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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

ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON PROPOSED 2023 PREFERRED SYSTEM PLAN AND TRANSMISSION PLANNING PROCESS PORTFOLIOS

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ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON PROPOSED 2023 PREFERRED SYSTEM PLAN AND TRANSMISSION PLANNING PROCESS PORTFOLIOS

Summary

This ruling seeks input from parties on a package of materials proposed to be part of the 2023 Preferred System Plan (PSP) and portfolio to be sent to the California Independent System Operator (CAISO) for analysis in its 2024-2025 Transmission Planning Process (TPP) and to give direction to load serving entities (LSEs) regarding their procurement activities and for their next round of individual integrated resource plans (IRPs).

The ruling first presents the results of the aggregation of the individual IRPs filed by each LSE on or around November 1, 2022. The resulting electricity resource portfolio was then analyzed using both capacity expansion modeling and production cost modeling to construct additional scenarios to be considered as candidates for a PSP portfolio, and better characterize the reliability and emissions performance of the scenarios. This ruling and the associated materials posted on the Commission's web site summarize the analysis.[1]

Ultimately, this ruling recommends that the Commission adopt the aggregated portfolio that is based on planning to a greenhouse gas (GHG) target for the electricity sector of 25 million metric tons (MMT) by 2035, which is the lower of the two targets the LSEs were directed to plan for in Decision (D.) 22-02-004. The ruling also suggests basing the portfolio on the aggregation of

[1] The detailed analysis leading to the recommendation in this ruling, as well as other supporting materials, are posted on the 2022-2023 IRP Cycle Events and Materials page at the following link on the Commission's web site: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials

the LSE plans, augmented with additional resources, where necessary, to meet reliability and/or GHG emissions targets.

In addition to analyzing the recommended PSP portfolio as the 2024-2025 TPP base case, the ruling also recommends that the CAISO analyze a high gas retirement sensitivity, which represents retirement of over 15 gigawatts (GW) of existing natural gas generation.

This ruling also presents analysis related to the consideration of two petitions for modification (PFMs) of the mid-term reliability (MTR) decisions (D.21-06-035 and D.23-02-040). One PFM seeks an extension to the requirements in D.21-06-035 for the category of resources designed to partially offset the loss of the Diablo Canyon Power Plant with procurement that was required by 2024 and 2025. The other PFM seeks to extend the deadline of 2028 for long lead-time (LLT) resources set in D.23-02-040, which was already an extension to the 2026 deadline originally set in D.21-06-035. The ruling further proposes that if the LLT resource extension is granted, that LSEs be required to procure 2,000 megawatts (MW) of replacement clean energy capacity in 2028.

The ruling also includes a description of a proposal to install and count as incremental long-duration energy storage at some natural gas facilities to augment system capacity during period of stressed grid conditions and extreme weather events.

Also included in this ruling is a proposed set of reliability standards to be used by the Commission in the IRP context, as distinct from the resource adequacy context. Finally, the ruling proposes to continue funding for consulting support to Commission staff as part of the IRP process.

A workshop to explain the analysis and recommendations included in this ruling and the associated materials, and to answer questions, will be held in

October 2023. The workshop details will be shared with the service list of this proceeding and posted on the Commission's Daily Calendar.

Comments are invited to be filed and served by interested parties by no later than November 13, 2023. Parties are requested to organize their comments in the order in which topics appear in this ruling, with any additional topics added at the end. Parties who have conducted their own modeling analyses to support their comments may also present their modeling results in the November 13, 2023 comments. Reply comments are due no later than December 1, 2023.

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

One of the most important purposes of the Commission's IRP process is to take the individual IRPs, aggregate them, and evaluate the aggregated portfolio against the overall electric system needs of California, and particularly the CAISO system. The aggregated portfolio is compared against reliability and GHG constraints, while seeking to meet any residual resource need for those constraints at the lowest reasonable cost to ratepayers. The aggregation of the individual LSE portfolios also serves to determine if there are gaps in the collective portfolio that will require action by the Commission, including potential procurement orders, to address. LSE IRP filings are also the vehicle by which the Commission and stakeholders gain insight into individual LSE plans for meeting state goals.

This section describes the general process Commission staff used to aggregate the portfolios of the individual LSEs filed on or around November 1, 2022. More detail is included in the "2022 LSE Plan Aggregation Steps" slide deck posted on the Commission's web site under "Preferred System Plan and Portfolios for 2024-2025 Transmission Planning Process."[2]

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 approached 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 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

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

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.

This ruling also requests that LSEs who have not already done so make a formal filing in the docket of this proceeding with the final version of their RDT and/or CSP calculator, by no later than October 16, 2023, to ensure that the record reflects their correct information. For updated filings requesting confidentiality, if the LSE already filed a Motion to File Under Seal with its original submission, an additional motion with the corrected/updated filing is not required.

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 and 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 or deliverable to the CAISO. Those RDTs do not contain planned resources to meet reliability and GHG targets, and so 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, 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 created 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.[3] Since the planning horizon is now out to at least 2035, this ruling now refers to these extended targets by their 2035 target GHG emissions levels, namely: 30 MMT by 2035 and 25 MMT by 2035.[4]

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[3] Because only a portion of the state's retail providers of electricity are within the Commission's IRP purview, the actual emissions targets of the Commission's LSEs were 24.7 MMT and 18.6 MMT by 2030.

[4] The 2035 emissions targets of the Commission's LSEs for the two cases translate to 18.8 MMT or 15.0 MMT.

The aggregated portfolios meeting both the 30 MMT GHG target and the 25 MMT GHG target were studied in SERVM to determine their reliability and GHG emissions (discussed below in Section 2.3) 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 throughout the remainder of this ruling, and are discussed in more detail in Section 2.

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.

Figures 1 and 2 below show the new resource buildout associated with both the 30 MMT and 25 MMT LSE aggregated plans. LSEs included a diverse set of resources including offshore wind (OSW), out-of-state wind, geothermal, and long-duration storage, as well as a great deal of solar and battery storage. All of these resources are incremental to the updated baseline.

Figure 1. Planned Resource Additions (MW), Aggregated 30 MMT LSE Plans

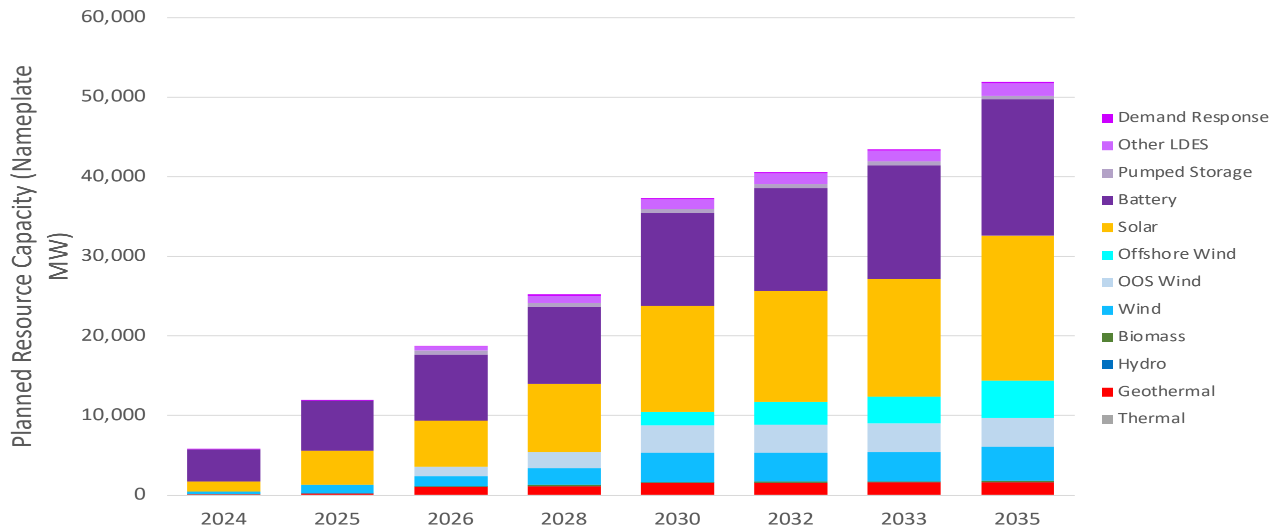
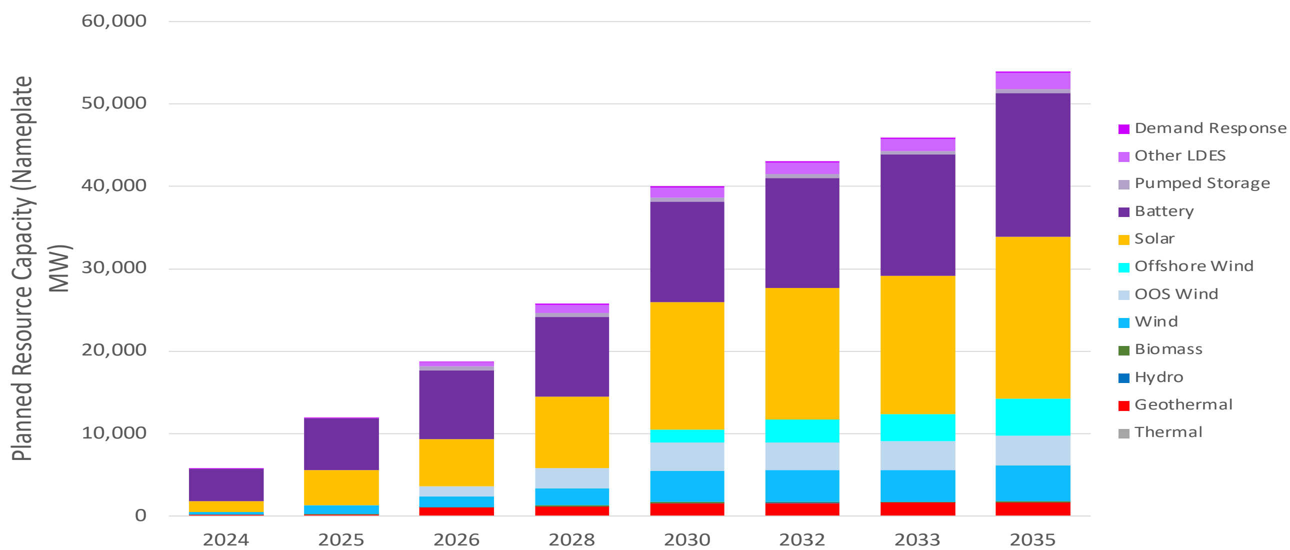


