Decision **PROPOSED DECISION OF ALJ FITCH (Mailed 1/13/2023)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	Rulemaking 20-05-003

DECISION ORDERING SUPPLEMENTAL MID-TERM RELIABILITY PROCUREMENT (2026-2027) AND TRANSMITTING ELECTRIC RESOURCE PORTFOLIOS TO CALIFORNIA INDEPENDENT SYSTEM OPERATOR FOR 2023-2024 TRANSMISSION PLANNING PROCESS

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Summary

This decision addresses two primary topics. First, the decision requires supplemental mid-term reliability procurement of a total of 4,000 megawatts (MW) of net qualifying capacity (NQC) in addition to the 11,500 MW ordered previously in Decision (D.) 21-06-035. This additional procurement for 2026 and 2027 is required for several reasons: 1) updated load forecasting from the California Energy Commission (CEC) that suggests that electricity demand is increasing and will continue to increase compared to when D.21-06-035 was adopted; 2) the increasing and accelerating impacts of climate change; 3) the likelihood of some additional fossil-fueled generation resource retirements that were not anticipated at the time D.21-06-035 was issued; and 4) the likelihood that some delays beyond 2026 in the procurement of long lead-time resources required by D.21-06-035 will be necessary. In addition to the additional 4,000 MW NQC of procurement ordered in this decision, requirements for procurement of long lead-time resources from D.21-06-035 are automatically postponed to 2028, but the existing February 1, 2023 procurement data filing requirements remain unchanged.

Second, this decision recommends electricity resource portfolios to the California Independent System Operator to study in its 2023-2024 Transmission Planning Process. The decision includes recommendations that are broadly consistent with the staff recommendations included in the October 7, 2022 Administrative Law Judge ruling issued in this proceeding, with some

modifications to respond to parties' comments. The general recommendations are as follows:

- Base case portfolio, for both reliability and policy-driven purposes, to be used to determine transmission investments needed: a portfolio that expects 69 gigawatts (GW) nameplate of new resources by 2033 and 85 GW nameplate of new resources by 2035 to be built to meet a 30 million metric ton greenhouse gas emissions target in 2030, and uses the CEC's 2021 Integrated Energy Policy Report "Additional Transportation Electrification" high load scenario.
- One sensitivity portfolio, for study purposes:
    - A portfolio of 75 GW nameplate of new resources in 2035 that is designed to refine and update transmission capability and upgrade assumptions relevant to offshore wind resources, such that offshore wind is 13.4 GW by 2035 as compared to 4.7 GW in the base case.

This proceeding remains open.

1. Background

1.1. Mid-Term Procurement Issues

On September 8, 2022, an Administrative Law Judge's (ALJ) ruling was issued seeking comments on, among other things, potential near-term actions the Commission could take to encourage additional procurement to meet or exceed the requirements of Decision (D.) 19-11-016 and D.21-06-035. The ruling also sought ideas for the Commission to remove any barriers to additional procurement. Among the options discussed in the ruling were modifications to the way D.19-11-016 and D.21-06-035 treated "baseline" resources. In addition, parties were invited to suggest their own options for steps the Commission could take to encourage procurement.

Comments in response to the September 8, 2022 ALJ ruling were timely filed no later than September 26, 2022, by the following parties: Alliance for Retail Energy Markets (AReM); Bioenergy Association of California (BAC); California Independent System Operator (CAISO); California Community Choice Association (CalCCA); Central Coast Community Energy (C3E); City and County of San Francisco (CCSF); Clean Energy Alliance (CEA); Clean Power Alliance of Southern California (CPA); Diamond Generating LLC (Diamond); East Bay Community Energy (EBCE); Environmental Defense Fund (EDF); Fervo Energy (Fervo); Green Power Institute (GPI); Hydrostor, Inc. (Hydrostor); L. Jan Reid (Reid); LS Power Development (LS Power); Pacific Gas and Electric Company (PG&E); Peninsula Clean Energy (PCE); Public Advocates Office of the California Public Utilities Commission (Cal Advocates); San Diego Community Power (SDCP); San Diego Gas & Electric Company (SDG&E); San Jose Clean Energy (SJCE) and Marin Clean Energy (MCE), jointly; Shell Energy North America (Shell); Sierra Club and California Environmental Justice Alliance (CEJA), jointly; Silicon Valley Clean Energy (SVCE); Sonoma Clean Power Authority (SCPA) and Redwood Coast Energy Authority (RCEA), jointly; Southern California Edison Company (SCE); and Vistra Corp. (Vistra).

Timely reply comments were filed in response to the September 8, 2022 ALJ ruling by no later than October 6, 2022, by the following parties: ACP-CA; AReM; CAISO; Cal Advocates; CalCCA; CEJA and Sierra Club, jointly; California Energy Storage Alliance (CESA); Enchanted Rock, LLC (Enchanted Rock); EDF; Fervo; Hydrostor; PG&E; SCE; SDCP; SDG&E; and Shell.

1.2. CAISO TPP Portfolios

Under longstanding agreement among the California Public Utilities Commission (Commission), the California Energy Commission (CEC), and the

California Independent System Operator (CAISO), and according to the terms of the CAISO tariff, every year the Commission recommends to the CAISO base case electricity resource portfolios to be used as key inputs to the CAISO transmission planning process (TPP). Typically, there is both a base case portfolio for reliability and another that is policy driven; the two portfolios have often been identical. In addition, the Commission usually requests that the CAISO study one or more sensitivity cases designed to help inform future planning and analysis.

On October 7, 2022, an ALJ ruling was issued seeking comments from parties on Commission staff recommendations for portfolios to be used in the upcoming 2023-2024 TPP. The ALJ ruling included a recommended framework for TPP portfolio selection, descriptions of the proposed portfolios, and a methodology for resource-to-busbar mapping and assumptions.

The following parties timely filed comments on or before October 31, 2022, in response to the October 7, 2022 ALJ ruling: American Clean Power - California (ACP-CA); Avangrid Renewables, Inc. (Avangrid); Bay Area Municipal Transmission Group (BAMx); Cal Advocates; CalCCA; CESA; CEJA and Sierra Club, jointly; CAISO; California Wind Energy Association (CalWEA); Center for Energy Efficiency and Renewable Technologies (CEERT); Coalition for the Optimization of Renewable Development (CORD); Defenders of Wildlife (DOW); EDF Renewables, Inc. (EDF Renewables); EDF; Geothermal Rising; Golden State Clean Energy, LLC (Golden State); ~~Green Power Institute (~~GPI~~)~~; GridLiance West LLC (GridLiance); Reid; Large-Scale Solar Association (LSA); LS Power; Natural Resources Defense Council (NRDC); Offshore Wind California (OWC); PG&E; RCEA; SDG&E; Solar Energy Industries Association (SEIA); and SCE.

The following parties timely filed reply comments on or before November 10, 2022, in response to the October 7, 2022 ALJ ruling: ACP-CA; BAMx; California Efficiency + Demand Management Council (CEDMC); California Unions for Reliable Energy (CURE) and Coalition of California Utility Employees (CCUE), jointly; CAISO; CalCCA; CEERT; CESA; EDF; Geothermal Rising; Golden State; GPI; GridLiance; LSA; LS Power; NRDC; PG&E; RCEA; SCE; SEIA; and Vistra.

2. Mid-Term Procurement Issues

The September 8, 2022 ALJ ruling described a number of circumstances that have changed since the two prior procurement orders in the integrated resources planning (IRP) context have been issued (D.19-11-016 and D.21-06-035). Those changes include, but are not limited to, the following factors that contributed to recent higher CEC demand forecasts, as well as the need for more procurement:

- Increasing frequency of extreme weather conditions, including heat leading to increased electricity demand and drought leading to decreased availability of hydroelectric generating capacity;
- Increasing electricity demand overall, beyond levels forecasted by the CEC in previous annual demand forecasts. This is likely due to a combination of factors including weather, increasing penetration of electric vehicles, increasing penetration of air conditioning, electrification of buildings, and changing consumption patterns during and after the COVID-19 pandemic;
- Decreasing availability of imported electricity, due to the above factors impacting other states in the West, especially the Northwest, on which California traditionally relies for seasonal imports;
- Less electric capacity availability in the market, due to aging and retirement of some older generating units; and

- Accelerating goals for clean energy production and reductions in greenhouse gas (GHG) emissions through 2045 and earlier.

In addition, there have been several recent changes to the regulatory and statutory landscape that impact procurement activities, including the following:

- Changing the resource adequacy obligations of the load serving entities (LSEs) (*see* D.22-06-050);
- The introduction of a state strategic reliability reserve (*see* Assembly Bill (AB) 205 (Stats. 2022, Ch. 61));
- Allowing for an extension of the timeline for the retirement of the Diablo Canyon Power Plant (*see* Senate Bill (SB) 846 (Dodd, 2022));
- Creating legally binding goals for carbon neutrality (AB 1279 (Muratsuchi, 2022) and SB 1020 (Laird, 2020)); and
- Requiring the transmittal of resource portfolios that extend 15 years into the future instead of the earlier practice of 10 years (SB 887 (Becker, 2022)).

While policy and regulatory developments are ongoing with respect to some of these items, the clear collective trend points towards increasing demand for clean electricity and increasing need for additional resources.

The September 8, 2022 ALJ ruling focused on any additional changes the Commission could make in the near-term to encourage LSEs to continue with successful procurement of electricity resources in a difficult market environment, prior to our next formal need assessment that will take place over the next several months and prior to the adoption of a preferred system plan (PSP) and implementation of a programmatic approach also discussed in the September 8, 2022 ALJ ruling.

The September 8, 2022 ALJ ruling also discussed that, in addition to all of the above factors, LSEs and developers are facing exogenous factors such as supply chain impacts on availability of raw materials, import investigations with respect to solar panels, tightening of the economy in the face of inflation, increased demand for clean energy resources throughout the west and globally, and other factors that have material impacts on the development of projects.[1]

In light of all of the above trends and factors that put generally-increasing emphasis on the need for procurement of resources and development of new clean energy resources, the Commission has continued to encourage LSEs to procure as much as possible to meet both current and future electricity resource needs.

In addition, the PSP adopted in D.22-02-004 shows the need for approximately 35,000 MW nameplate of new resources on the electric system by 2030 in order to meet both reliability and GHG goals. Even if all of the incremental resources ordered to date were to come to fruition, that procurement will only meet roughly half of the additional resources needed by the end of the decade to meet the expected portfolio being adopted later in this decision to be used for transmission planning. Thus, the September 8, 2022 ALJ ruling discussed that it is imperative that LSEs continue to procure, both to meet these needs in the next decade, in advance of any additional procurement requirements from the Commission, as well as due to the potential for some projects currently in development not to reach commercial operation on the required procurement timelines.

The September 8, 2022 ALJ ruling noted that, in the event of an LSE's failure to meet one or more of the required procurement targets, the Commission will carefully evaluate whether an LSE continued to procure to help meet system

[1] Also note the work of the Tracking Energy Development Task Force, with more information available at the following link: www.cpuc.ca.gov/trackingenergy

reliability and GHG needs, even if the procurement is slightly delayed or otherwise does not meet the letter of the decisions' requirements.

The September 8, 2022 ALJ ruling also noted that, in general, indications are that projects expected to meet the requirements of D.19-11-016 for the years 2021 and 2022 have been contracted for and are coming online, and although some have been delayed in terms of contracted online dates, collectively LSEs appear to have brought online new resources that meet the D.19-11-016 requirements for 2021 and 2022. It also appears that most projects required for 2023 in D.19-11-016 are also contracted, but it remains to be seen whether the projects will come online on time (by ~~June~~August 1, 2023) to meet Summer 2023 needs. In addition, progress towards D.21-06-035 requirements for 2023 and 2024, which are large, appears to be lagging. The next opportunity for a formal check of status of D.19-11-016 procurement ~~will be~~is with the February 1, 2023 progress filings due from LSEs as provided for in D.20-12-044, when the Commission ~~will receive~~received the data to determine whether any backstop procurement may be needed for any LSEs that have failed to meet their obligations. Commission staff are currently reviewing these filings. This ~~will~~is also ~~be~~ the first opportunity for a formal compliance check related to D.21-06-035 procurement. This decision may have an impact on some elements of these filings subsequent to the February 1, 2023. In the meantime, for the February 1, 2023 filing requirements, LSEs should continue to follow current direction in decisions already adopted, filing requirements from Commission staff, and other provided instructions such as the Frequently Asked Questions (FAQ) provided by Commission staff.[2]

[2] Available at the following link: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procureme

2.1. Baseline Resources

In response to the September 8, 2022 ALJ ruling, LSEs were asked to identify resources that were included in the baseline for D.19-11-016 and/or D.21-06-035, but which have not come online. "Baseline" resources are projects that the Commission assumed would be online when determining the capacity needs required by D.19-11-016 and D.21-06-035.

2.1.1. Responses from Parties

Six LSEs (PG&E, MCE, SCPA, SCE, SDG&E, and SVCE) and one developer (Vistra) identified projects that were in the baselines and still pending or that were in the baselines but unlikely to come to fruition.

For the D.19-11-016 baseline projects that were originally expected but currently unlikely to come online based on current project status, a total of 24 renewable projects and two storage projects were identified, totaling 222 MW and 19 MW nameplate, respectively. LSEs stated that all of ~~the~~these renewable and storage projects have been terminated and none is expected to come online.

For the D.21-06-035 baseline projects that were originally expected to come online but now unlikely to come to fruition, ten projects were identified. Four are renewable projects totaling 240 MW nameplate. Six are battery storage projects totaling 152 MW nameplate, one of which is the Oakland Energy Storage project (36 MW) that is terminated and not expected to come online. There is also one fossil-fueled project that is 55 MW that was retired in 2021.

There are seven additional projects that were included in the baseline for D.19-11-016 and D.21-06-035, one renewable that is 13.5 MW in nameplate, and

nt/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track six battery storage projects that total 180 MW nameplate, that have not come online.

2.1.2. Discussion

Based on the above information submitted by LSEs and Vistra, in total the approximate nameplate capacity of the baseline projects that have not materialized but may still be able to come online is roughly 570 MW.

2.2. Potential Baseline Resource Adjustments

The September 8, 2022 ruling sought input from parties where some clarification from the Commission may result in the removal of a barrier to procurement and development of additional resources. In D.19-11-016, the baseline that was set included a number of prospective resources that had not yet come online as of the date of the order, but where offtake contracts had been signed. The intent was to order procurement that is in addition to those resources that were already in the pipeline.

As discussed in Section 2.1 above, the potential for some previously expected baseline resources to still be developed is a maximum of roughly 570 MW nameplate. In most, if not all, cases, the reliability of the electric system would benefit from having these resources online, but because of the way the baseline was set for D.19-11-016, they do not "count" toward the D.19-11-016 additional capacity requirements. Likewise, because the baseline for the additional procurement required in D.21-06-035 was built upon the D.19-11-016 baseline, the resources also currently would not count toward D.21-06-035 requirements, by the terms of the Commission's previous orders.

These resources are important for reliability and were already being counted on for planning purposes when the Commission considered the additional procurement requirements. At the same time, if the Commission were to allow them to count toward D.19-11-016 or D.21-06-035 procurement requirements, the reliability benefits of the incremental resources required in those orders would be diluted by the same amount.

To remedy this situation, the September 8, 2022 ruling proposed the following solution: the "baseline" for both D.19-11-016 and D.21-06-035 procurement would be reframed to allow any resource that has come online since January 1, 2020, to count toward the LSE's procurement obligations.

In general, incremental resources coming online after January 1, 2020, would be counted first toward the D.19-11-016 obligations, with any excess applied to D.21-06-035, assuming the particular resource meets the general capacity requirements or the specific attributes required for the specific procurement categories in the D.21-06-035 obligations.

In addition, an amount of net qualifying capacity (NQC) commensurate with the capacity of baseline resources that have not yet come online would be added to the obligations of all LSEs collectively in 2025, to account for the dilution effect of allowing resources in the original baseline to count toward D.19-11-016 or D.21-06-035 obligations.

Alternatively, the September 8, 2022 ALJ ruling stated that LSEs with baseline resources not yet online could identify the resource to the Commission and have that amount of capacity added to their own individual obligation in 2025.

