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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

ADMINISTRATIVE LAW JUDGE'S RULING ON ENERGY DIVISION'S LOSS OF LOAD EXPECTATION STUDY

On July 19, 2024, Energy Division issued its Resource Adequacy Loss of Load Expectation (LOLE) Study to the service list in this proceeding. Attached to this ruling as Appendix A is Energy Division's Resource Adequacy LOLE Study.

IT IS RULED that Energy Division's Resource Adequacy Loss of Load Expectation Study is attached to this ruling as Appendix A.

Dated July22, 2024, at San Francisco, California.

/s/ DEBBIE CHIVE
Debbie Chiv
Administrative Law Judge

APPENDIX A

(2026 LOLE Report Study)

Loss of Load Expectation Study for 2026

Including Slice of Day Tool Analysis

Recommendation for Slice of Day Planning Reserve Margin

July 19, 2024
Prepared for CPUC Rulemaking (R.) 23-10-011

California Public
Utilities Commission

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List of Acronyms

AAEE – Additional Achievable Energy Efficiency	LSE – Load Serving Entity
AAFS – Additional Achievable Fuel Substitution	MW – Megawatt
BAA – Balancing Authority Area	NQC – Net Qualifying Capacity
BTM PV – Behind the Meter Photovoltaic	PCAP – Perfect Capacity
CAISO – California ISO	PRM – Planning Reserve Margin
CEC – California Energy Commission	PU Code – Public Utilities Code
ELCC – Effective Load Carrying Capability	RA – Resource Adequacy
EUE – Expected Unserved Energy	SERVM – Strategic Energy Risk Valuation Model
IEPR – Integrated Energy Policy Report	SOD – Slice of Day
IRP – Integrated Resource Planning	TAC – Transmission Access Control
LOLE – Loss of Load Expectation	UCAP – Unforced Capacity
LOLH – Loss of Load Hours	WECC – Western Electric Coordinating Council

Executive Summary

The purpose of this Loss of Load Expectation (LOLE) study is to test CAISO system reliability using the latest input datasets and inform Resource Adequacy (RA) requirements for 2026. This is a key policy issue under consideration in the California Public Utility Commission's (CPUC's) Resource Adequacy proceeding, Rulemaking (R.) 23-10-011. In addition to testing the sufficiency of resources needed for reliability, the LOLE study both establishes a planning reserve margin and supports the translation of resource needs in the 24-hour Slice of Day (SOD) Resource Adequacy Framework (SOD Framework).

In March 2024, as part of the RA proceeding, R.23-10-011, Energy Resource Modeling staff in Energy Division (Staff), in collaboration with CPUC consultants, performed multiple updates to the inputs and assumptions used for modeling efforts in both the Integrated Resource Planning (IRP) and RA proceedings. These updates are documented in the Inputs and Assumptions document published on March 15th, 2024.[1] This 2026 RA LOLE study is the first use of these updated modeling datasets. The model input datasets will be posted to a new link that will be added to the 2024-2026 IRP Cycle Events and Materials webpage.[2]

Staff modeled the existing fleet of resources and calibrated the LOLE level resulting from the model using an evening hours CAISO simultaneous import constraint as the tuning variable instead of retiring thermal generation. Since the existing and planned additions to the fleet already achieved better than target LOLE during the study period, no Perfect Capacity additions were needed to achieve an acceptable target LOLE.

In contrast with previous years, staff performed analysis centered around the California Energy Commission's (CEC's) Integrated Energy Policy Report (IEPR) California Energy Demand Forecast managed peak instead of consumption peak.[3] After extensive analysis staff determined that the 2023 IEPR CAISO coincident managed peak forecast appeared more consistent with historical trends than the consumption forecast. The 2023 IEPR, more so than previous years, reflects a large gap between the CAISO coincident consumption and managed peaks largely driven by different hourly profiles of consumption demand resulting from the differing demand models used for the LOLE study and the IEPR. By tuning the median managed peak in the LOLE model to match the IEPR managed peak, staff confirmed that the model met the target reliability level of 1 day in 10 years (0.1 LOLE) using the updated Baseline set of resources and evening peak hours CAISO simultaneous imports constrained to 2,500 MW rather than the prior assumption of 4,000 MW.

