in the region for potential use in future TPP cycles.

3.6.6. Issues Related to Gas Capacity Not Retained

Related to the mapping of specific natural gas plants currently online, Calpine comments that the Delta Energy Center should not be assumed offline, because the initial busbar mapping did not consider the plant's efficiency, functional age (based on major upgrades), and potential for CCS efforts. For this base case portfolio, Commission staff have made the change requested as part of addressing broader methodological issues related to the need to align with RESOLVE's selection of gas technology type not retained. For the next TPP cycle, we will consider modifying the methodology overall for mapping of the natural gas plants not retained, with potential updates to include the unit efficiency, potential for decarbonization, local reliability factors, and repowering and/or upgrade potential.

There are two possible types of gas capacity not retained in the portfolio: capacity that is not retained because it is identified by policies that are forced into the RESOLVE model and do not appear as RESOLVE-selected resources, and RESOLVE-selected generation not retained due to RESOLVE's economic cost optimization. The RESOLVE-selected generation not retained is only identified in aggregate amounts of gas capacity by technology type, but for the TPP studies, individual units need to be identified for non-retention. In identifying which units to model as offline, Commission staff implemented a scoring criteria to developed a prioritized ranking of plants to model as not retained. The scoring included environmental/community factors, performance-related factors, and the local reliability factor. The plants selected are intended to identify transmission needs and impacts, not select specific gas generators to retire, decisions over which the Commission does not have regulatory control.

For this year, RESOLVE identified gas capacity not retained totaling approximately 785 MW of combined cycle gas turbines and 890 MW of combustion turbines (peaking units). Commission staff implemented this non retention in busbar mapping by selecting units that scored the worst on the criteria up to the quantities identified within the zonal constraints required to avoid triggering reliability concerns, supported by the analysis in SERVM discussed in Section 3.7 below. These capacities have been replaced in busbar mapping with generic battery storage up to the quantities identified in the CAISO's 2030 Local Capacity Technical Reports, released in April 2025.[24]

EDF also recommends that the gas capacity workbooks and public materials be updated to more explicitly indicate scores and show the work behind the non-retention decisions, especially for exempted plants. In response

[24] The CAISO Local Capacity Technical Reports are available at the following links: https://stakeholdercenter.caiso.com/InitiativeDocuments/Final-2026-Local-Capacity-Technical-Report.pdf and https://stakeholdercenter.caiso.com/InitiativeDocuments/Final-2030-Long-Term-Local-Capacity-Technical-Report.pdf.

to this comment, Commission staff have updated the materials that are posted on our website.

Commission staff will also continue to refine the process for identifying natural gas units to be modeled as not retained in the next TPP cycle by incorporating additional stakeholder feedback on the methodology.

3.6.7. Specific Remapping Requests

A number of parties raised particular concerns with specific mapping decisions in the preliminary portfolio. LS Power states that corrections are required to accurately reflect the current status of the Manning 230 kV and 500 kV substations. Staff have made modifications in response to this comment, in order to increase alignment with the mapping criteria and provide consistency with the previous TPP base case portfolio.

PG&E requests that the 140 MW Helms PSH uprate project be mapped to the Gregg substation. PG&E also suggests revising the busbar mapping methodology to avoid the scenario in which commercial interest is not accurately reflected due to constraints on entering the CAISO queue and possible limitations on other proposed methodologies such as land-use permitting. Commission staff have discussed the Helms Uprate project with the CAISO and will remap the project as requested, which is consistent with the 2024-2025 and 2025-2026 TPP base cases. This should result in deliverability being reserved for the project, since it is a non-battery LDES project. Commission staff will also revise the treatment of unaccounted-for TPD, as discussed above, which is related to the Helms Uprate project.

3.7. Production Cost Modeling Analysis of Base Case Portfolio as Mapped

As with past TPP portfolios, Commission staff have conducted production cost modeling (PCM) of the recommended base case portfolio for the key years needed by the CAISO for its TPP, to ensure that it meets reliability standards and that the GHG emissions are within an acceptable range. For the 2026-2027 TPP base case portfolio, Commission staff conducted the PCM using SERVM on the busbar-mapped version of the recommended portfolio.