Either way, this proposal would act to maintain the same level of reliability expected by the Commission when D.21-06-035 was issued,[3] while increasing the

[3] The need determination analysis that led to D.21-06-035 did include an allowance for some project failure.

flexibility of LSEs to bring new resources online and continue procuring toward their obligations.

Finally, the September 8, 2022 ALJ ruling suggested that, should the Commission adopt this proposal, new resources would be considered incremental if their actual online date was later than the January 1, 2020 online date cutoff suggested. Thus, there would no longer be a "baseline" list maintained by Commission staff for testing whether procurement "counts" toward a particular obligation. The eligibility of a new resource toward compliance with procurement orders would be based on online date, along with any other criteria required by the future decision, with no relation to existing baselines.

2.2.1. Comments of Parties

CAISO questions the feasibility of eliminating the baseline because the Commission will need to track planned resources that are delayed or fail to come online. CAISO recommends 1) providing a list of prospective resources assumed in IRP procurement authorizations and 2) tracking each resource's progress. This list, according to the CAISO, should reference the IRP procurement order and be used to authorize future procurement commensurate with the delayed resources' effective capacity. Lastly, the CAISO urges the Commission to authorize immediately additional procurement to replace the effective capacity of retiring units.

CAISO is also concerned with a capacity shortfall that may occur using an arbitrary baseline cutoff date. CAISO recommends that the Commission require LSEs to procure additional resources to replace delayed baseline resources commensurate with the delayed resource's original NQC, to overcome decreasing effective load carrying capability (ELCC) values. CAISO states that the effective capacity is more accurate because ELCC values generally decrease over time. Thus, according to the CAISO, increasing LSE obligations in 2025 does not address the pressing capacity need ~~until~~before that date, and the Commission should order replacement capacity as soon as possible to address the reliability gap. Finally, CAISO highlights changes to the demand forecast and stresses the recent heatwave experiences, combined with uncertainty around retiring resources and the impact of extreme heat on generating unit outages, as reasons to order replacement capacity for delayed baseline resources.

EDF supports the proposed baseline modification, with a modification to allow baseline resources that have come online between January 1, 2020 and now to count towards LSEs' procurement obligations without adding an amount of NQC equivalent to the capacity of these resources to future LSE procurement obligations. EDF notes that the Commission should modify the proposal to ensure that the amount of NQC equivalent to the capacity of all baseline resources not online as of January 1, 2020 should be added to the LSE's 2025 procurement obligations to ensure no reduction in system reliability.

GPI supports adding baseline resource capacity not yet online to LSEs' 2025 obligations, but would do it based on load share. GPI also notes that the Commission would need to clarify if the additional 2025 NQC would need to meet a specific procurement category as defined by D.21-06-035 or if it would be limited by D.19-11-016 requirements. GPI also recommends that the Commission make clear that fossil-fueled resources should not be allowed to count for any reallocated NQC requirements.

Further, GPI notes that the baseline NQC approach in both procurement orders may have deterred procurement, with LSEs potentially incentivized to hold off on any additional procurement above and beyond the orders to ensure that any additional procurement could count towards likely new and additional orders. As such, GPI recommends clarifying the baseline for future orders will be set to before January 1, 2020. GPI also notes the programmatic approach being created, but still recommends clarifying to remove any uncertainty or gaps. Finally, GPI notes that re-allocating NQC to 2025 could also account for retiring resources, which could be added to the 2025 procurement date.

Cal Advocates supports allowing resources that are not currently online to count towards the procurement order and adding them to LSEs' procurement obligations in 2025. Cal Advocates recommends that the Commission 1) adjust the NQC value of remaining baseline capacity in 2020, and 2) include a methodology for allocating procurement responsibility among LSEs for remaining capacity in 2025. Cal Advocates contends that the Commission should account for changes in NQC to determine the final capacity need in 2025. Finally, Cal Advocates opposes getting rid of the baseline list of resources, stating that it is important so that other parties can validate their modeling.

SCE supports allowing any eligible resource that came online after January 1, 2020 to count toward LSE procurement obligations. SCE concurs with statements in the ruling calling out specific factors making procurement more difficult, and also highlights delays in the CAISO cluster process as further hampering resource development. SCE notes that the proposed baseline changes provide flexibility to balance these challenges without jeopardizing reliability. SCE also supports adding the capacity to the 2025 obligations, and suggests the Commission clarify the NQC requirements for D.19-11-016 or D.21-06-035 obligations to ensure the LSE is fulfilling the need of both decisions.

SCE also raises that LSEs using resources that were originally part of the baseline should be responsible for procuring an equivalent amount of NQC to ensure fair procurement. SCE recommends that LSEs submit filings demonstrating which resources they are counting towards procurement requirements to allow the Commission to determine what additional NQC is needed in 2025. SCE further contends that the baseline modification should apply to resources procured under the cost allocation mechanism (CAM), with those resources retaining their CAM cost recovery but allowing the investor -owned utilities (IOUs) to file Tier 2 Advice Letters to change which procurement obligation the CAM resources are being counted towards. SCE also asks for clarification on ELCC values to be used for NQC valuation.

EBCE supports modifications that allow resources online after January 1, 2020, to be considered incremental because this provides LSEs greater certainty when procuring resources. EBCE states that a single date is easier for LSEs to use and for the Commission to evaluate. EBCE also supports having additional capacity added back to an LSE's procurement obligation, noting that having LSEs responsible for their share of reliability and greenhouse gas (GHG) reducing procurement provides greater certainty to LSEs and protects those that have already met their own procurement obligations.

PG&E suggests that the Commission should consider supplementing the current procurement orders to ensure that procurement targets are met. PG&E encourages the Commission to keep other procurement targets within their respective proceedings, noting that Renewable Market Adjusting Tariff (ReMAT) resources included in the baseline that are delayed should remain within the ReMAT program and not IRP to prevent double-procurement and additional ratepayer costs. For resources not accounted for in other proceedings, PG&E supports assigning procurement responsibility to the LSE that was supposed to bring the resource online. PG&E also recommends that replacement resources be required by June 1, 2026, and not 2025, to give LSEs enough time to issue and complete solicitations. Finally, PG&E also recommends not allowing for opt-outs, consistent with D.21-06-035.

SDG&E requests additional clarification about how capacity would be allocated among LSEs and how the additional capacity would be considered for future procurement obligations before supporting the baseline adjustment proposal.

2.2.2. Discussion

After consideration of parties' input, we will adopt a "swap" process that allows an LSE to nominate a project on the D.19-11-016 and/or D.21-06-035 baseline generator list to be considered for removal. An equal amount of procurement obligation (in NQC) will then be added to the LSE's 2025 procurement obligation under the provisions of D.21-06-035. This new "swap" process will be in addition to the process that is already available to LSEs if their request meets the criteria established by Commission staff in a prior guidance document.[4] In the already-established process, an LSE that specifically procured a resource for D.19-11-016 and had that resource put into the D.21-06-035 baseline before that resource was online, and subsequently suffered a delay and procured replacement resources for its D.19-11-016 obligation, may follow the staff guidance and submit a request for a swap. LSEs in any other circumstance, or who otherwise do not meet the criteria outlined in the staff guidance memo, must use the process outlined in this decision. This is to ensure that any LSE requesting to remove a resource from the baseline has already procured

[4] The staff guidance document is available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/d2106035_baselineswap_d1911016_ver2.pdf

replacement resources, or will be required to procure them in 2025 by the terms of this decision.

An LSE seeking a baseline swap using the new process adopted in this decision will need to file a Tier 2 Advice Letter with its request. Commission staff will maintain and post to our web site two current baselines list for both D.19-11-016 and D.21-06-035 resources~~, as well as each~~. Each LSE's procurement obligations, as adjusted to account for any approved baseline swaps authorized, will also be posted, maintaining individual LSE confidentiality, as necessary. ~~A~~The swap process adopted in this decision will allow an LSE that held or holds a resources that is on the baseline to count towards an IRP obligation provided it adds capacity to its procurement obligation at a later date. Since the baseline development process did not yield a baseline list that definitively identified the LSE that originally contracted for the resource, this swap process will be necessary to be handled informally by Commission staff.

Additionally, if a new LSE wants to contract for and count a baseline resource towards its IRP procurement obligation, when that LSE had previously not held a contract with the project and the original purchasing LSE has terminated the contract, the new LSE may also make a baseline waiver request to Commission staff. In such cases, which are expected to be rare, the resources may be removed from the baseline entirely and counted toward a later obligation of the new LSE, resulting in a slight dilution of the original baseline. Staff will track and evaluate these situations on a case-by-case basis.

We will not allow CAM resources to participate in ~~this~~the swap or waiver process outlined in this decision. Given that the costs and benefits for CAM resources are shared among all LSE customers in an IOU's service territory, it could be unfair and difficult to allow an IOU to remove a CAM resource from the baseline and apply it solely to its own future procurement obligation. It is also potentially inequitable to allow IOUs to do this, when other LSEs would not have such flexibility or access to CAM resources.

If a project is removed from ~~the~~either baseline list, it can be allowed to count toward either procurement obligation (D.19-11-016 or D.21-06-035) and its NQC will be based on the decision for which it is being counted for compliance. In other words, if an LSE seeks to remove a project from the D.19-11-016 baseline list and instead wants to count it toward a D.21-06-035 obligation, the resource will be counted towards the D.21-06-035 obligation using D.21-06-035 ELCC values, according to whichever tranche the project is coming online to meet. If it is being used to meet the D.19-11-016 obligations, then it will be counted using the D.19-11-016 vintage of ELCC values. Then, the LSE's 2025 procurement obligation will be increased by the same amount, with updated NQC amounts based on ELCC values for 2025.

We recognize that, in general, it is likely that the project's NQC will be lower if it is removed from the baseline and added to the 2025 D.21-06-035 obligation of an LSE. This is still preferable to not having the resource developed at all (which may occur if we do not provide a pathway for counting the resource), because we want to see as much capacity developed as possible.

We also note that D.19-11-016 obligations are smaller and not subject to the penalties that are attached to D.21-06-035 obligations. We will empower Commission staff to scrutinize any requested baseline swaps that appear to be gaming attempts to avoid penalties. We delegate to Commission staff~~ will have the discretion~~ to review any swap request against the LSE's progress toward their total procurement obligations for each of the two procurement decisions. If staff ~~suspect~~find evidence that the LSE is gaming the swap to avoid penalties, staff will not make the swap but will instead refer the request to the ALJ to evaluate further through inclusion in the formal record of the IRP proceeding, for ultimate disposition.

We also prohibit any contract that is terminated after this proposed decision was published (after January 13, 2023) from participating in any baseline adjustment or swap. This is in response to concerned raised by parties, including CalCCA, about the potential for market power. In addition, if a resource appears on both the D.19-11-016 and D.21-06-035 baseline generator list, an LSE can request that the resource be removed and added to a procurement obligation, but the resource must first be used to fill any unmet D.19-11-016 requirement before being applied to D.21-06-035 obligations. This baseline swap process is also not extended to the new procurement ordered in this decision.

In response to PG&E's concern about ReMAT or other non-IRP procurement requirements, we agree that we want to avoid the risk of double-counting capacity if the resource is addressed in another proceeding (such as ReMAT, which is addressed in the RPS proceeding) but removed from the baseline in this proceeding. In general, and to clarify, eligibility of those resources that are required in other proceedings will not be disturbed in this proceeding, even if the resource is removed from the IRP procurement baseline for either D.19-11-016 and/or D.21-06-035.

By addressing the baseline resource issues with the swap opportunity for individual LSEs, we are allowing resources that come online after January 1, 2020 to count towards IRP compliance, while the LSE that seeks the swap increases its individual 2025 IRP obligations. As noted above, these swap arrangements will be posted on the IRP website for transparency and will require Commission staff to maintain procurement baseline generator lists for both D.19-11-016 and D.21-06-035.

Regarding the CAISO's concern about the need for a baseline for modeling purposes, we clarify that the September 8, 2022 ALJ ruling was not intended to question the use of baselines for modeling. We recognize that a baseline set of resources is a fundamental input to modeling, particularly capacity expansion modeling. The current assumptions are available on our website.[45]

2.3. Additional Procurement Requirements

The September 8, 2022 ALJ ruling invited parties to suggest other changes that the Commission might make or actions we might take to encourage additional procurement by LSEs to meet or exceed the requirements of D.19-11-016 and D.21-06-035. One party, Cal Advocates, put forward a proposal in their opening comments to have the Commission order additional procurement of a total of 4,000 MW NQC between 2026 and 2030.

Cal Advocates proposes five annual increments of 500 MW to account for the forecasted CAISO system 1-in-2 peak load growth (coincident peak load is forecasted in the 2021 Integrated Energy Policy Report (IEPR) to increase by 500 MW each year, starting in 2027). In addition, Cal Advocates proposes one increment of 1,000 MW NQC to account for additional climate change impacts that may not be reflected in the forecast. There would also be a final 500 MW NQC increment to allow for additional resource retirements that may occur in advance of assumed retirement dates. As part of its proposal, Cal Advocates suggests accelerating procurement one year ahead of the predicted need. The

[45] *See* the following link: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/unified-ra-and-irp-modeling-datasets-2022

resulting additional procurement Cal Advocates proposes to be required by the Commission is summarized in Table 1 below.

Table 1: Cal Advocates' Additional Procurement Requirement Recommendations (in Annual MW NQC, except final column)

Need Type	2026	2027	2028	2029	2030	Cumulative
Load Increase	500	500	500	500	500	2,500
Climate Change	1,000	0	0	0	0	1,000
Retirements	0	500	0	0	0	500
Total	**1,500**	**1,000**	**500**	**500**	**500**	**4,000**

Cal Advocates also recommends adopting all rules and mechanisms associated with D.21-06-035 for expediency. Cal Advocates argues that the critical benefit of ordering some minimum procurement immediately is to afford the LSEs greater lead time, and therefore greater project development feasibility.

2.3.1. Comments of Parties

CAISO supports the Cal Advocates proposal and suggests the procurement be authorized well ahead of need, to reduce bottlenecks. CAISO also suggests that LSEs make every effort to procure in locations where few, if any, transmission upgrades are needed or where transmission is already under development.

Hydrostor also supports the proposal and suggests a minimum of 605 MW of long duration energy storage be procured.

EDF supports the proposal, as long as the order will not divert Commission resources away from the development of the Reliable and Clean Power Procurement Program. EDF is concerned about the Commission becoming stuck in a cycle of ad hoc, interim procurement orders.

Enchanted Rock supports the Cal Advocates proposal and suggests the Commission expand the orders to include renewable natural gas as an eligible resource.

AReM opposes the Cal Advocates proposal. AReM states that, at a minimum, additional procurement should only be ordered after a transparent stakeholder process and should be supported by rigorous analysis. AReM believes that further rushed procurement in current market conditions risks increasing costs without defined benefits.

PG&E also opposes the proposal of Cal Advocates, on the grounds that the Commission should not issue an additional order that is not need-based and is not driven by cost causation principles. PG&E also states that pursuing the Cal Advocates proposal would continue the out-of-cycle procurement processes already used in IRP and run counter to the Commission's aim to move towards a more programmatic approach to procurement.

CEJA and Sierra Club also oppose the proposal and suggest that the Commission take a few months to conduct a need determination and order new procurement based on that analysis, focusing on zero emission resources and demand-side programs. CEJA and Sierra Club further suggest that the Commission should act to take advantage of federal funding and strengthen demand-side programs authorized in the emergency reliability decisions in the past few years.

2.3.2. Discussion

The September 8, 2022 ALJ ruling included a list of factors that have contributed to the likely need for more procurement of electricity resources in California, including the following:

- Increasing frequency of extreme weather conditions, including heat leading to increased electricity demand and drought leading to decreased availability of hydroelectric generating capacity;

- Increasing electricity demand overall, beyond levels forecasted by the CEC in previous annual demand forecasts. This is likely due to a combination of factors including weather, increasing penetration of electric vehicles, increasing penetration of air conditioning, electrification of buildings, and changing consumption patterns during and after the COVID-19 pandemic;
- Decreasing availability of imported electricity, due to the above factors impacting other states in the West, especially the Northwest, on which California traditionally relies for seasonal imports;
- Less electric capacity availability in the market, due to aging and retirement of some older generating units; and
- Accelerating goals for clean energy production and reductions in GHG emissions through 2045 and earlier.

