Decision **PROPOSED DECISION OF ALJ FITCH** **(Mailed 1/10/2024)**

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 ADOPTING 2023 PREFERRED SYSTEM PLAN AND RELATED MATTERS, AND ADDRESSING TWO PETITIONS FOR MODIFICATION

TABLE OF CONTENTS

Title **Page**

TABLE OF CONTENTS

Title **Page**

DECISION ADOPTING 2023 PREFERRED SYSTEM PLAN AND RELATED MATTERS, AND ADDRESSING TWO PETITIONS FOR MODIFICATION

Summary

This decision evaluates the 2022 individual integrated resource plan (IRP) filings of all of the load serving entities (LSEs) under the Commission's IRP purview. Twenty-nine LSEs have IRPs that are approved or certified in this decision; nine are determined to be exempt from the requirement to file an IRP in 2022. An additional twelve LSEs did not provide all of the required information in their IRPs and therefore their IRPs are not approved or certified in this decision. Those LSEs will have the opportunity to provide the required information in a Tier 2 advice letter and have their IRPs approved or certified after the subsequent submission.

This decision also adopts a Preferred System Plan (PSP) portfolio that meets a statewide 25 million metric ton (MMT) greenhouse gas (GHG) target for the electric sector in 2035. This portfolio was developed first with an aggregation of the individual IRPs of all LSEs, reflecting the resource preferences of those LSEs through 2035. Then, Commission staff augmented the resources using modeling analysis to ensure reliability standards and GHG targets were met through 2035, and to extend the resource planning timeframe out to 2039 for transmission planning purposes. This proposed PSP portfolio reduces emissions by 28 MMT in 2035 compared to the 2020 electric sector emissions in the California Independent System Operator (CAISO) area, translating to a 58 percent reduction. By 2045, the proposed portfolio reduces emissions by 85 percent and achieves a level of 113 percent clean energy, based on the Senate Bill 100 (Stats. 2018, Ch. 312) 100 percent goal for 2045; the clean energy level can

exceed 100 percent because it is based on retail sales and includes exported energy.

This decision further recommends to the CAISO that the 25 MMT PSP portfolio be utilized as both the reliability base case and the policy-driven base case for study in its 2024-2025 Transmission Planning Process (TPP). This decision also recommends that the CAISO analyze a policy-driven sensitivity case designed to test the transmission buildout needed for a grid stress case where 15 gigawatts of natural gas generation resources are retired by 2039.

This decision also addresses two petitions for modification (PFM) of earlier procurement decisions in this proceeding, namely Decision (D.) 21-06-035 and D.23-02-040.

The first PFM was filed jointly by Southern California Edison Company (SCE) and Pacific Gas and Electric Company (PG&E), seeking a two-year extension on the energy required to be procured in D.21-06-035 to partially replace the attributes of the Diablo Canyon Power Plant. The SCE and PG&E PFM is denied in its current form in this decision primarily due to concerns regarding system reliability and equity among LSEs; the decision allows for continued exploration of creative solutions to fulfill the spirit of the Diablo Canyon replacement requirements in D.21-06-035.

The second PFM was filed jointly by California Energy Storage Alliance (CESA) and Western Power Trading Forum (WPTF), seeking modifications to D.23-02-040 and D.21-06-035, to allow extension of deadlines for procurement of long lead-time (LLT) resources when certain conditions are met. The CESA and WPTF PFM is granted, in part, with modifications as discussed further in the decision. LSEs that require an extension to bring online the required LLT resources beyond the June 1, 2028 deadline must procure generic capacity to cover the shortfall, and still bring online LLT resources by no later than June 1, 2031.

This decision also formally adopts high-level aspects of the reliability framework for IRP that has been used throughout the past two years in the proceeding, including a 0.1 loss of load expectation standard for determining reliability need, a planning reserve margin based on gross peak, and resource counting conventions using marginal effective load carrying capability analysis that is updated periodically. This framework will be in place at least until the consideration of a programmatic approach to procurement in the context of IRP, and will be coordinated closely with the resource adequacy program framework.

Finally, the decision makes reimbursable funding available to Commission staff for consulting resources to continue to support the IRP process for the next six years.

This proceeding remains open.

1. Procedural Background

The sections below detail the procedural background on the topics that will be addressed in this decision.

1.1. Individual Integrated Resource Plan Filings

In Decision (D.) 22-02-004, the Commission required all load serving entities (LSEs) to file their individual integrated resource plan (IRPs) on or before November 1, 2022. As requested in an October 5, 2023 Administrative Law Judge (ALJ) Ruling, updated filings with corrections or changes in response to requests from Commission staff were filed on or about October 15, 2023. The entities filing individual IRPs, or notices of exempt status, were as follows:

1.1.1. Investor-Owned Utilities (IOUs)

1. Bear Valley Electric Service (BVES), Inc., with Motion to File Under Seal (MFUS);

2. Liberty Utilities (CalPeco Electric), LLC, with MFUS;
3. Pacific Gas and Electric Company (PG&E), with MFUS;
4. PacifiCorp;
5. San Diego Gas & Electric Company (SDG&E), with MFUS;
6. Southern California Edison Company (SCE), with MFUS;

1.1.2. Community Choice Aggregators (CCAs)

1. Apple Valley Choice Energy (AVCE), with MFUS;
2. Central Coast Community Energy (C3E), with MFUS;
3. City of Palmdale (Palmdale), with MFUS;
4. City of Pomona (Pomona), with MFUS;
5. Clean Energy Alliance (CEA), with MFUS;
6. Clean Power Alliance of Southern California (CPA), with MFUS;
7. CleanPower San Francisco (CleanPowerSF), with MFUS;
8. Desert Community Energy (DCE), with MFUS;
9. East Bay Community Energy (EBCE), now doing business as Ava Community Energy (Ava), with MFUS;
10. King City Community Power (KCCP), with MFUS;
11. Lancaster Choice Energy (LCE), with MFUS;
12. Marin Clean Energy (MCE), with MFUS;
13. Orange County Power Authority (OCPA), with MFUS;
14. Peninsula Clean Energy Authority (PCEA), with MFUS;
15. Pico Rivera Innovative Municipal Energy (PRIME), with MFUS;

16. Pioneer Community Energy (PCE), with MFUS;
17. Rancho Mirage Energy Authority (RMEA), with MFUS;
18. Redwood Coast Energy Authority (RCEA), with MFUS and motion for late-filing;
19. San Diego Community Power (SDCP), with MFUS;
20. San Jacinto Power (SJP), with MFUS;
21. San Jose Clean Energy (SJCE), with MFUS;
22. Santa Barbara Clean Energy (SBCE); with MFUS;
23. Silicon Valley Clean Energy (SVCE), with MFUS;
24. Sonoma Clean Power Authority (SCPA), with MFUS and motion for late-filing;
25. Valley Clean Energy Alliance (VCEA);

1.1.3. Electric Service Providers (ESPs)

1. 3 Phases Renewables (3PR), Inc., with MFUS;
2. Brookfield Renewables Energy Marketing US, LLC (BREMUS), filing stating it is not serving load;
3. Calpine Energy Solutions (Calpine ES), LLC, with MFUS;
4. Calpine PowerAmerica-CA (Calpine PA), LLC, with MFUS;
5. Constellation NewEnergy, Inc. (CNE), with MFUS;
6. Direct Energy Business, LLC (DEB), with MFUS;
7. EDF Industrial Power Services (CA), LLC (EDF-IPS), with MFUS;
8. EnerCalUSA, LLC (EnerCal), filing stating it is not serving load;
9. Gexa Energy California, LLC, filing stating it is not serving load;
10. Pilot Power Group (PPG), LLC, with MFUS;

11. Praxair Plainfield, Inc., filing stating it is not serving load;
12. Regents of the University of California (UC Regents), with MFUS and motion for late-filing;
13. Shell Energy North America (US), L.P., (SENA), with MFUS;
14. Tiger Natural Gas, Inc., filing stating it is not serving load;

1.1.4. Electric Cooperatives

1. Anza Electric Cooperative – filing requesting approval for exemption;
2. Plumas-Sierra Rural Electric Cooperative (Plumas-Sierra) – filing requesting approval for exemption;
3. Surprise Valley Electric Cooperative – filing requesting approval for exemption; and
4. Valley Electric Association, Inc. (VEA) – filing requesting approval for exemption.

On December 2, 2022, initial comments on the individual IRPs were filed by the following parties: California Community Choice Association (CalCCA); Green Power Institute (GPI); GridLiance West LLC (GLW); Public Advocates Office at the California Public Utilities Commission (Cal Advocates); PG&E; Sierra Club and California Environmental Justice Alliance (CEJA), jointly; and SDG&E.

Commission staff reviewed and analyzed the original IRP filings, and contacted LSEs when errors were found. On October 5, 2023, an ALJ ruling was issued, seeking comments on the proposed PSP, TPP portfolios, and asking LSEs to re-file corrected versions of their individual IRP information. Nearly all LSEs re-filed corrected versions of their individual IRPs, in the form of compliance filings, in response to the October 5, 2023 ALJ ruling, on or around October 16,

2023. The following LSEs made corrected filings, along with updated motions to file under seal: 3PR; AVCE; BVES; Calpine ES; Calpine PA; CCCE; CEA; CleanPowerSF; CNE; CPA-SC; DCE; DEB; EBCE; KCCP; LCE; MCE; OCPA; Palmdale; PCE; PG&E; Pomona; PPG; PRIME; RCEA; RMEA; SBCE; SCE; SCPA; SDCP; SDG&E; SENA; SJCE; SJP; SVCE; UC Regents; and VCEA.

1.2. Preferred System Portfolio and Transmission Planning Process Recommendations

Commission staff aggregated the resources identified in the LSEs' individual IRP filings, analyzed the electricity resource portfolio results using both capacity expansion modeling and production cost modeling (PCM) to construct a candidate Preferred System Plan (PSP) portfolio, and proposed a PSP portfolio for consideration by the Commission. This analysis was included in the October 5, 2023 ALJ ruling for comment by parties. The same portfolio was also recommended as a base case for analysis in the California Independent System Operator's (CAISO's) Transmission Planning Process (TPP) for 2024-2025. In addition, Commission staff recommended a policy-driven sensitivity portfolio for the CAISO to analyze.

The following parties filed comments in response to the October 5, 2023 ALJ ruling on or before November 13, 2023: AES Alamitos and Air Products (AES-AP); Alliance for Retail Energy Markets (AReM); American Clean Power - California (ACP-CA); Bay Area Municipal Transmission Group (BAMx); BHE Renewables (BHER); Brightline Defense Project (Brightline); CAISO; CalCCA; Calpine Corporation (Calpine); California Wind Energy Association (CalWEA); CEJA and Sierra Club, jointly; California Energy Storage Alliance (CESA); California Western Grid (CWG); Center for Energy Efficiency and Renewable Technologies (CEERT); Coalition for the Optimization of Renewable

Development (CORD); Diamond Generating Company (Diamond); Defenders of Wildlife (DOW); EBCE; Environmental Defense Fund (EDF); EDF Renewables (EDFR); Enchanted Rock; Fervo Energy (Fervo); Form Energy (Form); Gallatin Power Partners (Gallatin); GLW; GPI; GreenGen Storage (GreenGen); Golden State Clean Energy (GSCE); Hydrostor, Inc., (Hydrostor); Independent Energy Producers Associations (IEP); LS Power Development (LS Power); Mainspring Energy (Mainspring); Mussey Grade Road Alliance (MGRA); Middle River Power (MRP); NextEra Energy (NextEra); Natural Resources Defense Council (NRDC) and Union of Concerned Scientists (UCS), jointly; Offshore Wind California (OWC); Protect Our Communities Foundation (PCF); PG&E; Cal Advocates; RWE Offshore Wind Holdings (RWE); SCE; SCPA; SDG&E; Solar Energy Industries Association (SEIA); and Large-Scale Solar Association (LSA); SENA; Swan Lake North Hydro (Swan Lake); TerraGen; and Vineyard Offshore (Vineyard).

Reply comments were filed on or before December 1, 2023 by the following parties: ACP-CA; AReM; BAMx; BHER; CAISO; CalCCA; Cal Advocates; Calpine; CalWEA; CEERT; CEJA and Sierra Club, jointly; CESA; CWG; DGC; DOW; EDF; Fervo; Gallatin; GLW; GPI; GreenGen; GSCE; Hydrostor; IEP; LS Power; MGRA; MRP; NRDC; OWC; PCF; PG&E; RWE; SCE; SDG&E; SEIA and LSA, jointly; SENA; Swan Lake; Vineyard; Equinor; Invenergy; New Leaf; Pattern Energy (Pattern); and Western Power Trading Forum (WPTF).

1.3. Petitions for Modification of Decisions (D.) 21-06-035 and D.23-02-040

Two petitions for modification (PFM) were filed of recent procurement-related decisions in this proceeding.

1.3.1. PFM Related to Long-Lead Time (LLT) Resources

On May 30, 2023, CESA and the Western Power Trading Forum (WPTF) jointly filed a PFM of D.21-06-035 and D.23-02-040, seeking the ability to request an extension of up to three years for procurement of LLT resources, to no later than 2031 from the current deadline of 2028.

On June 29, 2023, the following parties filed responses to the CESA/WPTF PFM: ACP-CA; AReM; BHER; Cal Advocates; CCCE; Form; Hydrostor; PG&E; SCE; SENA; Vistra Corporation (Vistra). Cal Advocates, SCE, and PG&E all concurrently filed motions to file a confidential version of their responses under seal, because bidding information was contained in the responses. All three motions to file under seal were granted by email ruling by the assigned ALJ on July 27, 2023.

1.3.2. PFM Related to Replacement Energy for Diablo Canyon Power Plant

On August 9, 2023, SCE and PG&E jointly filed a PFM of D.21-06-035, seeking an extension of two years for the procurement of the category of resources designed to replace a portion of the energy from the Diablo Canyon Power Plant (Diablo Canyon). Both SCE and PG&E also concurrently filed motions for leave to file confidential materials under seal related to their PFM; the confidential appendices to the PFM contain bid information from solicitations conducted by the utilities.

On September 8, 2023, the following parties filed responses to the SCE/PG&E PFM of D.21-06-035: AReM; Cal Advocates; CESA; EDF; GPI; and LSA. Cal Advocates also filed a concurrent motion to file under seal (MFUS) a confidential version of its comments, containing information about recent bids received by the utilities in response to solicitations.

2. Evaluation of Individual Integrated Resource Plans

On or around November 1, 2022, all LSEs under the Commission's IRP purview filed their individual IRPs, to be evaluated and approved or certified by the Commission.

This section includes a summary of our review and evaluation of each individual LSE's IRP. First, we describe the steps used to conduct the review. Then we include observations of common themes and issues across plans. Finally, we cover critical portions of each LSE's plan and whether they satisfied the Commission's requirements for an IRP, leading to a finding of whether an LSE's plan should be approved or certified, or whether a refiling is required.

2.1. Review Approach

D.18-02-018 contained the original process and requirements for all LSEs to file individual IRPs with the Commission. D.20-03-028 and D.22-02-004 also updated some filing requirements. Commission staff developed Filing Requirements to help guide LSE submission of their individual IRPs. The Filing Requirements included a Narrative Template; a Resource Data Template (RDT) which requires each individual LSE to demonstrate that its portfolio includes the perfect capacity equivalent megawatts (MW) of their resources being equal to or greater than its individual reliability need; and a Clean System Power (CSP) calculator, where LSEs input their existing and planned resources to estimate the GHG and criteria pollutant emissions of their portfolios and to verify that their portfolio achieves the LSE's assigned GHG planning benchmark.

Once the individual IRPs were filed on or about November 1, 2022, Commission staff reviewed all aspects of each plan and requested updates from all LSEs to ensure accurate and comparable data for aggregation purposes.

Similar to the 2020 set of IRP filings, in this round Commission staff also utilized a scorecard system when evaluating the LSEs' Narrative Templates to determine whether each LSE plan adequately satisfied the requirements established by the Commission.

In general, the Narrative Templates varied somewhat in quality, and this experience will be used to update and refine individual filing requirements for the upcoming cycle. For most LSEs, certain sections of the Narrative Templates either satisfied or exceeded the Commission's requirements, while other sections of the same plan failed to satisfy other requirements. In the LSE Narrative Template scorecards (discussed further below), we use the term "adequate" to reflect a satisfactory fulfillment of the individual requirement; this score indicates that the LSE largely provided the required information. An "exemplary" score reflects surpassing requirements and potentially setting a standard for future best practices for other LSEs to emulate. For example, in the area of requirements to address disadvantaged communities, LSEs with an "exemplary" score not only provided the required information, but also discussed their activities to address communities beyond just those technically defined as disadvantaged, and discussed other programs or efforts that are designed to further equity goals. Scores of "deficient" generally reflect a failure to meet the requirement or answer the question included in the template or in the statutory language that underlies the filing requirement.

Once staff determined that all the required materials and information with respect to resource plans and commitments were submitted, they aggregated all LSE plans into a portfolio of resources. More detail about this process is included in Section 3 below.

Commission staff relied heavily on the data submitted confidentially under seal by the LSEs. Thus, all of the motions to file under seal by the LSEs are granted in this decision, to allow use of the confidential information in the data aggregation process, leading to Commission staff recommendations discussed herein.

Commission staff then validated the integrity and consistency of the aggregated portfolio with physical system limits. Energy and resource adequacy contracts were tabulated by LSE, to ensure that contracts did not overlap and that capacity resources were not over-subscribed. This list was checked against the CAISO net qualifying capacity (NQC) list and the list of resources allocated via the cost allocation mechanism (CAM). Staff assessed which capacity resources remained uncontracted. Staff also confirmed that the estimates of transmission and resource potential limits from the RESOLVE model were not exceeded. Staff then aggregated the LSEs' specific data to preserve confidentiality of information.

A full dataset of the aggregated LSE portfolios, including the list of baseline and new physical units, but not contract information, was posted to the Commission's web site.[1]

Finally, Commission staff conducted production cost modeling of the aggregated LSE portfolio datasets. The Strategic Energy Risk Valuation Model (SERVM) was used to measure operational performance and system reliability.

[1] These data are available at the following link: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/aggregated-lse-plans-and-baseline-resources-2023-psp_v2.xlsx.

2.2. Treatment of Requirements for Impacts on Disadvantaged Communities

The Commission's Environmental and Social Justice Action Plan includes several important actions related to Commission policy on reliability and GHG reductions, including a review of IRP plans for the impacts on disadvantaged communities.[2] Commission staff reviewed the individual LSE plans for compliance with all requirements previously set by the Commission. Since this is the third set of individual IRPs filed, we set a slightly higher standard of review for the 2022 plans than the 2018 or 2020 plans.

As with the previous two sets of plans, one area where there is a great deal of variation in treatment is with respect to the requirements to address impacts on disadvantaged communities. The Commission notes the following high-level observations about how the LSEs handled these aspects of their plans.

The majority of LSEs followed filing instructions and provided descriptions of the disadvantaged communities they serve, if any, using the definition provided in the Narrative Template. As described in the Narrative Template, for the purposes of IRP, a disadvantaged community is defined as any community statewide scoring in the top 25 percent statewide or in one of the 22 census tracts within the top five percent of communities with the highest pollution burden that do not have an overall score. As instructed, LSEs used the CalEnviroScreen tool for this purpose. The majority of the LSEs also specified customers served in disadvantaged communities along with the total disadvantaged population number served as a percentage of the total number of

[2] The Environmental and Social Justice Action Plan is available at: https://www.cpuc.ca.gov/news-and-updates/newsroom/environmental-and-social-justice-action-plan.

customers served. A few LSEs exceeded the requirements by specifying low-income communities, which were not necessarily marked as disadvantaged communities by the ranking definition.

Several LSEs noted that they do not serve any disadvantaged communities, and therefore did not address the topic further. As we have stated before, even if LSEs do not specifically serve disadvantaged communities as part of their customer base, almost all LSEs have impacts on disadvantaged communities, at least indirectly, as a result of their reliance on some system power or other power with local pollutant or GHG emissions, which can still impact disadvantaged communities. We note that for future IRPs, we continue to expect the LSEs to take a more expansive view of their responsibilities in this area, and describe their efforts to address disadvantaged community impacts, not only in their own service areas, but also in the state as a whole. Along with the impacts, the LSEs should also address programs and activities they offer to mitigate these impacts.

As in the last set of IRPs, many LSEs that do serve disadvantaged communities did not provide specific quantitative evidence of how their preferred portfolios minimized local air pollutants, with early priority on disadvantaged communities. These LSEs provided general, qualitative statements that their plans are consistent with the goal of minimizing local air pollutants with early priority on disadvantaged communities and that they have considered the impact of their resource procurements on disadvantaged communities. This was the case as well for many LSEs in terms of their current and planned activities and programs addressing disadvantaged communities. These LSEs only provided general statements on their activities and programs. For all IRP filings, we expect more specific information from all LSEs.

Some LSEs in their 2022 IRPs did provide detailed activities and programs focusing on disadvantaged communities, including procurement opportunities to reduce reliance on fossil-fueled power plants, affordability programs, transportation and building electrification, energy efficiency, demand response, residential solar, outreach programs, education and training programs, recruiting and hiring, and others. These are the sorts of activities we encourage to have detailed by all LSEs going forward in their individual IRPs. In Section 2.5 below, we identify the LSEs with deficiencies and those that provided exemplary information.

More detailed information for specific LSEs is available on their individual scorecards as detailed further below in Section 2.5, and Commission staff are available to meet individually with LSEs that have questions or concerns.

2.3. Overview of Disposition of Individual Plans

Table 1 below summarizes the disposition of the individual IRPs filed by all LSEs. In the case of ESPs and IOUs, their IRPs are either "approved" or "not yet approved" pending the refiling of the IRPs with the missing information via Tier 2 Advice Letter as discussed in Section 2.4 below. In the case of CCAs, their IRPs are either "certified" or "not yet certified," also pending refiling of the IRPs with the missing information via Advice Letter. Also included are those LSEs whose filings demonstrated that they qualify as "exempt" from the requirement to file an IRP, though those entities are still required to file information substantiating their eligibility for an exemption on each required IRP filing date in the future.