Staff propose the CPUC adopt an RA obligation for LSEs that requires an 18.5% Planning Reserve Margin (PRM) on top of the 2023 IEPR CAISO coincident managed peak demand forecast for all 12 months.

1 https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M527/K361/527361341.PDF

2 https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2024-26-irp-cycle-events-and-materials

3 Described in more detail later in this report, consumption demand represents counterfactual electricity demand absent projected load modifying effects from behind-the-meter solar PV and storage, energy efficiency, fuel substitution, and electric vehicle charging. Managed demand represents net electricity demand inclusive of these load modifying effects.

While the SOD PRM results suggest a higher PRM need for February, Staff believes that an 18.5% is still appropriate at this time. The results of this study show that with the baseline including existing resources and expected resource additions based on LSE contracting and development milestones, RA obligations can be met while allowing for some uncertainty or delay in resource development. Specifically, a 1,500 MW surplus/cushion is implied by the decrease to the evening CAISO simultaneous import constraint from 4,000 MW to 2,500 MW in tuning the study to achieve a 0.1 LOLE target. Staff implemented the resource portfolio from this study in the SOD PRM tool and calculated the required PRM in all 12 months of the year and performed stress tests on the varying levels of PRM needed to meet target reliability level.

As part of this study, staff analyzed the Path 26 transmission constraint to better understand the impact of this constraint on reliability, LOLE, and cost in CAISO. The analysis indicates congestion on Path 26 may occur at times when the CAISO simultaneous import constraint was also binding or decreasing. Since staff tuned to the target reliability level using reductions to the import constraint as the capacity lever, staff tested the sensitivity of Path 26 congestion to the import constraint. Staff conclude that Path 26 binds only when coincident with a binding CAISO simultaneous import constraint. When CAISO's simultaneous imports are constrained, SCE leans on PGE to alleviate any shortage by relying on North to South flows over Path 26. Therefore, Path 26 is critical for CAISO reliability mostly in times of broader regional resource constraints.

Introduction and Results Summary

In June 2022, in Decision (D.) 22-06-050, the Commission adopted a minimum 17% PRM for the RA program year 2024 for the existing RA monthly program (also referred to as the current RA construct). In the June 2022 decision, the Commission allowed for a potential revision in June 2023 depending on a review of the Energy Division's updated LOLE modeling. As directed, Staff submitted a refreshed RA LOLE study was submitted into the RA proceeding in January 2023 and that second study was considered by the Commission in June 2023, in D.23-06-029. The Commission chose to retain the 17% PRM in D.23-06-029, as initially adopted in the D.22-06-050, stating "[g]iven the realities of available RA supply and persistent delays in development projects, it is prudent to retain the status quo 17% PRM for the 2024 and 2025 years. Increasing the PRM without greater certainty about installed RA resources for 2024 and 2025 is not appropriate at this time."

The CPUC's 17% PRM for setting RA obligations was adopted based on the current RA construct, with variable resources counted at their ELCC and PRM calculated relative to a Managed Peak Demand forecast. In D.22-06-050, and reiterated in D.23-04-010, the Commission decided that a single PRM will apply to all hours of the year for initial implementation of the SOD Framework. The Commission further noted that it may consider whether multiple PRMs for various months or times of year are appropriate for the SOD Framework in a future phase of the RA proceeding.