Several modeling updates to SERVM were made prior to conducting the analysis:

- The model was changed to reschedule up to 20 percent of generator maintenance around extreme weather events, to avoid unnecessarily causing reliability problems in winter months in future years.
- Import constraint assumptions were ramped during the hours ending 17 through 22 by adding three steps of 6,330 MW, 4,000 MW, and 8,660 MW, to avoid the sudden change from 11,040 MW down to 4,000 MW, which caused unrealistic dispatch patterns.
- GHG pricing assumptions were revised to be imposed only on in-state emitting units and unspecified imports to CAISO.
- SERVM's storage dispatch logic was revised to operate storage more efficiently and better align with RESOLVE's storage dispatch.
- BTM photovoltaic hourly profiles were improved to better align with those used in the CEC's IEPR demand forecast process.
- Unit mappings were corrected for weather-driven thermal derating of gas and geothermal units.
- One-hour offset corrections to electric demand hourly profiles were implemented.
- Existing units with a monthly NQC were capped at that value.
- Other smaller corrections and debugging were performed to ensure accuracy of model results.

In addition, the model was calibrated to match the 2024 IEPR managed demand forecast from the CEC, including changes to the annual peak and energy forecasts, as well as penetration of demand-side resources.

SERVM modeling was conducted on the portfolio after the resources were mapped to transmission busbars. Busbar mapping considers transmission and interconnection constraints in more detail than the RESOLVE model and incorporates changes to siting of new resources between SERVM regions compared to the raw RESOLVE results.

Table 9 presents the key metrics for the recommended base case portfolio, including LOLE and GHG emissions from various sources (in-CAISO generation, unspecified imports, and BTM CHP). The table includes comparisons of GHG emissions metrics from RESOLVE and SERVM. Table 9 shows the SERVM results for 2036 and 2041, which reflect the more optimal busbar-remapping of new resources mentioned above, that prioritizes placement in the PG&E sub-region. Table 10 shows the same metrics, but for the portfolio outputs taken directly from RESOLVE, prior to busbar mapping. Table 10 is provided for comparison purposes. In both tables, the RESOLVE results are identical and reflect the RESOLVE results of the portfolio before busbar mapping.

Table 9. Reliability and GHG Results in Key Planning Years for Proposed 2026-2027 TPP Base Case After Mapping to Busbars on the Transmission System

Metric	**2036**		**2041**		**Units**
Model	**RESOLVE**	**SERVM**	**RESOLVE**	**SERVM**	
LOLE	***NA***	***0***	***NA***	***0.084***	***days/year***
EUE	NA	0	NA	109.4	MWh
Loss of Load Hours (LOLH)	NA	0	NA	0.104	hours/year

Metric	2036		2041		Units
Model	**RESOLVE**	**SERVM**	**RESOLVE**	**SERVM**	
LOLH/LOLE (average length of outage)	NA	0	NA	1.154	hours/day
Normalized EUE (EUE divided by total electric demand)	NA	0	NA	0.00007	percent
CAISO emitting generation	24,873	34,156	16,130	30,110	GWh
CAISO generator emissions	10.23	14.17	6.50	11.75	MMT
Unspecified imports	13,091	9,162	14,114	8,943	GWh
Unspecified import emissions	5.60	3.92	6.04	3.83	MMT
CAISO BTM CHP emissions	3.16	3.16	-	-	MMT
Total CAISO emissions	***18.99***	***21.25***	***12.54***	***15.58***	***MMT***
GHG emissions difference		2.25		3.04	MMT

Table 10. Reliability and GHG Results in Key Planning Years for Proposed 2026-2027 TPP Base Case Before Mapping to Busbars

Metric	2036		2041		Units
Model	**RESOLVE**	**SERVM**	**RESOLVE**	**SERVM**	
LOLE	***NA***	***0.003***	***NA***	***0.154***	***days/year***
EUE	NA	1.8	NA	246.3	MWh
LOLH	NA	0.003	NA	0.193	hours/year
LOLH/LOLE (average length of outage)	NA	1.000	NA	1.231	hours/day
Normalized EUE	NA	0.00000	NA	0.00016	percent
CAISO emitting generation	24,873	34,179	16,130	30,149	GWh
CAISO generator emissions	10.23	14.14	6.50	11.74	MMT
Unspecified imports	13,091	9,168	14,114	9,219	GWh

Metric	**2036**		**2041**		**Units**
Model	**RESOLVE**	**SERVM**	**RESOLVE**	**SERVM**	
Unspecified import emissions	5.60	3.92	6.04	3.95	MMT
CAISO BTM CHP emissions	3.16	3.16	-	-	MMT
Total CAISO emissions	***18.99***	***21.22***	***12.54***	***15.69***	***MMT***
GHG emissions difference		2.22		3.15	MMT

As parties involved in the IRP process over the past several cycles are likely aware, there are differences between the RESOLVE and SERVM models in many aspects. Some differences, particularly in terms of GHG emissions estimates, are expected.