Table 1.
Summary of Disposition of Individual LSE 2022 IRP Filings

#	LSE	LSE Type	Approved or Certified	Not Yet Approved or Certified
1	3 Phases Renewables	ESP		X
2	Anza Electric Cooperative	Coop	Exempt	
3	Apple Valley Choice Energy	CCA	X	
4	Ava Community Energy (fka EBCE)	CCA	X	
5	Bear Valley Electric	IOU		X
6	Brookfield Renewables Energy Marketing US	ESP		Not serving load
7	Calpine Energy Solutions	ESP		X
8	Calpine PowerAmerica CA	ESP		X
9	Central Coast Community Energy	CCA		X
10	City of Palmdale	CCA	X	
11	City of Pomona	CCA	X	
12	Clean Energy Alliance	CCA	X	
13	Clean Power Alliance of Southern California	CCA	X	
14	CleanPower San Francisco	CCA	X	
15	Commercial Energy of California	ESP		X
16	Constellation NewEnergy	ESP		X
17	Desert Community Energy	CCA	X	
18	Direct Energy Business	ESP	X	
19	EDF Industrial Power Services	ESP		X
20	EnerCalUSA	ESP		Not serving load
21	Gexa Energy California	ESP		Not serving load
22	King City Community Power	CCA		X
23	Lancaster Choice Energy	CCA	X	
24	Liberty Utilities (CalPeco Electric)	IOU		X
25	Marin Clean Energy	CCA	X	
26	Orange County Power Authority	CCA	X	
27	Pacific Gas and Electric	IOU	X	
28	PacifiCorp	IOU	X	
29	Peninsula Clean Energy Authority	CCA	X	
30	Pico Rivera Innovative Municipal Energy	CCA	X	

#	LSE	LSE Type	Approved or Certified	Not Yet Approved or Certified
31	Pilot Power Group	ESP		X
32	Pioneer Community Energy	CCA	X	
33	Plumas Sierra Cooperative	Coop	Exempt	
34	Praxair Plainfield	ESP		Not serving load
35	Rancho Mirage Energy Authority	CCA	X	
36	Redwood Coast Energy Authority	CCA	X	
37	Regents of the University of California	ESP		X
38	San Diego Community Power	CCA	X	
39	San Diego Gas & Electric	IOU	X	
40	San Jacinto Power	CCA	X	
41	San Jose Clean Energy	CCA	X	
42	Santa Barbara Clean Energy	CCA	X	
43	Shell Energy	ESP	X	
44	Silicon Valley Clean Energy Authority	CCA	X	
45	Sonoma Clean Power Authority	CCA	X	
46	Southern California Edison	IOU	X	
47	Surprise Valley Electric Cooperative	Coop	Exempt	
48	Tiger Natural Gas	ESP		Not serving load
49	Valley Clean Energy Alliance	CCA	X	
50	Valley Electric Association	Coop	Exempt	

2.4. Resubmission Process for 2022 IRPs

For those entities that have parts of their IRPs that are determined to be "deficient," their plans are not approved (in the case of IOUs and ESPs) or not certified (in the case of CCAs) in this decision, as summarized in the table above.

In order to remedy these deficiencies, we will require that the LSE file a Tier 2 Advice Letter by no later than May 1, 2024, providing, at a minimum, an appendix or supplement to its IRP, with the missing or inadequate information from the November 2022 and/or October 2023 versions. New resource data templates or other attachments are not required. The next section includes more detailed guidance to each LSE about the information it needs to improve in order to have its IRP approved or certified by Commission staff via the Advice Letter process.

2.5. Review of Individual LSE Plans

This section includes the scorecards for each LSE. The scorecards included in this decision only address a subset of the topics included in the individual IRPs, where content could be assessed against specific criteria. Below the scorecard is a summary of the next steps required for that LSE, if any. A more detailed version of these scorecards, with staff comments included, can be found 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

2.5.1. IOUs

Bear Valley Electric Service

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Deficient
	e.i) Cost and Rate Analysis (IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Exemplary
	b. Disadvantaged Communities	Deficient

Resubmission requirements to address deficient items:

- **Focus on Disadvantaged Communities:** LSE should describe and provide specific details of outreach to DACs undertaken prior to finalizing and submitting its IRP, summarize the feedback received from DACs and their representatives, and describe how such feedback influenced development of the LSE's Preferred Conforming Portfolios.

- **Disadvantaged Communities**: LSE should describe and provide specific details on any current and planned LSE activities/programs to address DACs, including those located within the geographic area served by the LSE and beyond, and describe how the LSE's actions and engagement have changed over time. LSE also needs to provide specific details on current and planned activities to conduct outreach and seek input from any DACs, including those located within the geographic area served by the LSE and beyond, that could be impacted by procurement resulting from the implementation of the LSE's Plan procurement. If the LSE is not conducting targeted outreach directed toward DACs, it must explain why and discuss its plans for conducting such outreach in the future.

Liberty Utilities (CalPeco Electric)

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Deficient
	d.ii) Focus on Disadvantaged Communities	Deficient
	e.i) Cost and Rate Analysis (IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Deficient

Resubmission requirements to address deficient items:

- **Local Air Pollutants:** LSE needs to report CSP results for NOx, SO2, and PM2.5 from Preferred Conforming Portfolios.
- **Focus on Disadvantaged Communities:** LSE needs to **confirm** information from CalEnviroScreen 4.0 was used **correctly**. LSE also must describe and provide specific details of outreach to DACs undertaken prior to finalizing and submitting its IRP, summarize the feedback received from DACs and their representatives, and describe how such feedback influenced development of the LSE's Preferred Conforming Portfolios.
- **Disadvantaged Communities:** LSE must describe or address any **analysis** or activities targeted at minimizing criteria air pollutants in DACs and identify feasible procurement opportunities to reduce reliance on fossil-fueled **power** plants, particularly those that are located within DACs, including specific metrics and scoring criteria that the LSE uses to prioritize the minimization of criteria air pollution in DACs, how those metrics and scoring criteria have been used in past procurement, and how those metrics and scoring criteria will be applied to planned procurement. LSE should also provide specific details on current and planned activities to conduct outreach and seek input from any DACs, including those located within the geographic area served by the LSE and beyond, that could be impacted by procurement resulting from the implementation of the LSE's Plan procurement. If the LSE is not conducting targeted outreach directed toward DACs, it must explain why and discuss its plans for conducting such outreach in the future.

Pacific Gas and Electric Company

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Exemplary
	b. Disadvantaged Communities	Adequate

PacifiCorp

Area	Specific Requirement	Assessment
Required Forms	Provide file either a Narrative Template or an IRP prepared for other jurisdictions?	Adequate
Treatment of Disadvantaged Communities	Describe its objectives for its IRP analytical work?	Adequate
GHG Target Planning	Use any modeling software, and if so, describe differences between it and RESOLVE and how those differences should be considered?	Adequate

San Diego Gas & Electric

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Exemplary

Area	Specific Requirement	Assessment
	e.i) Cost and Rate Analysis (IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Exemplary

Southern California Edison

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Exemplary
	d.ii) Focus on Disadvantaged Communities	Exemplary
	e.i) Cost and Rate Analysis (IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Exemplary
	b. Disadvantaged Communities	Exemplary

2.5.2. CCAs

Apple Valley Choice Energy

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

Ava Community Energy (Formerly East Bay Community Energy)

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Exemplary
	b. Disadvantaged Communities	Adequate

Central Coast Community Energy

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Deficient
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

Resubmission requirements to address deficient items:

- **Cost and Rate Analysis (non-IOUs):** LSE must provide a narrative description of its approach in considering cost and rate impacts on its customers.

Clean Energy Alliance

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

Clean Power Alliance of Southern California

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Exemplary
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

CleanPowerSF

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Exemplary
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Exemplary
	b. Disadvantaged Communities	Adequate

Desert Community Energy

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Exemplary
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Exemplary
	b. Disadvantaged Communities	Adequate

King City Community Power

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Deficient
	e.i) Cost and Rate Analysis (non-IOUs)	Deficient
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Deficient

Resubmission requirements to address deficient items:

- **Focus on Disadvantaged Communities:** LSE must describe how its Preferred Conforming Portfolios minimize localized air pollutants with early priority on DACs and describe and provide specific details of outreach to DACs undertaken prior to finalizing and submitting its IRP, summarize the feedback received from DACs and their representatives, and describe how such feedback influenced development of the LSE's Preferred Conforming Portfolios.
- **Cost and Rate Analysis (non-IOUs):** LSE needs to provide more detail in their narrative description of their approach in considering cost and rate impacts on their customers.
- **Disadvantaged Communities:** LSE must describe and provide specific details on any current and planned LSE activities/programs to address DACs, including those located within the geographic area served by the LSE and beyond, and describe how the LSE's actions and engagement have changed over time. LSE also needs to describe or address any analysis or activities targeted at minimizing criteria air pollutants in DACs and identify feasible procurement opportunities to reduce reliance on fossil-fueled power plants, particularly those that are located within DACs, including specific metrics and

scoring criteria that the LSE uses to prioritize the minimization of criteria air pollution in DACs, how those metrics and scoring criteria have been used in past procurement, and how those metrics and scoring criteria will be applied to planned procurement. LSE should also provide specific details on current and planned activities to conduct outreach and seek input from any DACs, including those located within the geographic area served by the LSE and beyond, that could be impacted by procurement resulting from the implementation of the LSE's Plan procurement. If the LSE is not conducting targeted outreach directed toward DACs, the LSE must explain why and discuss its plans for conducting such outreach in the future. LSE directs reader to the prior DAC section 3(d)(ii), but questions are not addressed there either.

Lancaster Choice Energy

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

MCE

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Exemplary
	b. Disadvantaged Communities	Adequate

Orange County Power Authority

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

Palmdale

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

Peninsula Clean Energy Authority

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Exemplary
	d.i) Local Air Pollutants	Exemplary
	d.ii) Focus on Disadvantaged Communities	Exemplary
	e.i) Cost and Rate Analysis (non-IOUs)	Exemplary
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Exemplary
	b. Disadvantaged Communities	Adequate

Pioneer Community Energy

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

City of Pomona

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

Pico Rivera Innovative Municipal Energy

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

Redwood Coast Energy Authority

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Exemplary
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Exemplary
	b. Disadvantaged Communities	Exemplary

Rancho Mirage Energy Authority

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

Santa Barbara Clean Energy

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

San Diego Community Power

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

San Jose Clean Energy

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

San Jacinto Power

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

Sonoma Clean Power

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Exemplary
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Exemplary
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

Silicon Valley Clean Energy

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Exemplary
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Exemplary
	b. Disadvantaged Communities	Exemplary

Valley Clean Energy Authority

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Exemplary
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

2.5.3. ESPs

3 Phases Renewables, Inc.

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Deficient
	d.i) Local Air Pollutants	Deficient
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Deficient

Resubmission requirements to address deficient items:

- **Preferred Conforming Portfolios:** LSE needs to describe its Preferred Conforming Portfolio and the reasons for its portfolio preferences.
- **Local Air Pollutants:** LSE must report CSP results for NOx, SO2, and PM2.5 from Preferred Conforming Portfolios.
- **Disadvantaged Communities:** LSE did not provide any information here, but refers back to Section 3(d)(ii). LSE should provide specific details on any current and planned LSE activities/programs to address DACs, including those

located within the geographic area served by the LSE and beyond, and describe how the LSE's actions and engagement have changed over time. LSE should describe or address any analysis or activities targeted at minimizing criteria air pollutants in DACs and identify feasible procurement opportunities to reduce reliance on fossil-fueled power plants, particularly those that are located within DACs, including specific metrics and scoring criteria that the LSE uses to prioritize the minimization of criteria air pollution in DACs, how those metrics and scoring criteria have been used in past procurement, and how those metrics and scoring criteria will be applied to planned procurement. LSE should provide specific details on current and planned activities to conduct outreach and seek input from any DACs, including those located within the geographic areas served by the LSE and beyond, that could be impacted by procurement resulting from the implementation of the LSE's Plan procurement.

Calpine Energy Solutions, LLC

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Exemplary
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Deficient

<u>Resubmission requirements to address deficient items:</u>

- **Disadvantaged Communities:** LSE needs to describe and provide specific details on any current and planned LSE activities/programs to address DACs, including those located within the geographic area served by the LSE and beyond, and describe how the LSE's actions and engagement have changed over time. It should also describe or address any analysis or activities targeted at minimizing criteria air pollutants in DACs and identify feasible procurement opportunities to reduce reliance on fossil-fueled power plants, particularly those that are located within DACs, including specific metrics and scoring criteria that the LSE uses to prioritize the minimization of criteria air pollution in DACs, how those metrics and scoring criteria have been used in past procurement, and how those metrics and scoring criteria will be applied to planned procurement. LSE must also provide specific details on current and planned activities to conduct outreach and seek input from any DACs, including those located within the geographic area served by the LSE and beyond, that could be impacted by procurement resulting from the implementation of the LSE's Plan procurement. If the LSE is not conducting targeted outreach directed toward DACs, it should explain why and discuss its plans for conducting such outreach in the future.

Calpine PowerAmerica-CA, LLC

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Deficient

<u>Resubmission requirements to address deficient items:</u>

- **Disadvantaged Communities:** LSE must describe and provide specific details on any current and planned LSE activities/programs to address DACs, including those located within the geographic area served by the LSE and beyond, and describe how the LSE's actions and engagement have changed over time. It also needs to describe or address any analysis or activities targeted at minimizing criteria air pollutants in DACs and identify feasible procurement opportunities to reduce reliance on fossil-fueled power plants, particularly those that are located within DACs, including specific metrics and scoring criteria that the LSE uses to prioritize the minimization of criteria air pollution in DACs, how those metrics and scoring criteria have been used in past procurement, and how those metrics and scoring criteria will be applied to planned procurement. LSE must also provide specific details on current and planned activities to conduct outreach and seek input from any DACs, including those located within the geographic area served by the LSE and beyond, that could be impacted by procurement resulting from the implementation of the LSE's Plan procurement. If it is not conducting targeted outreach directed toward DACs, LSE needs to explain why and discuss its plans for conducting such outreach in the future.

Commercial Energy of California

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Deficient
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Deficient
	e.i) Cost and Rate Analysis (non-IOUs)	Deficient
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Deficient
	b. Disadvantaged Communities	Deficient

Resubmission requirements to address deficient items:

- **Preferred Conforming Portfolios:** LSE needs to describe its Preferred Conforming Portfolio and the reasons for its portfolio preferences.

- **Focus on Disadvantaged Communities:** LSE should describe which DACs it serves and specify customers served in DACs along with total disadvantaged population number served as a percentage of total number of customers served. LSE must also describe and provide specific details of outreach to DACs undertaken prior to finalizing and submitting its IRP, summarize the feedback received from DACs and their representatives, and describe how such feedback influenced development of the LSE's Preferred Conforming Portfolios.
- **Cost and Rate Analysis (non-IOUs):** LSE needs to expand narrative description of their approach in considering cost and rate impacts on their customers.
- **Proposed Procurement Activities and Potential Barriers:** LSE should provide more details relating to proposed procurement activities, barriers, and risks for each planned resource identified.
- **Disadvantaged Communities:** LSE did not provide any information here, but refers back to Section 3(d)(ii), but the questions are not addressed there. LSE should provide specific details on any current and planned LSE activities/programs to address DACs, including those located within the geographic area served by the LSE and beyond, and describe how the LSE's actions and engagement have changed over time. LSE should describe or address any analysis or activities targeted at minimizing criteria air pollutants in DACs and identify feasible procurement opportunities to reduce reliance on fossil-fueled power plants, particularly those that are located within DACs, including specific metrics and scoring criteria that the LSE uses to prioritize the minimization of criteria air pollution in DACs, how those metrics and scoring criteria have been used in past procurement, and how those metrics and scoring criteria will be applied to planned procurement. LSE should provide specific details on current and planned activities to conduct outreach and seek input from any DACs, including those located within

the geographic areas served by the LSE and beyond, that could be impacted by procurement resulting from the implementation of the LSE's Plan procurement.

Constellation New Energy

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Deficient
	b. Disadvantaged Communities	Adequate

Resubmission requirements to address deficient items:

- **Proposed Procurement Activities and Potential Barriers:** LSE should provide more details relating to proposed procurement activities, barriers, and risks for each planned resource identified.

Direct Energy Business

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

EDF Industrial Power Services (CA), LLC

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Deficient
	d.i) Local Air Pollutants	Deficient
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

Resubmission requirements to address deficient items:

- **Preferred Conforming Portfolios:** LSE needs to describe its Preferred Conforming Portfolio and the reasons for its portfolio preferences.
- **Local Air Pollutants: LSE** must report CSP results for Nox, SO2, and PM2.5 from Preferred Conforming Portfolios.

Pilot Power Group, Inc.

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Deficient
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Deficient

Resubmission requirements to address deficient items:

- **Focus on Disadvantaged Communities:** LSE should describe which DACs it serves and specify customers served in DACs along with total disadvantaged population number served as a percentage of total number of customers served. LSE must also describe and provide specific details of outreach to DACs undertaken prior to finalizing and submitting its IRP, summarize the feedback received from DACs and their representatives, and describe how such feedback influenced development of the LSE's Preferred Conforming Portfolios.

- **Disadvantaged Communities:** LSE did not provide any information here, but refers back to Section 3(d)(ii), but the questions are not addressed there. LSE should provide specific details on any current and planned LSE activities/programs to address DACs, including those located within the geographic area served by the LSE and beyond, and describe how the LSE's actions and engagement have changed over time. LSE should describe or address any analysis or activities targeted at minimizing criteria air pollutants in DACs and identify feasible procurement opportunities to reduce reliance on fossil-fueled power plants, particularly those that are located within DACs, including specific metrics and scoring criteria that the LSE uses to prioritize the minimization of criteria air pollution in DACs, how those metrics and scoring criteria have been used in past procurement, and how those metrics and scoring criteria will be applied to planned procurement. LSE should provide specific details on current and planned activities to conduct outreach and seek input from any DACs, including those located within the geographic areas served by the LSE and beyond, that could be impacted by procurement resulting from the implementation of the LSE's Plan procurement.

Shell Energy North America

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Adequate
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

University of California Regents

Area	Specific Requirement	Assessment
3. Study Results	b. Preferred Conforming Portfolios	Adequate
	d.i) Local Air Pollutants	Adequate
	d.ii) Focus on Disadvantaged Communities	Adequate
	e.i) Cost and Rate Analysis (non-IOUs)	Deficient
4. Action Plan	a. Proposed Procurement Activities and Potential Barriers	Adequate
	b. Disadvantaged Communities	Adequate

Resubmission requirements to address deficient items:

- **Cost and Rate Analysis (non-IOUs):** LSE needs to expand narrative description of their approach in considering cost and rate impacts on their customers.

2.6. Specific IOU-Requested Authorizations

All three of the large IOUs (PG&E, SCE, and SDG&E) requested, in their individual IRPs, certain Commission actions. Unlike the other LSEs, the IOUs require Commission authority for certain activities and for their cost recovery. BVES, Liberty Utilities, and PacifiCorp did not request any particular authorizations in their individual IRPs. This section discusses the requests by PG&E, SCE, and SDG&E, and their disposition in this decision.

PG&E, in its individual IRP, estimates that it will need to procure up to 12 terrawatt-hours (TWh) of electricity in order to meet the overall clean energy and reliability goals in its plan. PG&E requests explicit authority from the Commission to procure new resources via procurement activities, including solicitation and bilateral negotiations. PG&E also explains the benefits of continuing to conduct procurement on a gradual basis through at least 2030, to help mitigate a number of future risks, including but not limited to:

- Uncertainties regarding project development timeframes including supply chain constraints or delays;
- Significant demand for projects, including new construction and emerging resources as LSEs ramp up procurement for increasing GHG emissions reductions and Renewables Portfolio Standard (RPS) requirements for 2030 and beyond;
- Potential cost impacts due to state and federal policy changes in tax credits and/or tariffs on imported materials;
- Potential increase in demand due to increased electrification, especially across the transportation sector;
- Potential transmission constraints for new projects, and potential scarcity of viable projects if required transmission infrastructure does not keep pace with the number of new resources needed; and
- Potential for competition for out-of-state resources as jurisdictions out of California increase their climate mitigation efforts.

SCE, in its individual IRP, simply requests that the Commission authorize SCE to begin to procure the resources to meet the needs identified in its 25 MMT

Bundled Portfolio with a flexible approach, which SCE describes as the following:

- Using a least-cost, best-fit approach to evaluate and select the resources that will best meet a specific need through competitive solicitations;
- Procuring on a technology-neutral basis;
- Not procuring exactly to what is listed in its individual IRP, either in terms of exact resource type or exact year for procurement, but rather putting together a set of resources determined by the offers received by developers with reasonable pricing.

SCE seeks the option to conduct solicitations annually or periodically based on market conditions, and to procure incrementally over time, in order to maximize value to its customers and minimize rate impacts.

SDG&E, in its individual IRP, requests authorization to procure to meet its 30 MMT target for its bundled customers. SDG&E also includes extensive discussion on the load departures to CCAs taking place in its service area, and requests that the Commission ensure equitable distribution of procurement orders based on retail load served.

The requests of all of the IOUs are reasonable and we will approve all three to continue procuring to meet their 25 MMT portfolios, consistent with the direction in Section 3 below for the PSP portfolio overall. Thus, SDG&E may not only procure to meet its 30 MMT portfolio, but also beyond to meet the 25 MMT portfolio by 2035.

All three IOUs are authorized to conduct flexible procurement activities as market conditions dictate, including solicitations and bilateral negotiations, to meet the resource needs identified in their 2022 individual IRPs, 25 MMT portfolios.

Resources procured under this authorization may also count towards future procurement mandates or compliance requirements established by the Commission in this proceeding. The IOUs shall submit Tier 3 advice letters for approval of contracts for resources procured according to this authorization, unless they are utility-owned requiring applications, and unless the contracts are otherwise authorized pursuant to another proceeding before the Commission where another authorization vehicle is in place. For administrative efficiency, more than one contract may be presented to the Commission in a single advice letter submission.

2.7. Procurement Encouragement for all LSEs

In addition to the specific procurement authorization discussed above, which is needed for IOUs to conduct procurement activities, in this decision we encourage all LSEs to continue timely procurement of resources identified in their plans. We do not require strict compliance with the plans, since we understand that plans can change, particularly over a period of a decade or more, and that pricing may be different in actual bids than anticipated ahead of time. We also know that for grid reliability and GHG emissions purposes, steady and continued addition of clean energy resources to the electric system will be required by all LSEs to reach our state goals. Each LSE is responsible for reliably serving its own customers in the most cost-effective manner, including anticipating future reliability needs and meeting California's critical climate goals.

As parties know, consideration of a programmatic approach to procurement of electric resources is pending in this proceeding. Commission staff have published options for the design of a Reliable and Clean Power Procurement Program (RCPPP) that would require all LSEs to serve their load reliably and within their assigned GHG benchmarks. A staff proposal for RCPPP design is due to be released soon. We state affirmatively that procurement conducted in advance of the adoption of a programmatic approach will be counted towards the LSE's obligations under whatever program is adopted, as long as it meets the applicable requirements. In addition, if the Commission needs to adopt any more "interim" procurement orders, new resources procured and built will also count towards any incremental requirements of the individual LSEs (as long as they are not already used toward D.21-06-035 or D.23-02-040 obligations) and that the procurement baseline will not be further updated from the baseline for D.21-06-035. Therefore, the LSEs are strongly encouraged to continue to solicit and procure the volume of clean resources throughout the planning period (at least through 2035) that are included in their individual plans discussed in this decision.

3. Preferred System Portfolio and GHG Target for 2035

The individual IRPs filed by the LSEs contain information, in both narrative and spreadsheet form, about the electricity resources that the LSEs plan to rely on through the year 2035.