With a decision to move forward with a 17% PRM for the current RA construct and also decisions to implement a test year in 2024 for the RA SOD Framework, the CPUC directed staff to establish a PRM for the SOD Framework. In April 2023 in D.23-04-010, the Commission authorized the Energy Division to integrate the PRM calibration tools as proposed by the Natural Resources Defense Council (NRDC) and Southern California Edison (SCE) to translate the results of the LOLE study to the 24-hour SOD Framework. Staff translated the results of this LOLE study to a single PRM that represents the necessary capacity to maintain a LOLE result within established metrics (0.1 LOLE). Staff presented these results to stakeholders in Fall 2023.

To translate the results of the 2024 RA LOLE study to a SOD PRM, Staff utilized the methodology adopted in D.23-04-010. This methodology included using the current SOD counting rules for resources and the 2021 IEPR worst day load forecast (both reflect September values). The results of this translation resulted in a recommended 15.43% SOD PRM reflecting an annual LOLE study and the SOD PRM in September, the peak month. This PRM value of 15.43% is currently in use for the 2024 SOD RA Framework test year.

In Track 1 of the current RA proceeding, Staff put forward two options to translate the adopted 17% PRM to a SOD PRM for use in the 2025 RA compliance year. These options included using the 15.43% PRM (provided by the calibration tool) or use of the 17% PRM (which would provide a more comparable level of reliability to the existing 17% PRM level). In addition to putting forward a proposal to translate the 17 % PRM to a SOD PRM for use in the 2025 compliance year, Staff also put forward its plans to conduct a new 2026 RA LOLE in Track 2 of the proceeding for use in informing the 2026 RA program obligation PRM for the SOD Framework. Staff also detailed its plans to perform several stress tests on the 2026 LOLE study results to ensure monthly PRM levels are within acceptable LOLE metrics.

In June 2024, the most recent RA decision, D.24-06-004, the Commission both decided to move forward with SOD in 2025, adopted a 17 percent PRM level for RA compliance in 2025, and extended the effective summer reliability excess PRM mechanism (originally adopted in the Extreme Weather Proceeding) through 2025, finding that this higher level of reliability is more appropriate for the 2025 RA compliance year but that the higher level could be met with a combination of the RA obligation at 17% and the effective PRM approach.

Translating the PRM from the current RA construct to the SOD Framework has proven a complex analytical task. To implement the SOD Framework, staff must perform a LOLE study and translate it into the SOD PRM tool, to produce a PRM for all 12 months that ensures meeting the 0.1 LOLE target. In 2023, staff produced a study for just the peak month, and did not provide a means to ensure that the same PRM in other months would likewise protect reliability. Staff and stakeholders discussed means to verify reliability with and without additional LOLE studies but failed to reach a satisfying consensus. Staff and stakeholders returned to the core contention that a LOLE study and monthly PRM calibration is needed to ensure the LOLE target is met, and not some other simpler method. As part of the current proceeding, Staff filed proposals to implement the SOD program, specifically by conducting an updated LOLE study for 2026 study year and using the SOD PRM tool to inform a new PRM requirement for the SOD Framework. These proposals also intended to produce a PRM requirement for each month of the year that would satisfy LOLE requirements by keeping total LOLE at 0.1 or below and use the SOD tool to implement a monthly SOD PRM requirement.

In March 2024, as part of Track 2 of the RA proceeding, Energy Resource Modeling staff in Energy Division (Staff), in collaboration with CPUC consultants, performed multiple updates to the inputs and assumptions for the LOLE model and issued a proposed Inputs and Assumptions document to the RA proceeding. These updates included:

- Updating the CAISO baseline generating fleet from the current CAISO Master Generating Capability List
- Updating existing or under construction non-CAISO units from the 2032 WECC Anchor Data Set (ADS) and available LSE IRPs from balancing authority areas external to CAISO
- Incorporating the California Energy Commission (CEC) 2023 Integrated Energy Policy Report (IEPR) California Energy Demand Forecast
- Updating weather and hydroelectric data to include historical years 2021 and 2022
- Revising the weather normalization model for synthesizing hourly demand shapes
- Revising the hourly wind generation model
- Updating scheduled and unscheduled outage rates for several resource classes
- Incorporating ambient temperature output derating for thermal generating units.