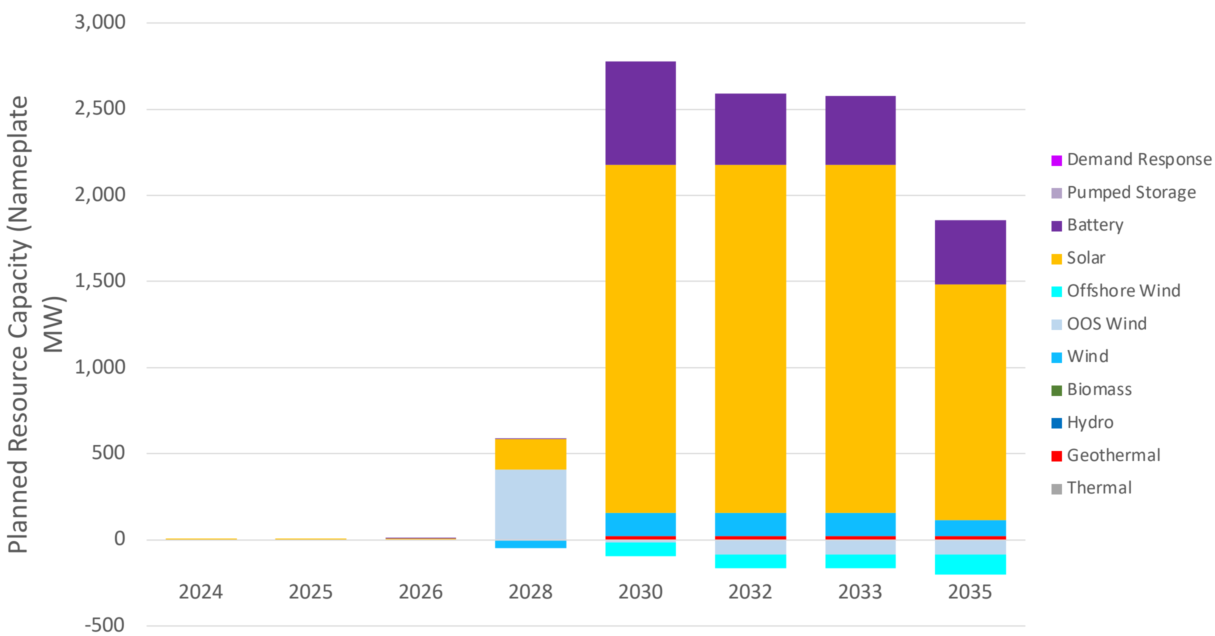
Figure 2. Planned Resource Additions (MW), Aggregated 25 MMT LSE Plans



Parties will likely quickly note that the buildout associated with the 30 MMT and 25 MMT aggregated LSE plans are very similar. In the case of the 30 MMT LSE plans, the actual LSE emissions aggregated from the individual CSP calculators were 18.3 MMT by 2030 and 14.1 MMT by 2035, over 5 MMT below the emissions targets. In the 25 MMT LSE plans, the aggregated emissions were projected at 15.1 MMT by 2030 and 12.2 MMT by 2035, or roughly 3 MMT below the targets. All LSEs met their assigned GHG benchmarks in both portfolios submitted, with some achieving emissions well below their assigned benchmarks.

LSEs relied largely on solar and storage resources to close the emissions gap between their 30 and 25 MMT plans. Some LSEs planned to contract with existing GHG-free resources, which are counted in the baseline and not included in the recommended PSP portfolio. Figure 3 below shows the planned resource additions by resource type.

Figure 3. New Resource Additions, Growth from 30 MMT to 25 MMT Aggregated LSE Plans



Relative to the 2021 38 MMT by 2030 PSP Portfolio and 30 MMT by 2030 PSP Sensitivity adopted in D.22-02-004, the current aggregated LSE plans are slightly smaller overall in terms of resource buildout, with some differences with respect to resource composition. The smaller size of the portfolios is likely due to several factors.

First, some early year resources in the 2021 PSP portfolios have now become part of the baseline due to LSE contracting activities, and thus do not show up in the resource buildout charts. Figures 1, 2, and 3 show only resources incremental to the baseline and thus, the comparison of the size of the portfolio is relative to the above-baseline planned resources and not the total installed capacity.

Second, LSE plans cover only the Commission-jurisdictional portion of the CAISO load (roughly 86 percent), while the PSP portfolios cover the full CAISO load. And finally, LSEs demonstrated a slight preference for higher capacity-factor and longer-duration resources than in previously-adopted portfolios.

In comments in response to this ruling, parties are invited to comment on the aggregation analysis described above and present any alternatives or improvements recommended.

2. Proposed Preferred System Plan Portfolio

To conclude the evaluation of the most recent LSE IRP filings from November 2022 and give direction for the LSEs' next biannual IRP filings, this ruling considers a proposed PSP and 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[5] was used as the basis for developing the LSE filing requirements for their 2022 individual IRP filings. The PSP recommended in this ruling

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

will likely 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 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 build.

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 reliably at the lowest reasonable cost and with the lowest GHG emissions possible, resulting in reduced reliance on fossil fuels and the cleanest potential portfolio.

To begin 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,[6] Western Electricity Coordinating Council (WECC),[7] 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 Diablo Canyon Power Plant (Diablo Canyon) was assumed to retire in 2024/2025, as previously planned and approved. Operational constraints for cogeneration, geothermal, and biomass resources were revised using data from the CAISO bidding database and the CAISO Masterfile. 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

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

[7] The WECC 2032 Anchor Data Set.

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 18-22) 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 minus existing transmission contracts. Load and resource balances for regions external to California 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 to meet peak demand conditions, possibility 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, transportation electrification, time-of-use rates, and behind-the-meter (BTM) storage were drawn directly from the 2022 IEPR. The BTM photovoltaic hourly profiles, on the other hand, were developed from 1998-2020 solar radiation data to model variability across many years. The median 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.

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. Transmission import hurdle rates were escalated from 2018 dollars to 2022 dollars.

Resource cost data was 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 assumptions document is available at the following link under "IRP Inputs and Assumptions:" https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials

In general, the costs of many renewable resources have been somewhat reduced from assumptions used in previous IRP cycles, with the notable exception of the estimates for the costs of offshore wind (OSW), which increased in the latest iteration of the I&A, where the OSW costs are based on the most recent 2023 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB). The OSW cost assumptions are a significant driver of modeling results, but Commission staff recognize that the assumptions are as-yet untested with actual procurement processes in California, so reality could vary significantly from the assumptions. Battery storage costs also saw an increase 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, including incorporating the CEC's new land-use screens for renewable energy. One key change that resulted from this process is an increase in resource potential available for selection for several renewable and storage resources. Of particular significance is the fact that more land-based in-state and out-of-state wind is 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 meets 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 throughout this ruling as the "Core" cases. These Core cases use the resources contained in the LSE 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.

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

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 current analysis, the two additional scenarios are called the 25 MMT and 30 MMT "Least Cost" scenarios, since 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 1 below.

Table 1. 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 full detailed results of the RESOLVE analysis of the above scenarios are available at the following link under "Preferred System Plan and Portfolios for 2024-2025 Transmission Planning Process" in the "2023 Proposed PSP and 2024-2025 TPP RESOLVE Analysis" slide deck: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials

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 currently available include sensitivities analyzing natural gas retirements, costs, and reduced resource availability.

In general, the Least-Cost cases show a visibly lower-cost portfolio than the Core cases, estimated at roughly $1.5 billion annually over the planning period, or approximately 2 percent of the NPV of the total CAISO revenue requirement.

The Least-Cost portfolios also have a more diverse composition than the Core portfolios, including more additions of pumped hydroelectric storage, in-state wind, and shed demand response. Notably, no offshore wind is selected in the Least-Cost portfolios during the entire planning horizon, due to the higher OSW costs and the reduced costs (and increased potential) of resource alternatives.

2.1. Recommended PSP Portfolio

This ruling recommends the 25 MMT Core portfolio as the PSP. There are several reasons for this recommendation. Related to the choice of GHG target, the resource buildouts in the 25 MMT and 30 MMT Core scenarios are very similar until at least 2030. Second, it appears that 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. The 25 MMT target is at the low (most aggressive) end of the target range for the electricity sector set by the California Air Resources Board in its most recent Scoping Plan update.[8]

[8] *See* more details on the Scoping Plan available at the following link: https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan

Figure 4 and Table 2 below show the planned and expected capacity for the 25 MMT Core case. Parties will note that solar and overall capacity grow steadily over the time period, and long-duration storage, particularly 8-hour batteries, are added for LSEs' compliance with D.21-06-035 and D.23-02-040 requirements. All three categories of wind (in-state, out-of-state, and offshore) also show steady growth in the 25 MMT Core case, but RESOLVE does not select additional OSW beyond the levels included in the LSE plans.