Commission staff took the resources in each of the individual IRPs and aggregated them together to evaluate the aggregated portfolio against the electric system needs of California, and particularly the CAISO system. The aggregated portfolio was compared against reliability and GHG constraints, while seeking to meet any residual resource needs to meet those constraints at the lowest reasonable cost to ratepayers. The aggregation of the individual LSE portfolios also served to determine if there were gaps in the collective portfolio requiring Commission action, such as procurement orders.

The individual IRPs all included LSE-specific information on planned GHG reductions, reliability resources, imports and exports, impacts on disadvantaged communities, estimated costs, and other related elements of long-term planning. Each individual IRP was required to contain three elements:

- A Narrative Template, which describes how the LSE approaches the process of developing its plan, presents the results of analytical works, and demonstrates to the Commission and stakeholders the LSE's planned actions.
- A Resource Data Template (RDT), which collects planned and existing LSE contracting data, including for future resources which do not exist yet. The RDT provides a snapshot of the LSE contracted and planned monthly total energy and capacity forecast positions over a ten-year look-ahead period. The RDT is also used to verify that LSE portfolios achieve the assigned reliability need, which is based on the reliability planning standard.
- A Clean System Power (CSP) Calculator, which is used to estimate the GHG and criteria pollutant emissions of the LSE's portfolio and verify that the portfolio achieves the LSE's assigned GHG planning benchmark.

Contained in the RDTs is information about existing resources, resources contracted for and in development, and planned resources for which there are no current contracts. Commission staff developed aggregated LSE plans using the data submitted in the RDTs, which had to be evaluated for completeness and internal consistency to ensure that they accurately reflected LSE planning.

To analyze the RDTs, Commission staff used a tool built to aggregate the portfolios and check errors called the RDT Error Checking, Aggregation, and Reallocation Tool (RECART). RECART performed the following functions: combining the filings into one dataset; producing LSE-specific workbooks that tracked errors; and performing diagnostics for Commission staff to use when analyzing LSE filings. RECART compiled energy and capacity resources under contract, contracted resources by technology type and LSE, and aggregated new resources that were either in development or planned for future procurement.

LSEs were contacted when errors were found by RECART and some LSEs resubmitted their RDT filings, where necessary. This process continues to ensure that the Commission works from plans that fully reflect LSE planning and priorities. Improvements made by Commission staff to the RDT and the RECART tool, as well as growing LSE familiarity, continue to result in fewer required LSE resubmissions since the inception of the process in 2021.

Commission staff also worked with the California Energy Commission (CEC) staff to develop RDTs for publicly-owned utilities (POUs) that are within the CAISO footprint, to reflect existing contracts held by POUs to create an accurate picture of all resources across the CAISO system. The POU RDTs contain existing contracts held by the POUs for online and in-development resources located in the CAISO area or deliverable to the CAISO. The POU RDTs do not contain planned resources to meet reliability and GHG targets, and therefore do not reflect the same magnitude of new resources as the RDTs of the LSEs under the Commission's IRP purview. The lack of planned resources for POUs not under the Commission's jurisdiction, due to the Commission's lack of visibility into those plans, may contribute to an identified gap in the total resources required to meet GHG reduction targets by 2035, even though the POUs may, in fact, be planning to procure those resources.

Commission staff assembled information from all of these sources, checked for overlap and double counting, and assembled one curated list of resources to create an accurate picture of all resource planning across the LSEs within the

CAISO system under Commission IRP purview, as represented in the LSEs' plans.

According to D.22-02-004, LSEs were required to submit plans that met their individual share of two different statewide electric sector GHG emissions targets: a 38 MMT target by 2030 and a 30 MMT target by 2030. Because we are in a new cycle of IRP and the planning horizon is now out to at least 2035, these extended targets are now referred to by their 2035 target GHG emissions levels, namely: 30 MMT by 2035 and 25 MMT by 2035.

The aggregated portfolios meeting both the 30 MMT GHG target and the 25 MMT GHG target were studied in the Strategic Energy and Risk Valuation Model (SERVM) modeling software to determine their reliability and GHG emissions and then used as the starting point to develop and recommend the PSP portfolio. These aggregated portfolios containing the resources included in the LSE plans serve as the basis for the proposed PSP portfolio. These cases use the resources contained in the LSEs plans as a minimum buildout, and then are augmented with resources selected by the RESOLVE capacity expansion model to reach the GHG targets and meet reliability needs. These cases are referred to as the "Core" cases.

It is worth noting that a number of LSEs submitted the same set of existing and planned resources to meet both targets. In other words, many LSEs are planning to meet the lower 25 MMT GHG target, even if the Commission does not order it. According to the CSP calculators submitted, all LSEs met their assigned GHG benchmarks, with some planning to achieve emissions well below their assigned benchmarks.

LSEs included a diverse set of resources including in-state land-based wind, offshore wind (OSW), out-of-state wind, geothermal, and long-duration storage, as well as a great deal of solar and battery storage.

To conclude the evaluation of the individual LSE filings and to give direction for the next IRP filings, the October 5, 2023 ALJ ruling recommended a proposed PSP portfolio. The PSP portfolio, once adopted by the Commission, serves a number of purposes and use cases, including, but not necessarily limited to, the following:

- LSE planning. The 2021 PSP[3] was used as the basis for developing the LSE filing requirements for their 2022 individual IRP filings. The PSP adopted in this decision will be used as the basis for the next round of individual IRPs.
- CAISO TPP. The PSP is typically adopted by the Commission and transmitted to the CAISO for assessing transmission needs in their TPP base case. Sensitivity cases may also be transmitted.
- Avoided Cost Calculator (ACC). The PSP will likely be used as the basis for the 2024 ACC update for demand-side resources, and will also inform the calculations for net energy metering compensation.
- Aliso Canyon. The PSP is the basis for the natural gas forecasts used in other proceedings, such as the Aliso Canyon Investigation (I.) 17-02-002.
- Senate Bill (SB) 100 (Stats. 2018, Ch. 312). The PSP serves as a foundation upon which SB 100 analysis and findings are built.

In sum, the PSP represents the collective plan of the LSEs and the blueprint endorsed by the Commission for how electricity customers will be served

[3] Adopted in D.22-02-004.

reliably at the lowest reasonable cost while meeting state policy objectives for GHG emissions reduction, resulting in reduced reliance on fossil fuels and the cleanest potential portfolio.

To analyze scenarios or potential adoption as the 2023 PSP, Commission staff conducted several sets of modeling analyses. Most parties are familiar with the RESOLVE and SERVM models. The former is the capacity expansion model that has been used since the beginning of the IRP process in 2016, while the latter is the reliability and production cost model (PCM) used to inform multiple Commission proceedings for several years, including IRP. Before being used in this round of analysis, including the aggregation described in the previous section, several updates were made to the models, as described below.

First, to update the list of baseline resources, Commission staff reconciled data from multiple sources including CAISO,[4] Western Electricity Coordinating Council (WECC),[5] CEC, and the Energy Information Administration (EIA). Newly contracted in-development resources included in LSE plans were added to the baseline. A common set of CAISO generation units was used for both SERVM and RESOLVE.

For fossil-fueled generation resource retirements, the candidate portfolios described below assumed retirement of those thermal units where there was an already-announced retirement by the CAISO or the generation owner. The RESOLVE model then has the option to choose to economically not retain additional gas resources as it solves for an optimal portfolio. The once-through-cooling (OTC) steam units were assumed to go offline by the end of 2023 and

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[4] The CAISO Master Generating Capability List as of January 2023, plus the unit operating cost data from the CAISO, was used.

[5] The WECC 2032 Anchor Data Set.

Diablo Canyon Power Plant (Diablo Canyon) was assumed to retire in 2024/2025, as previously planned and approved in D.18-01-022.

Operational constraints for cogeneration, geothermal, and biomass resources were revised using data from the CAISO bidding database and the CAISO Master File. The monthly average production during peak managed demand, which is equivalent to the resource net qualifying capacity (NQC), was used to set the resource's maximum output, while monthly schedule and bidding data was used to set the minimum output. Cold and hot startup profiles were also updated.

In SERVM, the 1998-2020 hydroelectric data was refreshed using hourly and monthly data collected from EIA, CAISO, and Bonneville Power Administration. In addition, hydroelectric years were made independent of the weather years in the model stochastic inputs, increasing the number of hydro-demand combinations. Analysis of hydroelectric production vs. peak loads and temperatures showed little correlation, supporting the modeling choice of making weather and hydroelectric inputs independent.

With respect to imports, the CAISO summer evening simultaneous imports (hours ending 18 through 22) were capped at 4,000 MW while all other hours of the year were capped at 11,040 MW, which is the CAISO 2023 Maximum Import Capability (MIC) minus existing transmission contracts. Load and resource balances for regions external to the CAISO were tuned to approximate a 0.1 days per year loss of load expectation (LOLE) reliability level, which is an industry standard and has historically been used for planning by this Commission. The tuning was required to model realistic flows between balancing areas and not have any one region excessively leaning on another during critical system conditions, possibly distorting the calculation of LOLE for the CAISO region.

On the demand side, the electric demand was updated to the 2022 CEC Integrated Energy Policy Report (IEPR) Planning Peak and Energy Forecast data. The hourly demand modifier profiles for energy efficiency, fuel substitution, transportation electrification, time-of-use rates, and behind-the-meter (BTM) storage were drawn directly from the 2022 IEPR demand forecast. The BTM photovoltaic hourly profiles, on the other hand, were developed from 1998-2020 solar radiation data to model the variability present in those years. The average annual energy of the hourly profiles was calibrated to match the single annual energy values in the 2022 IEPR for each IEPR Planning Area.

The 1998-2020 historical weather-based distribution of hourly electric demand was calibrated such that the median CAISO coincident managed peak matches the single annual CAISO coincident 1-in-2 managed peak of the 2022 IEPR demand forecast. In addition, all future years were assumed to start on a Monday, with demand modifier profiles adjusted to align with a Monday day-of-week start. In modeling efforts from prior years, Commission staff have used both methods of either all Monday starts for future years, or starting on the day-of-week dictated by the calendar of the future year. Staff decided to use all Monday starts in this cycle to ensure each future year only varied from load, resources, and cost projections, and not based on which day-of-week start was used.

Gas prices and gas delivery hubs were updated from the CEC's draft 2023 NAMGas model. Carbon prices were derived from the GHG price forecast included in the 2022 IEPR. These costs, as well as hurdle rates for transferring energy between balancing areas, were all translated into 2022 real dollars.

Resource cost data were also updated using the inputs and assumptions (I&A) most recently developed by Commission staff, and to which numerous parties provided informal comments and input. The latest I&A document is available at the following link: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/inputs-assumptions-2022-2023_final_document_10052023.pdf.

In general, the costs of many renewable resources were somewhat reduced from assumptions used in previous IRP cycles, with the notable exception of the estimates for the costs of OSW, which increased in the latest iteration of the I&A. All renewable technology costs are based on the most recent 2023 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB). The increase in OSW cost assumptions is a significant driver of modeling results, but Commission staff recognize that the assumptions are as-yet untested with actual procurement processes in California, so actual costs for OSW could vary significantly from the assumptions. Battery storage costs also increased compared to the last IRP cycle, reflecting current market conditions.

The other additional key update to resource costs was the inclusion of new and/or extended investment or production tax credits (ITC or PTC) as part of the federal Inflation Reduction Act (IRA). The IRA included tax credit extensions (*e.g.*, wind PTC) and expansions (*e.g.,* stand-alone storage ITC, solar PTC credits, new credits for green hydrogen and carbon capture and storage, etc.). These credits have a significant impact on portfolio build and portfolio costs in RESOLVE.

Resource potential updates were also implemented for several renewable and storage resources. These updates included expanding resource potentials to include areas not previously modeled, incorporating the CEC's new land-use screens for in-state solar, wind, and geothermal resources, and updating to higher resource density assumptions for onshore and offshore wind. Transmission assumptions and modeling were also updated to better reflect the constraint system outlined by the CAISO White Paper on transmission capability estimates and to incorporate updates from the new 2023 version of the White Paper and information on approved upgrades from the CAISO's 2022-2023 TPP.[6] These updates do result in an increase in resource potential available for model selection for several renewable and storage resources. Of particular significance is the fact that more land-based in-state and out-of-state wind was made available for selection.

Once all of these updates were completed, Commission staff used RESOLVE to construct scenarios that could be considered as candidates for a PSP portfolio that met the reliability and emissions standards.

The aggregated LSE portfolios were used as the starting point for modeling to develop and recommend the PSP portfolio. The aggregated portfolios containing the resources LSEs included in the November 2022 IRP filings, plus RESOLVE modeling, are referred to as the "Core" cases. These Core cases use the resources contained in the LSE plans as a minimum buildout, and then augment them with resources selected by the RESOLVE capacity expansion model to reach either of the two GHG targets and also meet reliability needs.

In total, RESOLVE was used to select two scenarios for each GHG target, for a total of four analyses: two "Core" cases (for 25 MMT and 30 MMT) were

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[6] *See* the following link: https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=03DCF912-0ECF-4CF9-A304-A05F4ED5B2CD.

based on LSEs' planned new resources and two "Least-Cost" cases (for 25 MMT and 30 MMT) were based only on RESOLVE's economic selection algorithm. While all scenarios include LSEs' contracted in-development resources because they are part of the baseline, LSEs' planned new resources were excluded in the two additional Least-Cost scenarios.

Parties who have followed the IRP process since the beginning will recognize this type of analysis as similar to the Reference System Plan analysis of past cycles, where Commission staff analyzed a theoretical resource portfolio based on optimal capacity expansion modeling and used it as a benchmark against which to evaluate other buildout scenarios. In the analysis leading to the October 5, 2023 ALJ ruling recommendations, the two additional scenarios were called the 25 MMT and 30 MMT "Least Cost" scenarios, because they use the RESOLVE model's cost minimizing optimization to identify the most cost-effective way to meet all policy, reliability, and emissions constraints for the electricity system.

Thus, four scenarios were evaluated as the potential PSP portfolio, as shown in Table 2 below.

Table 2.
Four Scenarios Analyzed as Potential PSP Portfolios

GHG Emissions Target in 2035	RESOLVE Assumptions	
25 MMT	25 MMT Core (LSE Plans)	25 MMT Least-Cost
30 MMT	30 MMT Core (LSE Plans)	30 MMT Least-Cost

The detailed results of the RESOLVE analysis for the above scenarios are available at the following link: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/2023-proposed-psp-and-2024-2025-tpp-resolve-analysis-slide-deck_final-v2.pdf

In addition to these four scenarios, a variety of sensitivity cases were analyzed in RESOLVE and are also summarized at the same link above. The sensitivities analyzed include natural gas retirements, individual resource costs, and reduced resource availability, among other things.

Based on the analysis described above, the October 5, 2023 ALJ ruling included the Commission staff recommendation for the Commission to adopt the 25 MMT Core portfolio as the PSP portfolio.

3.1. Comments of Parties

Most parties did not comment on the aggregation process used by Commission staff to analyze the PSP portfolio. Of those that did, CalCCA and ACP-CA explicitly supported the process used by staff. No party opposed the process, though several offered improvements and refinements that could be made now or in the future.

IEP, AReM, and Cal Advocates expressed concerns about how the Commission accounts for the resource planning of POUs. AReM commented that there is ambiguity about where POUs are planning to meet state emissions standards and, if this is left in the PSP, there could be an unfair cost shift to LSEs under the Commission's purview. IEP suggested that the CEC gather more detailed information about POU planning and contracting. Cal Advocates suggested that the Commission include additional planned resources in the PSP to represent the resources that non-jurisdictional LSEs will need for compliance with state policy.

GPI and ACP-CA were concerned that the baseline should be adjusted because it does not appropriately account for uncontracted and potentially retiring baseline resources.

With respect to the recommended PSP portfolio, the majority of parties supported the selection of the 25 MMT Core portfolio as the PSP portfolio, including at least 23 parties that explicitly supported this choice in their comments. These parties were: CESA; PG&E; NRDC/UCS; CEERT; CalWEA; SEIA/LSA; DOW; EDFR; Gallatin; GPI; NextEra; GLW; OWC; IEP; CalCCA; Hydrostor; MGRA; EDF; SCE; SCPA; CEJA/Sierra Club; ACP-CA; and GSCE.

CalCCA and CEJA/Sierra Club urged the Commission to adopt a 2045 target of 0 MMT, in addition to the PSP portfolio. SCPA suggested testing the economics of a target of 8 MMT by 2045. PG&E supported adopting both the 30 and 25 MMT targets, given the divergence between the SERVM and RESOLVE GHG results. EDF commented that the portfolio should include an additional 300-600 MW of demand response beyond what appears in the Least-Cost portfolio.

SEIA/LSA recommended that the Core portfolio be used through 2030, switching to the Least-Cost portfolio after that, in order to keep the level of OSW investment consistent with LSE plans.

Hydrostor commented that the Least-Cost and High Gas Retirement sensitivities demonstrate the need for long-duration energy storage (LDES) beyond the level included in LSE planning.

Several parties, including CalWEA, DOW, NextEra, SCPA, and EDF, commented that the 5 GW of wind included in the Core portfolio in Southern Nevada may be unrealistic, and should be located instead in Northern California and/or the San Joaquin Valley. These and a few other parties, including RWE and Vineyard, were concerned that the land-use and environmental screens are not granular enough in the non-California areas and therefore the out-of-state wind potential should be reduced. GPI also commented in general on the additional economic benefits of in-state resources rather than imported renewables.

GLW also commented that the Core portfolio should be updated to include the 2022-2023 CAISO TPP approval of a transmission upgrade in their service area, thus increasing the amount of resources that could be selected in that geographic area without requiring transmission upgrades.

CalCCA also commented that the years beyond 2030 should not be binding on LSEs given that inputs and assumptions will evolve before LSEs need to finalize their procurement decisions for that period.

Several parties representing OSW interests commented on the Core Portfolio, including OWC, RWE, and Vineyard. Their general concerns were that the IRP capacity expansion modeling does not capture the full suite of non-energy benefits. In addition, they commented that the PSP and TPP results do not reflect the goal of 25 GW of OSW by 2045 included in the CEC's plan required by Assembly Bill (AB) 525 (Stats. 2021, Ch. 231).

Several other parties also commented on OSW issues. BAMx and Cal Advocates raised concerns about OSW related to costs and generally advocated for no additional OSW in the PSP portfolio. EDF commented that it is worth investing in OSW even if it is slightly higher cost, to provide California with renewable resources and diverse capacity contributions. NRDC/UCS and GPI generally advocated for increased alignment between the Commission and other state agencies for planning and goals.

Very few parties encouraged the Commission to adopt only a 30 MMT portfolio or to rely solely on the Least Cost portfolio. IEP noted that the Least-Cost analysis is informative, but did not suggest adopting it.

Cal Advocates and ACP-CA suggested that the portfolio should be updated based on the 2023 IEPR assumptions, because there may be significant changes to the peak load forecast compared to 2022.

Several parties were concerned with RESOLVE assumptions. GSCE suggested that the CAISO's 20-year Outlook results should be included in RESOLVE assumptions. Cal Advocates and MGRA suggested that pumped storage should be replaced in the portfolio with other resources because of the limitations on its development timeline. ACP-CA asserted that RESOLVE does not take into account state policy preferences beyond the GHG targets, with specific concern about OSW and transmission development.

Several parties also commented with concerns about import assumptions. AReM noted that these assumptions are a key driver of procurement need within the CAISO, and suggested that staff should run a sensitivity fully relaxing the 4 GW import cap during peak hours in SERVM to see if it affects the LOLE results. BAMx also suggested that staff should develop a more "analytically robust" import constraint. PG&E noted that the SERVM import-export results are surprising and staff should review and provide more information. CalCCA pointed out that actual maximum imports through September 2023 have been lower than the total import cap assumed. BHER also commented that the 4 GW cap during peak hours is too low, and that historical observed levels may not be representative of future levels. In addition, observed import flows are not necessarily the same as the MIC amount.

Some parties also had some specific concerns about costs used in the models. CalCCA stated concerns with how transmission costs for already-approved but not-yet-constructed upgrades are not directly factored into the RESOLVE modeling of the portfolios analyzed. MGRA had particular concerns about the battery cost estimates and the use of an escalator beyond 2023 assumptions. CEJA and Sierra Club requested consideration of the social cost of carbon and not just total resource costs. CEERT stated that RESOLVE assumptions should be refined to reflect best-available cost information for long lead-time (LLT) resources. CEJA and Sierra Club state that the assumptions do not account for several programs included in the federal IRA.

Finally, a number of parties included comments that are not actionable within the timeframe for this decision, but that can be considered for the next IRP cycle. These included, but were not limited to, the following comments:

- Commission staff should consider using a different production cost model given the ongoing GHG results discrepancies between RESOLVE and SERVM (SDG&E);
- Assumptions about hydrogen, including renewable hydrogen, and renewable natural gas should be included (DGC, NRDC/UCS, Mainspring, AES-AP, Enchanted Rock);
- The RESOLVE model overly relies on solar-storage resources, has limited ability to calculate realistic curtailment rates, and fails to account for all the benefits of offshore wind (Vineyard Wind, GPI);
- Include more explicit acknowledgement of the benefits of carbon capture and sequestration (Calpine);
- Need to develop more granular and deeper assumptions for distributed energy resources (DERs) (PG&E, CEERT);

- Address cost uncertainties for all resource types by modeling low, medium, and high sensitivities (NRDC/UCS, CEERT);
- Use 24-hour analysis for the 2025-2026 TPP (CalWEA); and
- Increase focus on modeling resource and transmission needs beyond 2035, incorporating emerging technologies, extending reliability modeling, and refining estimates of out-of-state resource availability (SCPA).

With respect to the sensitivity cases analyzed by Commission staff, several parties offered comments. Four parties explicitly supported the natural gas retirement sensitivity and the sensitivity cases overall, including CalCCA, CEJA/Sierra Club, IEP, and SCE. IEP recommended that the natural gas sensitivity not be used to set policy direction. CEJA/Sierra Club also recommended that natural gas retirements should be prioritized in DACs and criteria pollutant non-attainment areas.

Several parties also explicitly supported the High Gas Retirement sensitivity as it relates to SB 887. PG&E noted that it is rational for the Commission to develop sensitivities to assess high level of gas retirements in local capacity areas, given the SB 887 requirements, and recommended that additional modeling and coordination with the CAISO should be performed to help plan for the future of the natural gas fleet. CEJA/Sierra Club supported prioritizing the High Gas Retirement sensitivity and stressed that it makes sense to begin with a sensitivity and then incorporate the results into the IRP planning process as quickly as possible. Vineyard noted that the 25 MMT Core portfolio itself is compliant with SB 887 requirements.