Summary of 2026 LOLE Study Results

Staff completed an annual LOLE study, meeting demand with a static portfolio of resources and focusing on total LOLE across the 2026 year. On an annual basis, staff was able to achieve LOLE of 0.1 with a sizable surplus of capacity. Focusing on the peak month only, staff found that the baseline resource fleet was over reliable, allowing for a decrease in the evening CAISO simultaneous import constraint from 4,000 MW to 1,700 MW. Table 1shows the PRM in each month, and the amount of extra demand (24 hour static blocks) added to each month to levelize the PRM. These extra blocks of demand were then added to SERVM and the study was rerun to ensure that with these PRM levels (and demand blocks) CAISO still achieved a LOLE of 0.1 across the months of the year. When performing the monthly SOD stress tests, however, staff spread or levelized LOLE across the summer by raising the import constraint back up to 2,500 MW (raising the PRM in September) and adding blocks of demand to other months in order to raise LOLE. Thus overall, 18.5% PRM levels are appropriate for the entire year, reflecting the large surplus of existing RA resources in offpeak months, and a small increase in PRM in September. On a monthly levelized basis, at 18.5% PRM, annual LOLE levels meet the 0.1 LOLE target with the exception of February. Staff will continue to investigate February's LOLE levels.

The final monthly results of staff's 2026 LOLE study and SOD translation are provided in Table 1 below.

Table 1 Summary of Results - Levelized Proposed SOD PRM level

Month	Stressed Hour	Load	Total Supply	Demand block added to levelize PRM	Target PRM
1	19	30,003	41,139	4,750	18.37
2	20	29,165	44,668	8,000	20.19
3	20	29,412	45,376	9,000	18.13
4	2	26,182	41,017	8,900	16.92

5	1	25,183	40,954	9,400	18.42
6	20	40,117	54,350	5,842	18.25
7	20	43,347	54,012	2,200	18.58
8	20	41,769	52,354	2,425	18.46
9	19	44,885	53,756	400	18.71
10	19	35,905	48,289	4,800	18.63
11	18	31,645	45,752	6,950	18.54
12	19	30,392	41,504	4,650	18.44

The 2026 LOLE study results above reflect the resource portfolio summarized in Table 2. This portfolio represents what is needed to maintain LOLE of 0.1 in the CAISO area. The resource portfolio includes the updated baseline resources with the evening CAISO simultaneous import constraint set to 2,500 MW. In Table 2, BTMPV is drawn from the 2023 IEPR and the hydro amount represents maximum available hydroelectric output in a particular weather year and month and does not reflect hydroelectric installed capacity. This portfolio was translated into the SOD tool.

Table 2: Resource Portfolio in 2026 Study Year

	Fleet Summary 2026	
Unit Category	**Capmax**	**Unit**
Battery Storage	14,018	MW
Biomass	786	MW
BTMPV	18,098	MW
CC/CT/ICE/Stea	26,013	MW
Coal	-	MW
Cogen	2,664	MW
DR	2,377	MW
Geothermal	1,513	MW
Hydro	5,835	MW
Nuclear	2,935	MW
OffshoreWind	-	MW
OOSWind	-	MW
PSH	1,483	MW
Solar	23,339	MW
Wind	7,730	MW

Summary of Recommendation and Proposed PRM

Staff propose the CPUC adopt an RA obligation for LSEs that requires an 18.5% PRM on top of the 2023 IEPR CAISO coincident managed peak demand forecast for all 12 months. While the SOD PRM results suggest a higher PRM need for February, Staff believes that an 18.5% is still appropriate at this time. The results of this study show that with the baseline including existing resources and expected resource additions based on LSE contracting and development milestones, RA obligations can be met while allowing for some uncertainty or delay in resource development. Specifically, a 1,500 MW surplus/cushion[4] is implied by the decrease to the evening CAISO simultaneous import constraint from 4,000 MW to 2,500 MW in tuning the study to achieve a 0.1 LOLE target.