In addition, the September 8, 2022 ALJ ruling cited several recent changes to the regulatory and statutory landscape that impact procurement activities, including the following:

- Changing the resource adequacy obligations of the LSEs (*see* D.22-06-050);
- The introduction of a state strategic reliability reserve (*see* Assembly Bill (AB) 205 (Stats. 2022, Ch. 61));
- Allowing for an extension of the timeline for the retirement of the Diablo Canyon Power Plant yet maintaining the need for the Commission not to consider the energy or capacity of Diablo Canyon as available for resource planning purposes (*see* Senate Bill (SB) 846 (Dodd, 2022)); and
- Creating legally binding goals for carbon neutrality (AB 1279 (Muratsuchi, 2022) and SB 1020 (Laird, 2020)).

All of the factors putting pressure on system reliability remain in effect. As much as we would like to agree with EDF that we should focus on development of a programmatic approach to procurement, we also are convinced that we cannot wait for that larger process to be complete before ordering additional procurement. In 2022, the electric system came very close to running out of resources, and it actually did run out in 2020. The system is much closer to a supply and demand balance than is comfortable for reliability purposes. While the Commission-jurisdictional LSEs did collectively procure sufficient resources to exceed our resource adequacy obligations in 2022, the tight market conditions led to high capacity prices and some LSEs were deficient in some months of the year. These situations, coupled with the lengthy lead time needed for the development of new resources, persuade us that we need to order new procurement now so that the LSEs can have sufficient time to contract for and develop the resources in a timely and cost-effective fashion.

In contemplating requiring additional procurement, we are in complete agreement with Cal Advocates that the procurement should be an addition to the resources ordered in D.21-06-035 and utilize the same eligibility and compliance rules as that decision. Thus, we will require the additional procurement we order here to be an addition to the capacity ordered in D.21-06-035, and it shall be subject to the same baseline, compliance rules, penalties, monitoring and enforcement process, and need allocation. These items are discussed in more detail below.

Even as we issued D.21-06-035, we were aware that additional procurement may be needed, especially in the latter two years of the period addressed (which covered 2023-2026). In particular, there was uncertainty, even in early 2021, about the feasibility of developing the 2,000 MW long-lead-time (LLT) resources required in 2026. In addition, the resource procurement requirements in D.21-06-035 were front-loaded due to the large capacity of resources anticipated to go offline with the retirement of both units of Diablo Canyon. The need determination for 2025 and 2026 was therefore less certain than the need determination for 2023 and 2024. Further, we agree with Cal Advocates' suggestion that procurement should be ordered at least a year ahead of when it is shown to be needed, to allow for some buffer in the event that procurement takes longer than anticipated, as a safety precaution.

Taking all of these factors into consideration, as well as the proposal from Cal Advocates, we will order the additional 4,000 MW NQC proposed by Cal Advocates be added to the mid-term reliability procurement requirements from D.21-06-035, but in a slightly different manner from the proposal, as follows.

We are mindful that the 6,000 MW of procurement requirements for 2024 is a heavy lift for the LSEs. Procurement of those requirements should be well underway and LSEs might be unlikely to achieve any additional procurement in 2024 even if we ordered it. The requirement in 2025 is an additional 1,500 MW, for a total of 7,500 MW over the 2024-2025 period, which is still a large amount of procurement in a short period.

The D.21-06-035 requirement in 2026, however, was for a different sort of procurement, for LLT resources. LLT resources are defined as long-duration storage (able to deliver at maximum capacity for at least eight hours from a single resource) and generation capacity that has no on-site emissions or is eligible under the requirements of the renewables portfolio standard program with a capacity factor of at least 80 percent. The latter category of resources must not be use limited or weather dependent, and cannot be storage projects.[~~5~~6]

As already noted, even in 2021 we were uncertain whether those resources could be developed in time for a 2026 need, and therefore we included provisions in D.21-06-035 for extensions of those requirements up to 2028.

By way of this order, we will amend the LLT requirement slightly and allow any LSE to show compliance with its LLT requirements at any time between June 1, 2026 and June 1, 2028. Effectively, this moves the requirement for 2,000 MW of LLT resources to 2028, instead of 2026. If the LLT resources come online in a year prior to 2028, then the individual LSE would still have a generic capacity procurement obligation in 2028. LSEs should still provide evidence of the good faith efforts required in D.21-06-035, Ordering Paragraph (OP) 5, by the February 1, 2023 milestone filing, but the Commission will hold off ordering any backstop of this type of ~~resources~~resource as a result of that filing.

For LSEs that have already procured some or all of their required LLT resources, they may substitute those resources for the 2026 or 2027 resources required in this order, and move the additional procurement required herein to 2028. In other words, in total, there will be 2,000 MW of LLT resources procured between 2026 and 2028, such that the total resource procurement in each year adds to 2,000 MW NQC.

This change obviates the need for approval of any extension requests by LSEs that ~~anticipate~~anticipated not making the original 2026 online date deadline in D.~~21-06-035 and will remove a lot of necessary regulatory process for LSE, the~~

[~~5~~6] *See* D.21-06-035, OP 2, for the formal definition of these requirements.

~~Commission, and staff around the LLT requirements and anticipated extension requests~~21-06-035.

In place of the 2026 requirements for LLT resources, we will instead require procurement of 2,000 MW of September NQC resources by June 1, 2026. These resources may be of any sort that would otherwise qualify under the generic category in D.21-06-035, which means non-emitting, storage, and/or RPS eligible, but not fossil-fueled resources. In addition, we will add an additional 2,000 MW of September NQC procurement requirement by June 1, 2027 of the same type of generic clean resources. Thus, the expanded mid-term reliability requirements will be as given in Table 2 below.

Table 2: Increased Mid-Term Reliability Procurement Requirements (in MW, September NQC)

Need Type	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
General D.21-06-035 requirements[~~6~~7]	2,000	6,000	1,500			
LLT resources, as defined in D.21-06-035						2,000
New in this decision				2,000	2,000	
Total	**2,000**	**6,000**	**1,500**	**2,000**	**2,000**	**2,000**
Total (cumulative)	**2,000**	**8,000**	**9,500**	**11,500**	**13,500**	**15,500**

Counting of qualifying capacity will be based on ELCC studies published by Commission staff for the year in which the procurement is required. Commission staff may provide ~~new~~final compliance ELCCs for resources to meet the procurement being required here, if necessary, by no later than ~~the end of~~June 30, 2023, and will notify stakeholders via a notice to the service list of this

[~~6~~7] This includes ~~the~~2,500 MW of procurement ~~category requiring~~ from zero-emissions generation, generation paired with storage, or demand response resources, ~~and does not include the category~~which is specifically designed for replacement of Diablo Canyon capacity online by 2025, as further defined in D.21-06-035.

proceeding. Preliminary values have already been published.[8] For resource types not addressed by additional guidance from Commission staff, NQC counting will be in accordance with the ~~new~~ system resource adequacy NQC counting rules at the time the contract is executed for the new resource or capacity added to an existing resource ~~is executed~~.

The procurement required in Table 2 above results in a relatively steady procurement requirement for the years 2025-2028, and will allow the Commission to continue to evaluate, in consultation with the CAISO and CEC, the system reliability picture between now and the end of the required procurement period. The procurement requirements adopted herein in NQC terms are still less than the totals the PSP portfolio totals show in nameplate,[~~7~~9] strongly suggesting that future procurement will continue to be required for many years to come.

We decline to extend the additional requirements to 2030, as suggested by Cal Advocates, because we intend to develop the programmatic procurement approach in time to influence procurement ordered after this decision. Should that plan not come to fruition, we will need to reevaluate how to order additional procurement in the future.

In the meantime, the procurement requirements will be allocated among all LSEs ~~using the same method used by D.21-06-035. This means~~currently serving load, utilizing a combination of both the ~~2021~~2023 year-ahead resource adequacy forecasts and the energy load forecasts of individual LSEs from the

[8] *See* 2023 ELCC Study and accompanying Staff Transmittal Memo posted at the following link: 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

[~~7~~9] *See* D.22-02-004.

~~2020~~2022 IEPR for ~~2021~~2023. Resources procured in compliance with this order will be subject to the power charge indifference adjustment (PCIA) vintage cost responsibility based on the date of this decision. The IOUs are authorized to file a Tier 2 Advice Letter within 60 days of the effective date of this decision, if necessary, to update their PCIA balancing accounts to account for this change. Load migration between the IOUs and non-IOU LSEs since the D.~~21-06-035~~21-06-035 order ~~are~~is already accounted for through the ~~power charge indifference amount (~~PCIA~~)~~ mechanism.

LSEs will be responsible for conducting their own procurement for the additional need allocated to them, and LSEs will not have the option to opt out to have another LSE procure on their behalf.[10] Responsibility for the new procurement only will be allocated to LSEs currently in the market and the allocation of the existing D.21-06-035 procurement requirements will not be readjusted, except for in instances where an LSE has exited or entered the market. This means that the 4,000 MW total requirements for 2026 and 2027 will be allocated to current LSEs based on the ~~2021~~2022 IEPR demand forecast~~,~~ and 2023 year-ahead resource adequacy forecasts, but the LLT resource allocation will remain as it was in D.21-06-035 for LSEs currently serving load.

As suggested by numerous parties in comments on the proposed decision, we have included below a table showing the exact allocation of the procurement responsibilities to each LSE, with electric service provider allocations shown in aggregate only, to be transmitted confidentially by Commission staff within one week of the effective date of this decision. We also round the procurement

[10] This does not preclude limited compliance obligation trading, as described further in Section 2.4.4 of this decision.

requirements to whole numbers of capacity in MW (with one exception for a small LSE), to simplify procurement and implementation. Thus, the individual numbers do not add precisely to 4,000 MW, due to the effects of rounding.

Table 3: Allocation of Procurement Responsibility by LSE

LSE	2026	2027	Total
PG&E Bundled	388	388	777
PG&E Direct Access (Aggregated)	74	74	147
CleanPowerSF	31	31	63
East Bay Community Energy	68	68	136
King City Community Power	0.4	0.4	0.8
Marin Clean Energy	61	61	122
Central Coast Community Energy	55	55	111
Peninsula Clean Energy Authority	35	35	70
Pioneer Community Energy	19	19	38
Redwood Coast Energy Authority	7	7	14
San Jose Clean Energy	40	40	80
Silicon Valley Clean Energy	40	40	79
Sonoma Clean Power	23	23	45
Valley Clean Energy Alliance	8	8	16
SCE Bundled	684	684	1367
SCE Direct Access (Aggregated)	86	86	172
Apple Valley Choice Energy	3	3	6
Baldwin Park, City of*	0	0	0
Pomona, City of	4	4	7
Clean Power Alliance of Southern California	117	117	235
Desert Community Energy	4	4	9
Lancaster Energy Clean	7	7	13
Pico Rivera Innovative Municipal Energy	2	2	5
Rancho Mirage Energy Authority	3	3	6
San Jacinto Power	2	2	4
Santa Barbara Clean Energy	4	4	7
Western Community Energy*	0	0	0
SDG&E Bundled	72	72	143
SDG&E Direct Access (Aggregated)	25	25	51

LSE	2026	2027	Total
Clean Energy Alliance	14	14	27
San Diego Community Power	80	80	160
Energy for Palmdale's Independent Choice**	6	6	12
Orange County Power Authority**	38	38	76
Total	*2,000.4*	*2,000.4*	*4,000.8*

*LSE is no longer serving load; SCE is procuring for these two LSEs.
**New LSEs since D.21-06-035 was adopted.

The backstop provisions of D.20-12-044 will remain in effect, along with the annual milestones, which will be extended throughout the period through the end of 2028. This means bi-annual procurement data filings from each LSE on February 1 and August 1 through 2023, and December 1 and June 1, beginning December 1, 2023, continuing in perpetuity unless we change this schedule in a subsequent decision. This will include backstop trigger determinations after the February 1, 2023 filings and the December 1 filings thereafter, as described in more detail in D.20-12-044 and D.21-06-035.

Cost allocation, in the event that we order backstop procurement, will follow the modified cost allocation mechanism (MCAM) requirements adopted in D.22-05-015.

Penalties for non-compliance for the increased/expanded mid-term reliability procurement requirements in this decision will follow the previously-established requirements in D.21-06-035, based on the net cost of new entry (net CONE). However, D.21-06-035 set only one penalty milestone date of June 1, 2025, for all procurement during the period 2023-2025. Because this decision begins to set ongoing and annual procurement requirements, after June 1, 2025, we will assess compliance on ~~an annual basis~~June 1, 2027 for the 4,000 MW NQC of new resources required in this order and June 1, 2028 for the LLT resources, with the potential for penalties to be assessed on each of those dates for any LSE for failure to meet ~~any of~~ the ~~annual~~ procurement requirements.

In addition, we note that we continue to require procurement for our IRP jurisdictional LSEs, without regard to procurement need that may be attributable to load being served by publicly-owned utilities within the CAISO. This matter was discussed in D.22-02-004 and still requires additional consideration for the future procurement program development and any subsequent procurement orders.

Finally, with respect to concerns raised by GPI, among other parties, we encourage LSEs to continue procuring resources in advance of any additional orders or our adoption of a comprehensive procurement program framework. Using whatever mechanism we adopt, we expect to give credit for and take into account proactive and early procurement by LSEs. As suggested by CalCCA in comments on the proposed decision, we make it explicit that 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.

2.4. Other Modifications to Prior Decisions to Facilitate Continued Procurement

Beyond ordering additional procurement amounts, the September 8, 2022 ALJ ruling invited parties to suggest other changes that the Commission might make or actions we might take to encourage additional procurement by LSEs to meet or exceed the requirements of D.19-11-016 and D.21-06-035.

Twenty one parties submitted proposed modifications to prior decisions or expressed a perception that future action is needed. Proposals included changes to penalty provisions, changes to D.21-06-035 procurement categories, changes to compliance rules, changes to bridge resource requirements, interconnection issues, proposals for new or modified procurement orders, consideration of the role of fossil-fueled resources, as well as other topics.

For time and space reasons, we are not including every suggested action in the discussion in this decision. We have eliminated some proposals from consideration because they are either out of scope, would require major changes to existing procurement requirements (and therefore would need additional record development), or are otherwise not immediately implementable in this decision. We have also ~~eliminated~~opted not to include any suggestions that were considered and rejected in prior decisions and where the circumstances have not changed to justify reconsideration. We did, however, read and carefully consider all proposed modifications.

2.4.1. Penalty Calculation and Enforcement for D.21-06-035 Procurement

In response to the September 8, 2022 ALJ ruling, several parties brought up desired clarifications to the penalty provisions of D.21-06-035.

2.4.1.1. Proposal of Parties

AReM, SCE, CalCCA, and EBCE all brought up the idea that the Commission should not enforce penalties against LSEs that make good faith procurement efforts but are still unable to procure, based on exogenous factors discussed in the September 8, 2022 ALJ ruling. Parties also suggested that the Commission should consider the potential of penalty "layering" since there are multiple regulatory programs and potential penalties in IRP, resource adequacy, and the RPS program.

In reply comments, this proposal was supported by SENA and AReM (supporting SCE and EBCE comments). CalCCA supports a modified version of SCE's penalty waiver proposal through a twelve-month compliance extension framework, based on an LSE's good faith showing. Hydrostor supports these proposals and suggests that the Commission clarify that if procurement is slightly delayed, including an online date after the mandated deadline, that good faith efforts will be taken into consideration. CAISO states that LSEs should not be penalized for delays due to network upgrades. SENA suggests the Commission should consider providing LSEs some form of relief, whether through grace periods, penalty waivers, or extended compliance deadlines, given the significant global supply chain uncertainty and overall difficult procurement circumstances.

AReM and CalCCA also asked for clarification of how the net cost of new entry (CONE) would be calculated, if the avoided costs calculator (ACC) moves away from including that provision in the future, as has been suggested in the integrated distributed energy resource (IDER) rulemaking where the ACC is updated. AReM and CalCCA also suggest that the Commission should clarify that a penalty imposed in 2025 will only be applied to the 2023-2025 procurement shortfall and not future years. Finally, they seek clarity on whether backstop procurement (and associated costs) will be for a ten-year period, or only until the LSE can bring its resource online.