Some parties also recommended additional sensitivities. CEERT recommended analyzing a natural gas retirement sensitivity that includes retirements at specific busbars, to address SB 887 considerations. GPI recommended analyzing scenarios that add defined volumes of high capacity factor resources (e.g., OSW) and then allowing RESOLVE to fill in around those chosen resources. SCE recommended that a sensitivity be analyzed that is designed specifically to address the impacts of climate change. PCF recommended one or more additional sensitivities to account for the potential that OTC units and Diablo Canyon may not retire as planned.

Finally, Fervo stated that, in the sensitivity cases, the aggregation of geothermal and hydrothermal resource costs creates inaccurate assumptions and that the two resources should be separated.

3.2. Discussion

The October 5, 2023 ALJ ruling included the reasons for the staff recommendation of the 25 MMT Core portfolio as the PSP portfolio. First, resource buildouts in the 25 MMT and 30 MMT Core scenarios are very similar until at least 2030. Second, the majority of LSEs had a preference in their individual IRPs to plan for the 25 MMT scenario. Third, California policy continues to be as aggressive as possible to reduce GHG emissions as soon as possible.[7] Fourth, the 25 MMT target corresponds to the low (most aggressive) end of the 2030 target range for the electricity sector (30-38 MMT of carbon dioxide equivalent) set by the California Air Resources Board (CARB) when adopting the most recent Scoping Plan update.[8] In modeling results that Commission staff released alongside the October 5, 2023 ALJ ruling, cost differences between the 30 MMT and 25 MMT Core portfolios were relatively small, driven in part by additional incentives from the federal IRA. Finally, no

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[7] *See*, for example, SB 100 requirements for the electricity sector.

[8] *See* more details on CARB's Resolution 22-21, available at the following link: https://ww2.arb.ca.gov/sites/default/files/barcu/board/res/2022/res22-21.pdf.

party objected to the adoption of the 25 MMT Core portfolio as the PSP portfolio; this choice has widespread support. Therefore, we will adopt the 25 MMT Core portfolio as the PSP portfolio.

In response to parties' comments, Commission staff made a number of changes to the specific contents of the portfolio. First, in response to the comments of numerous parties, including parties representing wind generation interests, with concerns about the lack of granularity in the environmental screens currently used for the out-of-state wind resources compared to those screens used on in-California resources, staff applied a significant scalar reduction on top of the existing land-use screen to the wind potentials made available for the RESOLVE model to select in Southern Nevada, Utah, Idaho, Wyoming, and New Mexico. In addition, the newly-created Avi Kwa Ame National Monument in Southern Nevada was excluded as a wind development area for purposes of the PSP portfolio. These adjustments result in the changes to the wind potential available to be selected represented in Table 3.

Table 3.
Adjustments to the Total Out-of-State
Wind Potential Available for RESOLVE Selection

Wind Area	Inputs and Assumptions Potential (GW)	Revised Potential (GW)
Southern Nevada – El Dorado	5.01	0.7
Idaho	7.68	1.54
New Mexico	166.88	33.38
Utah	18.85	3.77
Wyoming	67.14	13.43

In addition, the RESOLVE build limit for out-of-state wind from some states has been extended through the 2039 model year. The build limit previously only implemented through the 2035 model year capped the amount of wind that can be selected by RESOLVE based on the assumed capacity of in-development and potential new transmission lines that could likely be constructed in time to deliver the out-of-state resources to the CAISO in the modeled year, given the long lead-time for such large complex transmission infrastructure. Thus, the 2039 build limit for New Mexico Wind is now set to 6,000 MW. Idaho and Wyoming wind build limits are 1,100 and 6,000, respectively, in 2039.

In response to a specific comment from CalWEA about wind potential in Northeastern California (where transmission is scarce), wind potential remaining after the environmental screens has been added even if it is greater than 30 miles from an identified CAISO substation (a constraint that is maintained in the rest of the state but is not utilized for out-of-state resources outside of the CAISO balancing area including Wyoming, Idaho, and New Mexico wind). This results in an additional wind potential of approximately 700 MW in that geographic area.

Beyond this, a small portion of the in-state wind is being remapped as out-of-state wind. The portfolio includes in 2030 a significant amount of RESOLVE-selected in-state wind, which is challenging to map to busbars, particularly given that the estimated online dates for CAISO transmission upgrades in key wind mapping areas are after 2030. To address this issue, 900 MW of in-state wind in 2030 is being remapped as 767 MW of out-of-state wind (the total capacity difference is because of capacity factor differences), to better align transmission availability in the 2030 timeframe.

In addition, several smaller adjustments were made, including adding the Valley Electric Association (VEA) transmission upgrade as zero-cost because the CAISO has confirmed that this line will be approved among the 2022-2023 TPP projects. In addition, Central Nevada geothermal potential is now included as interconnecting in the GLW and VEA constraints, instead of only in the El Dorado substation constraints. This change aligns the geothermal resource potential to areas where the geothermal is likely to interconnect and reflects consistency with how this geothermal potential was mapped and studied in the 2022-2023 TPP and the 2023-2024 TPP.

In addition to the changes in the portfolio itself discussed in this decision as compared to the portfolio in the October 5, 2023 ALJ ruling, there were also some minor modeling improvements made in both RESOLVE and SERVM. These included some corrections to load and load modifiers in RESOLVE, plus small dispatch changes in SERVM, including increased minimum dispatch for biomass and biogas units, increased round-trip efficiency for new pumped storage units, and corrected CAISO subregion connection for Idaho Wind. In general, the results are consistent with and slightly improved (in terms of model GHG estimates) compared with the PCM results included in the October 5, 2023 ALJ ruling.

The portfolio has not been updated to include the not-yet-adopted and not-yet-fully-available CEC 2023 IEPR demand forecast dataset. During every IRP cycle, Commission staff are limited to conducting analysis based on an approved set of IEPR assumptions that will be updated by the time the analysis is complete. This cycle is no different; introducing a new load forecast now in response to comments would require starting over with portfolio analysis and then allowing additional vetting and comments, in a timeframe where the Commission would miss the CAISO's 2024-2025 TPP deadlines.

Regarding PG&E's comment about the SERVM import-export results, Commission staff has found that there was an error in the model's reporting. The error has been corrected, and new results will be available on the 2022-2023 IRP

Cycle "Events and Materials" page 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.

Figure 1 and Table 4 below summarize the new resources that will be required as a result of the final 2025 MMT by 2035 PSP portfolio analysis.

Figure 1.
Planned and Selected Resource Capacity (MW) for 25 MMT Core Case

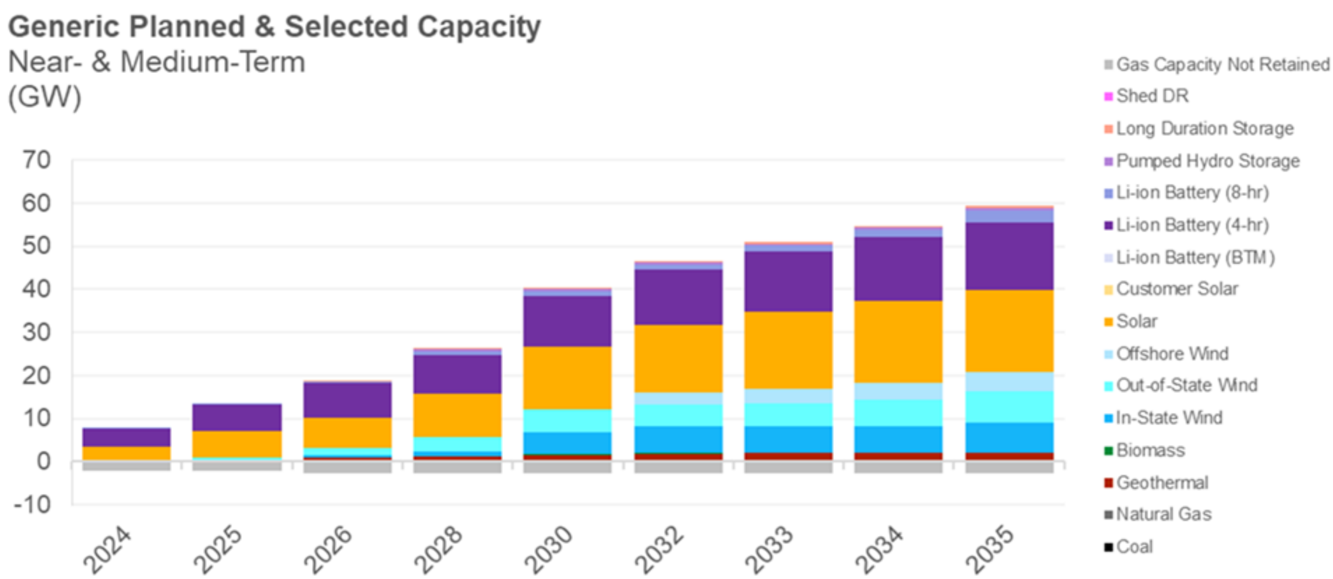

Table 4.
Planned and Selected Capacity (GW) for 25 MMT Core Case

Resource Category	2024	2025	2026	2028	2030	2032	2033	2034	2035	2039	2040	2045
Geo-thermal	0.0	0.0	0.8	1.1	1.5	1.8	2.0	2.0	2.0	2.0	2.0	2.0
Biomass	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
In-State Wind	0.3	0.4	0.8	1.1	5.0	6.1	6.1	6.1	7.0	7.0	7.0	8.3
Out-of-State Wind	0.0	0.6	1.7	3.4	5.3	5.3	5.3	6.1	7.1	9.1	9.1	12.7
Offshore Wind	0.0	0.0	0.0	0.0	0.0	2.7	3.3	3.9	4.5	4.5	4.5	4.5
Solar	3.0	6.0	6.9	9.9	14.8	15.7	17.9	19.0	19.0	30.7	35.0	57.5
Li-ion Battery (4-hr)	4.3	6.3	8.0	9.0	11.6	12.7	14.0	15.0	15.7	15.7	15.7	15.7
Li-ion Battery (8-hr)	0.0	0.0	0.4	1.0	1.2	1.4	1.4	1.7	2.8	7.2	9.0	19.5
Pumped Hydro Storage	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Long Duration Storage	0.0	0.0	0.1	0.3	0.3	0.4	0.4	0.5	0.5	0.5	0.5	0.5
Shed Demand Response	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas Capacity Not Retained	-2.2	-2.2	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-6.6
Total	**5.4**	**11.1**	**16.0**	**23.8**	**37.7**	**44.0**	**48.3**	**52.1**	**56.6**	**74.7**	**80.9**	**114.8**

We address the comments about wind resources and OSW, in particular, in the portfolio in Section 4.1 below. We address the comments about the sensitivity analyses in Section 4.2 below.

Commission staff have also conducted PCM to ensure that the modified portfolio is reliable and produces GHG emissions similar to the target. The results of the PCM are presented in Table 5 below.

Table 5.
Production Cost Modeling Results for Recommended PSP Portfolio

Results Category	Units	2026		2030		2035		2039	
		RESOLVE	SERVM	RESOLVE	SERVM	RESOLVE	SERVM	RESOLVE	SERVM
LOLE	Days/ year		0.015		0.001		0.021		0.13
CAISO emitting generation	GWh	59,916	72,578	36,793	44,477	18,080	37,643	6,365	37,577
CAISO generator emissions	MMT CO2e	23.5	30.0	14.5	19.0	7.1	15.3	2.5	15.1
Unspecified imports	GWh	18,185	7,295	12,060	11,665	20,454	9,438	27,214	8,594
Unspecified imports emissions	MMT CO2e	7.8	3.1	5.2	5.0	8.8	4.0	11.7	3.7
CAISO BTM CHP emissions	MMT CO2e	4.8	4.8	4.7	4.7	4.4	4.4	0.9	0.9
Total CAISO emissions	MMT CO2e	36.1	37.9	24.3	28.6	20.3	23.8	15.0	19.6
Emissions difference	MMT CO2e		1.8		4.3		3.5		4.6

The GHG emissions results difference between RESOLVE and SERVM is now smaller, an improvement over the portfolio modeled for the October 5, 2023 ALJ ruling. In addition, the LOLE results of the new portfolio still meet the 0.1 LOLE standard through 2035. While 2039's LOLE is slightly higher than 0.1 LOLE, the result still indicates a largely reliable portfolio and translates to a shortfall of only a few hundred MW PCAP in 2039. The 2039 LOLE result appears driven primarily by Path 26 constraints, which can be addressed in several ways without changing the adopted portfolio, such as changing where resources are retired and where other resources are added, increasing the system's South to North transmission capacity, and others. In addition, the 2034 model year is the key determinant for policy-driven transmission approvals for the TPP and not 2039. The CAISO is not required to approve transmission based on the 2039 portfolio, but can use the results to inform and guide upgrades recommended for approval for the 2035 portfolio. Finally, there are transmission and resource options to address shortfalls in the reliability standards in the outer years.

4. Portfolios for use in CAISO 2024-2025 TPP

Similar to the recommendation in many past years, the October 5, 2023 ALJ ruling included recommendations to the CAISO for portfolios to be used as the basis for their 2024-2025 TPP analysis. The recommended base case portfolio can result in the identification of specific transmission upgrades that can be taken to the CAISO Board directly for approval for investment. Any sensitivity portfolios are used to produce transmission location and cost information that can inform future analyses, but the sensitivity portfolios alone usually do not result in direction recommendations for investment for particular transmission projects in the current TPP cycle. This section discusses the portfolios recommended by the Commission to the CAISO for analysis in its 2024-2025 TPP.

4.1. Base Case Portfolio

The October 5, 2023 ALJ ruling recommended that the adopted PSP portfolio be the basis for the reliability and policy-driven base case scenario for the CAISO to analyze in its 2024-2025 TPP. This portfolio is based on the same policy guidance and GHG targets as the 2023-2024 TPP. The proposed PSP portfolio also includes resources out to 2039, as required by SB 887 (Stats. 2022, Ch. 358). SB 887 also requires the Commission provide to the CAISO a resource portfolio that substantially reduces, no later than 2035, the need to rely on "non-preferred resources in local capacity areas." Finally, SB 887 also requires the Commission to recommend projected OSW generation to allow the CAISO to identify and approve transmission facilities sufficient to make OSW deliverable to load centers.

The October 5, 2023 ALJ ruling confirmed that this base case portfolio meets these requirements, by including OSW included by LSEs in their portfolios, as well as including significant reductions (of approximately 70 percent) in natural gas plant utilization within the CAISO area by 2035 and further reductions (of approximately 90 percent) over the full 15-year planning horizon.

4.1.1. Comments of Parties

Many parties were generally supportive of the portfolio's high level policy goals, including both the 25 MMT GHG target as well as the use of the LSE planned resources rather than a least-cost portfolio. These parties include CAISO, CalCCA, CEJA/Sierra Club, GPI, LS Power, SCE, SCPA, and Vineyard. IEP was the only party that recommended using the 25 MMT Least-Cost portfolio as the base case for TPP purposes.

Several parties, in comments in response to the October 5, 2023 ALJ ruling, were concerned about the differences between the 2023-2024 base case TPP portfolio and the proposed 2024-2025 TPP base case portfolio. TerraGen, SEIA/LSA, and EDFR recommended that the Commission stress that the CAISO should approve projects in the 2023-2024 TPP based only on the 2023-2024 TPP results and not let portfolio-size changes in the 2024-2025 TPP portfolio result in not triggering transmission upgrades. BAMX recommends the opposite, urging the Commission to instruct the CAISO to avoid triggering transmission in the 2023-2024 results if the transmission is not needed in the 2024-2025 portfolio.

GSCE expressed concerns that the current portfolio recommendation is significantly smaller than last year's and that it may indicate problems with the RESOLVE model.

The CAISO also noted concerns with the smaller portfolio and recommended establishing stability in the portfolio. CAISO also recommended providing reconciliation analysis upfront when portfolio baselines are updated.

CWG expressed concerns that inclusion of gas plants in the base case does not align with SB 887 direction and the Commission should specify to the CAISO that gas plants in the local areas are to be used solely for backup/emergency purposes and cannot be relied upon for resource adequacy when planning and approving new transmission.

Finally, the general comments summarized in Section 3.1 above, and not repeated here, related to the inclusion of OSW in the portfolio are most relevant to our consideration of the base case portfolio. More specifically, CalWEA, ACP-CA, OWC, Vineyard, and RWE all criticized the low amount of OSW in the base case and particularly in the Humboldt area, with these parties recommending at least as much OSW as included in the 2023-2024 TPP base case or significantly more be mapped to Humboldt or the North Coast.

4.1.2. Discussion

First, we discuss the issues related to the appropriate amount of OSW to be included in the base case portfolio. We note that the 2023-2024 TPP base case portfolio included 1.6 GW of OSW in the North Coast (Humboldt) area and 3.1 GW off the Central Coast of California, in the Morro Bay area.

Based on analysis already conducted as part of recent TPPs including the 2021-2022 TPP and the current 2023-2024 TPP, we have learned that the Central Coast/Morro Bay area has a robust transmission network that can manage up to at least 5 GW of OSW resources, once Diablo Canyon retires. Thus, additional OSW up to that amount in the Central Coast is unlikely to trigger the need for additional significant transmission investments. The North Coast/Humboldt area, by contrast, has limited transmission capacity, whereas the quality of the wind generation resources in the region is higher. In their individual IRPs, LSEs indicated plans to develop nearly twice as much OSW on the North Coast as on the Central Coast. We also note that there are limitations of the RESOLVE model in terms of how transmission costs and flows are reflected, chiefly because it is a capacity expansion model and not a power flow model. In addition, more accurate OSW transmission cost information from the 2023-2024 TPP analysis will not be available until at least March of 2024.

The PSP portfolio recommended for adoption and use as the TPP base case includes a total of 4.5 GW of OSW, all of which the RESOLVE model selected on the Central Coast likely because of different levels of accessibility and costs associated with Central Coast transmission options compared to those on the North Coast.

When we transmitted the 2023-2024 TPP base case, including 1.6 GW of OSW on the North Coast, we noted that it was not a matter of if, but rather when, transmission upgrades would be needed on the North Coast. While there is uncertainty about resource and transmission costs, as well as permitting timelines, we still believe that to be a reasonable approach. Therefore, we will direct Commission staff to continue to map 1.6 GW of the total OSW amount selected by 2039 to the North Coast/Humboldt area, with the remainder (2.9 GW) on the Central Coast/Morro Bay, in order to promote consistency in planning for the development of transmission in an area where upgrades are indicated and where LSEs and developers have shown an interest in developing OSW due to the quality of wind generation resources. The full 1.6 GW of OSW will be mapped to Humboldt in 2039, with a partial 0.9 GW in the 2034 mapping, indicating that the transmission upgrade need is not immediate but rather long-term in nature. This should maintain progress toward studying and potentially developing transmission to support North Coast OSW, without impeding the development of OSW on the Central Coast, since that area already has sufficient transmission capacity to accommodate near-term wind generation development.

We encourage the CAISO to advance development of North Coast transmission with consideration of the timing of other long-term efforts, such as port and workforce development, to harmonize as much as possible the state's overall strategy for developing and evolving OSW. We also note that, consistent with the requirements of AB 1373 (Stats. 2023, Ch. 367), later this year the Commission will assess the current need for procurement of LLT resources.

Next, with respect to the question of SB 887, several parties agreed that the PSP portfolio as the base case is compliant with the requirements of SB 887, including PG&E, CEJA/Sierra Club, and Vineyard. Those parties also noted the rationality of conducting a High Gas Retirement sensitivity (see next section), as well as the need to closely coordinate with the CAISO, prior to including high amounts of gas retirements in the base case portfolio.

In addition, as already noted, the base case portfolio already includes reductions in utilization of natural gas plants (based on GWh of energy produced) within the CAISO area of 70 percent by 2035 and 90 percent by 2039, compared to the first modeled year, 2024. This is consistent with SB 887's requirements that we "substantially reduce" reliance on non-preferred resources by 2035, including in local areas. This PSP portfolio achieves clean energy production well beyond the SB 100 interim targets used for PSP modeling, achieving 101 percent (compared to the SB 100 90 percent target), 105 percent (compared to the 95 percent target), and 113 percent (compared to the 100 percent target) clean generation in 2035, 2040, and 2045, respectively. Generation percentages above 100 percent are achievable because SB 100 targets are based on retail sales and because exported energy counts towards these targets.

Thus, we adopt the PSP portfolio based on a 25 MMT GHG target in 2035 as a reasonable TPP base case and we recommend that outcome to the CAISO in this decision.

4.2. Sensitivity Portfolio

In addition to the reduction in use of non-preferred resources included in the recommended base case portfolio above, the October 5, 2023 ALJ ruling included a recommendation that the Commission ask the CAISO to study a policy-driven sensitivity portfolio that includes a large amount of fossil-fuel generation retirement, based on the High Gas Retirement sensitivity described in Section 3 above. The purpose of the sensitivity is to identify the transmission resources and costs associated with planning for the potential future retirement of fossil-fueled resources as their economics decline. The sensitivity case is based upon sensitivity scenarios analyzed by Commission staff for possible PSP portfolio purposes. The sensitivity case is also further inspired by SB 887, as well as SB 1158 (Stats. 2022, Ch. 347) and SB 1020 (Stats. 2022, Ch. 361), all of which encourage planning for reduced reliance on non-preferred resources.[9]

We also note that in a letter in January 2023,[10] and in D.23-02-040, the Commission requested, consistent with SB 887, that the CAISO identify the higher-priority transmission facilities needed in local areas, and in the 2022-2023 TPP approved by its Board, the CAISO identified and approved 12 transmission upgrades that reduce local capacity requirements from natural gas generation. Several of the upgrades also align with the upgrades identified in the Aliso Canyon sensitivity study that was conducted as part of the CAISO's 2022-2023 TPP cycle.

The October 5, 2023 ALJ ruling noted that natural gas resources can provide both energy and capacity to the electric grid. However, as more renewable resources deliver energy to the grid, grid reliability increasingly depends upon thermal resources for their reliable capacity at times when the grid is stressed. Over time, the capacity factors of thermal resources continue to decrease over time as their energy output is offset in the dispatch stack by zero-marginal-cost renewables. The ruling noted that this trend is a necessary precursor to retirement of thermal generation, as the economics of such units decline. The ruling also noted that the Commission does not have the authority

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[9] SB 1158 requires the Commission to review the total GHG emissions and the annual average GHG emission intensity reported for each retail supplier of electricity and assess whether those emissions, combined with the retail supplier's procurement plans for subsequent years, demonstrate adequate progress towards achieving the retail supplier's GHG emissions reduction targets. SB 1020 requires the Commission to establish new interim targets to reach clean energy goals of purchasing 100 percent zero-carbon electricity by 2035.

[10] *See* CPUC Request to CAISO in Accordance with SB 887: https://www.caiso.com/InitiativeDocuments/Letter-2022-2023-Transmission-Planning-Process-Jan%2013,%202023.pdf.

to order natural gas retirements directly. Finally, the ruling pointed out that removing individual plants from the electric grid results in increased production at remaining plants, if there are no other resources added that can provide the additional energy to the grid. During the process of mapping resources to busbars on the transmission grid (described further in the next section), Commission staff seek to map renewable and storage resources to locations where there is potential to displace the nearby output of natural gas power plants, including those in disadvantaged communities.