Methodology and Inputs Overview

To conduct a LOLE study, Staff measures aggregate system reliability with a stochastic production cost model that simulates resource commitment and dispatch for each hour of a target study year. The model calculates probability-weighted expected values for a variety of metrics across thousands of scenarios. Reliability metrics from the model include LOLE as well as Expected Unserved Energy (EUE) and Loss of Load Hours (LOLH).[5]

Staff targeted 0.1 LOLE (equivalent to one loss-of-load event every ten years) to determine the level of RA resources needed for adequate system reliability. The 0.1 LOLE target, although not officially adopted by the Commission, is in common use around the country and in past LOLE studies performed for CPUC proceedings, including the RA and IRP proceedings.

The stochastic production cost model software used by Staff for several years is the Strategic Energy and Risk Valuation Model (SERVM) developed by Astrapé Consulting. Staff configured SERVM to analyze the 2026 study year under a range of uncertainty including weather conditions (23 historical weather and hydroelectric years, 2000-2022), economic output (5 weighted levels), and multiple runs of unit performance (random outage draws). SERVM simulates hourly economic unit commitment including reserves and dispatch for individual generating units over all 8,760 hours of the study year. The model is currently configured to represent a simplified set of balancing areas across the Western Interconnect using a zonal representation of the transmission system, grouped into six zones for California and seven zones for the portion of the Western Interconnect closest to California. Zones roughly equate to actual balancing area boundaries and transmission flow limits and hurdle rates between zones are modeled. Staff updated the baseline set of resources in the model, using the CAISO Master Generating Capability List and the Western Electricity Coordinating Council (WECC) 2032 Anchor Data Set (ADS) vintage from January 2024. Other updates were also completed as described in staff's March 2024 Inputs and Assumptions document issued in the RA proceeding. Staff then used the CAISO evening Simultaneous

4 The CPUC jurisdictional LSEs subject to any CPUC adopted PRM only account for roughly 90% of the load in CAISO. Since non-CPUC jurisdictional LSEs are not subject to the CPUC's PRM (and historically have demonstrated less than 15% PRM), used non-RA eligible resources to meet their PRM, and not all use the IEPR load forecasts), any surplus/cushion identified herein may be lessened by the impact of the actions of the non-CPUC jurisdictional LSEs.

5 LOLE equals the expected number of loss-of-load events, regardless of length, in a given year. LOLH equals the expected number of hours with loss-of-load in a year. EUE equals the total MWh of unserved energy in a year. LOLE is a measure of frequency, not duration or magnitude. LOLH is a measure of duration, not frequency or magnitude. EUE is a measure of magnitude, not frequency or duration.

Import Constraint (set initially at 4,000 MW) as a lever to raise or lower LOLE instead of adding or removing individual power plants for the annual LOLE study as well as the monthly SOD PRM calibrations.

Once the LOLE study is complete and a reliable portfolio is determined, Staff translate the portfolio together with the hourly electric managed demand into a SOD PRM using the SOD calibration tool. The SOD tool compares a resource portfolio's hourly generation profile against the single worst day from the CEC IEPR forecast across each hour of the day and calculates the largest minimum margin of load over resources required during the day, and results in a required PRM that represents the given resource portfolio. More details about the SOD PRM tool are available later in this report.