2.4.1.2. Discussion

On the face of it, it is difficult to see how clarifying or loosening the penalty structure will help get additional resources procured and built faster, which was the purpose of the invitation to parties to provide ideas. Furthermore, indicating any laxity in the penalty structure up front may directly harm any ratepayers of LSEs that have endeavored to procure capacity, sometimes under difficult or costly terms. Therefore, we will not relieve any LSE of potential penalties up front. However, we recognize that there are exogenous factors happening in the market in general, including, but likely not limited to, the ones listed in the September 8, 2022 ALJ ruling. We also recognize that LSEs may make all good faith efforts to procure the required resources and simply be unable to for reasons beyond their control.

Nonetheless, the Commission expects LSEs to make those good faith efforts to procure the required resources to meet their allocated procurement requirements. The Commission and staff will consider deficiencies and non-compliance on a case-by-case basis, taking the LSE's efforts and all relevant and exogenous factors into account.

On the question of calculation of net CONE, if the IDER proceeding does not publish an updated net CONE figure for the year a penalty would be imposed (*i.e.*, 2025 or later), we will find another way to maintain the calculation of these values to be used for IRP penalty purposes. While it is clear that the IDER proceeding is not calculating this metric currently, it is less clear what will be included in future updates. Regardless, Commission staff will maintain and publish the net CONE calculation for IRP purposes with notice to the service list of this proceeding.

We do clarify that AReM and CalCCA are correct that penalty amounts assessed in 2025 will be based on the capacity obligations for 2023-2025, and not future years. In other words, the penalties will not be ongoing, but are for those specific years' worth of capacity obligations. However, once backstop procurement is ordered, the cost and quantity of the backstop procurement ~~amount is the responsibility of the deficient LSE for a full ten-year period, and the particular LSE (and its customers) will be responsible for the costs of the backstop procurement for the entire ten-year period~~will be recovered through MCAM charges, even if the LSE's contracted resources are brought online in the meantime. ~~If an LSE fails to meet a procurement obligation, it will pay an annual penalty for each year it is deficient, for up to ten years, and will additionally pay for the full cost of a ten-year contract for backstop for additional resources.~~

We also clarify that the questions of whether backstop procurement should be ordered and whether penalties should be assessed are separate, but related. It is possible that we could order backstop procurement, but not order penalties for a non-complying LSE, where best efforts simply did not produce the required capacity. It is equally possible that we could order penalties, but not backstop procurement, for example in a situation where the LSE's resource(s) will be online within a short period of time.

For purposes of the incremental procurement for 2026 and 2027 required by this order, we will assess compliance for both years with information contained in the June 1, 2027 filings by LSEs.

Finally, we note that because we are moving the deadline for the procurement of LLT resources from 2026 (as was ordered in D.21-06-035) to June 1, 2028 in this order, the question of whether penalties will be levied for LSEs that seek an extension past 2026 for LLT resources is now moot. Penalties may be assessed for failure to procure the required LLT resources ~~when penalties are considered for~~as of June 1, 2028.

2.4.2. Procurement Categories from D.21-06-035

In response to the September 8, 2022 ALJ ruling, several parties brought up desired changes or clarifications to the categories of procurement required by D.21-06-035. In most cases, these ideas represented suggestions that were already considered and dismissed when D.21-06-035 was adopted. However, below we discuss one potential clarification with respect to the category of resources designed to replace Diablo Canyon Power Plant capacity.

2.4.2.1. Proposal of Parties

SVCE and SCPA/RCEA propose that we provide additional flexibility to LSEs to meet the zero-emitting Diablo Canyon replacement category in D.21-06-035. SVCE/SCPA/RCEA propose that LSEs should be allowed to procure energy and batteries separately, so long as the energy is deliverable to the system. They argue that LSEs should be allowed to count hybrid resources for which an LSE may not contract for the energy directly, but where the energy is otherwise not used for compliance with D.21-06-035 and has economic incentives to charge the battery and dispatch during peak hours.

In reply comments, AReM and CalCCA support the proposal and SCE believes that procuring storage and renewables separately is already permissible. SCE requests that the Commission clarify that energy-only renewable generation contracts can be contractually paired with separate energy storage contracts.

2.4.2.2. Discussion

On these issues, we clarify that SCE is correct that energy and storage contracts can be procured separately and still comply with the Diablo Canyon replacement category of resources. However, both the energy and storage must be contracted by the LSE that is claiming them for compliance with the requirements of D.21-06-035.

Further, we clarify that contracts for energy-only renewables may be used to comply with the Diablo replacement category requirement, but only if they can demonstrate by engineering assessment that the energy delivered will be sufficient to charge the batteries to discharge to meet the resource requirements originally set forth in D.21-06-035 and subsequent FAQ documents from Commission staff.[~~8~~11] This would not enable the energy-only resources to count

[~~8~~11] Refer to this link under the heading "Additional Procurement Guidance" for more details: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procureme directly as capacity/NQC towards an LSE's obligation, but will support the counting of the NQC of the storage resource.

2.4.3. Bridge Resources for D.21-06-035 Procurement

In response to the September 8, 2022 ALJ ruling, several parties raised issues around the use of imports to serve as a bridge to bringing online new resources. The basic concept is to allow for additional development time for new resources to come online without compromising short-term reliability, by contracting on a short-term basis with existing resources to be firm and committed to serving load in California.

2.4.3.1. Proposal of Parties

AReM proposes to allow capacity and efficiency upgrades at existing natural gas facilities to count as bridge capacity.

SCE recommends that the Commission allow bridge capacity from any firm imports to California, including firm imports from fossil-fueled resources, resources that do not meet other D.21-06-035 eligibility requirements, and resources from other counterparties. SCE also recommends restricting firm imports as a bridge for only one year and not allowing the resources to count toward the LSE's resource adequacy requirements.

AReM supports allowing firm imports to count, but believes that this is already allowed. CEJA and Sierra Club oppose allowing bridge resources that create climate or air pollution impacts and support limiting bridge resources to one year. CAISO supports SCE's proposal, with no firm position on other eligibility requirements proposed by SCE. Enchanted Rock supports SCE's

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.

proposal and states that "ten year term for bridge capacity procured by 2025 should not result in any negative impacts for the Commission's goal to achieve a specified resource mix by 2035." PG&E and SENA also support SCE's proposal.

2.4.3.2. Discussion

We confirm AReM's interpretation that D.21-06-035 does allow firm imports to count toward capacity requirements and serve as bridge resources until new capacity comes online. Prior to now, those resources were required to be renewable and/or zero-emitting to qualify.

D.21-06-035 contains extensive discussion about the use of natural gas efficiency and capacity upgrades to existing natural gas plants in California to count toward its requirements, and concludes that these resources do not qualify to be counted. We do not disturb that determination here as it was thoroughly debated during the deliberations prior to D.21-06-035.

We do, however, allow for bridge resource purposes, the limited situation where an LSE wants to use a firm import contract for system power, which may include a mix of natural gas-fueled and/or unspecified resources, to count. We will allow this type of bridge, because it is not likely to be a long-term arrangement and is not likely to result in any increase or incremental capacity that is fossil-fueled to be built. Rather, it serves only as a temporary reliability hedge until such time as the LSE's clean resources come online. As proposed by PG&E and supported by CalWEA in comments on the proposed decision, we will allow these system power imports to count as bridge resources as long as they meet requirements under the Resource Adequacy program rules in place when the contract is executed.

We also will allow resources from other counterparties than the developer of the primary resource to serve as bridge resources, as suggested by SCE.

We decline to limit the term to one year, as proposed by SCE, because it seems unnecessarily limiting and we cannot know up front exactly the length of time that is needed to bridge to the new resources coming online. In any case, the term may not be longer than ~~ten~~three years, as proposed by UC and AReM in reply comments on the proposed decision, but may be more than one year. The ~~ten~~three-year maximum should ensure that this provision is not used to support development of new resources, but rather to utilize existing resources for reliability purposes.

We will not allow the bridge resources to serve as a bridge to the procurement of capacity for the Diablo Canyon replacement category identified in D.21-06-035, because that category was explicitly designed to support firm, clean resources. We also will not allow bridge resources to serve to support LLT procurement, because we are providing the extension to the deadline for that category instead. Thus, the bridge resources may only be used for the generic category of procurement from D.21-06-035 and the new procurement for 2026 and 2027 required in this decision.

Finally, the requirements in D.21-06-035 for imports to have a MIC allocation to be counted for compliance purposes, still apply for the bridge resource situation described here, and with the additional flexibility provided below in Section 2.4.5.2.

2.4.4. Compliance Rules for D.19-11-016 and D.21-06-035

In response to the September 8, 2022 ALJ ruling, several parties put forward proposals to clarify specific compliance rules for D.21-06-035 requirements.

2.4.4.1. Proposal of Parties

SENA proposes that the Commission confirm that LSEs may split capacity associated with a single resource that has come online since January 1, 2020, between its D.19-11-016 and D.21-06-035 procurement requirements.

SCPA and RCEA propose that the Commission clarify that LSEs may trade compliance obligations. For example, LSE A has a new resource coming online in 2025 for its own compliance obligation and may only need a two-year bridge to its online date. LSE B may have procured resources in excess of its allocated share for 2023 and 2024. Rather than requiring backstop procurement for LSE A who is short for 2023 and 2024, SCPA and RCEA propose that LSE A can transact for 2023-2024 share of its procurement obligation from LSE B.

CalCCA supports this proposal.

SCE states that the Commission did not address what cost recovery mechanism applies when an IOU takes on the procurement obligation of a failed LSE in D.21-06-035. SCE proposes that CAM treatment should apply when an LSE with an IRP procurement obligation declares bankruptcy or ceases providing retail service in California and the IOU is required to procure on behalf of the failed LSE's customers, even if the LSE's customers are not paying for capacity under the MCAM.

SDCP proposes that, due to significant changes impacting procurement since D.19-11-016 and D.21-06-035 were issued, the Commission should modify the provision in D.22-05-015, OP 4, to allow non-IOU LSEs the option to purchase their customers' share of D.19-11-016 resources from the incumbent IOU based on the most current version of load forecasts in the 2023 year-ahead load forecast process.

SCE opposes this SDCP proposal, as D.22-05-015 already allowed for a one-time provision at the market price benchmark.

2.4.4.2. Discussion

In response to SENA's suggestion, we clarify that an LSE may split the capacity associated with a single resource between its D.19-11-016 and D.21-06-035 obligations, as long as the resource meets the requirements of the decision for which it is being counted, including being incremental to the respective decision's baseline generator list of resources.

In response to SCPA and RCEA, we agree that trading of compliance obligations between LSEs is reasonable and permissible. ~~However, we~~In response to the concerns raised by PG&E and SCE in response to the proposed decision about the potential for this permission to result in inadvertent "opt-out" situations, we add a few requirements. Most importantly, the arrangement must actually be a trade of one compliance obligation for another. It may not be a purely financial arrangement where one LSE pays another to take on its procurement obligation. We are making this trade arrangement available to LSEs that have mismatches in the timing of their resource procurement, but not to allow LSEs to opt out of their procurement obligations entirely. An LSE may not "trade" away its entire obligation. There may be financial remuneration involved, but some compliance obligations also must be traded by both LSEs.

We also need a way to verify and track such arrangements. We already have a similar process in place where IOUs and non-IOUs can track changing obligations for load migration through the filing of a Tier 2 Advice Letter. For purposes of a trade of compliance obligations between any two LSEs, we will require the same mechanism. ~~Each~~At least one of the LSEs involved in the compliance obligation trade transaction shall file a Tier 2 Advice Letter providing documentation of the trade arrangement, including whether and to what degree financial terms were involved.

On the question of the cost recovery mechanism to be used when an IOU takes on the D.21-06-035 compliance obligation of a bankrupt LSE or one that ceases providing retail service in California, we agree with SCE. CAM cost recovery shall apply when an IOU takes on the D.21-06-035 obligation of an LSE that is in bankruptcy or is otherwise no longer providing retail service ~~if the LSE's customers are not already paying for the same capacity under the MCAM~~. This is the most fair mechanism, because the IOU's bundled customers should not be obligated to take on the full responsibility for the costs on behalf of customers previously served by another LSE. We also decline to adopt the CalCCA proposal to restrict the applicability of CAM treatment to situations where notice to the IOU is less than 24 months. This restriction could shift not only procurement, but also cost, responsibility for failed LSEs to bundled IOU customers.

Finally, with respect to the SDCP proposal to allow non-IOU LSEs the option to purchase its customers' share of D.19-11-016 resources from the incumbent IOU, we decline to authorize this here and note that it is the subject of a separate petition for modification of D.22-05-015, which we will address separately. Meanwhile, D.22-05-015 already allowed for a one-time provision of capacity from the incumbent IOU. After that one-time opportunity, the MCAM (D.22-05-015) makes clear that any subsequent load migration will be subject to the ~~power charge indifference adjustment (~~PCIA~~)~~ mechanism. SDCP does not have a D.19-11-016 compliance obligation, so to the extent that the purpose of the proposal involves the need for resource adequacy capacity, there is already a framework approved by the Commission for sales of excess capacity by the IOUs.

2.4.5. Interconnection Issues

In response to the September 8, 2022 ALJ ruling, several parties raised ideas related to generator interconnection.

2.4.5.1. Proposal of Parties

CalCCA and PCE propose that the Commission allow projects without a CAISO deliverability study to count temporarily toward D.21-06-035 requirements under certain conditions. CalCCA and PCE are concerned that there is a significant backlog for the CAISO interconnection study process. They state that the Commission should work with the CAISO to improve the interconnection study process, urge transmission owners to shorten interconnection times, and reevaluate the deliverability methodology as the current method is too restrictive.

CAISO disagrees that the deliverability methodology is too restrictive. CAISO points out that deliverability assessment supports reliability and LSEs should ensure procured in-state resources obtain deliverability and that there is sufficient maximum import capability (MIC) allocation for their imports. CAISO suggests, however, that LSEs should not be penalized for delays in project deliverability due to network upgrades.

CCSF, Fervo, PCE, SVCE, SCPA, and RCEA all suggest that the MIC process also presents an obstacle to compliance with D.21-06-035 requirements. They suggest that the Commission modify the MIC allocation requirements and consider crediting LSEs for imports either pseudo-tied or dynamically-scheduled into the CAISO that have achieved commercial operation, even if they do not yet have a MIC allocation, as long as the LSE is seeking to secure a MIC allocation. AReM supports this proposal.

Fervo further proposes that the Commission adopt policies to prioritize import capacity allocation for resources with capacity factors greater than 80 percent.

2.4.5.2. Discussion

First, it is important that parties understand that the MIC allocation process is not within the Commission's control, but is administered by the CAISO. Thus, we may offer recommendations, but the Commission does not make MIC decisions. Therefore, while we may be sympathetic with certain proposals, such as Fervo's for high capacity factor resources, we understand that the CAISO follows its established process for MIC allocations.

We also agree with the CAISO that the interconnection study process is important to ensure reliability, and therefore the deliverability ~~studies~~study process should ~~not~~ be ~~subjected to shortcuts~~followed.

We do clarify, however, that pseudo-tied and dynamically-scheduled projects are allowed to count toward D.21-06-035 requirements even if they do not yet have a MIC allocation, as long as the LSE is taking steps to obtain the MIC allocation. Since it is difficult or often impossible to secure a MIC allocation prior to the resource coming online, it is logical that the IRP procurement requirement should allow a resource to count towards a procurement obligation starting in the year it is actually providing power, even if the MIC allocation is not yet confirmed.

3. CAISO TPP Recommendations

In this section, we turn to the recommended portfolios we transmit to the CAISO for use in its 2023-24 TPP. The October 7, 2022 ALJ ruling in this proceeding contained the staff recommendations for portfolios. In this decision, we take into account the comments of parties in response to the staff recommendations.