Figure 4. Planned and Selected Resource Capacity (MW) for 25 MMT Core Case

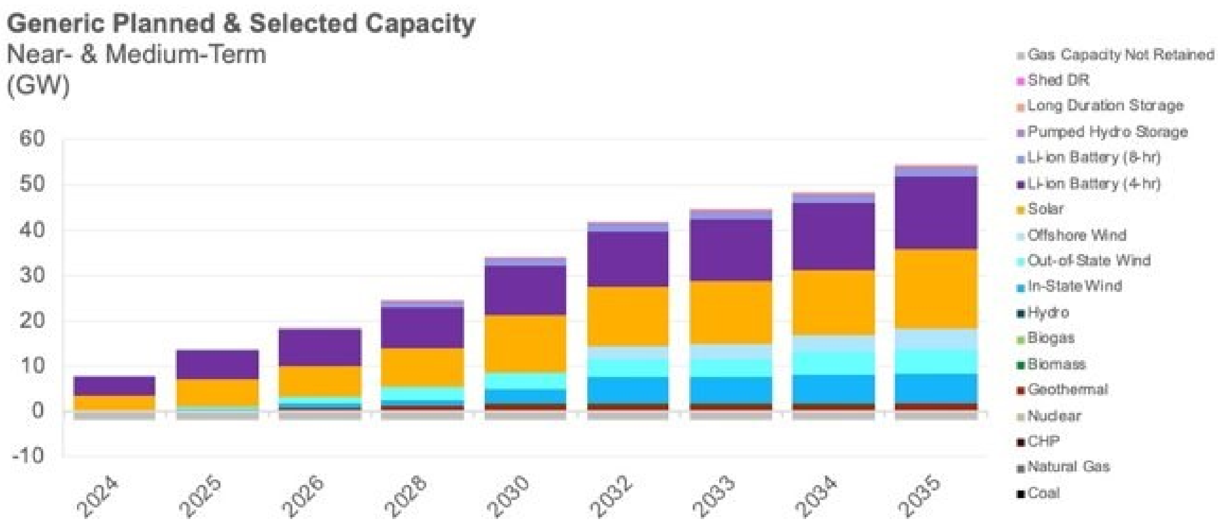


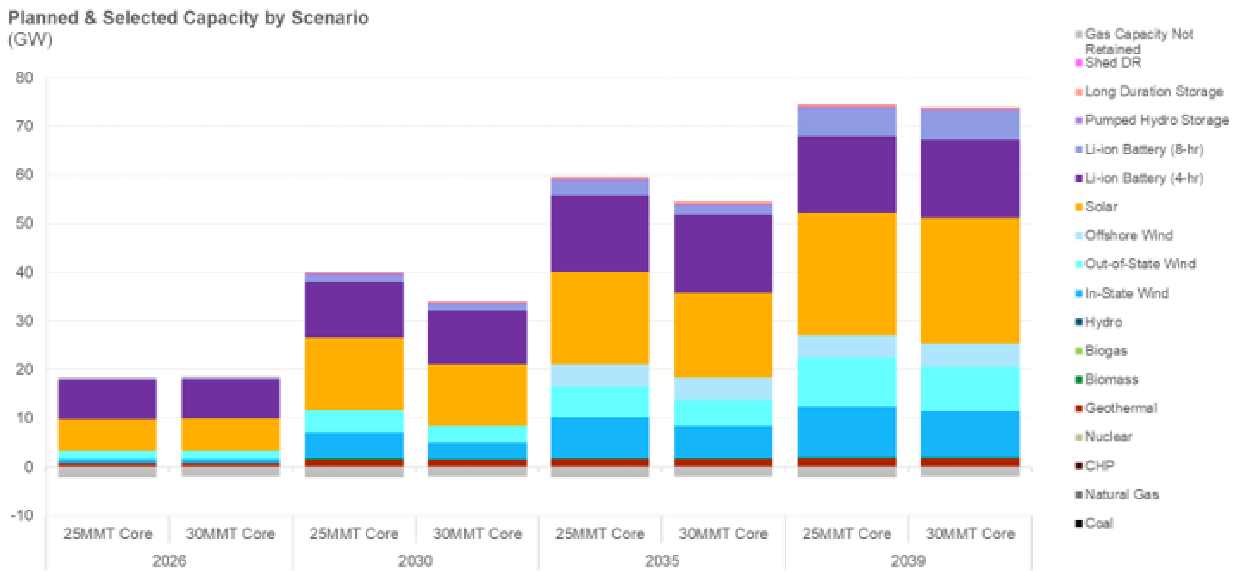
Table 2. Planned and Selected Capacity (GW) for 25 MMT Core Case

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	1.6	1.6	1.6	1.6	1.7	1.7	1.7
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	5.4	7.4	8.1	8.1	8.5	10.4	10.4	12.7

Resource Category	2024	2025	2026	2028	2030	2032	2033	2034	2035	2039	2040	2045
Out-of-State Wind	0.0	0.6	1.7	3.4	4.6	4.6	4.6	5.3	6.3	10.2	10.2	11.6
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	6.5	8.5	14.8	15.3	16.1	16.4	19.0	25.2	29.1	50.6
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	0.00	0.4	1.0	1.2	1.4	1.4	1.7	2.8	5.7	7.3	16.1
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 DR	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	-2.1	-2.1	-2.1	-2.1	-2.1	-2.1	-2.1	-2.1	-2.1	-2.1	-2.1	-4.0
Total	**5.5**	**11.2**	**16.2**	**23.0**	**37.9**	**44.5**	**48.1**	**50.9**	**57.5**	**72.4**	**78.0**	**110.1**

Since there is always some uncertainty about reaching the actual emissions reduction targets in reality, even after planning for them, this ruling suggests that planning for the most aggressive, but still realistic, emissions reductions is the most prudent at this stage. Since the impacts of climate change appear to be accelerating, our efforts in the electric sector should continue to be aggressive. Finally, the modeled cost differential between the 25 MMT and 30 MMT Core cases amounts to a total of approximately $125 million annually over the planning period, which is considerably less than past analyses have projected.

Figure 5. Comparison of Selected Resource Capacity (MW) in 25 MMT and 30 MMT Core Cases



$49,492	-$5M	$51,986	-$56M	$56,317	-$168M	$59,128	-$125M

Annual Costs ($MM/yr)

With respect to the question of whether to base the PSP portfolio on the Core cases or the Least-Cost RESOLVE-modeled scenarios, this ruling recommends using the Core case as the basis chiefly because this best represents the preferences of the LSEs actually conducting the procurement. The Core cases include more OSW, as well as more higher-capacity-factor resources.

Although the RESOLVE Least-Cost algorithm is based on the best-available cost information about specific resources, there is significant uncertainty about the actual costs of several resources that the state expects to rely on in the long term, including OSW, out-of-state wind and other renewables, and emerging long-duration energy storage (LDES) technologies. Thus, this ruling suggests that the LSEs continue pursuing all types of projects in their resource solicitations. Similar to the experience with other clean energy technologies such as solar and batteries, cost reductions with economies of scale beyond those already projected may also be possible with some of the newer resource options. In addition, there is inherent value in resource diversity, as the Commission has noted on numerous occasions.

Selecting 25 MMT as the GHG target in 2035 will also require LSEs to procure significantly higher levels of renewable energy than currently required by the renewables portfolio standard program (equivalent to approximately 90 percent renewables by 2030).

In response to this ruling, parties are invited to comment on the recommendation for the 25 MMT Core portfolio as the PSP portfolio, and recommend any alternatives, along with their rationale.

2.2. Sensitivity Cases

In addition to the four scenarios analyzed for potential selection as the PSP portfolio, Commission staff also analyzed a number of sensitivity cases to test changes to the results when using alternative assumptions for some key variables.

Some of the sensitivities were chosen because of significant uncertainty with respect to costs or availability of certain key resources. The sensitivities explore the impact on results from changing key assumptions around costs and availability of OSW, out-of-state wind, land-based wind, solar photovoltaics, battery storage, geothermal, and natural gas facilities.

The natural gas sensitivity cases, in particular, are designed to explore the impacts of LSE individual IRP decisions not to contract with existing natural gas facilities. Although the natural gas plants were not included in LSE plans, this does not necessarily guarantee that the facilities will retire, because the Commission or the CAISO may need to take action to keep them online for system or local reliability purposes, if the LSE plans alone do not ensure reliability. The natural gas sensitivities are also important to help in planning for transmission solutions to assist with reliability, as discussed further in Section 3.2 below.