The particular policy-driven sensitivity recommended for analysis in the CAISO 2024-2025 TPP in the October 5, 2023 ALJ ruling was the High Gas Retirement sensitivity, which includes 9.3 GW of natural gas retirements by 2035 and 15.9 GW by 2039. Included in these numbers are the 3.7 GW of once-through cooling (OTC) plants required to retire and an assumed phase-out of 1.7 GW of combined heat and power (CHP) plants between 2031 and 2039, in addition to retiring the capacity with which LSEs have no indicated plans to contract in their individual IRPs.

4.2.1. Comments of Parties

A large number of parties supported the High Gas Retirement sensitivity case proposal, including CAISO, CalCCA, GSCE, IEP, LS Power, PG&E, SCE, SCPA, SDG&E, and SEIA/LSA. Many parties noted the importance of studying this issue in advance of gas retirements, including parties that own or operate gas assets such as Calpine. CEJA/Sierra Club and EDF, while supporting the sensitivity, also would like to see sensitivities with additional gas retirements, including all gas plants, or at least all gas plants located in DACs.

Several parties also suggested iterative studies, in addition to the sensitivity portfolio analysis, to analyze what other resources, such as solar and storage, in addition to or instead of transmission alternatives, could be added to local areas. These parties included CalCCA, PG&E, SDG&E, SEIA/LSA, and BAMx. GPI proposed performing a high-baseload-renewables sensitivity. PG&E recommended additional analysis to identify specific hours when there may be a transmission deficiency.

EDFR recommended transmitting the Least Coast portfolio as a sensitivity, because it has an alternative resource mix that could help identify least-regrets transmission. BAMx noted that sensitivities were not necessarily set up to best identify least-regrets transmission in general.

CEJA/Sierra Club, while supporting the sensitivity portfolio, suggested conducting an air quality analysis of the portfolio to inform selection of scenarios in the future and to analyze impacts in the most impacted air basins. EDF suggested using criteria pollutant information, along with GHG emissions, to identify which specific plants should retire. NRDC/UCS requested that retirement criteria be released that will identify what plants are to be modeled as retired. Calpine, by contrast, expressed concerns that retirement criteria will not usefully guide retirement, given that proximity to or location in DACs does not necessarily correlate to impacts on DACs because of the complexity of air pollution and the fact that most of the state is an air quality non-attainment zone.

Finally, SCPA supported the absence of OSW in the sensitivity scenario, because it will test transmission needs if OSW development is not successful.

4.2.2. Discussion

Planning for the potential future retirement of natural gas plants is important for California to meet the SB 100 requirements and GHG emissions goals by 2045. Transmission is one of the most important tools to address the local reliability issues that are likely to arise with the retirement of at least a subset of the natural gas plants. Thus, this sensitivity portfolio is an important step for identifying the transmission that would be necessary with a large amount of retirement of gas plants. We therefore recommend the High Gas Retirement sensitivity to the CAISO for study as a policy-driven sensitivity in its 2024-2025 TPP.

Conducting locational analysis within the context of IRP is difficult, because much of our analysis historically has been focused at the system level. The CAISO, however, has the ability to do much more granular and detailed analysis of local reliability needs. Therefore, we find it prudent to ask the CAISO to conduct this sensitivity analysis for the 2024-2025 TPP.

We are also encouraged by the broad-based support in comments for this sensitivity portfolio, including from PG&E, CEJA/Sierra Club, and Vineyard, among others. These parties also seem to support the concept of conducting this study as a sensitivity, prior to triggering transmission investment, because there are multiple complex considerations that will inform the retirement of gas plants. CEJA and Sierra Club, in particular, also urged quick action after the results of the sensitivity scenario analysis are known. We will address these questions in the next cycle of the IRP process.

Figure 2 and Table 6 below summarize the resources, beyond the force-in gas retirements, included in the High Gas Retirement sensitivity portfolio that we recommend be analyzed in the 2024-2025 TPP.

Figure 2.
Planned and Selected Resource Capacity (MW) for High Gas Retirement Sensitivity Case

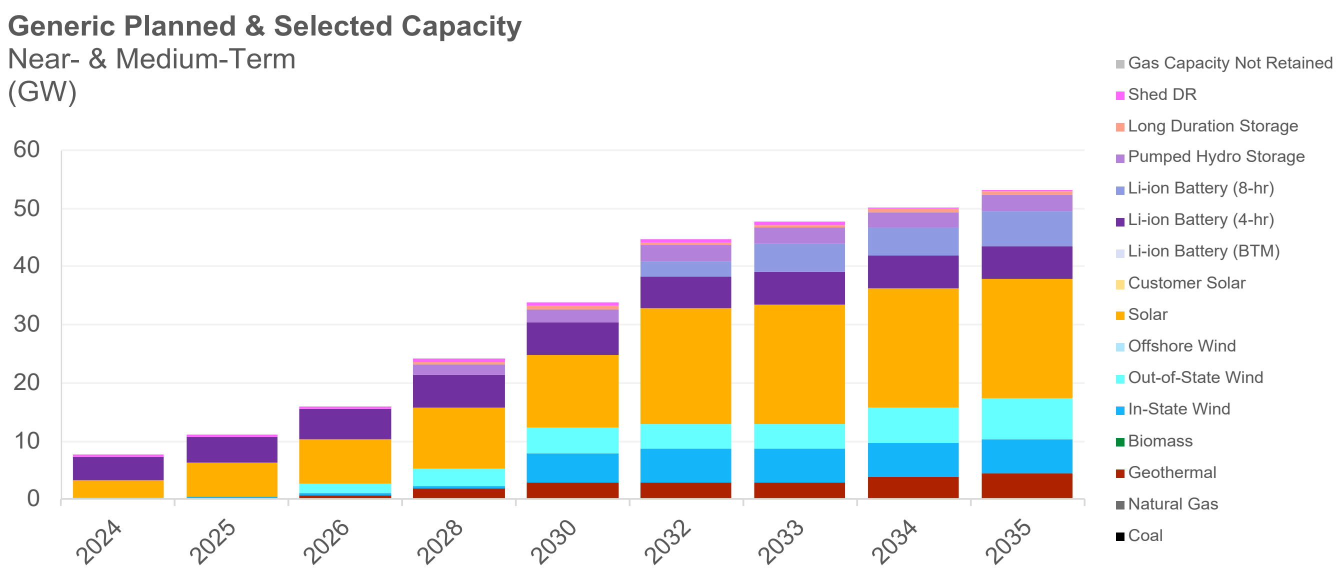

Table 6.
Planned and Selected Capacity (GW) for High Gas Retirement Sensitivity Case

Resource Category	2024	2025	2026	2028	2030	2034	2035	2039	2040	2045
Geothermal	-	-	0.6	1.8	2.9	4.0	4.6	5.1	5.1	5.1
Biomass	-	-	-	-	-	-	-	-	-	-
In-State Wind	0.3	0.4	0.4	0.4	5.1	5.7	5.7	5.7	5.7	5.7
Out-of-State Wind	-	-	1.6	3.1	4.3	6.1	7.1	7.1	7.1	7.1
Offshore Wind	-	-	-	-	-	-	-	-	-	-
Solar	3.0	6.0	7.8	10.5	12.5	20.6	20.6	52.2	62.9	76.9

Resource Category	2024	2025	2026	2028	2030	2034	2035	2039	2040	2045
Li-ion Battery (4-hr)	4.0	4.4	5.1	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Li-ion Battery (8-hr)	-	-	-	-	-	4.7	6.1	17.5	21.3	27.3
Pumped Hydro Storage	-	-	-	1.8	2.3	2.8	2.8	2.8	2.8	2.8
Long Duration Storage	-	-	-	0.5	0.5	0.5	0.5	0.9	0.9	0.9
Shed Demand Response	0.3	0.3	0.5	0.5	0.5	0.3	0.3	-	-	-
Gas Capacity Not Retained	-	-	-	-	-	-	-	-	-	-
Total	**7.7**	**11.1**	**16.0**	**24.2**	**33.8**	**50.2**	**53.2**	**96.8**	**111.5**	**131.4**

Comments on the proposed decision demonstrated considerable interest in the criteria to be used by Commission staff to identify the particular plants to be retired in this sensitivity portfolio. The busbar mapping results of the application of the criteria are being published with this decision. Commission staff identified seven criteria, as follows:

<u>Environmental and Community Factors</u>

1. Disadvantaged communities – plants in or near DACs receive highest score/priority.
2. Nitrous oxide (NOx) emissions rate (scaled by capacity factor) – plants with the highest NOx emissions receive highest score/priority.
3. Air Quality Non-Attainment Zones – plants in worse non-attainment areas receive highest score/priority.

Performance Related Factors

1. Capacity Factor – plants with highest capacity factors (by plant type) receive highest score/priority,
2. Heat Rate – plants with highest heat rate (by plant type) receive highest score/priority.
3. Age – oldest plants (by plant type) receive highest score/priority.
4. Local Reliability Factors.
5. Local Effectiveness Factor (LEF)[11] – plants with no LEF receive highest score/priority.

After further evaluation of the comments on the proposed decision, we will apply the above criteria as follows. First, we will not use capacity factor as a criterion, because it is likely that highest capacity factor plants are more economic and more likely to stay on the system. However, we will still use capacity factor as a weighting factor for the calculation of the NOx emissions from the plants.

Then, we will direct Commission staff to weigh the three categories of remaining criteria as follows:

- 50 percent weighting for the Environmental and Community Factors;
- 25 percent weighting for Local Reliability/LEF factor; and
- 25 percent weighting for Performance Factors.

In addition, two additional screens will be applied based on age and LEF. First, we will exclude from selection any generation in the first quartile of age, meaning any generator less than 24 years old in 2035, or coming online since

[11] The CAISO publishes effectiveness factors as part of Local Capacity Technical studies. These factors note the effectiveness of local resources in meeting temporal local reliability needs.

2010. Second, we will exclude any generator in the first quartile of LEF, meaning those with the highest LEF percentages.

Applying the criteria in this manner results in a diverse set of plants being selected, and a reasonable split between plants in Northern and Southern California. It also results in around 80 percent of the capacity selected being located in or near disadvantaged communities, which are the plants of greatest concern to many stakeholders. We do note again, however, that the application of these criteria to this sensitivity portfolio is not meant to signal Commission direction or preferences about particular plant retirements that will or should happen. Instead, it serves only as a plausible scenario to test for purposes of future transmission planning.

Finally, in busbar mapping of this sensitivity portfolio, some small adjustments needed to be made to align the projects contracted and in development with the amount of 8-hour and 4-hour storage projects in the portfolio. However, these are not anticipated to have a material impact on results.

4.3. Busbar Mapping

The October 5, 2023 ALJ ruling included an attachment with the most updated criteria that Commission staff proposed to use to map generation and storage resources to transmission busbars, so that the CAISO has the locations on the transmission system to analyze in its TPP. The process translates geographically-coarse portfolios to plausible network location for additional TPP modeling by applying specific rules and criteria. This process is conducted every year and each year improvements are made.

The updates summarized in the October 5, 2023 ALJ ruling that were proposed in this cycle include the following major adjustments:

- Updating the busbar mapping process flow chart and the Busbar Mapping Steps, which describe the workflow between the Commission, CEC, and CAISO staff, to best reflect recent and proposed changes in the mapping process;
  - Improving descriptions of the roles of the Commission, CEC, and CAISO staff, and the descriptions of the efforts that occur at each step of the mapping process;
- Unifying the renewable generation and battery mapping criteria for consistency across resource types and applying previously storage-only analysis for disadvantaged communities, air pollutant non-attainment zones, and load pockets to all resources;
  - Applying the disadvantaged communities and air pollutant non-attainment zones as locations with a priority to avoid mapping biomass and biogas resources.
- Adding new busbar mapping criteria and updating existing criteria based on new and updated datasets including:
  - Updating land-use and environmental criteria to utilize newly developed CEC land-use screens;
  - Adding parcelization criteria to incorporate a new dataset developed by the CEC that looks at the property fragmentation of land and its impact on potential resource development;
  - Updating cropland criteria analysis to utilize the CEC's new Cropland Index Model and incorporating information on critically overdrafted groundwater basins.
  - Utilizing more detailed interconnection data in collaboration with CAISO staff and the Participating Transmission Owners to better account for interconnection factors;
  - Incorporating IRA Energy Communities.

- Improving the implementation process and analysis of the busbar mapping criteria to better capture mapped resources' alignment with the criteria;
  - Increasing the number of criteria alignment levels to provide more distinction in how mapped resources align with criteria;
  - Overhauling many of the dataset-specific alignment thresholds to better capture policy priorities;
- Improving descriptions of how various datasets are utilized for criteria analysis and how the alignment to each criterion is assessed; and
- Updating the process and criteria for identifying the specific thermal generation units to model as offline when portfolios include either policy-driven or economically-driven gas retirements.

4.3.1. Comments of Parties

Parties filed numerous specific and detailed comments on the busbar mapping methodology and the mapping that had been done so far leading up to the comments on the October 5, 2023 ALJ ruling. The comments were about specific issues, as described below.

Several parties asked to see additional data on busbar mapping results, including more summary information and better visualizations, with additional informational workshops, including SEIA/LSA, DOW, Cal Advocates, and TerraGen.

On the gas retirement criteria, for mapping the sensitivity portfolio with natural gas plan retirements, Calpine expressed concerns that the criteria will not usefully guide retirement decisions, because proximity to DACs does not correlate to impacts on DACs, given the complexity of air pollution. Calpine was concerned about how the screening criteria will be weighted.

CEJA/Sierra Club and EDF supported prioritizing retirements based solely on DAC and air pollutant criteria. Al of these parties want to see application of the criteria and the ranking of specific power plants.

DOW and CORD requested additional datasets be applied to out-of-state resources, including in Southern Nevada, to have better uniform across the geographic areas in the analysis.

A number of parties had general comments on the land-use and environmental criteria datasets and their application. CalWEA expressed concerns with onshore wind land-use screens reducing too much wind potential and not being able to adequately capture the granularity of wind potential at the busbar level. CalWEA also recommended looking further than 20 miles from a substation or transmission line for mapping of larger wind projects.

GreenGen recommended additional criteria specifically for pumped storage, including license status, proximity to existing infrastructure, and above-ground impacts.

On the topic of the commercial interest criteria, which drives a large part of the busbar mapping, SEIA/LSA recommended prioritizing commercial interest with Phase 2 complete and executed interconnection agreements and not reallocating from those amounts particularly to avoid triggering transmission upgrades. TerraGen supports aligning mapping with commercial interest.

On the subject of transmission criteria/constraints, GLW expressed concerns that mapping does not capture the ability to up-size already approved upgrades, such as some approved in the 2022-2023 TPP cycle. TerraGen and CalWEA expressed concerns that CAISO white paper upgrades for the PG&E area are not the right kind of upgrades to be modeled as they are too focused on reliability and not capacity expansion; they suggest the Commission should incorporate upgrades from the CAISO 20-year outlook instead. BAMx recommended incorporating newly-identified pricing for the SWIP-North transmission into analysis to reassess Idaho wind. BAMx also generally supported remapping resources to locations to avoid triggering additional transmission, while Gallatin, SEIA/LSA, GLW, and CalWEA all noted support for triggering transmission instead of re-mapping resources to avoid it.

Several parties also expressed concerns with the approach to regional mapping. NextEra, CalWEA, and DOW expressed concerns with far too many wind resources mapped to Southern Nevada with very little potential to develop in the area without environmental conflict. NextEra expressed concerns with the amount of onshore wind resources mapped to the areas of Tehachapi, Solano, and Northern California because these areas are already developed, have significant local opposition, and/or high environmental conflicts.

SCPA expressed concerns over reduction in geothermal resources mapped to Northern California and Solano areas, as it is planning for significant development in the Geysers area.

CalWEA recommended mapping more onshore wind to the San Joaquin and Northern California areas. Gallatin recommended mapping wind, geothermal, and solar to Central and Northern Nevada areas.

GSCE expressed concerns that mapped resources are not geographically diverse; of particular concern was not enough resources in the PG&E areas, especially more solar/storage resources in Kern and Fresno areas.

GLW recommended mapping 3 GW more resources to Southern Nevada.

Finally, GreenGen suggested that the Commission clarify and update busbar mapping criteria for pumped storage projects in development, including license status, whether the project uses existing infrastructure, proximity to existing transmission, and above-ground land impacts.

4.3.2. Discussion

Busbar mapping of the recommended base case portfolio is being posted to the following link on the Commission web site concurrent with the publication of this proposed decision: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/assumptions-for-the-2024-2025-tpp.

The busbar mapping of the policy-driven sensitivity portfolio will take additional time to complete and will be forwarded to the CAISO subsequent to the publication of this decision. Commission staff will make the busbar mapping of the sensitivity portfolio and the selected natural gas plants to be modeled as not retained available (at the same link above) shortly after the adoption of this decision.

Several changes were made to the busbar mapping in response to parties' input. First, as already discussed in Section 3, significant resource potential adjustments were made for onshore wind and offshore wind.

Second, transmission constraints were updated to fix any errors identified but additional upgrades or updated pricing were not added, to avoid uneven or inconsistent data sets, with certain projects having updated costs and capacity but not others. These data will all be updated again for next year's TPP portfolio analysis.

Several other changes were already in progress that are responsive to parties' comments, including: applying environmental and land-use screens for in-state geothermal areas; incorporating Cluster 14 applications into lowconfidence commercial interest, and providing additional summaries, including mapping results by CAISO study area, and descriptions of the busbar mapping analysis in general.

Small adjustments were made in the mapping of resources in the base case portfolio reflecting stakeholder comments and replies on the proposed decision, including remapping of some amounts of 8-hour storage to LDES corresponding to a proposed expansion of the PG&E Helms facility. These adjustments are detailed in the supporting mapping documentation and do not have a significant impact on the results or their potential transmission implications.

In addition, in busbar mapping of the sensitivity portfolio, some small adjustments needed to be made to align the projects contracted and in development with the amount of 8-hour and 4-hour storage projects in the portfolio. However, these also are not anticipated to have a significant material impact on the results.

Finally, some additional analysis ideas need to be deferred since there is insufficient time to accomplish them in this cycle, including working to implement additional analysis for pumped storage, including above-ground impacts and hydrological implications, as well as more complete land-use analysis similar to the CEC's in-state land-use screens, for in-CAISO resources in Southern Nevada and Arizona, in particular.

Offshore wind mapping adjustments were already discussed in Section 4.1 above.

5. PFM on Diablo Canyon Replacement Energy and Capacity

The SCE and PG&E PFM of D.21-06-035 filed August 9, 2023 concerns the deadlines associated with the requirements in D.21-06-035 associated with the replacement energy for Diablo Canyon. D.21-06-035 required procurement of energy and capacity with particular characteristics, including generation, generation paired with storage, or demand response resources, to replace a portion of Diablo Canyon's contribution to system reliability, with new resources required to be online by no later than June 1, 2025.[12]

5.1. SCE and PG&E Request

The SCE/PG&E PFM requested that the deadline for the Diablo Canyon energy replacement resources be postponed to June 1, 2027. As justification for the requested delay, SCE and PG&E described the large amount of procurement already occurring by all LSEs in response to D.19-11-016 and D.21-06-035 in a resource-scarce and competitive market environment. SCE/PG&E discussed the lingering effects of the COVID-19 pandemic, global supply chain constraints, interconnection queue delays, and an economy with increasing interest rates and other costs, making it challenging for LSEs and developers to bring sufficient resources online in the timeframes required. In support of their request, PG&E and SCE also included confidential appendices showing bid information in their recent solicitations attempting to procure the required energy for the Diablo replacement category.

The October 5, 2023 ALJ ruling also included some reliability analysis to help illuminate the question of whether this PFM should be granted. In particular, the contingency analysis conducted by Commission staff showed that 2025 is a tight year from a reliability perspective, where resources required by the Commission already, even if they were to all come online, would not result in a 0.1 or better LOLE in that year, under normal conditions. This analysis assumed

[12] These resources are specifically described and required in Ordering Paragraph 6 of D.21-06-035.

that the Diablo Canyon units would retire as previously planned. Thus, the retention of those units provides some contingency reserve, as does the Strategic Reliability Reserve of approximately 2,430 MW of perfect capacity. The staff analysis showed that granting the PFM would increase the estimated 1,078 MW of reliability shortfall to the 0.1 LOLE standard to approximately 1,203 MW.

5.2. Responses to SCE/PG&E PFM

CESA supported the SCE/PG&E PFM based on first-hand knowledge of its members about global and state issues cited by the petitioners. Hydrostor also supported the PFM but asked that this extension not slow down the PFM filed by CESA and WPTF discussed in Section 6 below. CESA also asked that the SCE/PG&E PFM not "leapfrog" the CESA/WPTF PFM on LLT resources.

Cal Advocates also supported the PFM, primarily on the grounds that an extension could lead to a larger pool of offers in solicitations, potentially creating lower costs for ratepayers. Cal Advocates also suggested explicitly requiring the IOUs to coordinate their solicitations for zero-emitting resources for Diablo replacement resources with their solicitations for RPS needs.

EDF strongly opposed the SCE/PG&E PFM on the grounds that the state needs new clean power to come online now. EDF also argued that the economic conditions cited in the SCE/PG&E PFM have existed for a much longer period of time and aren't unique to the Diablo Canyon replacement category, and also were in place at the time D.21-06-035 was adopted. EDF also pointed out that the extension of time for Diablo Canyon to retire and to act as a buffer for the procurement of new resources is fast shrinking and may squander the extra time granted by the Legislature.

GPI also opposed the SCE/PG&E PFM, stating that the PFM lacks public quantitative justification, is inequitable, and also calls into question the ability of the IOUs to act as backstop procurement entities in the event that other LSEs fail to procure their required resources for D.21-06-035 capacity in general. In its response to the PFM, GPI also recommended that the Commission model the impacts of the proposed DCPP replacement extension.

LSA also opposed the PFM, stating that LSA generally opposes delaying all procurement needed for reliability and clean energy goals. LSA pointed to language in SB 846 (Stats. 2022, Ch. 239), where the statute expressly prohibits the Commission from factoring in the potential extension of Diablo Canyon units,[13] to avoid adjusting procurement targets. LSA argued this guidance should be factored into the Commission's consideration of the SCE/PG&E PFM. Further, LSA argued that the only way the Commission should consider granting an extension for the Diablo replacement category in D.21-06-035 is if the Commission determines that there are no projects available to meet the requirements (based on review of confidential data).

AReM strongly opposed the SCE/PG&E PFM because they argued it is unfair to LSEs that prioritized procuring the Diablo replacement category of resources in the near-term, possibly ahead of the generic procurement required in D.21-06-035. AReM argued that procuring the Diablo replacement category is not meaningfully more difficult than procuring generic resources, except that it may be more expensive, which would give IOUs a competitive advantage that is anti-competitive if they are allowed to delay procurement of the Diablo replacement resources. To remedy this, if the Commission grants the PFM, AReM suggested giving LSEs that meet their Diablo Canyon category of

[13] *See* Public Utilities Code Section 712.8.

procurement by June 1, 2025 a reprieve on potential penalties for any shortfall in generic capacity procurement required under D.21-06-035.