3.1. Base Case Portfolio

As most parties are aware, the Commission annually recommends a base case portfolio for study in the TPP. There can be both a reliability base case and a policy-driven base case. In recent years, the Commission has recommended the same portfolio as the base case for both reliability and policy. Once the CAISO studies the base case, transmission needs identified go to the CAISO board for approval.

3.1.1. GHG and Load Assumptions

For the 2023-2024 TPP base case, Commission staff in the October 7, 2022 ALJ ruling recommended using a portfolio that meets a 30 million metric ton (MMT) GHG target in 2030, with load assumptions based on the CEC's IEPR Additional Transportation Electrification (TE) Load Scenario. This is a portfolio with more resources required to serve more load than was adopted as the PSP to be used by LSEs to plan for their most recent individual IRPs filed on November 1, 2022. The portfolio includes approximately 86 GW of new resources by 2035, on top of the existing resource mix on the electric grid of approximately 75 GW. This is more than a doubling of nameplate capacity on the system within 12 years.

Table ~~3.~~ 4: Total Base Case Portfolio Resource Additions (in MW)

Resource	2026	2030	2033	2035
Natural Gas	-	-	-	128
Biomass	107	134	134	134
Geothermal	1,095	1,151	1,863	1,863
Hydro (small)	-	-	-	-
Wind	3,864	3,864	3,864	3,864

Resource	**2026**	**2030**	**2033**	**2035**
Wind (out of state, on new transmission)	312	4,828	4,828	4,828
Offshore Wind	120	3,100	3,261	4,707
Solar	11,073	21,367	32,025	39,072
Customer Solar	-	-	-	-
Battery Storage	11,145	13,529	21,738	28,381
Pumped Storage	196	1,000	1,524	2,000
Shed Demand Response	1,111	1,111	1,111	1,111
Total	**29,025**	**50,085**	**70,349**	**86,089**

The modeled portfolio also reveals that greenhouse gas emissions become the binding constraint on the portfolio starting in 2025, and the planning reserve margin also drives new resource development needs after 2028. Note also that Commission staff chose to replace the 128 MW of new gas selected in 2035 with 174 MW of geothermal in the preliminary busbar mapping analysis, since it is state policy not to plan for development of new natural gas resources if they can be avoided.[912]

The general rationale for recommending this portfolio, among other things, is that transmission planning and construction typically has a longer lead time than generation and storage. Recent work, including the SB 100 (DeLeon, 2018) report and the 20-year transmission outlook by the CAISO, demonstrates the need for significantly more generation and storage to meet California's climate policy goals, beyond what is included in this portfolio. Therefore, if California is to meets its aggressive reliability and environmental goals, more transmission will need to be planned and built ahead of generation and storage

[912] *See*, among other things, the letter from Governor Newsom to CARB, available at the following link: https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf?emrc=1054d6 .

development, and it is just a matter of exactly when, and not if, the transmission will be needed.

3.1.1.1. Comments of Parties

The clear majority of parties in this proceeding support the staff recommendation to use a 30 MMT GHG base case, with the higher electrification load assumptions. Those parties supporting include: ACP-CA, Avangrid Renewables, CAISO, CalCCA, Cal Advocates, CalWEA, CEERT, CESA, CEJA, Sierra Club, Western Grid, DOW, Golden State, GridLiance, Geothermal Rising, GPI, EDF, EDF Renewables, NRDC, SDG&E, and SEIA.

BAMx and Reid support using the 38 MMT portfolio in 2030. BAMx is concerned that the larger portfolio in the staff recommendation could lead to excessive or sub-optimal transmission upgrades. Reid is concerned that the 30 MMT portfolio will unnecessarily increase ratepayer costs.

SCE supports the staff base case proposal, but feels that the load forecast is likely too low. SCE is concerned that the proposed base case portfolio incorporating the 2021 IEPR Additional TE scenario does not reflect the recent accelerated Electric Vehicle (EV) adoption trend in the near term.

PG&E supports the proposed base case, but generally thinks it should be more aggressive than IRP planning to allow for transmission development. PG&E recommends future iterations of the IEPR Additional TE load forecast align with the California Air Resources Board (CARB) Scoping Plan scenarios or, to the extent they are not aligned, the CEC should articulate how and why the IEPR Additional TE scenario is not aligned with CARB's Scoping Plan scenarios.

3.1.1.2. Discussion

For the 2023-2024 TPP, we will adopt the staff recommendation to use the 30 MMT GHG scenario in 2030, with load based on the CEC's 2021 IEPR

Additional TE scenario. We generally agree with PG&E and SCE that the load forecasts should continue to be refined, in accordance with the CARB Scoping Plan. We will continue to work with the CEC and CARB to ensure that our planning efforts remain aligned. Given that the TPP is an annual process, the current portfolio (30 MMT in 2030, with the additional TE load forecast) will be aggressive enough, with 85 GW nameplate of new resources, and a significant advancement from previous base case scenarios. In fact, the 30 MMT scenario in 2030 is the most aggressive level within the range set by CARB in its 2022 Scoping Plan Update, which sets a range of 30-38 MMT by 2030 for the electric sector.[~~10~~13] Next year, as we do every year, we will consider whether the load forecast and other assumptions need to be updated further.

We disagree with Reid and BAMx in their recommendations to revert to a 38 MMT in 2030 base case. If we are to reach our aggressive goals, transmission infrastructure needs to be planned and built at a faster rate. The 30 MMT in 2030 base case will help accelerate the necessary transmission development.

In response to comments from CalWEA on the proposed decision, we also include here our encouragement to the CAISO to get a head start on identifying any associated transmission needs by considering the results of the similar sensitivity case that is currently undergoing analysis in the 2022-2023 TPP cycle to make transmission investment recommendations to the CAISO Board as soon as possible.

3.1.2. Planning Horizon

Commission staff, in the October 7, 2022 ALJ ruling, recommended a 12-year planning horizon, out to 2035, instead of the usual ten years. The

[~~10~~13] *See* https://ww2.arb.ca.gov/sites/default/files/barcu/board/res/2022/res22-21.pdf.

purpose is to align with both the CEC's IEPR process and the CAISO's TPP, both of which are now planning out to 2035.

3.1.2.1. Comments of Parties

Several parties explicitly support mapping out to 2035, as suggested by Commission staff, including CalCCA, CalWEA, CESA, EDF, GridLiance, Geothermal Rising, and Golden State.

ACP-CA, Avangrid Renewables, CESA, NRDC, and EDF also recommend extending the time horizon to 15 years or more, in line with future requirements of SB 887 (Becker, 2022).

3.1.2.2. Discussion

For this TPP cycle, we will keep the 2035 planning year, in keeping with the Commission staff recommendation. CAISO is still in the process of conducting its stakeholder process to formally extend its study timelines consistent with SB 887 requirements. In general, current planning tools and processes between the Commission, CEC, and CAISO require additional work before transmission investments should be made on their basis beyond the 12-year horizon adopted here. The 2035 planning year is in current alignment with the CEC and CAISO processes, and we will continue to stay coordinated as all of our planning processes evolve.

We do request, in accordance with SB 887 (Becker, 2022), that the CAISO do the following: 1) identify, based as much as possible on CAISO studies and Commission and CEC projections completed before January 1, 2023, the highest priority transmission facilities that are needed to allow for increased transmission capacity into local capacity areas to deliver renewable energy resources and/or zero-carbon resources that are expected to be developed by

2035 into those areas; and 2) consider whether to approve transmission projects as part of its 2022-2023 TPP.

3.1.3. Offshore Wind Amount, Location, and Timing

The October 7, 2022 ALJ ruling recommended including 4.7 gigawatts (GW) of offshore wind in the base case portfolio. Offshore wind was selected by the RESOLVE capacity expansion model at Morro Bay (3.1 GW) in 2033, and at the Humboldt location (1.6 GW) in 2035. The busbar mapping results linked in the ALJ ruling identified that mapping the amount selected at the Humboldt location to busbars would cause significant exceedance of the available transmission that could only be alleviated with significant new transmission development.

3.1.3.1. Comments of Parties

The majority of parties support at least the level of offshore wind in the portfolio, as well as the timing. Several parties recommend increasing the amount of offshore wind in the base case, to reflect either the increased energy density assumptions shown in the updated 2022 National Renewable Energy Laboratory (NREL) study of offshore wind potential[~~11~~14] or alignment with AB 525 (Chiu, 2021) planning goals, or both.

CalWEA is focused on aligning with the 2022 NREL resource potential amounts. ACP-CA and EDF focused on aligning with AB 525 goal amounts; OWC-CA stresses the importance of both. OWC, EDF, and NRDC also comment on the long development times and potential for delays, arguing that those require starting as early as possible to develop the transmission. RCEA and

[~~11~~14] Available at: https://www.nrel.gov/wind/offshore-market-assessment.html.

SCPA also strongly support more optimal study of the transmission needs on the north coast, as do CalWEA and ACP-CA.

PG&E and SCE note that development/permitting timeline uncertainty and cost uncertainty are large variables for offshore wind, particularly in the north coast/Humboldt area. Both suggest that additional study is needed, but do not recommend changes to the base case amounts or timing.

BAMX expresses concerns for the transmission cost assumptions in the Humboldt area, and recommends rerunning the model with higher transmission costs to see if the Humboldt offshore wind would still be selected.

CalCCA, RCEA, and SCPA express concern about the rapid buildout of Humboldt offshore wind between 2033 and 2035, suggesting instead a slower ramp up that starts earlier than 2035.

3.1.3.2. Discussion

For purposes of the base case, we will maintain the 4.7 GW of offshore wind, divided between the Morro Bay and Humboldt call areas, as recommended by Commission staff in the October 7, 2022 ALJ ruling. We will also continue to monitor and participate in the AB 525 effort to ensure that offshore wind amounts in future base cases consider the planning goals in the AB 525 strategic plan that is due to be released later this year.

We also choose to maintain the locations where the 4.7 GW of offshore wind is mapped, in both the central and north coasts, despite the high likelihood of the CAISO finding that this will require significant new transmission to be built to access generation in the Humboldt area. We expect that it is a matter of when, not if, north coast offshore wind is part of the resource mix needed to meet state GHG-reduction goals. Further, the recent results of the lease auctions for offshore wind resources show interest in the Humboldt area and support our assessment that we need transmission development in the area to commence soon. In addition, the Humboldt resource area will likely require longer development timelines compared to transmission development on the central coast, thus making it important to study, and with its inclusion in the base case portfolio, potentially be approved for development, sooner rather than later. CAISO's 2023-2024 TPP need findings could be further considered in conjunction with the AB 525 strategic plan to determine the urgency of the transmission development.

With respect to the comments about optimizing transmission buildout for offshore wind, our hope is that the offshore wind sensitivity portfolio described in Section 3.2 below will further assist for transmission planning purposes. The CAISO will be able to use the results of that sensitivity analysis to guide optimal transmission development on the north coast, both for the 2023-2024 base case and for future portfolios.

With respect to the rapid buildout of north coast wind between 2033 and 2035, we agree with CalCCA, RCEA, and SCPA that this may be unrealistic. However, the purpose here is to identify the transmission needs, and therefore the exact timing is likely less important than the volume, for TPP purposes. The reality will likely be similar to the more gradual buildout that the parties describe.

3.1.4. Addition of Geothermal Resources

In this section, we discuss a few parties' proposals to add additional diverse resources to the base case.

3.1.4.1. Comments of Parties

Several parties note that the base case portfolio is heavy on solar and battery storage buildout. For diversity purposes, therefore, some parties recommend the addition of more geothermal to balance the portfolio.

GPI argues for the inclusion of more baseload renewable resources, favoring high-reliability and resource diversity. GridLiance and Geothermal Rising also argue for additional geothermal, as well as updating cost assumptions for geothermal resources. GridLiance specifically argues for more geothermal located in Southern Nevada, while RCEA and SCPA would prefer to add geothermal in Northern California.

3.1.4.2. Discussion

At this time, we are not convinced that adding additional geothermal to the portfolio is warranted, given that it would likely go beyond identified commercial interest in its development. However, Commission staff has already replaced some of the selected fossil-fueled resources with geothermal and this may require new transmission investments. We are strongly in support of the development of additional geothermal, and will continue to assess the transmission needs to access it in the future.

3.1.5. Deliverability Study Expectations

This section discusses the request that the Commission made to the CAISO by letter dated July 1, 2022, when transmitting the high electrification portfolio for study in the 2022-2023 TPP. Specifically, President Alice Reynolds, Commissioner Rechtschaffen and Commissioner Gunda of the CEC requested that the CAISO study transmission resources needed to support LLT resources, as well as to expand MIC beyond the CAISO balancing area authority.

3.1.5.1. Comments of Parties

CAISO requests that the Commission clarify its guidance in this regard. CalCCA requests that the Commission use the same guidance as in the July 1, 2022 letter to the CAISO in the transmittal of the portfolios for the 2023-2024 TPP.

CESA recommends that the Commission modify its guidance to include long-duration energy storage as part of the study needed to support LLT resources.

3.1.5.2. Discussion

We generally request that the CAISO utilize the same methodology as discussed in the July 1, 2022 letter from Commissioners Alice Reynolds, Rechtschaffen, and Gunda. Specifically, we ask that CAISO continue the necessary studies to inform and enable opportunities to provide MIC expansion and the development of incremental transmission capacity to support the LLT resources mapped in the policy- and reliability-driven base case portfolio, while preserving the existing transmission capacity that has been allocated to other projects earlier in the interconnection queue.

To aid in addressing this request, as discussed in the October 7, 2022 ALJ ruling, Commission staff proposed prioritizing busbar mapping alignment to resources in the CAISO's interconnection queue that have been assigned transmission plan deliverability (TPD). In seeking to balance the various busbar mapping criteria, the resulting mapped portfolios will not fully account for assigned TPD in the key regions for mapped LLT resources, particularly for the 2033 study year. To that end, Commission staff will identify assigned TPD unaccounted for by the mapping result in the key regions for the CAISO to include in its TPP studies, in addition to the mapped portfolio results.

We also agree with CESA that if any of the long-duration energy storage resources are located out of the CAISO balancing area, then those resources should still be included within LLT resources. We generally consider long-duration energy storage to be a subset of LLT resources.

3.1.6. Portfolio Reliability

In this section, we discuss parties' requests/recommendations for reliability studies on the base case and sensitivity portfolios recommended by Commission staff.

3.1.6.1. Comments of Parties

SDG&E and Cal Advocates both recommend that the base case and sensitivity portfolios be subjected to production cost modeling to determine the loss of load expectation (LOLE) of each portfolio, in order to assess their reliability. In reply comments, PG&E, CalCCA, ACP-CA, GPI, CEERT, and CAISO all supported this request.

3.1.6.2. Discussion

A full loss of load expectation (LOLE) study has been done by Commission staff on the base case portfolio, including both the baseline resources as well as the new resources selected by the RESOLVE model. Commission staff translated RESOLVE portfolios in each study year into generation resources in the SERVM model, and the resulting portfolios were tested against the 2021 IEPR demand forecast in each of the four study years (2026, 2030, 2033, and 2035). During the period that this proposed decision was available for comment, Commission staff re-ran the LOLE study with some modifications that address some parties' concerns expressed in comments on the proposed decision.

Some changes were made to how the SERVM model characterizes cogeneration units. First, research into CAISO data resulted in changes to the baseline generator list maintained by Commission staff.[15] The updates will also be posted on our website. In addition, cogeneration, geothermal, and biomass units were capped at their NQC levels, whereas previously their output had been capped at their maximum output levels (Pmax). This change more effectively characterizes how the units actually operate on the system. Finally, some pumping load from the Department of Water Resources was changed in the model to be characterized as demand response instead of pumped storage.

The proposed decision also included an error in the total electric demand, with the prior draft just showing sales demand, not total consumption demand, including demand modifiers. The modeling was correct, but the table presented in the proposed decision was incorrect. The table below includes the corrected total annual demand for each year.

Updated LOLE results show that the portfolio is determined to be reliable, due to the total LOLE result being below the Commission's 0.1 LOLE standard~~,~~ ~~indicating~~. These results indicate that less than one loss-of-load event is expected in ten years, in each of the four study years. Table ~~4~~5 gives the results of the SERVM modeling on the base case portfolio.