Following is a list of the sensitivity cases that are contained within the "2023 Proposed PSP and 2024-2025 TPP RESOLVE Analysis" slide deck posted at the following link: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials

- A 25 MMT Least-Cost sensitivity with low OSW costs (basing the OSW wind costs on the previous NREL study from 2020, with California-specific costs);
- A 25 MMT Least-Cost sensitivity with moderate natural gas retirements based on the LSE plans (whereby natural gas plants without LSE planned contracts were assumed to retire);
- A 25 MMT Least-Cost sensitivity with high natural gas retirements based on a combination of assumed retirements where no LSEs had planned contracts and an age-based assumption of 35 years for thermal plant retirement;
- A 25 MMT Least-Cost sensitivity with high solar photovoltaic and battery costs;
- A 25 MMT Least-Cost sensitivity with high land-based wind costs;
- A 25 MMT Least-Cost sensitivity with high geothermal and biomass costs;
- A 25 MMT Least-Cost sensitivity with reduced land-based clean resource availability (significant reductions to in-state

wind, out-of-state wind, geothermal, and pumped hydro storage potential);

- A 25 MMT Least-Cost sensitivity with significantly reduced land-based clean resource availability (further reductions to in-state wind, out-of-state wind, geothermal, and pumped hydro storage potential);
- A 25 MMT Least-Cost sensitivity combining the low OSW wind costs and reduced land-based clean resource availability;
- A 25 MMT Least-Cost sensitivity combining the low OSW costs and significantly reduced land-based clean resource availability; and
- A 25 MMT Least-Cost sensitivity with low BTM photovoltaic growth.

Commission staff are continuing to analyze several additional sensitivities even after the publication of this ruling. Any additional sensitivities providing useful information will be posted to the following link by no later than October 20, 2023: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials

Sensitivities were performed on the Least-Cost scenario since that provides the greatest freedom for RESOLVE's optimization algorithm to find the least-cost solution in each sensitivity, providing the most insight into that sensitivity driver (compared to the Core cases, whereby LSE planned resources are forced into the portfolio, giving RESOLVE fewer degrees of freedom).

Based on the current set of sensitivities, some key insights emerge.

Sensitivities involving different assumptions regarding OSW costs and the availability of other competing resources, including land-based wind, geothermal, and pumped hydro storage, are included. In these sensitivities, particularly when lower OSW cost assumptions are combined with decreased availability of other resources, some OSW resources are selected by the model, which shows the model's dependence on these key assumptions.

The thermal power plant retirement scenarios are also of particular interest. Table 3 below shows the retirement assumptions layered into the two thermal retirement sensitivities.

Table 3. Cumulative Gas Retirement Assumptions (MW)

Type of Retirement	**2024**	**2025**	**2030**	**2035**	**2039**
Once Through Cooling (OTC)	3,700	-	-	-	-
Combined Heat and Power (CHP) Phaseout	-	-	-	953	1,731
LSE Contract Expirations	-	2,592	4,115	4,496	4,496
Age-Based Retirement (35 years)	-	409	767	871	9,623
Moderate Gas Retirement Sensitivity (includes OTC, CHP, and LSE contract amounts)	3,700	6,292	7,796	9,149	9,927
High Gas Retirement Sensitivity (includes OTC, CHP, and a combination of the LSE contract expirations and age-based retirement)	3,700	3,700	6,815	9,330	15,944

As the table above shows, basing assumptions on LSE contract expirations accelerates retirements in the near-term but then retirements remain relatively constant beyond 2030. The age-based retirement assumptions result in fewer retirements in the near-term but significantly more by 2039.

The Moderate Gas Retirement sensitivity combines the MW amounts from the remaining OTC gas plant retirements, as phaseout of combined heat and power (CHP) gas plants beginning in 2031, and the retirements based on LSEs' lack of planned contracts. The Moderate Gas Retirement sensitivity thus follows the same trend as the contract expirations assumptions with accelerated retirements in the near-term and then fewer additional retirements after 2035.

The High Gas Retirement sensitivity includes the OTC retirements and CHP phaseout with a combination of the LSEs' lack of planned contracting, delayed by five years, and the 35-year age-based retirement assumption. In this sensitivity the highest retirement amount between the lack of planned contracting retirements and the age-based assumptions was included in the total retirement amount. This High Gas Retirement sensitivity reduces retirements in the near term, aligns retirement with LSE planned contract expirations in the 2030s, and increases retirements in line with the age-based assumption by 2039.

In the two gas retirement sensitivities, only the net capacity amounts of retirements are modeled in RESOLVE on a system level, so the locations of the retirements and local reliability impacts are not captured or analyzed. The individual locations of the gas retirements will be identified as part of the Commission staff's busbar mapping process and local reliability impacts of these portfolios will be subject to further validation in CAISO local capacity technical studies.

Comparing the thermal retirement sensitivity cases with the 25 MMT Least-Cost reveals that the retirement sensitivities result in the thermal capacity being replaced with higher capacity-factor renewables such as geothermal, and about twice as much LDES, including 8-hour batteries. By 2039, a significant amount of additional solar capacity is also built to support charging the additional LDES added. The thermal retirement scenarios also have higher costs, with NPV values of between approximately $4 billion (for the Moderate Gas Retirements sensitivity) and $13 billion (for the High Gas Retirements sensitivity.

A high proportion of these costs comes later in the planning horizon (2035 and beyond) as the ability of renewable energy and storage to provide reliable capacity becomes saturated and firm capacity resources become increasingly valuable to the system. RESOLVE found that the gas retirement scenarios show a small reduction in in-state gas plant capacity factors (small because they are already approximately 5 percent by 2035). However, there was not found to be any significant emissions reduction associated with gas plant retirements, since the in-state generation at retired facilities was replaced by additional generation at remaining facilities and by additional unspecified imports (*i.e.*, RESOLVE modeled the in-state gas generation being replaced by out-of-state gas generation at the unspecified import emissions rate that is similar to a natural gas combined cycle power plant).

As long-time parties to the IRP process will recognize, the issue of how to plan for retention or retirement of fossil-fueled facilities is extremely important to the IRP planning outcomes and quite complex. The natural gas fleet is currently still needed for overall system reliability, as well as local reliability in certain load pockets, but it is also responsible for the majority of the remaining GHG and local criteria pollutant emissions from the in-state electricity sector (imported power makes up the rest of the emissions from the sector).

The majority of the large non-CHP natural gas units in the state have been built since the year 2000, and thus they are not generally considered to be of retirement age, while a large number of the CHP units (but not all) are considerably older. There have also been significant thermal plant retirements, including but not limited to the OTC units, in the past two decades.

The IRP process also has resulted in the procurement and planned procurement of approximately 18 GW of new clean resources, which is facilitating the reduced reliance on natural gas power plants. In order to further reduce reliance on natural gas plants, the planning process needs to ensure replacement of the reliability attributes of the natural gas facilities.

Since the beginning of the IRP process, this Commission, along with the CAISO and CEC, have been discussing the need to plan for orderly retirement of fossil-fueled generation in order to meet California's climate goals. In California, unlike in many other Western states, most natural gas facilities are independently owned, not owned by regulated utilities. Permitting is split between local agencies and the CEC, depending on the type and size of facility, with the CEC handling permitting for thermal plants over 50 MW.

The CAISO also has the authority, through its Capacity Procurement Mechanism and Reliability Must-Run tariffs approved by the Federal Energy Regulatory Commission, to require the retention of certain facilities, if necessary for reliability purposes.

The Commission also has clear procurement authority with respect to the resources contracted for by the utility LSEs, and can set criteria for the counting of other resources by all LSEs towards their procurement requirements in the IRP process. The Commission annually generates portfolios of resources to assist the CAISO in transmission planning. The Commission also already collects information from a variety of sources for the IRP planning process in general.

The IRPs of the LSEs subject to the Commission's IRP purview already plan for approximately 90 percent of the load on the CAISO system and about 75 percent of statewide electric load. In the IRP process, the Commission also considers a wide range of supply and demand resources and their contributions to state goals. Thus, it is clear that the Commission has a significant interest in these issues within the context of IRP and more globally, but there may be more effective ways of approaching the planning for the thermal fleet.

In comments in response to this ruling, parties are invited to comment on the sensitivity analyses presented and provide feedback and recommendations. Parties are also invited to comment on the insights provided by the natural gas sensitivities to assist in planning for further retirement of natural gas generation.

2.3. Production Cost Modeling

In order to test the viability of the PSP portfolio for reliability and GHG emissions impacts, Commission staff also conducted Production Cost Modeling (PCM) in the SERVM model, as in past IRP cycles. Conducting PCM with the current portfolios required several updates and steps, most of which were also described above related to RESOLVE updates.

To prepare for SERVM modeling, Commission staff updated the list of baseline resources, added the requirements of the existing Commission procurement orders, layered in LSE planned new procurement beyond the existing Commission requirements,[9] included resources selected by RESOLVE beyond the LSE plans (if necessary for reliability and/or GHG needs), and also considered planned and potential retirements of existing fossil-fueled generation resources.

Staff also spent considerable effort iterating to align the RESOLVE and SERVM models to ensure comparable results. In particular, the RESOLVE reliability need and resource counting metrics, in terms of effective load carrying capability (ELCC), were derived directly from the SERVM model. In addition, initial RESOLVE runs were used to develop further calibration factors to align

[9] The LSE planned resources used were “PlannedNew” and “Review” resources from the November 2022 IRP filings.

the models based on LOLE results from SERVM modeling of the initial RESOLVE portfolios.

Section 1 above describes how LSE plans were aggregated into portfolios as the starting point for modeling to develop and recommend the PSP portfolio. Commission staff's SERVM study results are shown in Tables 4 and 5 below. Table 4 includes results using both the 2021 IEPR forecast, which is what LSEs had available when creating their plans, and the updated 2022 IEPR forecast. These tables also include additional thermal retirements where individual thermal units were removed from the model if they were not specifically quantified as contracted or planned for in LSE plans. Implied California emissions equals CAISO emissions divided by 0.81, which equates to the CAISO footprint share of the total state energy demand.