The 2026-2027 TPP recommended base case has a significantly smaller difference in modeled GHG emissions for 2036 and 2041 than the last TPP base case portfolio, due to Commission staff's continued calibration efforts across both models.

In general, we are most focused on the SERVM results for 2036, since this is the first critical planning year for purposes of CAISO TPP analysis and the key driver in identifying transmission needs and resulting recommendations for transmission investments to be sent to the CAISO Board. The Commission transmits both a ten-year and a 15-year portfolio, but consistent with its FERC tariff, the CAISO has discretion on a case-by-case basis about transmission projects identified in the 15-year timeframe and the 2041 TPP analysis does not require immediate commencement of recommendations for transmission investments to the CAISO Board for all projects identified.

The SERVM results show an acceptable level of reliability, with LOLE results below our planning standard of 0.1 days per year in both 2036 and 2041.

In 2036, the LOLE is 0.00 days per year, which is due to the fact that meeting the 2031 GHG target requires additional renewable resource selection, as the GHG target is more binding than the reliability target in the early 2030s. The LOLE result for 2041 is 0.084, which Commission staff estimate to be within a few hundred PCAP MW of the 0.1 LOLE standard.

For GHG emissions in 2036, the estimate is 21.25 MMT of GHG emissions, which is consistent with the CAISO portion of the California electricity sector trajectory set by the CARB in the 2022 Scoping Plan for Achieving Carbon Neutrality (Scoping Plan Update).[25] For 2041, the SERVM GHG emissions estimate is 15.58 MMT, which is also consistent with the electric sector trajectory set by CARB in the 2022 Scoping Plan Update.

These are still modeled estimates projecting out ten and 15 years into the future where many inputs have significant uncertainty and both models can continue to be improved and calibrated during that time.

For the 2026-2027 TPP, we are satisfied that these results are acceptable and sufficient to conclude that the base case portfolio is a reasonable one for the CAISO to analyze further for transmission needs. We will continue to closely monitor actual progress toward the new resource investment and GHG reduction results from these portfolios and will conduct similar analysis with our TPP portfolio recommendations next year and in subsequent years.

4. Summary of Public Comment

Rule 1.18 of the Commission's Rules of Practice and Procedure (Rules) allows any member of the public to submit written comment in any Commission

[25] For more information, *see* more details on CARB's Resolution 22-21, available at the following link: https://ww2.arb.ca.gov/sites/default/files/barcu/board/res/2022/res22-21.pdf. The statewide range for 2035 is between 25 MMT and 30 MMT.

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.

Two individuals submitted public comments related to this decision. The first comment is concerned with the busbar mapping of distributed storage and solar resources from the Wholesale Distributed Access Tariff queue. In particular, the commenter is advocating that energy-only solar and storage resources be mapped to busbars for the CAISO to analyze.

The second public comment comes from a representative of the Blue Lake Rancheria, a federally-recognized Native American Tribe. The Tribe comments in support of offshore wind development on the North Coast, not only for its environmental benefits, but also as a catalyst for workforce development and livable wage careers.

Commission staff have met with various stakeholders in response to requests to conduct busbar mapping of distributed storage resources, and continue to discuss the potential for implementing this recommendation with both stakeholders and the CAISO.

5. Comments on Proposed Decision

The proposed decision of ALJ Julie A. Fitch in this matter was mailed to the parties in accordance with Public Utilities Code Section 311 and comments were allowed under Rule 14.3. Comments were filed on ____________________, and reply comments were filed on ____________________ by ____________________.

6. Assignment of Proceeding

Alice Reynolds is the assigned Commissioner and Julie A. Fitch and Colin Rizzo are the assigned ALJs in this proceeding.