Table ~~4.~~ 5: Base Case LOLE by Study Year (events/year)

Factor	2026	2030	2033	2035
LOLE	~~0.001~~0.098	~~0.000~~ 0.002	~~0.022~~0.009	0.070
Loss of Load Hours (LOLH)	~~0.001~~0.135	~~0.000~~0.002	~~0.005~~0.027	~~0.059~~0.260
LOLH/LOLE (hours per event)	~~1.000~~1.378	~~0.000~~1.000	~~2.500~~3.000	~~2.682~~3.714
Expected Unserved Energy (GWh)	~~2.641~~149	~~0.000~~2	~~18.032~~89	~~371.330~~1,749

[15] The September 2022 version is posted at the following link: 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

Factor	2026	2030	2033	2035
Annual Demand (GWh)	~~250,666~~256,149	~~261,745~~281,417	~~272,906~~314,879	~~276,261~~338,616

Since the base case scenario is being assessed for its transmission needs and will likely result in incremental transmission development and associated costs based on its findings, we agree it is important for the portfolio to be determined to be sufficiently reliable.

~~We note that the 2026 result is extremely reliable and parties may wonder why, earlier in this decision, we are ordering additional procurement for that year.~~ It is also important to understand that the TPP base case portfolio includes resources that are selected by the RESOLVE model as theoretical resources, but that are not yet online or contracted to be online. ~~The base case portfolio is a modeled portfolio, whereas we have based the need for additional procurement on the actual procurement data submitted to us by LSEs, indicating contracted and online resources.~~

In addition, we note that the SERVM weather year dataset only includes historical weather information up to 2020 and does not yet contain 2022 extreme weather data or further explicit climate impact adjustments. The impacts of extreme weather events and climate change on both resource availability and load are still being explored in this proceeding, and the impacts of these factors on modeled system reliability are likely to be significant. For example, the Summer 2020 heat events that results in rotating outages produced a system peak load that was roughly 10 percent above the IEPR forecasted median peak. As such, while this portfolio has been found to be sufficiently reliable for further assessment in the TPP, recent events and the likelihood of similarly extreme weather in the future, combined with the imperative to maintain an aggressive resource buildout trajectory to achieve the state's clean energy and climate goals, ~~justify the approach to~~mean that we will need to continue to assess grid reliability both for TPP and procurement ~~taken in this decision~~purposes.

In the case of the sensitivity cases recommended (*See* further discussion in Section 3.2 below), sensitivities are not designed to be expected scenarios, optimal alternatives, or even realistic, by definition. Instead, they are designed to test specific transmission needs to develop more cost and feasibility information. Thus, it is not clear there would be much value in conducting reliability studies on the sensitivity portfolios. We also have limited staff and consulting resources, and choose not to deploy them on reliability studies of the sensitivity portfolios, only the base case.

3.1.7. Updated Assumptions

In response to the October 7, 2022 ALJ ruling, several parties recommend updating specific resource costs or potential, as well as incorporating impacts of the Inflation Reduction Act (IRA) of 2022.

3.1.7.1. Comments of Parties

EDF Renewables recommends re-running the base case scenario with the impacts of the incentives in the IRA of 2022. Geothermal Rising recommends updating the base case portfolio with new geothermal cost and potential information.

3.1.7.2. Discussion

At this time, we are not inclined to make these changes to the base case portfolio. There are always new and improved assumptions to take advantage of, which is why Commission staff updates the inputs and assumptions to the modeling on a regular basis. We see no specific need to do so again here prior to transmitting the base case, given the timing of when CAISO needs the mapped portfolios to begin the 2023-2024 TPP cycle. However, we will update these assumptions again each year, as usual.

3.2. Sensitivity Cases

The October 7, 2022 ALJ ruling contained two recommended sensitivity portfolios for the CAISO to study in the 2023-2024 TPP. The first sensitivity is a portfolio with a large amount of offshore wind by 2035, including 5.3 GW at Morro Bay, 3 GW in Humboldt, and another 5 GW on the north coast. The second sensitivity is designed to study the transmission requirements of a portfolio with an alternative resource mix, which assumes only limited development of offshore and out-of-state (OOS) wind on new transmission by 2035. The objective of the second sensitivity is to better understand the transmission needs of a portfolio with significantly more solar, storage, and geothermal resources, and to identify transmission upgrades that may be common across many types of portfolios.

3.2.1. Offshore Wind Sensitivity

This section addresses the first sensitivity, related to approximately 13 GW of offshore wind.

3.2.1.1. Comments of Parties

Most parties commenting on the October 7, 2022 ALJ ruling sensitivity proposals supported asking the CAISO to study the offshore wind sensitivity as recommended.

OWC recommended amending the portfolio to contain the full 25 GW of offshore wind included in the AB 525 planning goal. PG&E specifically recommended allowing more OOS wind into the same portfolio.

3.2.1.2. Discussion

For this TPP cycle, we will keep the offshore wind sensitivity as recommended by Commission staff. Adding addition offshore wind at this time would be somewhat difficult, because the resources need to be mapped to specific locations, which are uncertain. We are uncertain how much more transmission information can be provided without more knowledge of detailed wind locations. However, we agree that more offshore wind is likely to be needed in the long run. Thus, we will look to the CAISO's 20-year transmission outlook and/or future TPP cycle sensitivity cases for more refined study of offshore wind, as its development progresses.

3.2.2. Limited Out-of-State and Offshore Wind Sensitivity

This section discusses the second sensitivity included in the October 7, 2022 ALJ ruling, intended to be an extreme (and unrealistic) portfolio designed to test the transmission needs of a larger portfolio of solar, storage, and geothermal resources, instead of additional offshore and OOS wind resources.

3.2.2.1. Comments of Parties

The second sensitivity portfolio recommended by staff was supported in comments by a number of parties, including CalWEA, CalCCA, Cal Advocates, CESA, EDF Renewables, Golden State, GridLiance, LSA, SEIA, SCE, and PG&E.

Several parties recommended changes to improve the sensitivity to better align with its goals. PG&E recommends further limiting offshore wind by delaying it until 2035. SCE and SEIA would eliminate offshore wind completely, to increase the alternative resources selected. SEIA would also limit OOS wind. Geothermal Rising would increase the amount of geothermal based on its resource potential. GridLiance suggests relaxing transmission constraints to allow further upgrades, enabling the RESOLVE model to select more resources overall. CEJA recommends additional natural gas plant retirements in local areas be included.

CAISO and ACP-CA opposed studying this portfolio. BAMx and GPI also opposed the portfolio, and instead proposed alternatives for study as a second sensitivity.

CAISO objected to this portfolio for several reasons. First, CAISO argues that the portfolio is not significantly different from the base case and fails to meet the objective of studying an alternative resource mix as laid out in the October 7, 2022 ALJ ruling. Second, CAISO is looking at 2035 for the base case, which they characterize as equivalent to studying another portfolio. Thus, they ask the Commission to be judicious in asking for another sensitivity study, since it will require significant resources and time commitments. CAISO also commits to providing new transmission information through a new white paper that will be based on the recent Cluster 14 studies, which CAISO notes will provide transmission information for a larger portfolio of resources than the sensitivity, because the cluster studies are based on significantly more resource development.

3.2.2.2. Discussion

On the basis of the CAISO recommendations, since they are our partner in these TPP studies, we will not request this second sensitivity. We are convinced to drop this sensitivity request mainly because the portfolio is similar to the base case and may not yield significantly new information at this time and because of CAISO's commitment to provide updated transmission information based on results of the recent Cluster 14 studies. Since the scenario was never designed to be realistic, but rather to test the need for transmission buildout under extreme conditions, we will revisit this concept if warranted in the future.

To the extent possible, we request that the CAISO note in the 2023-2024 TPP if policy-driven transmission projects would be least regrets transmission projects that will be needed whether the offshore and OOS wind resources are developed or not. In other words, we seek to identify multi-purpose transmission lines, using the base case portfolio, the offshore wind sensitivity, and any other existing information such as the 20 Year Transmission Outlook.

3.2.3. Other Proposed Sensitivities

As already mentioned, several stakeholders suggested alternative portfolios to be studied as policy-driven sensitivities.

3.2.3.1. Comments of Parties

CEJA and Sierra Club, as well as EDF, suggest a gas retirement scenario. CAISO supports this concept for future cycles, but not for 2023-2024 due to limited resources.

GPI suggests a portfolio with a high amount of geothermal or otherwise firm and diverse resources. CalCCA supports this suggestion for future TPP cycles.

BAMx suggests a scenario taking into account the extension of Diablo Canyon's license.

3.2.3.2. Discussion

We agree that several of these scenarios would be interesting and informative. We continue to explore, in particular, information about potential natural gas plant retirements, and we understand the Diablo Canyon situation is under examination in broader venues. However, we understand from the CAISO that sensitivity analysis is time intensive. Therefore, due to time constraints on our side and at the CAISO, at this time we will not recommend an additional sensitivity portfolio for study in the 2023-2024 TPP. We will continue to explore these recommendations for next year's TPP sensitivity portfolios.

3.3. Busbar Mapping Methodology

The October 7, 2022 ALJ ruling included updates to the methodology that Commission staff uses to map specific project locations to transmission busbars. Historically, the largest emphasis for location selection has been on identified commercial interest in development.

3.3.1. Priority Consideration of Commercial Interest With Other Criteria

As discussed in the October 7, 2022 ALJ ruling, Commission staff proposed prioritizing busbar mapping alignment to resources in the CAISO's interconnection queue that have been assigned transmission plan deliverability (TPD). If TPD is not accounted for, the TPP analysis may not identify transmission needed for new resources, since TPD is generally already allocated. This alignment was a shift from previous busbar mapping efforts, and resulted in staff prioritizing resources in areas not previously mapped. Thus, compared to the 2022-2023 TPP 30 MMT high electrification portfolio, this year's base case portfolio has fewer resources mapped to certain areas, particularly Southern Nevada, Northern California, and the San Diego and Los Angeles metropolitan areas.

3.3.1.1. Comments of Parties

Several parties commented on the priority balance between commercial interest, as demonstrated by TPD, and the need for other criteria.

CalCCA, CEJA, Sierra Club, and SDG&E all commented on the need for mapping resources to local areas for purposes of planning for natural gas plant retirement.

GridLiance recommends alignment with the mapping already done in the 30 MMT 2022-2023 TPP sensitivity portfolio.

SDG&E and several other parties recommend prioritizing geographic diversity. DOW recommends mapping to minimize environmental impact.

3.3.1.2. Discussion

We agree with parties that advocate for a more balanced mapping of resources, taking into account commercial interest particularly with already-allocated TPD, but also improving alignment with other mapping criteria, including locating storage resources in local areas and disadvantaged communities (DACs) near existing thermal generation. Using a more balanced approach to mapping portfolio resources, while still accounting for assigned TPD to identify the incremental transmission capacity needed to support LLT resources will result in the TPP analysis adding resources for unaccounted-for assigned TPD in addition to the identified portfolio. The benefit of this will be better alignment with multiple priorities. This will help us better identify the transmission needs of reducing dependence on natural gas in local areas, while still enabling assessment of transmission needs for LLT and other resources needing MIC allocations. The downside is that this approach could result in identification of more transmission than is currently needed for the resources identified in the 2035 portfolio, particularly if development does not occur as anticipated.

However, this risk is outweighed by the need to identify additional transmission needs sooner, and therefore staff are directed to work to better balance the portfolio among various mapping criteria outlined in the resource-to-busbar mapping methodology in Attachment A to this decision. Commission staff worked with the CEC and CAISO staff in the busbar mapping working group process to align the mapping more optimally with all the criteria and limit the extend to which resources were mapped to align with TPD at the expense of other criteria included in the methodology.

3.3.2. Inclusion of IRA Benefits in Mapping Criteria

In response to the October 7, 2022 ALJ ruling, both CESA and CEJA noted separate benefits in the IRA of 2022 that could change mapping priorities and criteria. Those are discussed in this section.

3.3.2.1. Comments of Parties

CESA notes that the IRA extends incentives to batteries, regardless of their co-location or standalone status. CESA recommends that we reconsider co-location prioritization of storage in the busbar mapping process.

CEJA notes incentives in the IRA for siting in "energy communities," as well in low-income communities or on Tribal land. CEJA recommends these factors be incorporated into the mapping process.

3.3.2.2. Discussion

We appreciate CESA and CEJA pointing out these aspects of the IRA and we intend to take them into consideration in the next TPP cycle. However, at this stage for the 2023-2024 TPP, there is insufficient time for staff to collect the data to assess and properly implement these new elements of the IRA incentives, which are complex. In the next TPP cycle, Commission staff already expect to do a significant overhaul of the land-use criteria to account for new CEC land-use screens that are currently under development. The aspects of the IRA described by CEJA will fit in well with these planned updates.

3.3.3. Minor and Technical Mapping Changes

In response to the October 7, 2022 ALJ ruling, some parties included specific recommended technical changes to the mapping methodology, criteria, or specific mapped resources.

3.3.3.1. Comments of Parties

Numerous technical recommendations included clarifications to specific import interview for Nevada geothermal, input from parties about resources at specific substations, corrections to commercial interest amounts at selected substations, and clarification requests for parts of the methodology.

3.3.3.2. Discussion

We do not address all of the numerous specific suggestions in this decision, but Commission staff have worked with the CEC and CAISO staff in the busbar mapping working group process to evaluate the particular suggestions of the parties and made changes to the resource-to-busbar mapping methodology and to the mapping results themselves that were warranted.

The final busbar mapping results being transmitted to the CAISO for the base case portfolio will be available at the following link: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/portfolios-and-modeling-assumptions-for-the-2023-2024-transmission-planning-process

The busbar mapping results for the sensitivity portfolio have not been fully developed as of this decision, but will be transmitted to the CAISO at a later date, as in past years. Once completed, the final mapping of the sensitivity portfolio will also be made available at the same link above, and parties to the proceeding will be made aware of its posting.

4. Comments on Proposed Decision

The proposed decision of ALJ Fitch in this matter was mailed to the parties in accordance with Pub. Util. Code ~~section~~Section 311 and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on February 2, 2023 by the following parties: ACP-CA; AES; Advanced Energy United (AEU); AReM and the Regents of the University of California (UC), jointly; CAISO; CalCCA; Cal Advocates; CalWEA; California Biomass Energy Alliance (CBEA); CEERT; CEJA and Sierra Club, jointly; CESA; DOW; EDF; EDF Renewables; Fervo; Form; Green Hydrogen Coalition (GHC); GPI; Hydrostor; LS Power; LSA; Middle River Power (MRP); NRDC and Union of Concerned Scientists (UCS), jointly; OWC; Pattern; Protect Our Communities Foundation (PCF); PG&E; RWE Renewables Americas, LLC (RWE); SCE; SDG&E; SEIA; Shell; SVCE and Central Coast Community Energy (3CE), jointly; The Utility Reform Network (TURN); and Western Power Trading Forum (WPTF).

Reply comments were filed on February 7, 2023 by the following parties: AReM and UC, jointly; City and County of San Francisco (CCSF); CAISO; CalCCA; CalWEA; CESA; CESA and Sierra Club, jointly; CEERT; Fervo; GPI; Independent Energy Producers Association (IEP); LSA; OWC; Pattern; PG&E; SCE; SDG&E; and Shell. MRP filed reply comments on February 8, 2023.

In this section, we summarize the comments of parties thematically. Where warranted, corresponding changes have also been made to the text of the decision.

The majority of parties, including many LSEs, AES, CAISO, CEJA/Sierra Club, EDF, NRDC/UCS, TURN, and Cal Advocates, support this decision's requirement for an additional 4,000 MW NQC of procurement in 2026 and 2027. PCF, CalWEA, SVCE/3CE, AReM/UC, and MRP disagree with the decision to order new procurement, requesting instead that we withdraw this decision and/or conduct additional need determination analysis.

Numerous parties comment with concern that this decision orders another tranche of capacity procurement outside of the programmatic framework that is being developed. Those parties include: AEU, ACP-CA, CAISO, CalWEA, EDF, GPI, and OWC. On this issue, we state our commitment to continuing to develop the programmatic framework for procurement in IRP in this proceeding. We expect this to be a near-term priority for 2023. We also expect that this is a complex undertaking, so we do not remove the procurement authorization in this decision, because we are committed to requiring steady and regular procurement by the LSEs during the time of development and implementation of the programmatic framework for procurement.