Table 4. Reliability and Emissions Results: 25 MMT by 2035 LSE Plans with Additional Gas Retirements for Units not Specifically Contracted or Planned for

Year	**2026**		**2030**		**2035**	
IEPR Forecast Vintage	2021	2022	2021	2022	2021	2022
LOLE Capacity (days/year)	0.051	0.061	0.009	0.036	0.061	0.338
CAISO Emissions (MMT)	38.9	39.1	27.0	30.2	26.5	34.1
Implied CA Emissions (MMT)	48.4	48.2	33.3	37.2	32.7	42.1

Table 5. Reliability and Emissions Results: 30 MMT by 2035 LSE Plans with Additional Gas Retirements for Units not Specifically Contracted or Planned for*

Year	2026	2030	2035
LOLE Capacity (days/year)	0.059	0.063	0.396
CAISO Emissions (MMT)	39.1	31.6	35.2
Implied CA Emissions (MMT)	48.2	39	43.4

** All runs use 2022 IEPR assumptions.*

When baseline gas capacity is retired in line with the amounts that LSEs did not collectively plan for, the system is reliable through 2030, but not in 2035, when using updated 2022 IEPR forecast assumptions. When using the 2021 IEPR forecast, which is what LSEs planned for with information available at the time, the results show that meeting the reliability filing requirements translated well to LOLE results. However, since the forecast has changed, the collective plans meet reliability standards through 2030, but not by 2035.

When it comes to emissions, the SERVM results show that the aggregated LSE plan portfolios do not achieve the CAISO emissions target in 2030 or 2035. This may be partly due to the lack of visibility to POU planned resources, as well as the fact that the 2022 IEPR load forecast is significantly higher than the 2021 IEPR forecast being used during the planning.

Given these results, it was necessary for Commission staff to use the RESOLVE model to augment the aggregated portfolios to the extent that more resources were needed to reduce emissions and/or maintain reliability, including through 2045, which was beyond the timeline for the LSE plans.

These RESOLVE Core and Least-Cost portfolios were then translated into SERVM inputs and simulated in SERVM for the years 2026, 2030, and 2035 to determine reliability metrics and GHG emissions results. Once the models were calibrated, Commission staff analyzed the 25 MMT Core and Least-Cost cases in SERVM for their reliability and GHG emissions results.

Tables 6 and 7 below present the results for the 25 MMT Core and 25 MMT Least-Cost portfolios, respectively.

Table 6. Reliability and Emissions Results, 25 MMT Core Portfolio

Results Category	Units	2026		2030		2035	
		RESOLVE	SERVM	RESOLVE	SERVM	RESOLVE	SERVM
LOLE	Days/ year		0.009		0.002		0.053
CAISO emitting generation	GWh	59,691	73,118	33,506	45,946	16,773	39,674
CAISO generator emissions	MMT CO2e	23.4	30.1	13.2	19.5	6.6	16.2
Unspecified imports	GWh	16,130	9,347	15,085	12,089	21,641	9,810
Unspecified imports emissions	MMT CO2e	6.9	4.0	6.5	5.2	9.3	4.2
CAISO BTM CHP emissions	MMT CO2e	4.8	4.8	4.7	4.7	4.4	4.4
Total CAISO emissions	MMT CO2e	35.1	38.9	24.3	29.4	20.3	24.8
Emissions difference	MMT CO2e		3.8		5.1		4.5

Table 7. Reliability and Emissions Results – 25 MMT Least Cost Scenario

Results Category	Units	2026		2030		2035	
		RESOLVE	SERVM	RESOLVE	SERVM	RESOLVE	SERVM
LOLE	Days/year		0.014		0.005		0.078
CAISO emitting generation	GWh	63,683	77,851	39,240	49,875	20,470	45,224
CAISO generator emissions	MMT CO2e	25.0	31.8	15.4	21.0	8.1	18.3

Results Category	Units	2026		2030		2035	
		RESOLVE	SERVM	RESOLVE	SERVM	RESOLVE	SERVM
Unspecified imports	GWh	15,185	7,436	9,835	10,822	18,220	9,083
Unspecified imports emissions	MMT CO2e	6.5	3.2	4.2	4.6	7.8	3.9
CAISO BTM CHP emissions	MMT CO2e	4.8	4.8	4.7	4.7	4.4	4.4
Total CAISO emissions	MMT CO2e	36.4	39.8	24.3	30.3	20.3	26.6
Emissions difference	MMT CO2e		3.4		6.0		6.3

The 25 MMT Core portfolio is extremely reliable in 2026, 2030, and 2035, with LOLE results well below the 0.1 standard. The 25 MMT Least-Cost portfolio is also very reliable in 2026 and 2030. The 25 MMT Least-Cost portfolio is just below the 0.1 LOLE target in 2035, consistent with the planning reserve margin (PRM) constraint binding in this year in the RESOLVE analysis, which indicates that RESOLVE and SERVM calibration led to RESOLVE building a 2035 portfolio hitting very close to a 0.1 LOLE.

In general, the reliability of the 25 MMT Core portfolio is consistent with the over-compliance with reliability targets and overbuilding of new resources beyond the MTR requirements found in the LSE plans. It is also due to RESOLVE's selection of additional GHG-free resources and retention of more natural gas plants than the LSE plans included.

RESOLVE chose to build clean resources earlier, largely due to the economics associated with the PTC and ITC associated with the federal IRA., as well as the high near-term natural gas prices assumed in the CEC's natural gas price forecast (which were $6.35 per million British Thermal Unit (BTU) in 2025).

As observed in prior IRP cycles and as continues to be a pattern in these modeling results, the RESOLVE model prefers to use unspecified imports over in-state gas, while SERVM tends to do the opposite. However, the total of in-state gas and unspecified imports in SERVM exceeds the amount in RESOLVE, resulting in SERVM showing a higher GHG emissions result, ranging from 3-6 MMT, depending on portfolio and year.

The major drivers of this difference appear to be higher renewable curtailment in SERVM, higher BTM photovoltaic generation in RESOLVE, lower biomass generation in SERVM, and higher annual energy demand being met in SERVM, leading to the need for additional generation. Other less significant drivers include dispatch modeling differences, including the dispatched mix of different types of in-state natural gas an unspecified imports, as well as how well storage is utilized.

This ruling suggests that the GHG results difference is reasonable and acceptable for a modeled result, given that no two models can be expected to produce identical results.

In response to this ruling, parties are invited to comment on the production cost modeling, as well as the reliability and GHG emissions results, along with any recommendations they wish to make.

3. Proposed Portfolios for CAISO TPP

As parties are aware, the CAISO TPP requires that the Commission recommend for analysis a base case portfolio for reliability purposes and/or policy-driven purposes, and the process also allows for sensitivity cases to be transmitted. In general, the base case portfolio analysis conducted during the CAISO TPP results in specific transmission upgrade recommendations that can be taken directly to the CAISO Board 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 do not usually result in direct recommendations for investment in particular transmission projects.

3.1. Reliability and Policy-Driven Base Case

This ruling recommends that if the 25 MMT Core portfolio is adopted by the Commission as the PSP portfolio, then it would be transmitted to the CAISO as both the reliability and policy-driven base case scenario to be analyzed by the CAISO in the 2024-2025 TPP. This portfolio is very similar to the base case portfolio being analyzed in the current TPP.

This portfolio also complies with the requirements of SB 887 (Stats. 2022, Ch. 358), which, among other things, requires the Commission to provide:

- Projected resource portfolios and electricity demand for at least 15 years into the future;
- A resource portfolio that substantially reduces, no later than 2035, the need to rely on "non-preferred resources in local capacity areas;"
- Projected offshore wind generation to allow the CAISO to identify and approve transmission facilities sufficient to make OSW deliverable to load centers.

The proposed PSP portfolio includes resources out to 2039. In addition, OSW is represented in the 25 MMT Core portfolio and has also been analyzed extensively in sensitivity analyses during the past two TPP cycles.

The portfolio also includes significant reductions (of approximately 70 percent) in natural gas plant utilization within the CAISO area by 2035 and further reduction (of approximately 90 percent) over the full 15-year planning horizon.

In response to this ruling, parties are invited to comment on the proposed base case and recommend any alternatives, along with their rationale.

3.2. Sensitivity Case

Consistent with the above discussion of thermal power plant retirement scenarios, this ruling proposes to transmit one sensitivity portfolio to be analyzed by the CAISO for transmission needs in the future. The purpose of the sensitivity is to identify the transmission resources and costs necessary to plan for potential future retirement of fossil-fueled resources as their economics decline. The sensitivity case is based upon the sensitivity cases described in Section 2.2 above, where Commission staff looked at various assumptions that would result in greater decrease in natural gas generation capacity. This sensitivity is also inspired by the SB 887 requirements, as well as SB 1158 (Stats. 2022, Ch. 357) and SB 1020 (Stats. 2022, Ch. 361).[10]

It should be noted that the Commission requested in January 2023 and D.23-02-040 that the CAISO identify the highest-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 which reduce local capacity requirements from natural gas generation. Several of the upgrades also

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[10] 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.

align with the upgrades identified in the Aliso Canyon sensitivity study that was conducted as part of the CAISO's 2022-2023 TPP cycle.