Findings of Fact

1. Commission staff conducted an analysis of electric reliability needs between 2028 and 2032 with SERVM, using an updated 2024 IEPR load forecast, and updated list of resources procured to meet MTR and Supplemental MTR requirements, and in response to comments on the RCPPP proposal and the ACP-CA Motion to Amend the Scoping Memo in R.20-05-003.

2. Several things have changed since the Commission last ordered IRP procurement in D.23-02-040 (as modified by D.24-02-047): (1) the CEC's 2024 IEPR demand forecast projects significant load growth in 2028-2032; (2) Federal tax credit benefits are being rapidly phased out over the next few years; and (3) other Federal actions have been taken imposing tariffs and limiting or delaying renewables siting on Federal lands.

3. Commission staff SERVM analysis results in an estimated need for a cumulative total of 6,267 MW of perfect capacity to be online by June 1, 2032.

4. The proposed aggregate average of 1,500 MW of procurement per year is in line with prior procurement orders and LSEs have been on notice that in R.20-05-003 an ongoing procurement requirement as part of RCPPP may be imposed by the Commission.

5. It is likely that there are still some renewables projects without contracts that can take advantage of expiring Federal tax credits, in order to provide cost savings to ratepayers.

6. Requiring procurement by 2030 and 2032 is far enough in the future that it should mitigate potential negative market impacts.

7. DCPP is likely to remain online at least through 2030.

8. Based on the Commission staff analysis presented in the September 30, 2025 ALJ Ruling, there is likely to be a reliability shortfall of approximately 6,000 MW by 2032 based on current load forecasts and expected resources online.

9. The MTR and Supplemental MTR orders specified that eligible new resources must be either zero-emitting or otherwise eligible under the RPS program. Repowered resources were eligible on the basis of any incremental capacity added during repowering, but not for the full capacity of the resource. Incremental capacity from modifications or upgrades to resources on the baseline line is also eligible, but only for the capacity above and beyond the baseline amount.

10. D.23-02-040, Ordering Paragraph 13, allowed LSEs to undertake baseline swaps, for eligible resources under the MTR and Supplemental MTR orders.

11. Energy storage, especially battery storage, has made up a large proportion of the resources procured to meet MTR and Supplemental MTR requirements, both due to its declining costs, its modularity, and its fast average development timelines.

12. Individual ESP energy and peak load forecasts are maintained confidentially by the Commission due to the cap on direct access load and competitiveness implications.

13. LSEs are eligible to count excess procurement in response to D.21-06-035 toward D.23-02-040 requirements.

14. D.21-06-035 and D.23-02-040 (as modified by D.24-02-047) required new resources used to satisfy their requirements be under contracts of at least ten years in length.

15. Resource accreditation under the MTR and Supplemental MTR decisions was on the basis of marginal ELCCs produced by Commission staff.

16. D.25-09-007 generally allowed LSEs a grace period of up to three years, if they can show long-term contracts to satisfy MTR and Supplemental MTR requirements, and are otherwise in compliance with resource adequacy requirements during the period of delay.

17. LSEs with procurement obligations under D.21-06-035 and D.23-02-040 (as modified by D.24-02-047) are subject to non-compliance penalties set as the net CONE level. Under those decisions, the Commission may also order backstop procurement to be conducted if LSEs are deficient in their obligations.

18. With each annual TPP cycle, Commission staff make updates to inputs and assumptions, which can include resource cost assumptions, import assumptions, transmission constraints, and/or other updates. This year's updates include changed assumptions related to Federal action on tax credits, tariffs, and renewables siting on Federal lands. Other updates include resource potential for solar, wind, and near-field EGS, transmission cost adders for out-of-CAISO wind and geothermal resources in Northeast California and Imperial Valley, full representation of deep EGS on CAISO transmission deliverability constraints, retention costs of existing thermal units, and corrections to offshore wind hourly generation profiles.

19. The base case portfolio being recommended in this decision builds upon and is a reasonable middle ground between the previous TPP base case portfolio and sensitivity portfolio included in D.25-02-026.

20. The base case portfolio recommended in this decision is consistent with the precedent of building on recently-adopted portfolios to move the base case incrementally toward the state's clean energy goals.

21. The base case portfolio recommended in this decision meets our adopted GHG and reliability targets.

22. The CAISO's selection reports for the two transmission projects needed to support offshore wind development on the North Coast (the Humboldt projects) contain several types of cost containment measures for ratepayer protection as proposed by CalGrid, the approved project sponsor for both projects.