Several parties also note that this procurement order continues the pattern of orders not based on the more rigorous analysis that this proceeding has developed and deployed for other purpose, namely the adoption of the reference and preferred system portfolios. Parties raising this concern include AReM, UC, CalWEA, GPI, CalCCA, SCE, NRDC, and UCS. While we understand the concerns of these parties, we do note that the TPP base case portfolio also recommended in this decision has been subjected to rigorous production cost modeling analysis. The updated results are included in modifications to this decision, and they do show a potential need for reliability resources by 2026. While AReM and UC, among others, suggest that if the need is for GHG-reducing resources, the orders should be for RPS resources, we prefer to evaluate the resource needs more holistically in this proceeding, and we still find that the need in this timeframe is primarily driven by reliability considerations.

CalCCA also points out that this decision continues to evaluate and order procurement for the CAISO system as a whole, without consideration for the non-Commission-jurisdictional LSEs and their procurement. This is a long-term planning consideration that we will continue to evaluate, but we are concerned that the procurement as a whole is always based on imperfect forecasts that are an inexact science to begin with. Thus, we are not inclined to order "just barely enough" procurement. Rather, we will seek ways to coordinate and communicate with the CEC and the other non-jurisdictional LSEs in order to develop the best possible information about the plans and activities of all LSEs in the future.

CalCCA asks that we state explicitly that procurement that exceeds a compliance obligation in one year can be used to count towards future obligations. We agree and have added this clarity to the text and conclusions.

Cal Advocates supports the procurement ordered herein, as well as the modification to allow LLT resources to come online by 2028 instead of 2026, but asks that we clarify that the required online date for 2028 should be no later than June 1, 2028. CAISO and CESA agree in reply comments. We agree and have made this clarification, including in the relevant conclusion and ordering paragraph.

GHC and Fervo suggest further delaying the compliance date for LLT resources to 2030, in part to take advantage of the benefits in the IRA of 2022. While we appreciate this perspective, we expect to continue to evaluate whether we need more LLT resources beyond those already ordered in D.21-06-035.

Therefore, we decline to offer a further extension at this time, and hope to offer further direction for additional LLT resource procurement in the near future.

Several parties, including Hydrostor and Form, would like the Commission to further specify requirements for more or particular types of LLT resources as part of or in addition to the 4,000 MW of NQC procurement required herein. We decline to do so at this time, but will continue refining our analysis for potentially providing such direction in the future. We share these and other parties' concerns about the need for more resource diversity in the portfolio, particularly as time goes on.

Numerous parties, including GPI, Shell, WPTF, SDG&E, SCE, AReM, UC, and CalCCA, advocate that the allocation of procurement responsibility for the 4,000 MW of NQC required in this order should be based on more recent load forecasts, specifically a combination of the 2022 IEPR load forecasts and the 2023 year-ahead resource adequacy forecasts. These parties argue that this update would better reflect the reality of which LSE is serving which load, and be more equitable. We agree and have made this change in the decision. Several parties including SDG&E, PG&E, and CalCCA also request that the specific allocations be included in this decision. Table 3 has been added to address this concern and offer clarity. We also note that the allocation of the LLT resource requirements now required to be procured by June 1, 2028, is unchanged from D.21-06-035.

This also means, as pointed out by many of the same parties, that the PCIA vintage for cost responsibility should be consistent with the load forecast used to allocate the obligations. Thus, the PCIA vintage will be based on the effective date of this decision.

Several parties had comments on the topic of the appropriate ELCC values to be used for the new procurement ordered in this decision. AReM, UC, and

CalCCA, in particular, request an opportunity for stakeholder engagement around the development of the values. Cal Advocates and several other parties also request that the ELCC values be locked down earlier than the end of 2023, which was the deadline stated in the proposed decision. Since the proposed decision was issued, Commission staff have made updated and new ELCC values available to parties and the service list. Therefore, we have modified the deadline for finalizing the values to be no later than June 30, 2023, and barring any identification of factors that would require significant re-study, the final values have already been published. If staff identifies any factors that warrant additional study, they will update the ELCC values and publish a final version no later than June 30, 2023. As for a stakeholder process, we have invited stakeholder input in the past[16] and intend to undertake additional stakeholder engagement around ELCC values generally, because they impact many aspects of the IRP process. We will not, however, order additional stakeholder process for purposes of the ELCC values to be used for the procurement ordered herein, since many LSEs are concerned that we lock down the values as soon as possible to allow maximum time for procurement activities.

A number of parties, including GPI and TURN, are concerned about the provisions in the proposed decision that would have allowed imported system power to count as a bridge for new resources to come online for up to ten years. SCE's original proposal was for contracts of no more than one year. TURN, CEJA/Sierra Club, and NRDC/UCS, as well as CEERT and CalWEA in reply comments, continue to recommend a limit of one year. GPI, CEJA, and Sierra

[16] *See* Modeling Advisory Group materials posted at the following link: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials

Club suggest a limit of no more than five years. In reply comments, PG&E agrees with a five-year limit, while AReM and UC suggest a limit of three years. Because the intent of this provision is to provide a bridge toward the online date for a new resource, we agree with the majority of parties that ten years is too long and could inadvertently result in supporting retention of emitting resources. However, one year may also be too short. The proposal of AReM and UC for a three-year limit strikes the right balance while still achieving the original purpose; we have modified the decision to reflect a three-year limit.

PG&E and SCE also request that we make it clear that bridge arrangements can be used to comply with all procurement categories in D.21-06-035 or this order, including replacement capacity for Diablo Canyon. We disagree, because the explicit purpose of that category of procurement was to support clean, firm power to replace Diablo's non-emitting resource. Thus, bridge resources will not be allowed to count for that category. We also will not allow bridge resources to support LLT procurement, because with the extension included in this decision to 2028, there should be enough time to bring those resources online without the need for a bridge.

PG&E, and CalWEA in reply comments, also suggest that unspecified imports should be allowed to count as a bridge as long as they meet current resource adequacy requirements. This is logical and we adopt this suggestion as well. We reject AReM and UC's more specific suggestion to limit the resource adequacy to the summer months as too narrow. We prefer PG&E's more basic definition as complying with resource adequacy rules at the time the contract is executed.

MRP argues that allowing unspecified system power imports to count as a bridge for new resources coming online is discriminatory toward in-state emitting resources. This may appear to be the case because we expect all existing in-state resources to continue to be needed during the procurement period covered by this decision. In-state emitting resources cannot serve as a bridge for new resources because they are already needed and expected to be procured, and therefore cannot be considered incremental to the baseline.

CBEA also makes the point that the need analysis for this and the two prior orders (D.19-11-016 and D.21-06-035) is predicated on the expectation of no loss of baseline resources, though expected thermal plant retirements were considered in our analysis. Still, several other parties including GPI are also concerned with this issue of retention of existing resources, as are we. We support re-contracting with existing baseline resources. This does not mean, however, that re-contracting with these existing resources will be eligible to meet the requirements for new/incremental capacity of 4,000 MW NQC in this order. Similarly, GHC argues for eligibility of material improvements, retrofits, or other investments to enhance the capacity of existing thermal plants. These arguments were considered and rejected during consideration of D.21-06-035 and we do not revisit them here. We do, however, agree with GHC that a broader hydrogen policy is important and is under consideration in other venues at this time.

Several parties had comments about the compatibility of the procurement required in this decision with activities and requirements in other proceedings. Pattern is concerned that the slice-of-day resource counting framework in the resource adequacy proceeding may be inconsistent with the requirements herein for September NQC. CalCCA is concerned with the potential for procurement to be required in the proceeding addressing the long-term role of Aliso Canyon natural gas storage. In both cases, we do not make any changes to this decision, but will continue to coordinate with the other relevant proceedings.

PG&E in opening comments, and supported by SCE in reply comments, proposes that the IOUs be allowed to file Tier 3 Advice Letters for any utility-owned projects used to satisfy the procurement requirements of D.21-06-035 or this order. This was raised and rejected in D.21-06-035 and we do not add this provision here. Any utility-owned projects are required to file applications if they are used to satisfy the procurement requirements of D.21-06-035 or this order.

SCE, AReM, UC, SVCE, and 3CE all continue to advocate that we provide more specific direction and a list of factors that will be considered when determining if a penalty should be issued. These issues are already discussed in the text of this decision and we decline to offer additional specificity now. At the time of consideration of penalties, we will evaluate all relevant factors, including the LSE's conduct and good faith efforts, on a case-by-case basis for each LSE and each compliance date.

SCE, AReM, and UC point out that the compliance dates and deadlines for filing semi-annual procurement information by LSEs shift in 2023. We have made corrections to clarify that beginning after the August 1, 2023 compliance date, filing dates shift to December 1 and June 1 every year, beginning December 1, 2023. As stated in D.21-06-035, the need for backstop procurement will be assessed after the December 1 filing date each year for the following year.

SCE, in its comments, supports the provision in the proposed decision that would have cost allocated through CAM if an IOU takes on the compliance obligation of another LSE due to bankruptcy or any other reason the LSE stops providing retail service. SCE argues that the caveat that this applies "unless the LSE's customers are already paying for the same capacity under the MCAM described in D.22-05-015" should be removed because the Commission already decided this issue in D.22-05-015 without the caveat. Thus, SCE argues, CAM cost recovery treatment applies regardless. We agree with SCE and have made modifications to this decision to clarify this.

PG&E and SCE also argue that the references to a ten-year limit on cost recovery for backstop procurement should be removed, while CalCCA argues to emphasize them. PG&E and SCE are correct that D.22-05-015 already addresses these issues and we do not need to repeat them here. Thus, references to a ten-year limit have been removed.

Nearly all parties, including all LSEs, AEU, CalWEA, DOW, EDF, and LS Power, support the Commission's recommendation of the 30 MMT GHG target by 2030 as the base case portfolio for the CAISO to analyze in this TPP. Two parties, OWC and RWE, support the base case recommendation but would prefer that more offshore wind be included, particularly at Humboldt, to plan now for the full potential to be built later. PCF opposes including offshore wind in the base case and generally recommends an overhaul of the entire base case to reduce new transmission development. At this stage, we are not including additional offshore wind in the base case, but hope to learn more about costs, feasibility, and environmental impacts during the time the sensitivity case is being analyzed in the TPP. In the meantime, the amount of offshore wind in the base case represents a least regrets approach.

All parties who commented on the 12-year planning horizon, including ACP-CA, also supported that change, though some parties such as CEERT would also prefer we plan even longer term, going out as far as 20 or 25 years. We will consider longer-term transmission planning in the future as it becomes more feasible and in line with the requirements of SB 887, but for this cycle of TPP, we are satisfied that the 12-year horizon is reasonable.

Most parties, including AEU and OWC, also support the recommended sensitivity case that emphasizes the transmission requirements for a heavy offshore wind portfolio. OWC urges in favor of the scenario including more offshore wind, including the full AB 525 planning goal of 25 GW by 2045, with additional offshore wind in the base case. While this may ultimately be prudent, since these cases only go out to 2035, we will rely on the portfolios already developed here for this TPP and consider the addition of more offshore wind in subsequent TPP cycles.

PCF opposes the offshore wind sensitivity, because it argues that there are other lower-cost alternatives that are proven and abundant, including warehouse rooftop solar. While we support development of warehouse rooftop solar, it is not to the exclusion of offshore wind, which is a considerable resource that we find prudent to analyze further for potential development.

Several parties, including CEJA and Sierra Club, CEERT, EDF, and PCF, continue to advocate that we develop a sensitivity portfolio, at least for the next TPP cycle, that evaluates the potential for additional or all natural gas generating units to retire by 2030 or 2035. CalCCA also advocates that we examine the potential for retirement of fossil-fueled resources in local areas. CEJA and Sierra Club also specifically refer to SB 887 which requires us to look at ways to reduce the need to rely on nonpreferred resources in local capacity areas. We acknowledge this requirement and our intent to collaborate with the CAISO to meet it. The importance of planning for additional natural gas plant retirements has been a priority for us for some time and Commission staff have begun work to develop this type of analysis. The analysis is complex, and we commit to beginning a process for stakeholder input on it in 2023. If it is ready, we will include it in consideration for a sensitivity analysis in the next TPP cycle.

With respect to the busbar mapping process, some parties, including DOW, continue to be concerned that commercial interest receives too much emphasis. We understand these concerns and Commission staff, along with CEC and CAISO partners, have already taken steps in this round to balance the commercial interest factor with the other factors included in the busbar mapping methodology.

Several other parties, including EDF Renewables, SEIA, and LSA, as well as CEERT in reply comments, would like additional opportunities for stakeholder input. CalCCA, ACP-CA, and Pattern also sought clarification for how we are treating imports with respect to MIC allocations.

We intend to continue to refine the busbar mapping process going forward, but we do not make any additional changes to further de-emphasize commercial interest at this time. We also understand parties' continued desire for more input to the busbar mapping process. We have made significant improvements to allow more stakeholder involvement in the past few years, and will continue to work toward more opportunities for party input earlier in the process. Commission staff will clarify in a supplemental mapping report why certain adjustments were made and how we are recommending that the CAISO treat MIC assumptions for identified imports (treating the new import resources as requiring MIC expansion and therefore likely to trigger transmission upgrades within the CAISO).

Finally, several parties brought up concerns about the backlog and delays in interconnections and network upgrades to support new capacity, including RWE, ACP-CA, and LSA. While the interconnection process itself is the purview of the CAISO, we continue to expect that the IOUs will do everything in their power to expedite interconnection and development of associated network upgrades to the greatest extent possible. We have added a conclusion to emphasize this point.

5. Assignment of Proceeding

Alice Reynolds is the assigned Commissioner and Julie A. Fitch is the assigned ALJ in this proceeding.

Findings of Fact

1. LSEs have identified 24 renewable and two storage projects, totaling 222 MW and 29 MW nameplate respectively, that have not come online but were included in the D.19-11-016 baseline.

2. LSEs have identified four renewable and six battery storage projects, totaling 240 MW and 152 MW nameplate respectively, that have not come online but were included in the D.21-06-035 baseline.

3. LSEs have identified one renewable and six battery storage projects, totaling 13.5 MW and 180 MW nameplate respectively, that have not come online but were included in the baseline for both D.19-11-016 and D.21-06-035.

4. In total, roughly 570 MW nameplate of renewable and battery storage resources were included in either the D.19-11-016 or D.21-06-035 baseline, or both, that have not come online but still may be able to. These resources can still provide reliability benefits to the electric grid.

5. Allowing LSEs to swap out resources that were listed on the D.19-11-016 and/or the D.21-06-035 baseline resource list and count them toward either decision's procurement obligations, while adding a commensurate procurement obligation to the individual LSE in 2025, will help contribute to electric system reliability.

6. Cal Advocates proposes requiring an additional 4,000 MW of procurement requirements between 2026 and 2030, based on the increased load

forecast, increasing impacts of climate change, and the likelihood of retirement of additional natural gas generation units.

7. Since D.21-06-035 was issued, the CEC has increased the demand forecast and California has been facing the accelerating impacts of climate change. Other exogenous factors, such as increasing penetration of electric vehicle, decreasing availability of imports, increasing building electrification, increasing penetration of air conditioning, etc. have also added additional pressure to the reliability of the electric system.

8. 4,000 MW of NQC, divided evenly between 2026 and 2027, will increase the reliability of the electric grid.

9. Due to changes in load since D.21-06-035 was adopted, updated load forecasts are necessary to allocate procurement required by this order to LSEs. The most current load forecasts are contained in the 2022 IEPR and the 2023 year-ahead resource adequacy peak load forecasts.

10. ~~9.~~ As already contemplated in D.21-06-035, some LSEs may need until 2028 to procure the LLT resources specified in that decision.

11. ~~10.~~ D.21-06-035 set penalty levels for failure to provide the required resources based on net CONE. We will maintain that level and clarify that it is for the year in which non-compliance occurs and is not ongoing.