In addition, it is important to note that natural gas resources can provide both energy and capacity to the electric grid. As more and more renewable resources deliver energy to the grid, thermal resources are increasingly depended on for their reliable capacity value at times where the grid is stressed, while their capacity factors will continue to decrease over time as zero marginal cost renewable energy generation offsets them in the CAISO's merit order dispatch stack. This means that there are fewer emissions, both GHG and local pollutants, since the generation is running significantly less. These trends result in gas generation on the margin being more costly per-MWh than many of the renewable resources, because the fixed costs of the natural gas plants are being spread over a smaller production base, which in turn makes their competitiveness decline. This type of trend is a necessary precursor to retirement of thermal generation, as their economics decline. In addition, while the Commission is continuing to study scenarios for retirement of thermal plants, the Commission does not actually have the authority to order natural gas retirements.

Finally, it should be noted that removing individual plants from the grid will result in increased production at the remaining similar plants, if there are no other resources added that provide additional energy to the grid. Through the busbar mapping process, Commission staff seek to map renewable and storage resources to locations that are identified as aligned with the busbar mapping criteria, where the resources could provide reliability and energy output that could displace the nearby output of gas power points, including those in disadvantaged communities.

The particular sensitivity case this ruling recommends be transmitted to the CAISO is the High Gas Retirement sensitivity, which includes the largest amount of natural gas plant retirements by 2039. First, it includes the 3.7 GW of OTC plants retiring and an assumed phase-out of 1.7 GW of CHP between 2031 and 2039. Then, it also retires the capacity amount representing the plants with which LSEs have not indicated plans to contract in their IRPs. Finally, it includes an age-based retirement assumption of 35 years, instead of the usual 40-year assumption that has been used in the past. Taken together, these assumptions result in a total of 9.3 GW of retirements by 2035 and 15.9 GW by 2039. The latter amount includes almost half of the existing natural gas fleet currently in operation.

Thus, it is a stress case that, among the RESOLVE sensitivity cases, will provide the most information about what transmission investment would be needed in order to make it possible to facilitate such a large number of thermal plant retirements. The information generated by a TPP sensitivity analysis, in tandem with other information, could then be used to assess how transmission solutions compare to new clean capacity solutions, in terms of cost, and how they solve for system and local reliability needs associated with the attributes of retired thermal plants. Information generated by this TPP sensitivity analysis can then be used to inform future planning and procurement efforts, consistent with SB 887 requirements.

Commission staff and consultants working on the IRP process have also been developing new local area modeling capabilities to better analyze these dynamics. Commission staff anticipate conducting a workshop or webinar on this topic later in the Fall of 2023.

Successfully modeling the generation and transmission system is an iterative process and this sensitivity portfolio being recommended to the CAISO for study in the 2024-2025 TPP will help better inform decision making for the appropriate base case in the following TPP cycle.

Parties are invited to comment on the proposed sensitivity case and recommend any alternatives, along with their rationale.

3.3. Busbar Mapping

As in past IRP cycles, Commission staff has updated the methodology for mapping individual generation and storage resources to busbars on the grid. This process translates geographically-coarse portfolios to plausible network locations for additional TPP modeling by applying specific rules and criteria. This process is a necessary precursor for the CAISO to conduct its assessments to identify necessary transmission upgrades. The updated methodology document is posted at the following link: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/assumptions-for-the-2024-2025-tpp

The current version of the methodology improves upon the previous version released with the 2023-2024 TPP portfolios (on January 13, 2023) by including 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.

Busbar mapping of the recommended base case portfolio is currently underway and Commission staff will post the results to the following link and alert the service list for this proceeding when the results are ready, no later than November 1, 2023: 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

If the ultimate PSP adopted by the Commission differs significantly from the portfolio recommended in this ruling, revised mapping may become available only during the pendency of a proposed decision before the Commission to adopt the PSP and parties may have limited time to comment beyond the opportunity afforded by this ruling.

4. Analysis Related to MTR Procurement Sufficiency and Petitions for Modification of D.21-06-035 and D.23-02-040

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

On August 9, 2023, Southern California Edison Company (SCE) and Pacific Gas and Electric Company (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 Diablo Canyon.

As part of studying reliability as part of the 2023 PSP development and to assist in consideration of the two PFMs of the MTR decisions, Commission staff conducted additional PCM to evaluate the sufficiency of the MTR procurement already ordered. This PCM consisted of the following types of studies:

1) Baseline-only studies; and
2) Baseline + ordered-procurement studies.

The baseline-only studies aim to determine the current reliability situation, by including planned retirements and existing resources, plus those in development and coming online between 2024 and 2028. These studies exclude "PlannedNew" or "Review" resources included in LSEs' November 2022 IRP filings, because such resources are not certain enough to be included in the baseline. Baseline-only resources include a portion of procurement ordered in D.21-06-035 and D.23-02-040 that is online or under development, totaling approximately 5,000 MW by 2026. All analysis assumes that Diablo Canyon is retired in 2024/2025 as previously planned.

In these studies, Commission staff quantified the amount of perfect capacity (PCAP), the equivalent to ELCC MW, required to be added to the baseline to achieve an LOLE of less than 0.1 in each year from 2024 through 2028. The results from the baseline-only studies may be informative to the ongoing reporting related to SB 846 (Stats. 2022, Ch. 846) concerning the possible continued reliance on Diablo Canyon for up to five additional years.

Next, Commission staff analyzed the sufficiency of the MTR procurement decision by taking the following analytical steps:

- Calculate the cumulative required MTR NQC amounts (these are the amounts required in D.21-06-035 and D.23-02-040);

- Subtract the MTR incremental procurement in the 2023 PSP baseline to calculate the "remaining MTR procurement;"
- Compare the remaining MTR procurement to the calculated PCAP shortfall from the baseline-only studies, to calculate any potential MTR "gap."

This analysis was conducted using the PSP baseline thermal power plant retention assumptions, meaning that no natural gas plants were assumed to retire beyond the OTC plants scheduled to retire at the end of 2023. Additional gas retirements are a key risk, along with import availability, climate change impacts, and project development delays. These risks were analyzed separately, to get a sense of their relative magnitude.

The gas retirement risk was assessed based on an assumption that gas plants would retire after reaching a 40-year age. Project development risk was assessed with two scenarios, one assuming that 20 percent of required procurement is delayed by one year, and another assuming that 40 percent of ordered procurement is delayed by one year. Climate risk was analyzed by re-weighting the 23 weather years in SERVM to assume that the extreme August heat wave in 2020 occurs every five years instead of every 23 years, while also considering a sensitivity based on the ability of the strategic reserve capacity procured to date to offset the risk of climate extremes. Import risk was assessed by modeling imports as only providing 4 GW during all hours, instead of the current base IRP assumption that imports -- subject to external zone resource availability – provide 4 GW during Hours Ending 18-22 in June through September, but 11 GW during all other hours of the year.[11]

[11] SERVM modeling performed during this PSP analysis process indicates that the base import assumption may lead to over 6,000 MW of reliability value from imports as early as 2026, as battery storage additions flatten the net peak and shift the risk periods back to hours prior to Hour Ending 18.

Table 8 below presents the results of the basic analysis, with Table 9 showing the layering on of the risks described above.

Table 8. MTR Sufficiency Analysis Results

	(Units = Perfect capacity MW)	2023	2024	2025	2026	2027	2028
A	MTR Ordered Procurement (annual)	2,000	6,000	1,500	2,000	2,000	2,000
B	MTR Ordered Procurement (cumulative)	2,000	8,000	9,500	11,500	13,500	15,500
C	MTR Incremental Procurement (in PSP Baseline)	2,896	4,219	4,578	4,700	4,719	4,750
D	Remaining MTR Procurement (above PSP Baseline)	(896)	3,781	4,922	6,800	8,781	10,750
E	SERVM PCAP Shortfall (using PSP Baseline)	n/a	2,200	6,000	5,800	8,000	8,000
F	MTR Gap: MTR ordered relative to SERVM shortfall	n/a	(1,581)	**1,078**	(1,000)	(780)	(2,750)

Table 9. MTR Procurement Sufficiency Analysis with Risks

	(Units = Perfect capacity MW)	2023	2024	2025	2026	2027	2028
G	Reliability Need Impact of 40-year age-based retirement assumption for thermal		89	419	545	1,018	1,438
H	MTR Gap including Risk		(1,492)	1,497	(455)	237	(1,312)
I	One-year delay to 20% of ordered procurement		1,200	300	400	400	400
J	MTR Gap including Risk		(381)	1,378	(600)	(381)	(2,350)

	(Units = Perfect capacity MW)	2023	2024	2025	2026	2027	2028
K	One-year delay to 40% of ordered procurement		2,400	600	800	800	800
L	MTR Gap including Risk		819	1,678	(200)	19	(1,950)
M	Weather year re-weighting		1,500	1,500	1,500	1,500	1,500
N	MTR Gap including Risk		(81)	2,578	500	719	(1,250)
O	Strategic Reserve procurement		(2,430)	(2,430)	(2,430)	0	0
P	MTR Gap including Risk and Mitigation		(2,511)	148	(1,930)	719	(1,250)
Q	Flat 4 GW Imports, PSP baseline				400		
R	MTR Gap including Risk				(600)		
S	Flat 4 GW Imports, LSE Plans				2,100		
T	MTR Gap including Risk				1,100		

In summary, the MTR procurement already ordered addresses the shortfall between the 0.1 LOLE reliability standard and the baseline except for the year 2025. The 2025 risk to reliability is too soon to be addressed by any further procurement action by the Commission this year. However, it should be mitigated by the Strategic Reliability Reserve of approximately 2,430 MW of PCAP contribution. Also, under consideration separately in Rulemaking (R.) 23-01-007, is the extension of Diablo Canyon, which could have bearing on the potential reliability capacity shortfall in 2025. Meanwhile, the various risks quantified may or may not actually come to pass, or they may occur in conjunction with one another or with other risks not analyzed here.