23. If transmission deliverability is not reserved by the CAISO for the LLT and other diverse resources in the portfolio, it is possible that transmission may not be available by the time the diverse resources are developed and ready to come online.

24. Both the recommended base case and sensitivity portfolios for this year's TPP contain solar build rates that are several multiples of any recent year's accomplished development.

25. Consistent with prior experience, there is not sufficient time to adopt many busbar mapping methodology improvements proposed by parties in this year's TPP cycle, but much input from past years was included this year, and new comments this year will be carefully considered for next year's busbar mapping improvements.

26. Based on the results of SERVM production cost modeling, the recommended base case portfolio for the 2026-2027 TPP meets the Commission's reliability standard of less than 0.1 LOLE in 2036 and 2041, and has GHG emissions results that are within the CARB Scoping Plan range for the electricity sector.

Conclusions of Law

1. Based on the staff reliability analysis summarized in the September 30, 2025 ALJ Ruling, the Commission should require approximately 6,000 MW NQC of new resource procurement through 2032.

2. Requiring procurement in 2030 should allow LSEs to take advantage of any remaining projects that are able to qualify for expiring Federal tax credits, if they provide cost savings to ratepayers.

3. Requiring more of the procurement at a later date, in 2032, should mitigate potential negative market effects and help secure reasonable costs to ratepayers.

4. The Commission should require LSEs to procure 2,000 MW NQC of total new procurement to be online by June 1, 2030.

5. The Commission should require LSEs to procure 4,000 MW NQC of total additional new procurement by June 1, 2032.

6. The Commission should maintain resource eligibility rules for the procurement ordered in this decision consistent with MTR and Supplemental MTR requirements, which means that resources must be zero-emitting or RPS-eligible, repowering or modifications/upgrades are eligible only for the incremental capacity (if any) that was added during repowering or modification/upgrade, and baseline swaps, baseline waivers, and obligation swaps should be allowed.

7. Energy-only contracts should be eligible to be counted toward the procurement required in this decision, in the limited situation where there are generation and storage projects that are co-located, the storage is fully deliverable, and the multiple resource IDs have the same point of interconnection on the CAISO system.

8. The Commission should avoid over-reliance on storage resources by imposing a cap such that no more than 50 percent of the capacity otherwise eligible to be procured in response to this decision may come from storage. Thus, at least half of the procurement will be from generation resources that are otherwise eligible.

9. Imposing a local procurement requirement for the capacity required by this decision is likely to increase costs and make procurement more difficult. Therefore, the Commission should not require a specific amount of local procurement, though LSEs are encouraged to pursue procurement in local areas where it makes sense for their portfolios.

10. The Commission should maintain the principle that each LSE is responsible for procuring electricity resources to serve its own load where possible, unless there is a compelling reason to order centralized procurement for logistical or cost reasons.

11. Responsibility for the 6,000 MW NQC of new resource procurement required in this decision should be allocated to LSEs on the basis of each LSE's share of the managed peak on the electric system as of resource adequacy program year 2026, and weighted by the 2026 energy load forecasts for IOUs and CCAs from the CEC's adopted 2024 IEPR.

12. Individual LSE allocation of procurement responsibility should be as given in Attachment A. The ESP allocations should be calculated by dividing the individual ESP's year-ahead adjusted peak resource adequacy forecast for 2026 (for month 9) by the total/aggregate year-ahead adjusted peak resource adequacy forecasts for 2026 (for month 9) for all Commission-jurisdictional LSEs.

13. Commission staff should transmit individual ESP allocations confidentially within two weeks after this decision is adopted.

14. This decision should keep compliance and enforcement as similar as possible to MTR and Supplemental MTR requirements, and also keep the requirements as simple as possible.

15. LSEs should be eligible to count any excess procurement undertaken to meet D.21-06-035 or D.23-02-040 requirements toward the requirements of this decision, if the resources otherwise qualify under the terms of this decision.

16. LSEs should be required to bring online a total of 2,000 MW NQC by June 1, 2030 and a total of an additional 4,000 MW NQC total by June 1, 2032.

17. Contracts used to satisfy the capacity procurement requirements in this decision should be required to be at least ten years in length and must begin deliveries by the required online date for each tranche.