In response to the reliability analysis included in the October 5, 2023 ALJ ruling, SENA recommended denying the SCE/PG&E PFM, because it would unfairly penalize LSEs that prioritized procurement of the required Diablo Canyon replacement category.

5.3. Discussion

The SCE/PG&E PFM concerns us because the 2025 requirement in D.21-06-035 for the procurement of the Diablo Canyon replacement resources is approaching very soon. Thus, any delay we might grant could have a reliability impact in the near term, even if the Diablo Canyon Power Plant itself stays online during this period. The staff analysis included in the October 5, 2023 ALJ ruling showing that 2025 is a year where we already face reliability challenges demonstrates that granting the PFM will likely compound the risk of reduced system reliability.

In addition, we are persuaded by the arguments of AReM and SENA that the granting of the SCE/PG&E PFM could also create inequities for LSEs that procured resources to meet the Diablo Canyon replacement requirements on time, perhaps at greater cost. We do acknowledge PG&E's arguments in its comments on the proposed decision that the inputs and assumptions used for analysis in this cycle of IRP show potential cost increases to the resource types most likely to meet the Diablo Canyon replacement category requirements. However, there would still be timing inequities if the PFM were granted in current form. In addition, we are concerned that some LSEs may be in a position to comply and granting of the PFM could discourage them from following through on the original compliance timetable, which could in turn still have reliability impacts.

Granting of the SCE/PG&E PFM now could have impacts both for system reliability in 2025 and for fairness and equity between LSEs. For both of these reasons, we deny the SCE/PG&E PFM of D.21-06-035. We encourage all LSEs to make their best efforts to procure the Diablo Canyon replacement resources required in Ordering Paragraph 6 of D.21-06-035 by the June 1, 2025 deadline. If their actions are not successful, documentation of procurement actions can be submitted as evidence of good faith efforts when compliance and enforcement determinations are made in the future.

6. PFM on LLT Procurement

The CESA and WPTF PFM concerns the deadlines associated with the required procurement of LLT resources, originally required in D.21-06-035 to be procured by 2026, with the possibility of extension to 2028 after a showing of "good faith" efforts to procure the resources. D.21-06-035 required 1,000 MW of net qualifying capacity (NQC) of long-duration storage resources, and another 1,000 MW NQC of "clean firm" resources that could deliver power at a minimum capacity factor of 80 percent. The deadlines for procurement of these resources were modified in D.23-02-040 to require delivery by June 1, 2028 instead of 2026. In the course of modifying the deadline, D.23-02-040 also removed the provisions relating to LSEs requesting extensions for "good faith" efforts, and instead simply extended the deadline to 2028 for all LSEs.

The October 5, 2023 ALJ ruling contained Commission staff analysis about the potential reliability impact of granting the CESA/WPTF PFM. In general, the staff analysis concluded that after accounting for the procurement already ordered by the Commission in D.21-06-035 and D.23-02-040, reliability of the system in 2028 is expected to meet the 0.1 LOLE reliability standard. However, this analysis did not assess the probability of several of the risks analyzed occurring at the same time.

The October 5, 2023 ALJ ruling also proposed that, if this CESA/WPTF PFM is granted, an additional procurement requirement be put in place for LSEs to procure a total of 2,000 MW NQC of generic clean energy resources in place of the LLT resources that are proposed to be delayed.

6.1. CESA and WPTF Request

As justification for the PFM, CESA and WPTF point out that many LSEs are in the middle of their procurement processes for LLT resources today, and real-time issues are emerging in negotiations that signal a hesitancy on the part of LSEs to sign contracts for projects that have longer permitting timelines, material supply constraints, potential for interconnection delays, and unavoidably long construction periods. CESA and WPTF state that LSEs are reluctant to sign these contracts due to the risk of developer delays, which could result in non-compliance with procurement requirements and penalties.

For these reasons, the CESA/WPTF PFM requests that LSEs be allowed to make requests at any time for extensions to the commercial online-date (COD) requirements for LLT resources to come online beyond June 1, 2028, but no later than June 1, 2031, upon meeting the criteria for good faith efforts and demonstrated need for such an extension, for any resources already contracted by LSEs. This is the primary relief requested in the PFM.

The PFM also suggests that in the alternate and as a minimum, LSEs should not be assessed penalties, nor should backstop procurement be ordered, for LLT resources based on the June 1, 2028 compliance deadline if good faith efforts are demonstrated and accepted by Commission staff.

The PFM requests that extension requests be allowed to be submitted at any time in advance of the June 1, 2027 and June 1, 2028 compliance filings. The PFM suggests that applicable evidence for good faith efforts in D.21-06-035 be limited to evidence of at least two of the following: an executed contract, evidence of site control, an interconnection agreement, and/or a notice to proceed. The PFM argues that evidence of a solicitation or bids in a solicitation should not suffice for an extension request. Essentially, the PFM filers still want LSEs to be required to solicit, negotiate, and sign contracts for the LLT resources, and then work in good faith with the developers should there be delays and barriers during the development and construction phases. As development delays are somewhat outside of an LSE's control, allowing for an extension due to a delayed timeline could make it easier for LSEs and developers to come to mutually agreeable contract terms.

Further, the CESA/WPTF filing also emphasizes the importance of the Commission expediting the adoption of a programmatic approach to procurement requirements within the context of integrated resource planning, and emphasizes near-term consideration of the RCPPP proposed by Commission staff.

6.2. Responses to CESA and WPTF PFM

All of the parties filing responses to the CESA/WPTF PFM originally generally supported the thrust of its request and the primary relief, which would be for the Commission to reinstate an option for a good-faith showing of progress leading to the potential for a project-by-project extension to the D.23-02-040 deadlines for LLT procurement. Numerous parties discuss, in their responses, the situation where the CAISO interconnection Cluster 13 may not contain enough resources in aggregate to meet the 2,000 MW NQC of LLT procurement requirements. Many parties note that if the deadline could be extended beyond 2028, then Cluster 14 and Cluster 15 projects may be able to compete, creating a larger bidder pool and allowing for LSEs to meet the requirements, potentially at lower costs.

SCE,[14] PG&E,[15] and Cal Advocates, [16] in their responses to the PFM, include confidential information about bids already received from developers to deliver LLT resources by 2028, and suggest that LSEs be permitted to use cost and affordability concerns as a reason for potential extension requests. This would mean that extension requests would not be limited to projects for which LSEs have signed contracts, but could also include showings that solicitations for June 1, 2028 COD resources are not competitive or that prices are unreasonable.

CCCE, in its response to the PFM, explicitly supports the option for an LSE to make an extension request only for projects that already have contracts in place.[17] Most of the developers filing responses seem to agree with this implicitly, by agreeing with the PFM proposal of CESA/WPTF, which suggested limiting extension requests in the same manner (to projects with signed contracts).[18]

The CESA/WPTF PFM suggests requiring signed contracts by the December 1, 2023 procurement data filing, and then allowing extension requests at any time up to the June 1, 2028 deadline, with extensions for online dates up to June 1, 2031.

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[14] SCE Response at 6-10.

[15] PG&E Response at 7-9 and Confidential Appendix.

[16] Cal Advocates Response at 6-13.

[17] 3CE Response at 4-5.

[18] Developer support includes ACP-CA, BHE Renewables, Hydrostor, and Vistra.

In their responses, parties support a range of deadline options for the signing of contracts and/or the filing of extension requests, from December 2023, to February 2024, and June 2027 or June 2028.

Cal Advocates also suggests, in its response to the PFM, that the Commission conduct a need determination analysis to determine whether any LLT extension that is granted should be required to be backfilled with generic capacity procurement by the LSE seeking the extension.[19]

Hydrostor, in its response to the PFM, suggests that the Commission require all LSEs to have a solicitation completed by the December 1, 2023 procurement data filing.[20]

Vistra, in its response to the PFM, requests that the Commission clarify that a resource must be online by June 1 of each year of the procurement compliance requirements (2027 or 2028), but that the resource does not necessarily need to be included in the resource adequacy supply plans for June (since being included in the resource adequacy supply plan for June would require an online date by April 1 of each year).[21]

SENA requests that the extensions provided for LLT resources also be provided for the category of resources in D.21-06-035 that is required to replace the capacity from Diablo Canyon.[22]

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[19] Cal Advocates Response at 13-14.

[20] Hydrostor Response at 9-10.

[21] Vistra Response at 10-11.

[22] SENA Response at 2.

Finally, numerous parties support the PFM's suggestion that the Commission take up consideration of the RCPPP as soon as possible, including Form[23] and AReM.[24]

Parties also offered further comments on this PFM in their responses to the October 5, 2023 ALJ ruling and its analysis of the potential impacts of granting the CESA/WPTF PFM, in particular.

CalCCA noted that CCAs are, in aggregate, over-procured. Thus, CalCCA would prefer that the PFM be denied and new procurement not be ordered. Instead, CalCCA suggests that the Commission offer relief from any potential penalties on LLT resources. SCPA would prefer that the Commission avoid requests for wholesale extensions of procurement deadlines, as proposed in the PFM, and instead recognize good faith efforts made by LSEs.

Ava Community Energy also opposed the extension requested in the PFM and proposed across-the-board replacement procurement, saying that LSEs should be given the option to extend their individual LLT procurement deadlines to 2031, with any party electing to do so being obligated to procure a proportional capacity of eligible resources online by 2028, under either bridge or long-term contracts.

EDF and PCF also opposed the PFM in comments in response to the October 5, 2023 ALJ ruling.

Form requested that if the PFM is granted, annual solicitations be required to show that LSEs are attempting to find 2028 resources.

Hydrostor, IEP, AReM, Cal Advocates, and SCE supported the PFM.

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[23] Form Response at 1-2.

[24] AReM Response at 2.

Swan Lake asked for clearer guidance on what is required to obtain and extension, recommending two pieces of documentation. Swan Lake also recommended adopting a deadline to execute contracts in order to obtain a future extension.

PG&E suggested that the Commission could allow an extension only for the firm zero-emitting resources and not long-duration storage.

CEJA commented that it would support additional procurement requirements and the LLT extension if additional procurement is targeted in local areas identified through busbar mapping to help phase out of natural gas plants, LSEs are allowed to fill the procurement mandate with community solar, and any combustion resources are not allowed to meet procurement requirements. GPI also recommended rejecting the allowance to use bridge resources, since they include fossil-fueled resources.

SCPA provided suggestions for increasing flexibility in D.21-06-035 requirements by allowing rebuilt facilities to be considered incremental and by allowing resources without full capacity deliverability status (FCDS) to count towards requirements.

6.3. Discussion

On the primary request of the CESA/WPTF PFM, which is to reinstate a project-by-project option for extensions to no later than June 1, 2031, if good faith progress is shown, we are persuaded by the majority of parties that it may not be possible to meet the 2028 LLT resource procurement deadline in all cases. This may be due to the small number of projects competing for contracts, combined with the inherent permitting, construction, and financing challenges associated with LLT resources. We have dubbed these "long lead-time" resources for a reason.

In particular, the constrained number of projects in CAISO interconnection Cluster 13 is one of the strongest indicators that more time is likely needed. We prefer to allow more projects in Cluster 14 and possibly Cluster 15 to compete for contracts, which will allow more time in the form of extensions requests until June 1, 2031, to allow the LSEs to take this into account in their solicitations.

We also note that this PFM is distinguishable from the SCE/PG&E PFM for Diablo replacement, in that the LLT resources are expected to be procured in the longer term, five years out or more, instead of immediately. This creates less potential for a system reliability impact, as there are resources that can be substituted for any delay of the LLT resources. There is still some potential for inequity among LSEs, since some may have prioritized the procurement of LLT resources ahead of other generic resources, potentially at a higher cost. We will discuss the remedy for that below.

In general, we are also persuaded by the arguments of SCE, PG&E, and Cal Advocates that extension requests should not be limited only to projects with signed contracts. We find it legitimate for the LSEs to seek extensions on the basis of high, non-competitive, or unreasonable pricing in the bids received in their solicitations. Our intent was never to require procurement of LLT resources at all costs, which must be borne by ratepayers, but rather to encourage their development on a reasonable and steady timetable. We are persuaded that our timing expectations need to be further adjusted. Therefore, we will structure the extension requested by CESA and WPTF in the PFM slightly differently than they proposed.

First, we will require all LSEs subject to the D.21-06-035 and D.23-02-040 requirements to procure LLT resources and seeking an extension to the June 1, 2028 COD requirement to provide, by no later than the June 1, 2025 semi-annual procurement data filing deadline: a set of proposed or signed contracts eligible to meet their LLT requirements with a COD no later than June 1, 2031. If an LSE elects to request such an extension, the request must come in the form of a Tier 2 advice letter and must include the proposed or signed contracts and pricing data for resources to come online by 2031, on which the request is based.

Second, we will allow LSEs with signed contracts for LLT resources to file, no later than June 1, 2028, a request for extension due to project development delays to no later than June 1, 2031 for the resources to come online, if a good faith showing is made. Components required for evidence of a good faith showing after June 1, 2024 but before June 1, 2028 are an executed contract, plus at least one of the following:

1. Evidence of site control;
2. An interconnection agreement; and/or
3. A notice to proceed.

An executed contract and at least one of these items must be included in the extension request made by an individual LSE for a deadline extension up to June 1, 2031, and these requests must be made in the form of Tier 2 advice letters by no later than June 1, 2028.

We also agree with the clarification suggested by Vistra, that resources be required to be online by June 1 of a given year, but not necessarily included in the resource adequacy supply plan for that year. It was not our intent to require online dates by April 1 of any given year, as showing a resource to a June monthly resource adequacy supply plan would likely require. Rather, a June 1 COD is sufficient to qualify for compliance with the 2024-2028 requirements of D.21-06-035, D.23-02-040, and/or this decision. This clarification also applies to all procurement required by D.21-06-035 and D.23-02-040, not just LLT procurement. Resources with CODs by June 1 of a given year will be considered compliant with the June 1 requirements for that particular year.

On the suggestion of Cal Advocates that we conduct an analysis to determine if replacement capacity should be required for any extensions granted for LLT resources, that analysis was included in the October 5, 2023 ALJ ruling, along with a proposal that replacement capacity of 2,000 MW could be required if this CESA/WPTF were to be granted.

Instead of requiring full replacement of 2,000 MW of LLT resources that were required to be online by June 1, 2028, we will implement an alternative procurement requirement as follows. Any LSE that does not meet its required LLT procurement requirements from D.21-06-035 as revised in D.23-02-040 will be required to procure the balance of its unmet LLT requirements through generic resource adequacy capacity procurement that otherwise meets the requirements of D.21-06-035. The capacity may be procured either through a long-term contract or a bridge contract, as long as the bridge resources are incremental and procured by the LSE for the full period until the LLT resource comes online. Bridge resources may also include firm imports eligible to serve as bridge resources, following the requirements in D.23-02-040. Inclusion of firm imports for bridge resources of three years or less does not change the fact that incremental generic resource adequacy capacity with a long-term contract or a contract longer than the bridge contract limit must be zero-emitting or otherwise RPS-eligible. The bridge or replacement resource must start delivery by June 1, 2028, but is not required to be identified in the LLT extension requests and can be procured at a later date.

If an LSE meets all of its individual required LLT resource procurement requirements on time (by June 1, 2028), then it will be finished with the LLT requirements. If an LSE meets some of its LLT requirements by no later than June 1, 2028, it will be required to fulfill the remainder of its LLT procurement obligation with generic resource adequacy capacity that is otherwise eligible under the D.21-06-035 eligibility or D.23-02-040 bridge resource requirements until the extended LLT resources come online. If an LSE seeks a delay for all of its LLT procurement past June 1, 2028, then the LSE shall procure all of its LLT resource requirements in generic resource adequacy capacity otherwise eligible for D.21-06-035 or D.23-02-040 bridge resource requirements until all of their LLT capacity comes online.

With respect to the SCPA request to increase flexibility for D.21-06-035 incremental resource eligibility for rebuilt facilities, we decline to adopt these changes at this time, because they would create far-reaching consequences for eligible resources and could jeopardize system reliability. Rebuilt resources would not provide incremental capacity compared to our modeling and compliance baselines. As we stated in our original IRP procurement order D.19-11-016, "capacity upgrades to and repowers to add capacity to existing resources, including baseline resources, are eligible based on the *incremental capacity addition"* (emphasis added).[25] This means that only the capacity beyond that included in the baseline is considered incremental.

Thus, any change to allow rebuilt resources to count would create an additional deficiency that would need to be filled in order to maintain planning for system reliability. While there may be case-by-case situations of errors that may need to be corrected, in general, removing capacity from the baseline in order to create an incremental resource, without adding a replacement resource,

[25] D.19-11-016, Ordering Paragraph 22.

would not result in improved reliability in our planning. In addition, allowing resources without FCDS to count was considered and ultimately rejected in D.23-02-040, where we stated: "We also agree with the CAISO that the interconnection study process is important to ensure reliability, and therefore the deliverability study process should be followed."[26]

Finally, we take note of the numerous parties that have urged us to expedite consideration of the RCPPP or a programmatic approach to procurement in general. While this decision is not the place for addressing the details, we assure parties that development of a programmatic procurement approach remains a priority in the proceeding generally.

7. Reliability Framework for IRP

The October 5, 2023 ALJ ruling contained a proposal to formalize the reliability framework already used by Commission staff in the 2022-2023 IRP cycle. This section discusses the framework and the comments from parties on it.

7.1. Proposed Reliability Framework

The reliability framework proposed by Commission staff is comprised of two elements: (1) a probabilistic reliability standard that can be translated into a reliability need; and (2) a resource counting approach with which to quantify the extent to which the reliability need is expected to be met or exceeded. Such a standard would continue to be used in IRP in capacity expansion modeling, in production cost modeling (loss-of-load probability modeling), and as part of planning and procurement by LSEs. The framework proposed for formal adoption by staff was already used in the current IRP cycle to run reliability and effective load carrying capability (ELCC) studies using SERVM, set LSE filing

[26] D.23-02-040 at 46.

requirements, and update and run capacity expansion modeling using RESOLVE.

7.2. Comments of Parties

17 sets of parties filed comments on this topic in response to the October 5, 2023 ALJ ruling. Some parties supported the framework being adopted, while others opposed it due to its differences with the resource adequacy program's slice of day (SOD) framework. Some parties would also prefer more stakeholder engagement before adoption of anything.

Numerous parties commented on the importance of a reliability framework being compatible with the eventual programmatic framework for IRP, such as the RCPPP. Calpine noted that if there is a disconnect, it could delay the launch of the RCPPP or otherwise require further ad hoc reliability procurement. Calpine and CalCCA suggested that the Commission could adopt a framework that initially utilizes ELCCs, and then potentially transition to one that uses 24 hourly slices, since the SOD framework has yet to be tested or implemented. CalCCA and SENA also noted that the ultimate determination of the IRP reliability framework should be made within the RCPPP adoption. AReM, in reply comments, disagreed with this view.

Numerous parties were also concerned that the IRP framework may differ from the resource adequacy SOD framework, including AReM, CEERT, IEP, MRP, PG&E, and SCE. IEP commented that the split between short-term and long-term procurement in the resource adequacy and IRP proceedings has contributed to the resource shortages that the Commission has struggled to overcome since 2019. CEERT and IEP generally prefer greater cooperation and integration between short- and long-term procurement, leading to a unified reliability framework. AReM was particularly concerned about duplicative effort and reduction in overall effectiveness of both resource adequacy and IRP procurement. SCE commented that portfolios the LSEs develop in IRP may not ultimately lead to satisfying their resource adequacy obligations. PG&E stated that as a result, portfolios may not end up being least-cost to ratepayers.

In terms of the standard for setting the reliability need, CAISO, MRP, SDG&E, and SEIA/LSA explicitly supported using the 0.1 days/year LOLE reliability standard. SDG&E, SCPA, and Calpine also supported transitioning to a perfect capacity (PCAP) construct, as proposed by Commission staff. SDG&E stated that the previous approach did not fully account for the interactive nature of the electric system portfolio, nor did it correctly credit behind-the-meter resources. SDG&E also supported calculating the planning reserve margin (PRM) relative to the gross peak. Form energy preferred adding additional reliability metrics including loss of load hours (LOLH) and expected unserved energy (EUE).

NRDC/UCS commented that using the marginal reliability need (MRN) is preferably to a PRM because the PRM can cause confusion.

On resource counting, Calpine, MRP, NRDC/UCS, and SDG&E explicitly supported using ELCCs. AReM, CEERT, CEJA, and SCE opposed using ELCCs, mainly due to perceived incompatibility with SOD. AReM was also concerned that ELCCs do not account for seasonal variations. CEERT and SCE were concerned that pre-calculated, portfolio-dependent annual ELCCs cause too much uncertainty for LSEs in planning.

CalCCA suggested starting with ELCCs and then assessing SOD. PG&E stated that it is reasonable to apply marginal ELCCs when procurement need is allocated on a load share basis with no consideration of an individual LSE's contribution to the need.

IEP and SCPA both stated that ultimately, there is a need for a manner in which to compare reliability contributions across all resource types.

In terms of potential methodologies to implement the proposed framework, parties expressed several different concerns. SDG&E suggested that ELCCs need to be updated at least every IRP cycle, because it is crucial that they remain accurate. IEP suggested that reliability analyses and forecasting methodologies continue to be refined while a unified reliability framework (coordinated with resource adequacy) is developed.

SDG&E would prefer to use climate-informed forecasting rather than historical weather years. Form also would prefer to ensure the use of weather data and correlated load and generation from 1-in-10 or 1-in-20 weather years, rather than average (1-in-2) weather years. SCPA was concerned about winter reliability challenges after 2035, when a single annual reliability metric may no longer be as relevant.

SEIA/LSA suggested that in addition to showing that preferred portfolios meet a 0.1 LOLE or better, Commission staff should also present reliability results using the SOD method, to help identify alignment issues between the short-term and long-term IRP.

Ultimately, several parties support formal adoption now of a reliability framework for IRP, including CAISO, Calpine, NRDC/UCS, SCPA, SDG&E, and SEIA/LSA.

CalCCA and SCE supported adopting a reliability framework, but would amend it. CalCCA would start with ELCCs and then assess whether to transition to SOD. SCE listed steps for implementing a 24-hour SOD framework in IRP.

Form and MRP would prefer additional stakeholder engagement before the Commission adopts an IRP reliability framework.

AReM, CEERT, and SENA opposed the adoption of any framework for IRP, preferring resource adequacy to be the venue for reliability, and restating concerns about compatibility with SOD.

7.3. Discussion

In considering issues around whether to adopt an IRP reliability framework, we note that a framework was already de facto used to develop the PSP portfolio being adopted in this decision. Since the inception of the IRP process in 2016, we have used reliability metrics and evolved them over time.