Finally, Commission staff looked at the impact of granting the two PFMs of the MTR decisions, with a delay in the procurement of the Diablo Canyon replacement energy by two years and the LLT resources by up to three years. Table 10 shows those results and the impact on the MTR procurement gap.

Table 10. Potential Impact on MTR Procurement Sufficiency if PFMs are Granted

	(Units = Perfect capacity MW)	2023	2024	2025	2026	2027	2028
F	MTR Gap: MTR ordered relative to SERVM shortfall	n/a	(1,581)	1,078	(1,000)	(781)	(2,750)
	If 2-year extension for Diablo Canyon replacement is granted		-	125	-	(125)	-
	MTR Gap Impact		(1,581)	1,203	(1,000)	(906)	(2,750)
	If extension is granted for LLT resources		-	-	-	-	2,000
	MTR Gap Impact		(1,581)	1,078	(1,000)	(781)	(750)

This analysis suggests that the granting of the SCE/PG&E PFM related to Diablo Canyon replacement energy could have a small negative impact, in a year that already has a predicted PCAP shortfall result of 1,078 MW to achieve a 0.1 LOLE. That is, the estimated 1,078 MW PCAP shortfall in 2025 compared to the 0.1 LOLE reliability standard would grow to 1,203 MW PCAP.

Granting of the CESA/WPTF PFM related to LLT resources, however, would still leave the system within the 0.1 LOLE reliability standard for the year 2028, albeit with a much smaller margin for error. That is, the 2,750 MW PCAP surplus would be reduced to 750 MW PCAP. In addition, since that estimate is further into the future, there is inherently more uncertainty associated with it.

750 MW is also a small margin of one or two medium or large power plants in a large electricity system on hot summer days, which will be increasing by 2028.

Parties are invited to comment generally on the MTR sufficiency analysis presented in this section, and the resulting recommendations related to the MTR PFMs pending in this proceeding. If parties have suggestions for mitigating the capacity shortfall risk for 2025, those are specifically invited.

5. Procurement-Related Recommendations

This section addresses potential procurement-related actions the Commission could take in its consideration of the adoption of the upcoming PSP.

5.1. Potential Additional Procurement to Allow Extension for LLT Resources

The analysis summarized in Section 4 of this ruling shows that if the CESA/WPTF PFM on LLT resources is granted and LSEs have an additional three years (until 2031, instead of 2028) to procure LLT resources, there will still be a capacity surplus of approximately 750 MW PCAP in 2028. The 2028 planning year is still five years from today, and is a product of certain assumptions, some of which may be optimistic, and/or not fully account for the other risks associated with procurement, including project delays, accelerating incidences and impacts of extreme weather, derating of thermal plants as a result of weather, localized forced outages, or other factors. In addition, the current market for capacity is already very tight, and it is likely not prudent to plan for exactly a 0.1 LOLE.

Because of these factors, this ruling further proposes that, if the CESA/WPTF PFM on LLT resources is granted, the Commission should order additional procurement of 2,000 MW of NQC of renewable or zero-emissions resources otherwise meeting the criteria in D.21-06-035 by 2028. This would allow for an extension of the LLT procurement requirements of up to three years, by no later than 2031, without any potential reliability impact in 2028.

Further procurement of clean resources (apart from the LLT resources already ordered in D.21-06-035 and D.23-02-040) beyond 2028 would be expected to be procured under the new Reliable and Clean Power Procurement Program (RCPPP) expected to be considered in 2024, to address procurement in a programmatic fashion.

Parties are invited to comment on the MTR sufficiency analysis, its relationship to the two PFMs, and the proposal for 2,000 MW of additional MTR clean capacity procurement in 2028 in their responses to this ruling.

5.2. Proposal on Long-Duration Energy Storage at Existing Natural Gas Generation Sites

Commission staff have discussed a proposal from at least one operator of natural gas generation to deploy LDES at existing points of interconnection on the transmission system being utilized by the natural gas generation, to provide near-term reliability benefits under the most stressed system conditions. The goal would be to build new LDES at existing gas sites that could qualify as incremental procurement in the context of the MTR decisions (D.21-06-035 and D.23-02-040). The further goal would be to provide incremental reliability during the tightest system conditions as soon as summer 2025, with the potential long-term opportunity to completely transition from the natural gas generation to LDES.

The proposal would be for minimum-8-hour LDES to charge from the grid and then supplement a gas turbine during reliability events when the gas turbines experience derating due to high ambient temperatures. The addition of

LDES could also reduce the GHG emissions from the natural gas facilities by creating the ability for the LDES to be dispatched in lieu of using gas generation.

In the long term, this could also allow gas plant operators to completely retire their natural gas turbines when no longer needed for reliability and transfer the facility deliverability to the LDES, transitioning to a carbon-free, dispatchable resource on the grid.

New storage built at existing sites would already be eligible to qualify for procurement required under D.21-06-035 and D.23-02-040 if it resulted in new NQC. However, under the current resource counting paradigm, the types of projects covered under this proposal would use existing interconnections and not result in new NQC. Since the proposed projects would be operating under the most stressed grid conditions, when natural gas plants may be seriously derated due to extreme heat, there is potentially a real reliability benefit to the addition of such LDES projects. However, it is unclear how the reliability benefit should be counted, both for IRP procurement purposes, as well as resource adequacy benefit.

Commission staff have so far considered two possibilities for resource counting, as follows:

1) The eligible "incremental" capacity of the LDES could be counted as the difference between the maximum interconnection value and the average capacity that the natural gas turbines have actually provided during historic reliability events.
2) A reliability study could be conducted to understand the incremental reliability value of adding LDES to existing natural gas generation facilities. The study would be similar to how ELCCs are developed for other resources.

Both of these proposals have pros and cons. The first option has the advantage of being relatively simple, assuming the owners of the natural gas generators are willing and able to provide the data needed for specific projects. The disadvantage of the first option is that it would require separate reliability valuations for each project. In addition, looking only at historical reliability events would result in the highest possible incremental NQC for each project. Finally, this is not a standard method for determining reliability value.

The second option would be fair and accurate, but it would likely require significant time and expense for staff and/or consultant work to undertake the study. It may also be the case that a separate study is required for each project.

It is also not clear why, if new LDES projects are allowed to count toward MTR procurement requirements and get built, they would not or should not be dispatched first, ahead of the natural gas facilities, when the grid is not in stress situations, since they are using the existing interconnection facilities of the natural gas.

In response to this ruling, parties are invited to comment on the above proposal, the resource counting options identified, and the potential impact on the existing natural gas facility dispatch. Parties may also to suggest alternatives. Parties should also note that the issue of value to the resource adequacy program would most likely need to be addressed separately outside of this proceeding, unless a process could be adopted to address both IRP and resource adequacy value together.

6. Proposed Reliability Framework for IRP

This section puts forward a set of recommendations the Commission could use to formalize a reliability framework in IRP that has been used by staff to set

LSE plan reliability filing requirements and to conduct modeling in this cycle of IRP. This framework is distinct from the methods used in the past, as well as from the resource adequacy framework, which is more near-term focused.

6.1. Background and Definitions

A reliability framework is comprised of the actual reliability standard adopted by policymakers (typically a probabilistic reliability metric, such as 0.1 days per year LOLE, that can be translated into a reliability need, most likely expressed in MW of capacity or a percentage margin over the forecasted load), coupled with the resource counting conventions used to determine whether the reliability standard is met.

Originally, for IRP planning and procurement purposes, the Commission used a PRM of a minimum of 15 percent of installed capacity (ICAP) over the median IEPR managed peak load forecast. This was originally derived from the PRM historically used for resource adequacy purposes. As parties are aware, the resource adequacy program has now begun to utilize a different, slice-of-day framework.

In addition, in the IRP context, the Commission has also used the standard of 0.1 days per year LOLE, commonly referred to as a 1-day-in-10-years standard, meaning the expectation of one loss of load day in a ten-year period.

In modeling analyses in past IRP cycles, Commission staff have estimated the required amount of additional NQC MW to achieve this 0.1 days per year LOLE level of reliability, and the Commission has based procurement requirements on that analysis. For example, the analysis that led to the procurement requirement of 11,500 MW of NQC in D.21-06-035 resulted in an effective ICAP PRM of approximately 22.5 percent, in order to achieve the 0.1 LOLE reliability standard.

This approach also relies on estimating and periodically updating the ELCC of individual resource types that contribute to the required NQC. In D.22-02-004, the decision that adopted the 2021 PSP, the Commission stated, "this does not constitute a formal update of the PRM. The appropriate PRM to use for IRP, which may or may not be the same as used in resource adequacy, will be evaluated and discussed further with stakeholders in the upcoming IRP cycle."[12]

SERVM modeling used to develop the 2022 LSE plan filing requirements confirmed that the historical ICAP PRM of 15 percent above the IEPR managed peak is no longer sufficient for the CAISO system to reach the 0.1 days/year LOLE standard.[13]

Conceptually, the collective procurement of all LSEs should add up to the reliability need of the system, including a margin that accounts for a variety of uncertainties, most notably the risk of years with extreme weather events driving very high loads. Most, but not all, utilities and regional transmission organizations (RTOs) in the country have adopted a physical probabilistic reliability planning standard designed to minimize the risk of rotating outages. As already stated, historically, the IRP process has planned to, and based procurement orders on, the 1-day-in-10 probabilistic reliability standard, which is consistent with standard industry practice and the current reliability standard used in all of the United States RTO or ISO resource adequacy programs.