18. Resources used to satisfy the new resource procurement requirements in this decision should be accredited on the basis of marginal ELCCs, to be calculated by Commission staff and published by no later than July 31, 2026 for the 2030 requirements and by no later than December 31, 2027 for the 2032 requirements.

19. Because this order requires only two tranches of procurement two years apart, the Commission should not apply the three-year delay provisions of D.25-09-007 to the procurement required by this decision. Each set of new resources for 2030 and 2032 should be assessed for compliance on the required online dates of June 1, 2030 and June 1, 2032.

20. LSEs who do not comply with the procurement required by this decision should be subject to penalties based on the net CONE for any resource amounts not online by the deadlines. LSEs should also be subject to the potential for backstop procurement, if ordered by the Commission, with cost responsibility allocated to the customers of the non-compliant LSE whose procurement must be

backstopped, in the same manner as for procurement required by D.21-06-035 and D.23-02-040.

21. LSEs should continue to be required to make semi-annual procurement compliance filings on June 1 and December 1 of each year through 2032, unless otherwise modified by the Commission in the future.

22. The Commission should update the TPP inputs and assumptions as recommended by Commission staff in the ALJ Ruling and as articulated in this decision.

23. The Commission should take parties' comments on the inputs and assumptions for this TPP into account when revising the inputs and assumptions for next year's TPP portfolios, to the extent feasible.

24. Commission staff should update the assumptions for next year's TPP based on the actual procurement accomplished by LSEs in response to MTR and Supplemental MTR requirements prior to the next TPP portfolios (for 2027-2028) being evaluated.

25. The base case portfolio described in this decision, which incorporates MTR resources and approximately half of the LLT resources found needed in D.24-08-064, with the offshore wind resources' online dates extended by four to six years, is reasonable and should be adopted as the recommendation for the CAISO 2026-2027 TPP.

26. The Commission should recommend that the CAISO allow the potential in-service dates for the Humboldt transmission projects to extend by two years to June 1, 2036, in order to have transmission available for when North Coast offshore wind generation projects are anticipated to begin coming online.

27. It is reasonable to ask the CAISO to continue to reserve deliverability for in-state geothermal, LDES, out-of-state wind, and offshore wind resources in the amounts given in Table 7 of this decision.

28. It is reasonable to ask the CAISO to study a sensitivity portfolio in the 2026-2027 TPP that includes a worst-case scenario for all types of wind development, because the loss of critical wind resources could have a material impact on transmission needs for the resources that would be substituted for the wind.

29. The recommended sensitivity portfolio is more expensive than the base case, but we are recommending it for study by the CAISO because it is a useful portfolio to analyze for potential transmission planning needs.

30. To address the potential challenges associated with the high annual build rates for solar resources necessary to reach either the base case or the sensitivity portfolio amounts by 2041, the Commission should consider evaluating, for the 2027-2028 TPP sensitivity portfolio and/or a PSP sensitivity portfolio, a scenario that could impact solar build rates.

31. It is reasonable to update the busbar mapping methodology for next year's TPP cycle to incorporate the items further discussed in Section 3.5 of this decision, including but not limited to, updating of the commercial interest criteria.

32. It is reasonable to update the busbar mapping for this year's TPP to incorporate the items further discussed in Section 3.6 of this decision, including but not limited to accounting for otherwise unaccounted-for TPD and remapping solar resources from SDG&E Arizona to PG&E and SCE areas.

33. The PCM results for reliability and GHG emissions for the recommended base case portfolio presented in Tables 9 and 10 in this decision are in a reasonable range to request that the CAISO study the portfolio further.

O R D E R

IT IS ORDERED that:

1. All load serving entities (LSEs) subject to the California Public Utilities Commission's integrated resources planning purview shall procure new net qualifying capacity (NQC) from non-emitting, storage, and/or resources eligible under the renewables portfolio standard program, with 2,000 megawatts (MW) NQC total due online by June 1, 2030 and an additional 4,000 MW NQC due online by June 1, 2032. To be counted, resources must be delivering power to the grid and contracted to begin deliveries by the above dates. Hybrid and co-located solar and storage resources may also be used to satisfy the requirements, if the co-located storage meets the online criteria stated above and the multiple co-located resources are interconnected to the transmission system at the same location. Repowered resources and other baseline resources that have been modified or upgraded that otherwise qualify may also be used, but only to the extent that the repowering or modification/upgrade results in incremental capacity, and only the incremental capacity may be counted toward the requirements. A maximum of 50 percent of each LSE's share for each procurement tranche (2030 and 2032) may come from storages resources.