12. ~~11.~~ Allowing ~~firm~~ imports from bridge resources (existing resources) contracted until a new resource has time to come online, if the imports used for bridge purposes meet current resource adequacy requirements at the time the contract is executed, will help enhance electric grid reliability.

13. ~~12.~~ Allocation of MIC is a CAISO function; the Commission may make recommendations but does not control the process.

14. ~~13.~~ The CAISO requires portfolio recommendations from the Commission to utilize in conducting their annual TPP, as outlined in their tariff.

15. ~~14.~~ The Commission should evaluate electric resource portfolios utilized for TPP purposes using a twelve-year planning horizon, now including 2035, to align with the CAISO and CEC planning efforts.

16. ~~15.~~ The electric resource portfolio that meets a 30 MMT GHG emissions target by 2030 with the demand forecast based on the Additional Transportation Electrification scenario will help identify transmission earlier, since it takes longer to develop transmission compared to generation or storage resources.

17. ~~16.~~ The electric resource portfolio that meets a 30 MMT GHG emissions target has been tested with production cost modeling and meets the Commission's current standards for system reliability.

18. ~~17.~~ The electric resource portfolio that meets a 30 MMT GHG emissions target based on updated assumptions includes significantly more renewables and storage resources than the previous portfolio analyzed by the CAISO in its previous TPP.

19. ~~18.~~ Transmission solutions to support both policy and reliability goals combined with ratepayer savings can provide significant benefits to California.

20. ~~19.~~ Best practices in transmission planning include cyclical annual study of portfolios that achieve greater GHG reductions and include the need for transmission to support deliverability of the portfolios in a linear fashion, building on prior annual analyses.

21. ~~20.~~ The Commission's role in the TPP is to select generation and storage resources for the CAISO to study for their transmission needs, not to select specific transmission solutions to be studied.

Conclusions of Law

1. Commission staff should continue to ~~produce~~maintain, and update if needed, two baseline generator lists for both D.19-11-016 and D.21-06-035 purposes.

2. The Commission should authorize staff to facilitate, via Tier 2 Advice Letter filings, baseline "swap" arrangements, where an individual LSE may count a resource listed on the baseline generator list for D.19-11-016 and/or D.21-06-035 and instead add a commensurate amount to its 2025 procurement obligation in D.21-06-035, based on the appropriate ELCC values, depending on which order the resource is being used to comply with and the timing of the obligation. To avoid potential for gaming this swap process should not apply to any contact that is terminated after the date this proposed decision was published (January 13, 2023), and any resource removed from the baseline of both D.19-11-016 and D.21-06-035 must first be used to satisfy D.19-11-016 obligations.

3. CAM resources should not be eligible to participate in a baseline resource swap for reasons of cost allocation fairness and equity for LSEs that do not have access to CAM resources.

4. The Cal Advocates proposal for an additional 4,000 MW NQC of procurement is reasonable and should be adopted, with modifications.

5. For ease of compliance, additional resource requirements of 4,000 MW NQC should be in addition to the resources ordered in D.21-06-035 and should utilize the same eligibility and compliance rules as D.21-06-035, unless otherwise specified in this decision.

6. The additional 4,000 MW NQC of procurement required herein should be divided between 2026 and 2027 compliance years, to be online by June 1 of each year.

7. The D.21-06-035 2,000 MW NQC requirements for LLT resources that were due in 2026 should be adjusted to be required ~~before~~by June 1, 2028, similar to the timeframe already provided for in D.21-06-035. An LSE should ~~not be required to seek an extension of the 2026 deadline, but should instead~~ be allowed to use the LLT resources defined in D.21-06-035 to count toward its 2026, 2027, or 2028 obligations ~~at any time during 2026 through 2028~~. If an LSE already has procured its share of the LLT resources by 2026 or 2027, it may substitute that resource for the requirements of this order and conduct additional procurement in 2028, such that in each year the total procurement obligations of all LSEs will be met with 2,000 MW NQC in each year, inclusive of the LLT resources. 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.

8. Capacity requirements to individual LSEs should be allocated based on the ~~same basis~~2022 IEPR and the 2023 year-ahead resource adequacy forecasts, as ~~assigned~~calculated in ~~D.21-06-035, for reasons of fairness in cost allocation~~Table 3 of this decision.

9. Each of the IOUs should be authorized to file a Tier 2 Advice Letter, if necessary, within 60 days of the effective date of this decision, to update its balancing accounts to reflect the PCIA treatment in this decision.

10. ~~9.~~ The semi-annual filing requirements for procurement data discussed in D.20-12-044 and D.21-06-035 should be continued in perpetuity, unless and until the Commission modifies this process. Compliance and the need for backstop

procurement should continue to be evaluated after the receipt of data on ~~February~~December 1 of each year beginning in 2023.

~~10. Backstop procurement, if ordered, should be covered and the costs allocated for a period of ten years.~~

11. Energy and storage contracts to comply with the D.21-06-035 category of resources to replace Diablo Canyon capacity should be able to be procured separately, but must be contracted by the LSE that is claiming them for compliance purposes. Energy-only contracts may also be used, but only if they can demonstrate by engineering assessment that the energy delivered will be sufficient to charge the batteries and discharge according to the D.21-06-035 and staff FAQ document requirements.

12. ~~Firm import~~Import contracts from any resource and with any counterparty should be allowed to be used as bridge resources until such time as new resources can come online for the general procurement category identified in D.21-06-035 or the procurement required in this order, and not including Diablo Canyon replacement capacity or long lead-time procurement ordered in D.21-06-035, for a period of not more than ~~ten~~three years. Imported energy used for this purpose should be allowed to count as long as it meets current resource adequacy requirements at the time the contract is executed.

13. It is reasonable to allow an LSE to split the capacity associated with a single resource between its D.19-11-016 and D.21-06-035 compliance obligations, as long as the resource meets all of the requirements of the decision for which it is being counted, including being incremental to the respective decision's baseline generator list of resources.

14. Trading of compliance obligations between LSEs is reasonable and should be permitted~~.~~, with some restrictions. The arrangement must actually be a trade

of one compliance obligation for another. It may not be a purely financial arrangement where one LSE pays another to take on its procurement obligation. One LSE should not be allowed to opt out of its procurement obligations entirely. There may be financial remuneration involved, but some compliance obligations also must be traded by both LSEs. A Tier 2 Advice Letter notifying the Commission and stakeholders of such a trade arrangement should be required.

15. CAM cost recovery is the most reasonable approach to the situation where an IOU takes on the D.21-06-035 or this order's compliance obligations because the LSE is in bankruptcy or no longer providing retail service~~, if the LSE's customers are not already paying for the same capacity under the MCAM mechanism~~.

16. Pseudo-tied and dynamically-scheduled projects should be allowed to count toward the obligations of D.21-06-035 and this order even if they do not yet have a MIC allocation, as long as the LSE documents that it is taking steps to obtain the MIC allocation.

17. To the extent possible, portfolios used for TPP purposes should be based on the most up-to-date assumptions included in the CEC's annual IEPR.

18. Based on analysis conducted by Commission staff thus far, utilizing the electric resource portfolio that meets the 30 MMT GHG emissions target as a reliability and policy-driven base case in the TPP will likely result in the need for new transmission investment to make the portfolio deliverable. Transmission projects should be evaluated for reliability, policy, and economic benefits.

19. The Commission should encourage CAISO to get a head start on transmission investments associated with the 30 MMT GHG emissions target in the 2022-2023 TPP cycle by bringing necessary projects to its Board based on the sensitivity case already being analyzed.

20. ~~19.~~ The Commission should seek CAISO TPP analysis of one sensitivity case in this TPP cycle: a case that tests the transmission needs of a significant amount of offshore wind.

21. ~~20.~~ Demonstration of commercial interest in projects in particular geographic areas, as represented by having a place in the CAISO's or other regions' interconnection queues, is reasonable to remain one major driver of the methodology for resource-to-busbar mapping, since it is more likely that those projects will be built compared with projects not in interconnection queues.

22. ~~21.~~ Additional busbar mapping considerations should include prioritizing locations where gas plants may retire, in disadvantaged communities and/or air quality non-attainment areas, and taking into consideration overall environmental impacts.

23. The IOUs should expedite transmission interconnection and associated network upgrades to the greatest extent possible to bring new electricity resources online.

O R D E R

IT IS ORDERED that:

1. Any load-serving entity subject to procurement requirements from Decision (D.) 19-11-016 or D.21-06-035 may file a Tier 2 Advice Letter seeking to count an individual electric generation or storage resource listed on the baseline generator list for either decision toward its obligation, but then must have an equal amount of net qualifying capacity added to its procurement requirement associated with D.21-06-035 for 2025. Contracts for resources terminated after January 13, 2023 do not qualify for this provision. The capacity counting will be based on the relevant effective load carrying capability (ELCC) value for the order for which the resource is being counted, and the additional 2025 capacity

procurement will be based on 2025 ELCC values. A resource that appears on the baseline generator list for D.19-11-016 and D.21-06-035 and being removed, must first be used to satisfy any unmet D.19-11-016 procurement requirements. Commission staff shall maintain on our web site ~~and~~two up-to-date baseline generator ~~list~~lists for both D.19-11-016 and D.21-06-035 compliance purposes. Each baseline generator list will be updated if any baseline adjustments are approved. Resources with costs allocated under the Cost Allocation Mechanism shall not be eligible for this capacity swap.

2. All load-serving entities (LSEs) required to procure capacity by Decision (D.) 21-06-035 shall procure an additional combined total of 2,000 megawatts (MW) of September net qualifying capacity (NQC) from non-emitting, storage, and/or renewable resources in 2026 and 2027, with resources required to be online by June 1 of each year. The long lead-time resources required by D.~~21-06-035~~21-06-035 may be ~~procured at any time during 2026 through~~brought online by June 1, 2028, such that the total NQC of all LSEs adds to 2,000 MW in each of the years 2026, 2027, and 2028. ~~LSEs~~ Commission staff are not required to ~~make~~evaluate or approve extension requests to postpone ~~their~~ long lead-time resource procurement to 2028. The extension to June 1, 2028 for long lead-time resources is authorized for all load serving entities.

3. The allocation of net qualifying capacity obligations described in Ordering Paragraph 2 to individual load serving entities (LSEs) shall be done using the same method as described in Decision 21-06-035, with updates to the load forecasts using a combination of both the ~~2021~~2023 year-ahead resource adequacy forecasts and energy load forecasts of individual LSEs for ~~2021~~2023 from the ~~2020~~2022 Integrated Energy Policy Report of the California Energy Commission~~, adopted in February 2021~~. Individual allocations are given in Table

3 of this decision and the allocations to individual electric service providers shall be maintained and transmitted confidentially by Commission staff within one week of the effective date of this decision.

4. Any resources procured by an investor-owned utility in response to this order should be subject to Power Charge Indifference Adjustment (PCIA) vintage cost responsibility based on the effective date of this decision. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company may each submit a Tier 2 Advice Letter within 60 days of the effective date of this decision to update their balancing accounts to address this PCIA treatment.

5. ~~4. All~~Beginning after the August 1, 2023 procurement information compliance filings, all load serving entities subject to our integrated resource planning oversight shall continue making procurement data filings on ~~February~~December 1 and ~~August~~June 1 of each year to be assessed for compliance unless and until the Commission sets different requirements. ~~Compliance and the~~The need for backstop procurement as discussed in Decisions 20-12-044 and 21-06-035 shall continue to be evaluated each year after receipt and analysis of the procurement data filed on ~~February~~December 1.

6. ~~5.~~ Any penalties associated with failure to comply with the requirements of Decision 21-06-035 or this order will be based on a calculation of the net cost of new entry, a calculation which the Commission will maintain for this purpose. The penalty will be assessed for each relevant compliance ~~year~~tranche (2023-2025, 2026-2027, and 2028).

7. ~~6.~~ In order to comply with the category of resources required by Decision (D.) 21-06-035 to replace capacity from the Diablo Canyon Power Plant, a load serving entity (LSE) may procure energy and battery resources separately, but

both resources must be contracted by the same LSE to be used for compliance. Energy-~~energy~~only renewables may also be used to satisfy the Diablo Canyon capacity replacement requirements, but only if accompanied by an engineering assessment that the energy delivered will be sufficient to charge the batteries so that they may discharge to meet the resource requirements in D.21-06-035.

8. ~~7.~~ For enhanced reliability purposes and compliance with the generic capacity ~~required by~~requirements of Decision (D.) 21-06-035 or this order, but not for the Diablo Canyon replacement capacity or long lead-time resource procurement required in D.21-06-035, a load serving entity may contract for ~~firm imports~~imported energy as a bridge until the online date of a new compliance resource, from any resource and with any counterparty, for a period of not more than ~~ten~~three years. The bridge contract for imported energy must meet resource adequacy requirements at the time the contract is executed.

9. ~~8.~~ For purposes of compliance with the requirements of Decision (D.) 19-11-016, D.~~21-06-035~~21-06-035, and this order, one load serving entity may split the capacity associated with a single resource (project) between more than one decision's compliance obligation, as long as the resource meets the requirements of the decision for which it is being counted, including being incremental to the baseline generator list of resources for the relevant decision.

10. ~~9.~~ Any two load serving entities (LSEs) with compliance obligations under Decision (D.) 19-11-016, D.21-06-035, and/or this order may trade compliance obligations in arrangements that may include financial remuneration, but may not result in one LSE being relieved of its entire procurement obligation under D.21-06-035 or this order. Both LSEs must trade portions of their compliance obligations under this provision. The two LSEs shall notify the Commission of a

trade of compliance obligations by at least one of the LSEs filing a Tier 2 Advice Letter providing documentation of the trade arrangement.

11. ~~10.~~ If an investor-owned utility takes on the compliance obligation of another load serving entity (LSE) due to a bankruptcy or other reason for the LSE no longer providing retail service, cost recovery for capacity procurement shall be through the Cost Allocation Mechanism ~~unless the LSE's customers are already paying for the same capacity under the Modified Cost Allocation described in Decision 22-05-015~~.

12. ~~11.~~ All load serving entities with capacity obligations under this order and Decision 21-06-035 may count pseudo-tied and/or dynamically-scheduled projects without maximum import capability (MIC) allocations towards their obligations if they demonstrate and document in their data filings that they are taking steps to obtain the MIC allocation.

13. ~~12.~~ The Commission transfers to the California Independent System Operator for its 2023-2024 Transmission Planning Process the reliability and policy-driven base case portfolio that meets the 30 million metric ton greenhouse gas emissions target by 2030, with updated assumptions from California Energy Commission's 2021 Integrated Energy Policy Report, including using the Additional Transportation Electrification scenario of the demand forecast, using the resource-to-busbar mapping methodology detailed in Attachment A of this order. The details of the portfolio are available at the following link: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/portfolios-and-modeling-assumptions-for-the-2023-2024-transmission-planning-process

14. ~~13.~~ The Commission transfers to the California Independent System Operator for its 2023-2024 Transmission Planning Process one policy-driven sensitivity portfolio for study purposes, that has been updated with assumptions from the California Energy Commission's 2021 Integrated Energy Policy Report: a portfolio that tests the transmission needs associated with approximately 13 gigawatts of offshore wind. The details of the portfolio will be posted at the following link: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/portfolios-and-modeling-assumptions-for-the-2023-2024-transmission-planning-process

15. ~~14.~~ In mapping electric resources to busbars to identify geographic locations to support the California Independent System Operator's Transmission Planning Process, Commission staff shall prioritize commercial interest, but shall also balance it with other criteria and considerations.

This order is effective today.

Dated ____________________, at San Francisco, California.

ATTACHMENT A

Modeling Assumptions for the 2023-2024 Transmission Planning Process

Document comparison by Workshare Compare on Tuesday, February 21, 2023 2:21:19 PM

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Document 2 ID	file://C:\Users\jnf\Desktop\REV 1\Agenda ID# 21286 - R2005003 Fitch PD (TPP-Procurement) REV. 1.docx
Description	Agenda ID# 21286 - R2005003 Fitch PD (TPP-Procurement) REV. 1
Rendering set	Standard

Legend:	
Insertion	
~~Deletion~~	
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Moved to	
Style change	
Format change	
~~Moved deletion~~	
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Deleted cell	
Moved cell	
Split/Merged cell	
Padding cell	

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