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[12] D.22-02-004 at 84.

[13] This analysis 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/2022-irp-cycle-events-and-materials/20220729-updated-fr-and-reliability-mag-slides.pdf

Loss of load probability (LOLP) modeling is the process used by all other ISO/RTOs to set the reliability procurement need consistent with this reliability standard. LOLP modeling considers the performance of all resources during all hours of all simulated years, including interactive effects among different resources. Thus, LOLP modeling and resulting metrics (including ELCC), address both the energy and capacity aspects of reliability.

Using this probabilistic reliability standard, a LOLP model can be used to determine the total effective capacity (in ELCC MW) needed to achieve the standard across a broad range – typically multiple decades -- of potential weather, load, and renewable energy conditions. Effective capacity, PCAP, and ELCC are all commonly used as synonyms to clarify that the MW of capacity being referenced are measured relative to the equivalent reliability contributions of a "perfect capacity" resource. This conceptual resource is fully dispatchable and has no uncertainty associated with its availability and input fuel. An LOLP-based method for determining reliability need can express the need in terms of effective capacity, which is useful for a capacity-based approach to planning and procurement. Expressing reliability need in terms of effective capacity creates a level playing field among all generators by accounting for any operational limitations in their ability to reduce loss of load risk. This approach is therefore both fair and economically efficient.

Resource counting rules for generators should take into account any and all operational limitations, including renewable energy variability, duration and use limitations, seasonal temperature de-rates, forced outages, etc. Aligning resource counting methods with the method used to set the total reliability need would provide efficient procurement incentives and is necessary to ensure an adequate system is procured. For instance, if LOLP modeling is used based on a target reliability standard to establish reliability need, then LOLP modeling using that same model and same reliability standard should be used to credit resources toward compliance. As has been done in California for many years now, LOLP modeling can be used to estimate the ELCC of each resource type.

ELCC is a metric for the expected contribution to reliability that the resource type will make over a given period of time. Commission staff expects that an annual ELCC is appropriate for planning in the medium-to-long-term, whereas the resource adequacy program uses a monthly view because it is focused on short-term reliability and transacting capacity between generators and LSEs, and among LSEs, in the operational (month-ahead) timeframe.

Marginal ELCCs credit resources based on their marginal contributions to reliability after accounting for all of the other resources within the portfolio. They also inherently capture saturation effects that cause declining reliability values within a resource type. For these reasons, they have been used in the renewable portfolio standard least-cost best-fit methodologies and in IRP procurement orders to value incremental resource additions to the current CAISO portfolio. Marginal ELCCs can also be used for existing resources to represent their marginal value to reliability should they consider exiting the market. Other ISO/RTO programs – including the New York and Midwest ISOs – are currently exploring moving to a marginal reliability planning framework.

Commission staff have proposed switching to a PRM for IRP that is based on perfect capacity (PCAP) over the gross peak load forecast, instead of ICAP over the managed peak load forecast. A PCAP-based approach means removing from the PRM an allowance for forced outages of firm resources, and accrediting all resource types at their respective ELCC (*i.e.*, their PCAP equivalent), based on simulations that consider their risk of outages, resource availability, and interaction with load and other resource types. These ideas were presented in Modeling Advisory Group (MAG) webinars in April and July of 2022.[14]

For the current PSP modeling, RESOLVE used a PCAP PRM over gross peak and counted all resource types at their ELCC value. LSE IRPs used a marginal reliability planning framework where all resources were counted at their marginal ELCC and the PCAP PRM over gross peak was translated into a "marginal reliability need" defined during the "net peak" hours where loss-of-load risk now exists.

6.2. Proposal

This ruling includes that the IRP reliability framework be comprised of: 1) a probabilistic reliability standard that can be translated into a reliability resource need and 2) resource counting rules with which to quantify the extent to which the need is expected to be met or exceeded. The framework is intended to be implemented differently depending on the particular use case in the IRP process:

- Capacity expansion modeling to examine portfolios of existing and new resources necessary to meet the IRP process objectives;
- LOLP modeling, to set the reliability inputs needed for capacity expansion modeling, as well as to iterate with capacity expansion modeling to confirm that a future portfolio will be reliable;
- Planning and procurement by LSEs, based on the reliability need found in IRP modeling, as well as to iteratively inform future modeling inputs (such as the future CAISO resource portfolio). Reliability procurement requirements carry compliance and enforcement consequences, whereas

[14] Materials can be found under the headings "Webinar 1" and "Webinar 2" 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

planning is generally informational, with exceptions, including where it interacts with the CAISO TPP.

The main difference between how the reliability framework is adapted for the system modeling use cases as distinct from the LSE-based uses cases is that system modeling aims to optimize across all LSEs with control over all of the resource decisions within the system, whereas the LSE use cases must use and produce information specific to each LSE that allows the LSE to make decisions about its own portfolio either in the absence of (or using an uncertain forecast of) perfect information about the resource decisions of other LSEs in the system. Thus, reliability information provided to LSEs within IRP reflects the retail market reality of the state and the bilateral nature of reliability planning and procurement within California.

The reliability framework will also interact with the RCPPP once designed and adopted, and this ruling does not seek to limit the potential design options for RCPPP in any way. In addition, the resource adequacy program has its own reliability framework, which shares some common features with IRP, but also has some differences associated with its shorter-term focus. This ruling's proposals do not intend to suggest modifications to the resource adequacy program framework.

The approach is to use consistent methodologies and inputs across all use cases, where possible. This ruling proposes that the steps to implement the reliability framework in IRP would be:

- Make any necessary updates to the probabilistic reliability modeling dataset;
- Confirm the probabilistic reliability standard;

- Calculate total system need via a PCAP-based total reliability need (TRN), then translate into a PCAP PRM above median gross peak;
- Calculate ELCCs through static values, curves, and/or surfaces for use in long-term planning in capacity expansion modeling;
- Using the latest system forecast of the CAISO resource portfolio, calculate marginal reliability need (MRN) relative to the TRN and marginal ELCCs for all resource types for use in LSE-level planning (this forecast can also be used in other Commission proceedings for consistency);
- Using the CEC's new multi-year LSE-specific managed peak share forecast, base LSE-specific need on the LSE's share of CAISO system load during the current and future loss-of-load risk periods (the same periods that align with the system MRN and the marginal ELCC resource contributions.

In comments in response to this ruling, parties are asked to include recommendations on the above proposed framework, the methodology to implement it, or their own recommended framework and methodology, as well as the process to prepare inputs.

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

To bring the IRP process to this point, Commission staff have benefitted from support from technical consultants to conduct modeling and assist with other planning tasks. Funding for this purpose was originally authorized in D.18-02-018 for a total of six years. Meeting the state's future GHG reduction goals while maintaining reliability and minimizing impacts on ratepayers will require ongoing maintenance and refinement of the analytical framework and tools that are being used for the IRP process.

The California Legislature's Annual Budget Act gives the Commission certain specific and limited ongoing reimbursable expenditure authority. Prior to exercising this authority, the Commission must issue a decision that identifies the contracting activities to be undertaken by the Commission, and the costs subject to reimbursement by utility companies.[15] This ruling proposes that the funding that has been in effect since 2018 be continued at the same level for an additional six years.

Beginning with the 2025-26 fiscal year, this ruling proposes authorizing expenditures of up to, but no more than, $3 million annually for up to six years, for a total budget not to exceed $18 million. The maximum nominal value of a contract would not exceed $18 million. The funds could be carried forward and expended in a subsequent year. If not spent within six years, the funds would be available in subsequent years, but still would not exceed the maximum total.

As this funding is currently handled, the Commission's Executive Director would approve the expenditures and seek reimbursement from PG&E, SCE, and SDG&E. Reimbursement would be sought from these three IOUs on a proportional basis in relationship to their annual retail sales reported in their current IRP, pending approval by the Commission. PG&E, SCE, and SDG&E would use their existing IRP Costs Memorandum Account (IRPCMA). These costs would be recorded when paid, for later recovery via distribution rates.

Similar to actions we have taken in the past,[16] we would propose to excuse other IOUs from these funding requirements, because their load is much smaller.

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[15] *See* Budget Act of 2010, Stats. 2010, Ch. 712, Item 8660-001-0462(6).

[16] *See*, for example, D.06-10-050 at 54.

Parties are invited to comment on this proposal and suggest any modifications they recommend.

IT IS RULED that:

1. Any load-serving entity (LSE) that filed an individual integrated resource plan on or around November 1, 2022 and where corrections to the Narrative Template, Resource Data Template or Clean System Power Calculator were requested informally by Commission staff, shall file its corrected materials formally in this proceeding by no later than October 16, 2023. If an LSE requests to file the corrected materials under seal and has already filed a motion to file under seal for its original submission, a new motion to file under seal is not required. LSEs shall file the materials using the confidential filing method.
2. Interested parties wishing to comment on any or all aspects of the proposals in this ruling shall file and serve comments by no later than November 13, 2023. Parties shall address the topics in this ruling in the order in which they are presented herein, with any additional topics added at the end. Parties who have conducted their own modeling analysis may file information and results of that analysis by the same November 13, 2023 deadline as part of their comments on this ruling.
3. Interested parties may file and serve reply comments by no later than December 1, 2023.

Dated October 5, 2023, at San Francisco, California.

JULIE A FITCH

Julie A. Fitch
Administrative Law Judge