2. The allocation of net qualifying capacity obligations in Ordering Paragraph 1 to individual load serving entities (LSEs) shall be done based on the individual LSE load forecasts from the 2024 California Energy Commission Integrated Energy Policy Report load forecast, weighted by contribution to the 2026 resource adequacy forecast managed peak, for community choice

aggregators (CCAs) and investor-owned utilities (IOUs). Individual allocations for IOUs and CCAs individually, and electric service providers (ESPs) in aggregate, are given in Attachment A. The ESP allocations shall be calculated by dividing the individual ESP's year-ahead adjusted peak resource adequacy forecast for 2026 (for month 9) by the total/aggregate year-ahead adjusted peak resource adequacy forecasts for 2026 (for month 9) for all Commission-jurisdictional LSEs.

3. The allocations to individual electric service providers shall be maintained and transmitted confidentially by electronic mail addressed to the load serving entity's designated primary contact person from California Public Utilities Commission staff within two weeks of the effective date of this decision.

4. All resources used to satisfy the requirements of Ordering Paragraph 1 shall be procured in contracts that are ten years or more in length and are required to be online, contracted to begin electricity deliveries, and actually delivering electricity to the grid, by June 1 in the year in which they are required in Ordering Paragraph 1.

5. Accreditation for resources used to satisfy the requirements of Ordering Paragraph 1 shall be determined on the basis of two marginal effective load carrying capability (ELCC) studies conducted by California Public Utilities Commission staff. The marginal ELCC study for 2030 resources shall be published by no later than July 31, 2026. The marginal ELCC study for 2032 resources shall be published by no later than December 31, 2027.

6. Any penalties associated with failure to comply with the requirements of Ordering Paragraph 1 shall be based on a calculation of the net cost of new entry and will be assessed separately for the 2030 and 2032 compliance requirements.

The need for backstop procurement shall be evaluated in 2030 and 2032 after receipt and analysis of the procurement data filed on June 1.

7. The three-year flexible compliance provisions in Decision 25-09-007 that allow load serving entities to be deemed compliant if they have the required resources under contract and are otherwise compliant with resource adequacy requirements shall not apply to the requirements of Ordering Paragraph 1.

8. Load serving entities subject to the California Public Utilities Commission's (Commission) integrated resource planning purview shall continue to provide procurement compliance filings on June 1 and December 1 of each year through the end of 2032, unless otherwise modified by the Commission.

9. Load serving entities subject to the California Public Utilities Commission's integrated resource planning purview that have procured resources in excess of the requirements of Decision (D.) 21-06-035 and/or D.23-02-040 may use the excess procurement to satisfy the requirements of this decision, as long as they otherwise meet the criteria specified herein.

10. The California Public Utilities Commission transfers to the California Independent System Operator (CAISO) for its annual Transmission Planning Process (TPP) a reliability and policy-driven base case portfolio that meets a 25 million metric ton greenhouse gas emissions level in 2035, incorporates the individual load serving entity resource plans from 2022, includes approximately half of the long lead-time resources found needed in Decision 24-08-064, as specified in Section 3.2 of this decision, includes delays to the expected online dates for offshore wind, and includes the results of the mapping of resources to busbars discussed in Section 3.6 of this decision. The base case portfolio includes

modeled years of 2036 and 2041, and CAISO TPP analysis is requested for both years.

11. The California Public Utilities Commission recommends that the California Independent System Operator allow the potential in-service dates for the Humboldt transmission projects approved to support North Coast offshore wind resources in the 2024-2025 Transmission Planning Process to extend by two years, to June 1, 2036.

12. The California Public Utilities Commission requests that the California Independent System Operator reserve deliverability on the transmission system for the amount of geothermal, long-duration energy storage, out-of-state wind, and offshore wind resources specified in Table 7 of this decision.

13. The California Public Utilities Commission transfers to the California Independent System Operator for its annual Transmission Planning Process a Limited Wind Sensitivity portfolio, as described in Section 3.3 of this decision, to facilitate contingency planning for transmission needed by other resources if the desired wind resources do not materialize.

14. Rulemaking 25-06-019 shall remain open.

This order is effective today.

Dated ____________________, at Santa Maria, California.

ATTACHMENT A