In the long term, we agree with those parties who would like to see a unified reliability framework that encompasses both the IRP long-term planning and the resource adequacy procurement horizon and makes sense in both contexts, or at least accounts for them. We also agree that these issues are complex and would like benefit from more stakeholder engagement and vetting prior to adopting any prescriptive and detailed implementation of any particular unified framework.

We also stress that nothing about our consideration of a reliability framework here is meant to prejudge or constrain the ultimate consideration and adoption of a programmatic approach to procurement such as RCPPP. Instead, our goal here is to achieve stability and some certainty in processes for LSEs from a planning perspective, so they know what to expect in the IRP process in the next cycle, until the reliability framework evolves or shifts in the future.

Thus, for now, we will adopt only the basic outline of the framework, so that LSEs know what to expect for the next cycle of IRP. We will then continue stakeholder engagement on the topic of selecting a reliability framework and on the relationship to RCPPP and resource adequacy, because at least some stakeholder comments appear to represent some level of misunderstanding about how these frameworks are used and how they can fit together.

In general, having two different frameworks for long-term planning and short-term procurement need not be incompatible. And in the long term, unifying all reliability processes under a single framework with consistent methods for need determination and resource counting will be a goal.

In this decision, we adopt the 0.1 days/year LOLE standard as the key input for determining reliability need, which is consistent with previous cycles of IRP and should come as no surprise to any parties. We will also determine the PRM based on gross peak and using a perfect capacity (PCAP) metric. Then, we will use ELCCs for resource counting in IRP to get to the 0.1 LOLE standard. SERVM-based ELCC inputs, including curves and surfaces, will continue to be used for RESOLVE capacity expansion, to signal to the RESOLVE model the marginal reliability value of resource additions. For LSE planning, marginal reliability need and marginal ELCCS will be used to allocate system need to LSEs and count resources against LSE need. This is consistent with the approach in the current cycle of IRP and used to develop and adopt the PSP portfolio in this decision.

In developing and disseminating the filing requirements for the next set of individual IRPs of LSEs, Commission staff will consider the resource adequacy SOD rules, alongside the marginal reliability need and ELCC approach, to allow some comparison and potential for harmonization between the two frameworks. In general, we expect to continue to take into account developments in the resource adequacy program rules, as well consider the IRP long-term planning reliability framework.

8. Funding for Continued Consulting Support to Commission Staff on IRP

The October 5, 2023 ALJ ruling proposed to continue reimbursable funding from large IOU distribution rates at current levels to fund consulting support to Commission staff and the IRP process. To this point, Commission staff have had support from technical consultants to conduct modeling and assist with other resource planning tasks. Funding for these purposes was originally authorized in D.18-02-018 for a total of six years. The October 5, 2023 ALJ ruling proposed $3 million annually for an additional six years, not to exceed $18 million total. The ruling proposed that SDG&E, PG&E, and SCE fund the consulting budget out of their existing IRP Costs Memorandum Account (IRPCMA) proportional to their retail load.

8.1. Comments of Parties

Most parties either did not comment on this proposal or did not oppose it. Several parties had technical comments as follows. CEJA and Sierra Club made comments about the prioritization used in current modeling work. SCPA suggested that funding should be augmented to allow for more sophisticated modeling capabilities beyond current work being done, given the importance of IRP.

SCE generally supported the proposal but asked that we clarify the basis for the cost sharing between the IOUs and suggested forecasted 2030 retail sales. SCE also requested additional visibility into the work being done and the results.

PCF was the only party opposed to the proposal. PCF suggested that funding not be approved until there is a transparent, open bidding process. PCF also raised issues with the existing contractor and its involvement in consulting engagements with IOUs.

8.2. Discussion

The past six years of Commission staff work has been supplemented successfully by the previous round of consulting funding authorized in D.18-02-018. Because the same amount of funding proposed in the October 5, 2023 ALJ ruling was available in the past six years and was sufficient to fund both startup and design work, as well as ongoing support, we do not see the need to augment the funding at this time. We could reconsider this if additional analysis is needed in the future.

In response to SCE, we clarify that the funding allocation between IOU distribution customers should be the same as in D.18-02-018, namely on the basis of 2030 forecasted load in each territory.

In response to PCF, we affirm that the funding authorized herein will be subject to competitive bidding requirements through the state contracting process, in the same manner as contractors were hired during the past round of consulting engagements. All existing contractors are subject to conflict of interest reviews and we understand all contractors are in compliance with those requirements.

With these clarifications, we will authorize the additional $18 million in consulting funds for the next six years, with unused funding available to be rolled over until no later than 2035. The IOUs shall record the $18 million in their IRPCMAs in proportion to the 2030 forecasted load for each territory. The Commission's Executive Director will seek all necessary budget authority for spending the consulting funds, and will make contracting and expenditure decisions.

9. Summary of Compliance Filing and Backstop Trigger Dates

In order to clarify any confusion about mid-term reliability (MTR) procurement required in D.21-06-035, supplemental MTR procurement required in D.23-02-040, and additional provisions in this decision, and the associated filing requirements and backstop procurement triggers, we are including below an updated table of upcoming dates.

Table 7.
Compliance Filing and Backstop Procurement Trigger Dates

Date	MTR/ Supplemental MTR Action
June 1, 2024	Compliance filing
December 1, 2024	Compliance filing/ Backstop procurement trigger
June 1, 2025	Compliance filing / Tier 2 advice letter submissions for LSEs seeking LLT extensions for reasons of affordability or CODs between 2028 and 2031
December 1, 2025	Compliance filing/ Backstop procurement trigger (supplemental MTR) / Initial LLT backstop procurement trigger (i.e., for extensions not granted or LSEs that are behind and have not requested extensions)
June 1, 2026	Compliance filing
December 1, 2026	Compliance filing/ Backstop procurement trigger (supplemental MTR)
June 1, 2027	Compliance Filing/ Backstop procurement trigger (final supplemental MTR)/ Potential to receive LLT extension requests
December 1, 2027	Compliance filing/ Potential to receive LLT extension requests
June 1, 2028	Compliance filing/ Backstop procurement trigger (final – MTR LLT if extension not granted)/ Potential to receive LLT extension requests

Date	MTR/ Supplemental MTR Action
December 1, 2028	Compliance filing to update status on LLT extension requests granted/ Backstop Procurement Trigger for granted LLT Extension Request (depending on date granted)
June 1, 2029	Compliance filing to update status on LLT extension requests granted/ Backstop Procurement Trigger for granted LLT Extension Request (depending on date granted)
December 1, 2029	Compliance filing to update status on LLT extension requests granted/ Backstop Procurement Trigger for granted LLT Extension Request (depending on date granted)
June 1, 2030	Compliance filing to update status on LLT extension requests granted/ Backstop Procurement Trigger for granted LLT Extension Request (depending on date granted)
December 1, 2030	Compliance filing to update status on LLT extension requests granted/ Backstop Procurement Trigger for granted LLT Extension Request (depending on date granted)
June 1, 2031	Compliance filing to update status on LLT extension requests granted/ Final Backstop Procurement Trigger for granted LLT Extension Request

10. Summary of Public Comment

Rule 1.18 allows any member of the public to submit written comment in any Commission proceeding using the "Public Comment" tab of the online Docket Card for that proceeding on the Commission's website. Rule 1.18(b) requires that relevant written comment submitted in a proceeding be summarized in the final decision issued in that proceeding.

While this is not the final decision expected to be issued in this proceeding, for purposes of this decision, no public comments were received that are related to the issues raised in the individual LSE IRPs, the CAISO TPP recommendation, or either of the PFMs on prior procurement orders discussed in this decision.

11. Comments on Proposed Decision

The proposed decision of ALJ Julie A. Fitch in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure.

Comments were filed on or before January 30, 2024 by the following parties: ACP-CA; AreM; Ava; BAMx; CAISO; CalCCA; Cal Advocates; Calpine; CalWEA; CEERT; CEJA and Sierra Club, jointly; CESA; CORD; CWG; DOW; EDF; Equinor; Fervo; Form; GPI; Gallatin; GreenGen; Hydrostor; IEP; Invenergy; LS Power; MGRA; MRP; OWC; Pattern; PCF; PG&E; RWE; SCE; SCPA; SDG&E; SEIA and LSA, jointly; SENA; Swan Lake; Vineyard; Vistra; and WPTF.

Reply comments were filed on or before February 5, 2024 by the following parties: ACP-CA; AreM and UC Regents, jointly; Californians for Green Nuclear Power (CGNP); CAISO; CalCCA; Cal Advocates; CalWEA; CEERT; CEJA and Sierra Club, jointly; CESA; Equinor; GPI; Hydrostor; IEP; Invenergy; MGRA; MRP; National Hydropower Association (NHA); OWC; Ormat Technologies, Inc. (Ormat); PCF; PG&E; RWE; SCE; SDG&E; SEIA and LSA, jointly; SENA; TerraGen; and Vineyard.

This section summarizes the comments of parties thematically and describes the corresponding changes made in the text of the decision in response to the comments.

PG&E requests that the Commission specify, for planning purposes, the due date for the next set of individual IRPs to be filed. Several other parties agree in reply comments. This matter is still under consideration, but here we clarify that the due date for the next individual IRP filings will be no earlier than November 1, 2024, and may be up to 12 months later.

Several parties, including ACP-CA, Equinor, Form, Invenergy, and Vineyard, request that we establish a separate track in the proceeding to address LLT procurement. In this respect we acknowledge that we have a deadline this year from AB 1373 that relates to this request and there will be activities in the proceeding this year on this topic.

Parties should expect an amended Scoping Memo in this proceeding in the first half of 2024 that will address the modified schedule for individual IRP filings and the implementation of AB 1373, as well as other pending matters such as consideration of the RCPPP.

Addressing the approval or certification of individual IRPs in the decision, several parties' comments noted errors or inconsistencies, including Ava, Cal Advocates (with respect to the omission of Commercial Energy of California), GPI, and CalCCA. Those inadvertent errors have been corrected herein.

Both AReM and CEJA/Sierra Club are concerned about LSEs repeatedly showing deficiencies in addressing disadvantaged communities issues in their individual IRPs, and seek greater direction on expectations. This could be considered when Commission staff disseminate the requirements for the filing of the next set of individual IRPs.

CEJA and Sierra Club object to the procurement authority given to the IOUs in the proposed decision, saying it provides "unfettered" procurement authority. We emphasize that the authority given herein to the IOUs is for procurement and solicitation activities; we make no change to the existing requirements for the IOUs to bring their contracts before the Commission for approval for any long-term contracts chosen.

At least nineteen parties, representing a wide variety of perspectives, in their comments, explicitly support adopting the 25 MMT Core portfolio as the PSP portfolio. Some parties recommend specific modifications to the portfolio.

A few parties express concern about the Commission's modeling tools used to develop the portfolios in the proposed decision. CEJA/Sierra Club are concerned that RESOLVE's estimate of GHG emissions is inaccurate and CEERT, SCE, and CEJA/Sierra reiterate concerns expressed previously about the difference between the GHG emissions estimated by RESOLVE and SERVM. SCE also suggests that the Commission conduct an overall assessment of the RESOLVE model, which GPI suggests is not suitable for IRP use. Commission staff continue to assess these issues, with particular focus on reducing the delta between RESOLVE and SERVM emissions estimates (which has been considerably reduced compared to previous IRP cycles, but continues to be an are the Commission endeavors to improve each cycle).

EDF suggests adding 600 MW of shed demand response that was selected in the Least-Cost portfolio into the PSP portfolio. While we generally support the development of real and reliable demand response products to qualify to meet our IRP procurement requirements, we decline to set aside this specific amount of demand response in the portfolio because it would be inconsistent with our treatment of other resources to single it out in the manner EDF suggests.

Several parties comment on the changes made between the October 5, 2023 ALJ ruling portfolio and the portfolio in the proposed decision, with particular respect to out-of-state resources. SCPA, DOW, CalWEA, and GPP support the adjustments made to the out-of-state wind potentials, and CalWEA also supports the in-state wind resource potential changes in Northern

California. Pattern, LS Power, Fervo, and ACP-CA oppose the out-of-state resource changes, pointing to the application of new land-use screens to these out-of-state resources. We are concerned that parties misunderstand the changes that were made and clarify the direction here. No new land-use screens were applied to out-of-state resources. Rather, the amount of available out-of-state resource potential was reduced by a discount factor, after application of the same land-use screens used in previous IRP cycles for out-of-state resources. DOW and Pattern voice support for the development of future land-use screens for out-of-state resources that are similar to those we use in California. We support that concept, but any such work would be in the future and has not been applied here. We are satisfied that the discounting of the available potential in the portfolio for out-of-state resources is a reasonable approach for this year's portfolio. The resource potential still far exceeds the volume of procurement needed during the planning horizon for California LSEs, and we will have the opportunity to continue to refine our approach for future portfolios.

CORD comments that the Commission should consider land-use screens that incorporate wildfire risk across the California and Southern Nevada regions of the CAISO. We clarify that wildfire risk in California is already a dataset included in the current analysis.

The CAISO also points out in its comments that the offshore wind transmission utilization numbers were incorrect in the dashboard of resources published for busbar mapping purposes along with the proposed decision. As part of the busbar mapping process, CAISO staff shared the updated utilization factors, along with other technical feedback. These utilization factors will be corrected in the final busbar mapping, and we note that this change will not materially impact the transmission implications of the busbar mapping results.

Some parties also express concerns about the characterization of particular resources, including pumped storage or other LDES, including GreenGen and Form. Form suggests that the Commission represent energy storage resources in a technology-neutral manner. We clarify that we are continuing to work on improving the types of resources available for RESOLVE to select for LDES, and note that the 12-hour pumped storage category is currently serving as a proxy for non-lithium-ion-battery technologies to some degree. However, when it comes to busbar mapping, particular types of resources in specific locations must be selected in order to study the impact on the transmission system.

GPI also requests several changes to the proposed decision to address its comments on the October 5, 2023 ALJ ruling. We have made those clarifications in the text, where warranted.

Numerous parties, including ACP-CA, CalWEA, Vineyard, RWE, Invenergy, Equinor, and OWC, suggest that the Commission should include more OSW in the reliability and policy-driven base case portfolio to be analyzed by the CAISO. Most of these parties recommend the inclusion of at least 10 GW, with some diversity of opinions as to whether the locational emphasis should be on the Central Coast or the North Coast. SCPA, CEERT, and Vineyard support the proposed decision's inclusion of 1.6 GW of OSW on the North Coast in the mapping of resources, while BAMx, OWC, RWE, Equinor, and Invenergy oppose it. BAMx is concerned that inclusion of the North Coast OSW without screening for viability will leave the state with underutilized transmission assets. OWC would include more OSW on the North Coast, and more OSW overall. Invenergy is concerned that reducing the Central Coast volume to 2.9 GW sends the wrong signal for transmission planning and resource commitments there.

On balance, we believe the proposed decision struck the right balance between the Least-Cost scenario analyzed, which would have chosen zero OSW, and the minimum 10 GW that many of the OSW-related parties request in their comments. While we recognize that the CEC's AB 525 report includes more OSW (up to 25 GW), we also note that the purpose of the AB 525 report is to set a goal, whereas our purpose here is to identify a realistic scenario for the base case TPP analysis. Thus, we affirm 4.5 GW as the amount of OSW to be included in this year's base case portfolio.

This is, however, only one additional step toward the development of transmission to support OSW generation resources. We also emphasize the importance of further developing the OSW wind for resource diversity and GHG reductions in California, and will continue to refine our estimates of what is realistic in the next 10-15 years in the portfolios regularly considered for adoption in IRP and analyzed in the TPP. We hope that OSW development progresses quickly in the next few years, and we will refine our portfolios accordingly, after taking this important next step in this decision toward supporting the first set of required transmission development.

We also emphasize that we will take steps this year to implement AB 1373, and may address the need for additional OSW capacity in that context. We look forward to working with parties to identify further steps in AB 1373 implementation to support OSW development and that of other LLT resources.

SEIA/LSA, CAISO, CEERT, GPI, CalCCA, and MGRA all support the High Gas Retirement sensitivity in comments. GPI also supports developing an alternative that reduces overreliance on solar and storage resources. BAMx opposes the High Gas Retirement sensitivity because it would result in more transmission upgrades being triggered, at higher cost. However, since this is a sensitivity portfolio, it will not automatically trigger any transmission projects. Calpine suggests that the proposed rankings for gas retirements in the sensitivity are not plausible or consistent with policy goals. We have addressed this concern with the additional discussion of criteria and its application in Section 4.2 above.

Many parties had particular comments on aspects of the busbar mapping results for the base case portfolio, including geographic or technology-specific concerns. For example, GreenGen is concerned about criteria for pumped storage projects, including CAISO queue placement. PG&E wants to ensure selected gas retirements are not confined to Southern California. CORD seeks modifications to add capacity in the GLW area so that the CAISO can study transmission upsizing opportunities. DOW is concerned about assigning capacity at the Kramer substation, until the Bureau of Land Management acts. On balance, we are satisfied that the busbar mapping approach is generally sound, and decline to make specific adjustments such as these for now. We continue to rely on the iterative nature of the annual transmission planning process to sort out these sorts of changes and updates as we learn more about actual project development. Commission staff are publishing the final busbar mapping results with the adoption of this decision, for use by the CAISO in its TPP. We also note, in response to a comment by SEIA/LSA and supported by TerraGen in reply comments, that the busbar mapping results are already published by both RESOLVE area and CAISO zone.

Several parties express concerns about the need to further analyze transmission options to reduce reliance on thermal resources in the Los Angeles Basin, including CalWEA, CEERT, and CWG. RWE and CalWEA are focused on SB 887 purposes for this analysis, and RWE takes issues with the characterization in the proposed decision that most parties agreed that the base case portfolio described in Section 4.1 is compliant with SB 887 requirements. Given that only a few parties commented on this topic, we have modified the characterization. We also point parties to the request made in a letter signed by President Alice Reynolds to the CAISO in January 2023 related to SB 887,[27] as well as the fact that the CAISO has already recommended to its Board approval of several projects that will alleviate local transmission constraints, including the large reinforcement project from the Imperial Valley into the Los Angeles Basin.

Turning to the PFMs addressed in the proposed decision, there were several comments from parties. On the SCE/PG&E PFM related to the Diablo Canyon replacement category in D.21-06-035 (Section 5 of the decision), CEERT and EDF agree with the denial of the PFM. In contrast, the IOUs all request that we reverse course and grant the PFM. SCE and PG&E point out that all other categories of required procurement have some type of alternative compliance option, including eligibility of bridge resources until projects can come online. Conceptually, we understand the IOUs' point. However, in the case of the Diablo Canyon replacement category in D.21-06-035, that procurement requirement is already a subset of the total capacity required to be procured by 2025. Thus, allowing bridge resources to count towards this Diablo replacement procurement category is substantively no different from simply granting the PFM, giving LSEs until 2027 to procure the resources. We decline to take that action here.

[27] The SB 887 letter is available at the following link: https://www.caiso.com/InitiativeDocuments/Letter-2022-2023-Transmission-Planning-Process-Jan%2013,%202023.pdf .

We note that in the original PFM, PG&E and SCE present their procurement challenges as associated with the energy component of the Diablo Canyon replacement category, rather than the capacity component. We also recognize that denying the PFM is not likely to create procurement opportunities for the IOUs where there are no projects or only very high-cost projects to be procured. Thus, we are open to other creative solutions to this near-term problem that will serve to enhance reliability and reduce customer costs.

For example, it may be possible to pair a clean firm imported energy contract with a new stand-alone storage facility in the CAISO area as a bridge for a short period of time (e.g., one to two years) until new resources that meet the Diablo replacement category's requirements come online, provided the quantity of clean energy contracted to charge the storage meets the energy requirements stipulated in D.21-06-035 for the Diablo replacement category.

We do agree with GPI, however, that an unspecified import contract or a contract with an emitting resource would not meet the spirit, due to requirements that Diablo Canyon's eventual retirement not increase emissions. Thus, any clean firm energy contract contemplated would need to be with an RPS-eligible or non-emitting resource.

As above, though we deny the SCE/PG&E PFM in its current form in this decision, we are open to having other solutions brought forth from Commission staff or any other party that may address the challenges with procuring the D.21-06-035 procurement category requirements associated with Diablo Canyon replacement. We also encourage all LSEs to continue to procure to meet the Diablo replacement category of procurement, showing good faith efforts, even if their efforts fall short of the total requirement. This will be taken into consideration with any potential future enforcement actions. Meanwhile, all LSEs should also focus on procuring the capacity requirements of D.21-06-035 and D.23-02-040 for each year 2024 through 2028.

We also note CAISO's comments that the SCE/PG&E PFM highlights the need for continued development of the RCPPP, because in this case, ordering procurement four years ahead of the need was still insufficient to complete procurement processes and account for the risk of delays. We agree with the sentiments of the CAISO and reiterate our commitment to RCPPP development and adoption as soon as possible.

Turning to the CESA/WPTF PFM related to LLT resources, CEERT, Ava, CAISO, and CalCCA support the proposed decision's disposition. CESA and Hydrostor both propose forms of reducing the amount of replacement or bridge capacity an LSE should be required to procure if they are granted an LLT extension, such as a waiver or advice letter process, if the Commission determines the replacement capacity is no longer needed. SENA and WPTF would go further, stating that we should not require any replacement capacity at all unless a later study shows that it is needed. We decline to make these changes because they would dilute the equity balance between LSEs that we intended to address by these provisions.

Several parties, including AReM, SENA, PG&E, and SCE, request that we move the deadline for LSEs to make affordability-based extension requests to December 2024. Vistra goes further, asking that we allow these affordability-based requests as late as 2027, in order to accommodate projects in Clusters 14 and 15 of the CAISO interconnection studies.

In response to these suggestions, we have made the following modification, which is a compromise among the various party suggestions. The deadline for an affordability-based extension will be June 1, 2025. However, at that time, LSEs will need to show, at a minimum, proposed or signed contracts for the actual projects that they will procure to meet the LLT requirements, with online dates between 2028 and 2031. Thus, LSEs will need to have completed a solicitation for LLT resources in order to comply with these updated requirements, which are reflected in the text and order in this decision.

Several parties, including SENA, Hydrostor, and WPTF, suggest that the Commission not require replacement capacity to be procured on a one-for-one basis with delays in LLT capacity online dates now, but instead wait until a later assessment, such as during or after RCPPP development since the capacity may not be needed once a later reliability assessment is completed. Hydrostor and WPTF also express concern that the requirement for replacement or bridge capacity could discourage investment by LSEs, particularly in newer LLT technologies due to the potential for higher development risk. While we understand these points, we emphasize that LSEs should not be burdening any existing or future LLT contracts directly with the potential for delays. Our purpose here is to encourage more resource diversity among LLT resources, not less, and even if investments in diverse LLT resources take a little longer than anticipated. The replacement and bridge resource provisions are intended to provide flexibility to the LSEs for meeting the LLT requirements flexibly, not to encourage LSEs to pass the risks onto the LLT developers.

Cal Advocates also points out some inconsistency in the proposed decision language with respect to whether bridge resources for extensions on the LLT requirements can include imports that are associated with emitting resources. We have clarified that emitting imports are eligible, and note that this is not a change with respect to the bridge resources already authorized previously in D.23-02-040. We also note that GPI opposes allowing emitting import contracts to count as bridge resources, but we do not modify the D.23-02-040 eligibility requirements for bridge resources.

DOW suggests that the evidence required for "good faith" efforts should be more stringent, requiring a conditional use permit or right-of-way approvals, etc. We decline to make changes for this purpose, but note that this could be a component of compliance and documentation requirements associated with the RCPPP and we can take up the DOW suggestions there.

Swan Lake suggests that the Commission affirm its belief in the benefits of resource diversity in the LDES category. We agree with Swan Lake and emphasize that one of the primary purposes of creating the LLT category in D.21-06-035 was to encourage greater resource diversity. We strongly encourage and support resource diversity within all of the procurement categories, including LDES options.

On the subject of the adoption of the reliability framework for IRP in the proposed decision, at least six parties, including CEERT, CAISO, Pattern, GPI, SCE, and TerraGen support the adoption of the 0.1 LOLE standard and the reliability framework, at least until the RCPPP is adopted. Form and AReM strongly disagree with the adoption of the reliability framework, with AReM suggesting it is a violation of Public Utilities Code Section 454.52(a)(1). Further, AReM is concerned about the description in this decision of the resource adequacy program, arguing it should be handled in the resource adequacy rulemaking. Form prefers that the reliability framework be handled in the RCPPP development. Most parties encourage alignment between the IRP framework and the resource adequacy requirements.

We clarify that the adoption of the reliability framework in this decision is intended as an interim approach until the adoption of the RCPPP. Basically, it is affirmation of the direction LSEs were given for their reliability requirements in the current cycle of IRP. We will continue to work towards alignment with the resource adequacy requirements, as well as to harmonize the reliability framework used for planning and procurement requirements. We also acknowledge that the resource adequacy requirements and timeframe are not the subject of this rulemaking, and any plans or changes to the resource adequacy program will be handled in the resource adequacy rulemaking (R.23-10-011). We have made several clarifying edits in the text, Conclusions of Law, and Ordering Paragraphs, to clarify these points.

On the direction to the IOUs to reimburse the Commission for certain analytical and consulting expenses to support the IRP process, SCE offers some modified language to reflect how the balancing accounts function. We have made those suggested changes in the decision.

Several parties, including CESA, IEP, MRP, and WPTF, object to our not including disposition of a proposal that was included in the October 5, 2023 ALJ ruling for comment, related to the potential for siting LDES at existing natural gas facilities. We clarify that this decision does not address the proposal at all, because comments in response to the ALJ ruling revealed the amount of complexity involved in the potential implementation of the proposal. This does not mean the concept is denied or rejected in this decision. It is simply not yet addressed. This decision is not required to address every topic currently in the record of this proceeding. The proposal for LDES projects at existing power plant sites may be the subject of further work and development in the future in this proceeding.

Vistra specifically notes that for resources coming online by June 1 of any given year for compliance with prior procurement orders, the resources should not be required to be on either June or July resource adequacy supply plans. We agree with this clarification and have made that change in the decision.

In its comments, SCPA reiterates its request that the Commission authorize staff to make adjustments to the procurement baseline for specific situations such as "catastrophic events." Ormat replied with some arguments as to the appropriate lifetime assumptions for geothermal facilities. We decline to make adjustments to the general language in this decision, since it is important to maintain the integrity of the baseline for certainty for LSEs procuring. Further, this decision is not the best venue for addressing the specifics of the Ormat facility that SCPA seeks to count toward the procurement requirements.

12. Assignment of Proceeding

Alice Reynolds is the assigned Commissioner and Julie A. Fitch is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. All LSEs required by D.18-02-018 and D.22-02-004 to file an individual IRP or documentation substantiating eligibility for an exemption filed materials by no later than November 1, 2022.

2. The following entities provided the appropriate information to justify an exemption from filing an individual IRP: Anza Electric Cooperative, BREMUS, EnergyCal USA (doing business as YEP Energy), Gexa, Plumas Sierra, Praxair, Surprise Valley, Tiger Natural Gas, and Valley Electric Association.

3. The individual IRP filings of the following IOUs provided all of the required information to an adequate degree or better: PacifiCorp, PG&E, SDG&E, and SCE.

4. The following IOUs included inadequate information in their individual IRPs in one or more categories: Bear Valley and Liberty Utilities (CalPeco Electric).

5. The individual IRP filings of the following CCAs provided all of the required information to an adequate degree or better: Apple Valley Choice Energy, Ava Community Energy, City of Palmdale, City of Pomona, Clean Energy Alliance, Clean Power Alliance of Southern California, Clean Power San Francisco, Desert Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy Authority, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San Jose Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy Authority, Sonoma Clean Power Authority, and Valley Clean Energy Alliance.

6. The following CCAs included inadequate information in their individual IRPs: Central Coast Community Energy and King City Community Power.

7. The individual IRP filings of the following ESPs provided all of the required information to an adequate degree or better: Direct Energy Business and Shell Energy North America.

8. The following ESPs included inadequate information in their individual IRPs: 3 Phases Renewables, Calpine Energy Solutions, Calpine PowerAmerica CA, Commercial Energy of California, Constellation NewEnergy, EDF Industrial Power Services, Pilot Power Group, and Regents of University of California.

9. PG&E, SCE, and SDG&E made specific requests in their individual IRPs for the Commission to authorize procurement activities, due to their ongoing need to procure resources to comply with IRP and system reliability needs.

10. Commission staff analysis to aggregate the portfolios included in individual LSE IRPs and check for overlap and double-counting, while taking into account POU plans to the extent known, was reasonable and necessary.

11. Commission staff analysis to aggregate the portfolios included in the individual LSE IRPs required extensive reliance on confidential data submitted under seal by LSEs.

12. The aggregated LSE IRP resources in the 25 MMT by 2035 portfolios, as augmented by Commission staff analysis leading to the 25 MMT Core Portfolio, meets the GHG requirements and reliability requirements out through 2035, according to PCM conducted by Commission staff in the SERVM model.

13. Commission staff analyzed both Core portfolios (consisting of resources contained in the individual LSE IRPs) and Least-Cost Portfolios generated using the RESOLVE capacity expansion model.

14. A reliability and policy-driven base case portfolio based on the 25 MMT GHG target by 2035 using the PSP portfolio is consistent with the Commission's recent approaches to recommending base case portfolios for TPP analysis.

15. The PSP portfolio recommended as a base case portfolio for TPP analysis results in usage of approximately 70 percent less natural gas than the current portfolio by 2035.

16. A TPP policy-driven sensitivity portfolio based on the High Gas Retirement sensitivity that retires a significant amount of natural gas generation capacity will require additional time to be mapped to busbars, after the issuance of this decision.

17. Last year's TPP base case portfolio included 1.7 GW of offshore wind on the North Coast.

18. D.21-06-035 required LSEs to procure, by no later than June 1, 2025, a total of 2,500 MW of NQC in resources, with associated energy, designed specifically to mitigate the loss of the Diablo Canyon Power Plant.

19. Commission staff analysis shows that there is a potential reliability shortfall to the reliability standard for the electric system in 2025, even if the procurement already ordered in D.21-06-035 comes online on time, because, despite Commission action, there is still some uncertainty about whether the Diablo Canyon Power Plant will remain online during this period. The Commission is also required by Public Utilities Code Section 454.52(f)(1) to plan as if Diablo Canyon will retire in 2024/2025.

20. Commission staff analysis shows that there is not a potential shortfall to the reliability standard in 2028 if the procurement ordered in D.21-06-035 comes online on time, assuming multiple potential procurement risks do not occur simultaneously.

21. D.21-06-035 required LSEs to procure, by no later than 2026, a total of 1,000 MW NQC of "clean firm" resources and a total of 1,000 MW NQC of long-duration energy storage resources (collectively, LLT resources), and created a process for LSEs to request extensions to the LLT compliance deadline after a good-faith-effort showing.

22. D.23-02-040 automatically extended the compliance deadline for LLT resources to June 1, 2028, and eliminated the project-by-project extension process.

23. The CAISO interconnection Cluster 13 does not contain enough generation or energy storage resources that could be online by 2028 to make a collectively competitive solicitation process for all LSEs to deliver their LLT requirements.

24. Confidential bid data submitted by PG&E, SCE, and Cal Advocates in response to the CESA/WPTF PFM shows evidence of potentially unreasonable

and non-competitive pricing for some LLT resources, representing a risk to ratepayers of unjust and unreasonable costs.

25. The PSP portfolio included in this decision is based on reliability need determined by a 0.1 LOLE standard, a PRM based on the gross peak, a reliability need measured in PCAP, and using ELCCs to count resources toward the reliability needs. LSE plans were developed using marginal reliability need consistent with a 0.1 LOLE standard and marginal ELCCs.

26. The Commission requires ongoing technical support funding to support the IRP process adopted in this decision because of its inherent complexity and requirements to achieve many different objectives, including reducing greenhouse gases, maintaining reliability, and minimizing ratepayer impacts.

Conclusions of Law

1. All of the motions to file under seal filed by LSEs along with their individual IRPs on or around November 1, 2022 should be granted.

2. The Commission should approve an exemption from filing an individual IRP in 2022 for the following entities: Anza Electric Cooperative, Brookfield Renewables Energy Marketing US, EnergyCal USA (doing business as YEP Energy), Gexa Energy California, Plumas Sierra Cooperative, Praxair Plainfield, Surprise Valley Electric Cooperative, Tiger Natural Gas, and Valley Electric Association.

3. The Commission should approve the individual IRPs of the following IOUs: Pacific Gas and Electric, PacifiCorp, San Diego Gas & Electric, and Southern California Edison.

4. The Commission should not approve the individual IRPs of Bear Valley Electric Service and Liberty Utilities (CalPeco Electric), pending resubmission of

the required supplemental information as discussed in Section 2 of this decision to be filed in a Tier 2 advice letter.

5. The Commission should certify the individual IRPs of the following CCAs: Apple Valley Choice Energy, Ava Community Energy, City of Palmdale, City of Pomona, Clean Energy Alliance, Clean Power Alliance of Southern California, Clean Power San Francisco, Desert Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy Authority, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San Jose Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy Authority, Sonoma Clean Power Authority, and Valley Clean Energy Alliance.

6. The Commission should not certify the individual IRPs of the following CCAs, pending them resubmitting required supplemental information discussed in Section 2 of this decision in a Tier 2 advice letter: Central Coast Community Energy and King City Community Power.

7. The Commission should approve the individual IRPs of the following ESPs: Direct Energy Business and Shell Energy North America.

8. The Commission should not approve the individual IRPs of the following ESPs, pending them resubmitting required supplemental information discussed in Section 2 of this decision: 3 Phases Renewables, Calpine Energy Solutions, Calpine PowerAmerica CA, Commercial Energy of California, Constellation NewEnergy, EDF Industrial Power Services, Pilot Power Group, and Regents of the University of California.

9. The Commission should require the entities that did not provide adequate information in their individual IRPs to refile the required supplemental

information via Tier 2 advice letters by no later than May 1, 2024. The information may be filed as an appendix or supplement to the November 2022 individual IRPs.

10. The Commission should authorize PG&E, SCE, and SDG&E to conduct flexible procurement activities to meet their 25 MMT portfolios, including conducting solicitations and bilateral negotiations.

11. The Commission should adopt the 25 MMT Core Portfolio as the preferred system plan portfolio.

12. The Commission should recommend to the CAISO that the PSP portfolio adopted in this decision be used as the reliability and policy-driven base case for the 2024-2025 TPP.

13. The Commission should maintain 1.6 GW of offshore wind mapped to the North Coast/Humboldt area in the base case for the 2024-2025 TPP, to be consistent with the prior portfolio and the plans of individual LSEs in the Core scenario.

14. The Commission should recommend that the CAISO study the High Gas Retirement scenario as a policy-driven sensitivity in the 2024-2025 TPP.

15. Granting the SCE/PG&E PFM of D.21-06-035 related to Diablo Canyon replacement category would create additional reliability risk in 2025, which is already a tight year. Granting the PFM would also create potentially serious inequities between LSEs that prioritized procuring the Diablo replacement resources and those that did not.

16. The SCE/PG&E PFM of D.21-06-035 related to Diablo replacement resources should be denied.

17. Allowing generation and storage resources in CAISO interconnection Cluster 14 and Cluster 15 to compete for contracts to deliver LLT resources

would make the process more competitive, but would also likely require compliance deadline extensions beyond June 1, 2028.

18. LSEs should be permitted to file individual requests for extension of the LLT compliance deadline of June 1, 2028 while making a good-faith showing of progress toward the required procurement.

19. LSEs seeking extensions for cost reasons or later COD options should be required, by June 1, 2025, to submit a Tier 2 advice letter showing their proposed or signed contracts designed to meet the LLT requirements, but with online dates after June 1, 2028 and before June 1, 2031, as well as bid pricing data.

20. LSEs with signed contracts for LLT resources should be allowed to file, no later than June 1, 2028, a request for extension for LLT online dates to no later than June 1, 2031, if a good faith showing is made in a Tier 2 advice letter.

21. Any resources procured in compliance with the requirements of D.21-06-035, D.23-02-040, or this decision should be required to achieve COD by June 1 in a given year to meet the compliance deadline but should not be required to be included in any particular monthly resource adequacy supply plan for that year.

22. The Commission should require LSEs that do not meet their LLT resource procurement requirements by June 1, 2028 to procure generic replacement capacity, either through long-term contracts or bridge contracts defined in D.21-06-035 and D.23-02-040, until such time as their LLT resources can come online, by no later than June 1, 2031.

23. LSEs should continue good faith efforts to procure a diverse set of LLT resources, even if they cannot meet a June 1, 2028 deadline.

24. The Commission should adopt a high-level reliability framework for IRP planning, consisting of the 0.1 LOLE standard to calculate reliability need, a PRM

based on gross peak, and an ELCC-based counting methodology. The Commission should maintain the use of marginal reliability need and marginal ELCC metrics for use in LSE plans in the next cycle of IRP at least until the development of the RCPPP requirements.

25. The Commission should continue to work with stakeholders to harmonize and rationalize the IRP reliability framework for planning with the resource adequacy SOD requirements.

26. The Commission should require $3 million per year for the next six years, in reimbursable funding, on a proportional basis reflected by the 2030 load forecast, from the three large IOUs, to fund technical assistance for the IRP process adopted in this decision.

27. PG&E, SCE, and SDG&E should be authorized to book IRP technical contractor costs with funding not to exceed $18 million over the next six years in their existing IRPCMAs.

28. Table 7 of this decision contains an updated list of compliance filing and backstop procurement trigger dates associated with D.21-06-035, D.23-02-040, and this decision. LSEs should be required to follow the dates in Table 7.

29. The LSEs subject to the Commission's IRP purview should not be required to file new individual IRPs before November 1, 2022. The deadline may be up to 12 months later. An amended scoping memorandum in this proceeding by mid-2024 should set a filing date for the next set of individual LSE IRPs.

30. This proceeding should remain open.

O R D E R

IT IS ORDERED that:

1. All motions to file under seal filed by load-serving entities with information contained in their individual integrated resource plans filed on or around November 1, 2022 are hereby granted. The information shall remain under seal and be accessible only to Commission staff.

2. The following load serving entities are approved as exempt from the requirements in Decisions (D.) 18-02-018, D.20-03-028, and D.22-02-004 to file an individual integrated resource plan in 2022: Anza Electric Cooperative, Brookfield Renewables Energy Marketing US, EnergyCal USA (doing business as YEP Energy), Gexa Energy California, Plumas Sierra Cooperative, Praxair Plainfield, Surprise Valley Electric Cooperative, Tiger Natural Gas, and Valley Electric Association.

3. The individual integrated resource plans filed in 2022 and supplemented or revised in 2023 are hereby approved for the following investor-owned utilities: Pacific Gas and Electric Company, PacifiCorp, San Diego Gas & Electric Company, and Southern California Edison Company.

4. The individual integrated resource plans filed in 2022 and supplemented or revised in 2023 are not approved for the following investor-owned utilities and they shall file supplemental information as detailed in Section 2 of this decision via a Tier 2 Advice Letter no later than May 1, 2024: Bear Valley Electric Service and Liberty Utilities (CalPeco Electric), LLC.

5. The individual integrated resource plans filed in 2022 and supplemented or revised in 2023 are hereby certified for the following community choice aggregators: Apple Valley Choice Energy, Ava Community Energy, City of Palmdale, City of Pomona, Clean Energy Alliance, Clean Power Alliance of

Southern California, Clean Power San Francisco, Desert Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy Authority, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San Jose Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy Authority, Sonoma Clean Power Authority, and Valley Clean Energy Alliance.

6. The following community choice aggregators' individual integrated resource plans are not certified in this decision and they shall file supplemental information as detailed in Section 2 of this decision via a Tier 2 Advice Letter no later than May 1, 2024: Central Coast Community Energy and King City Community Power.

7. The following electric service providers' individual integrated resource plans filed in 2022 and supplemented or revised in 2023 are approved: Direct Energy Business and Shell Energy North America.

8. The following electric service providers' individual integrated resource plans are not approved in this decision and they shall file supplemental information as detailed in Section 2 of this decision via a Tier 2 Advice Letter no later than May 1, 2024: 3 Phases Renewables, Calpine Energy Solutions, Calpine PowerAmerica CA, Commercial Energy of California, Constellation NewEnergy, EDF Industrial Power Services, Pilot Power Group, and Regents of the University of California.

9. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company are authorized to conduct procurement activities as market conditions indicate, including solicitations and bilateral negotiations, to procure the resource needs identified in their

2022 individual integrated resource plans with the portfolios designed to meet the 25 million metric ton greenhouse gas emissions target by 2035. Resources procured under this authorization shall be submitted to the Commission as Tier 3 advice letters unless the contracts are otherwise authorized pursuant to another Commission order in another proceeding.

10. The Core portfolio based on the 25 million metric ton greenhouse gas target by 2035, described in Section 3 of this decision, is adopted as the portfolio for the preferred system plan for 2023.

11. The Commission transmits to the California Independent System Operator for use in its 2024-2025 Transmission Planning Process the Preferred System Plan portfolio adopted in Ordering Paragraph 9 above, as both the reliability and policy-driven base case portfolio.

12. The Commission transmits to the California Independent System Operator (CAISO) the High Gas Retirement sensitivity as a policy-driven sensitivity portfolio to be analyzed in the 2024-2025 Transmission Planning Process.

13. The Commission delegates to Commission staff, in consultation with the staff of the California Energy Commission and California Independent System Operator (CAISO), the mapping of resources to busbars associated with the policy-driven sensitivity portfolio to be transmitted to the CAISO after the adoption of this decision.

14. The August 9, 2023 Petition for Modification of Decision 21-06-035 of Southern California Edison Company and Pacific Gas and Electric Company is denied.

15. The May 3, 2023 Petition for Modification of Decisions 23-02-040 and 21-06-035 of the California Energy Storage Alliance and the Western Power

Trading Forum to Address Long Lead-Time Resource Compliance Deadlines is granted, in part, as further described in this decision.

16. All load-serving entities subject to requirements of Decision (D.) 21-06-035 and D.23-02-040 to procure long lead-time (LLT) resources shall provide, by no later than June 1, 2025 either of the following (or a combination of each):

    (a) A set of signed contracts that meet their LLT obligations, to be included in the June 1, 2025 procurement data filing required by D.22-05-015;

    (b) A Tier 2 advice letter seeking an extension based on LLT cost considerations or projects with later commercial online dates, including signed or proposed contracts with projects with contract online dates up to June 1, 2031, and including confidential pricing and bid data to substantiate the basis for the request.

17. All load-serving entities subject to requirements of Decision (D.) 21-06-035 and D.23-02-040 to procure long lead-time resources who have signed contracts for such resources may request, by no later than June 1, 2028, extensions to the online dates to no later than June 1, 2031, by submitting a Tier 2 advice letter containing evidence of a good faith effort by including an executed contract and at least one of the following:

    (a) Evidence of site control;

    (b) An interconnection agreement; and/or

    (c) A notice to proceed.

18. Resources being used by load-serving entities to satisfy their requirements for procurement in Decision (D.) 21-06-035, D.23-02-040, and this decision shall be required to be online by June 1 of any given compliance year, but shall not be required to be included in any particular monthly Resource Adequacy supply plan.

19. Any load-serving entity that does not meet its required long lead-time (LLT) procurement requirements in Decisions (D.) 21-06-035 and D.23-02-040 by June 1, 2028 shall procure an equal amount (in net qualifying capacity) of the balance of its unmet LLT requirements through a bridge contract, which includes firm imports as defined in D.23-02-040, or long-term contracts that otherwise meet the characteristics required for generic procurement in D.21-06-035, to cover the shortfall until its LLT resources come online, from June 1, 2028 through June 1, 2031, at a minimum.

20. Any load serving entity that meets its long lead-time resource procurement requirements from Decisions (D.) 21-06-035 and D.23-02-040 by June 1, 2028 shall not be required to procure any additional generic capacity resources as a result of this decision.

21. The integrated resource planning process shall utilize a reliability framework where a 0.1 loss of load expectation shall be used to determine resource needs, a planning reserve margin shall be based on perfect capacity off of a gross peak load, and resource counting shall be done using effective load carrying capability (ELCC) estimates that shall be updated and published periodically by Commission staff. Load serving entity plans shall utilize marginal reliability need and marginal ELCCs. This high-level framework shall remain in place until the Commission modifies it in coordination and consultation with the resource adequacy program and/or the development and adoption of the Reliable and Clean Power Procurement Program.

22. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall record integrated resources planning consulting costs in their Integrated Resource Planning Cost Memorandum Accounts (IRPCMA) and submit Tier 1 advice letters modifying

their existing IRPCMA to implement this decision within 30 days of the adoption of this decision. Costs recorded in these accounts shall not exceed $18 million total across all three utilities, and the costs shall be allocated on the basis of proportion of projected 2030 load share, to all distribution customers.

23. The Commission's Executive Director shall hire and manage one or more contractors to perform tasks in support of the integrated resource planning process ordered in this decision. The costs of such tasks shall not exceed $3 million per year for six years, or a total of $18 million, with costs eligible to be rolled over annually until no later than 2035.

24. All load serving entities subject to the Commission's integrated resource planning process shall follow the compliance filing and backstop procurement trigger deadlines included in Table 7 of this decision.

25. Load serving entities subject to the Commission's integrated resource planning purview are not required to file individual integrated resource plans any earlier than November 1, 2024. The exact deadline will be set in an amended scoping memorandum to be issued in this proceeding in mid-2024, and may be up to 12 months after November 1, 2024.

26. Rulemaking 20-05-003 remains open.

This order is effective today.

Dated _____________________________, at Lake Forest, California.