2023 IEPR Forecast - Reconciling Changes from Prior IEPR

The annual California Integrated Energy Policy Report (IEPR) demand forecast is a key input used in the CPUC's LOLE modeling efforts. It is used to calibrate the CPUC model's 23 weather year normalized distribution of consumption demand hourly profiles to have median annual peak and energy that matches the 1-in-2 year annual consumption peak and energy forecasted in the IEPR for each modeled region in California. Consumption is defined as the expected demand without the effects from load modifiers included in the IEPR (electric vehicle charging, BTM storage, AAEE[6], AAFS[7], and BTMPV). Staff models these load modifiers explicitly as fixed shape resources in the CPUC model by recreating the IEPR-provided hourly profiles for electric vehicle charging, BTM storage, AAEE, and AAFS, and by using the IEPR forecasted BTMPV installed capacity and annual energy production to calibrate the model's 23 weather year normalized distribution of solar hourly production profiles such that the median annual energy production matches the IEPR. The end result is a CPUC model with a median consumption peak that matches the IEPR consumption peak. The CPUC model can also net out the effects of load modifiers and BTMPV and produce a median managed peak that should be reasonably close to the IEPR managed peak, but some difference is expected because the CPUC model's 23 weather year distribution of consumption and BTMPV production profiles are produced by CPUC Staff independently from the 1-in-2 hourly profiles produced in the IEPR development process.

The CPUC model's 23 weather year normalized distribution of consumption demand is developed as follows. While electric sales demand can be directly measured at the system bus bar, electric consumption is a counterfactual that reflects electrical demand adjusted by reconstituting measured sales and simulated or recorded demand modifiers. Demand modifiers include: BTMPV, Demand Response (DR), utility scale storage charging and other demand modifiers, which are collected and used to reconstitute estimated consumption demand. The reconstituted consumption demand data is then trained to predict demand shapes for other weather patterns via a Monash model, which creates 24 hourly models for each hour of the day and predicts demand from weather in each hour of a day, day of a week, and month of a year. For the 2023 IEPR cycle Staff produced Consumption shapes as follows:

Consumption = Sales + BTMPV + DR - Utility Scale Battery Charging

6 Additional Achievable Energy Efficiency

7 Additional Achievable Fuel Substitution

where all hourly quantities are defined to be positive. Other demand modifiers (such as AAEE and EV demand) that are future forecasts and not already part of the existing historical demand data is not part of the data used to reconstitute consumption from historical EMS data. They are instead included as resources that can meet consumption demand in the LOLE model.

The annual IEPR demand forecast is also used by the CPUC in setting annual and monthly load forecast obligations for individual Load Serving Entities for the coming RA compliance year. Beginning with 2025 RA compliance year the CPUC will be using the worst day hourly demand forecast provided by the IEPR to inform individual LSE SOD monthly forecast used for RA compliance.

The CEC adopted its 2023 IEPR (California Energy Demand) Forecast in February 2024.[8] There were numerous changes to sources and methods in this demand forecast development cycle.[9] The 2023 IEPR forecast projected lower annual electricity sales through 2032 than what was projected in the 2022 IEPR due to a variety of factors: slower growth in households and population than was previously projected by the Department of Finance, increases in BTM PV adoption compared to previous assumptions, and increases in electricity rates compared to previous assumptions. The 2023 IEPR Forecast also predicted that California will become a dual peaking system by 2040 due to increases in electric heating. For this cycle, staff understands the CEC used the following data to reconstitute consumption demand from historical sales data:

- Existing Datasets: Historical observed hourly impacts from demand response programs and BTMPV generation profiles updated to include through 2022 weather year. Flex Alert or other Emergency Load Reduction Program (ELRP) data received from CAISO
- New Dataset: Historical utility-scale storage charging data

The net effect of these and other changes to the 2023 IEPR demand forecast resulted in a significant decrease in annual sales forecast through 2032 and different trends than observed in prior IEPR vintages. For example, in 2026 the 2023 IEPR CAISO coincident consumption peak forecast is about 1.5 GW higher than the 2022 IEPR while the CAISO coincident managed peak is about 2.1 GW lower than the 2022 IEPR. Figure 1 compares CAISO coincident consumption and managed peaks across IEPR vintages and illustrates how the 2023 IEPR differs significantly from the prior two IEPR vintages. Note the large change (relative increase of more than 3 GW) in the difference between consumption and managed peaks with the 2023 IEPR.

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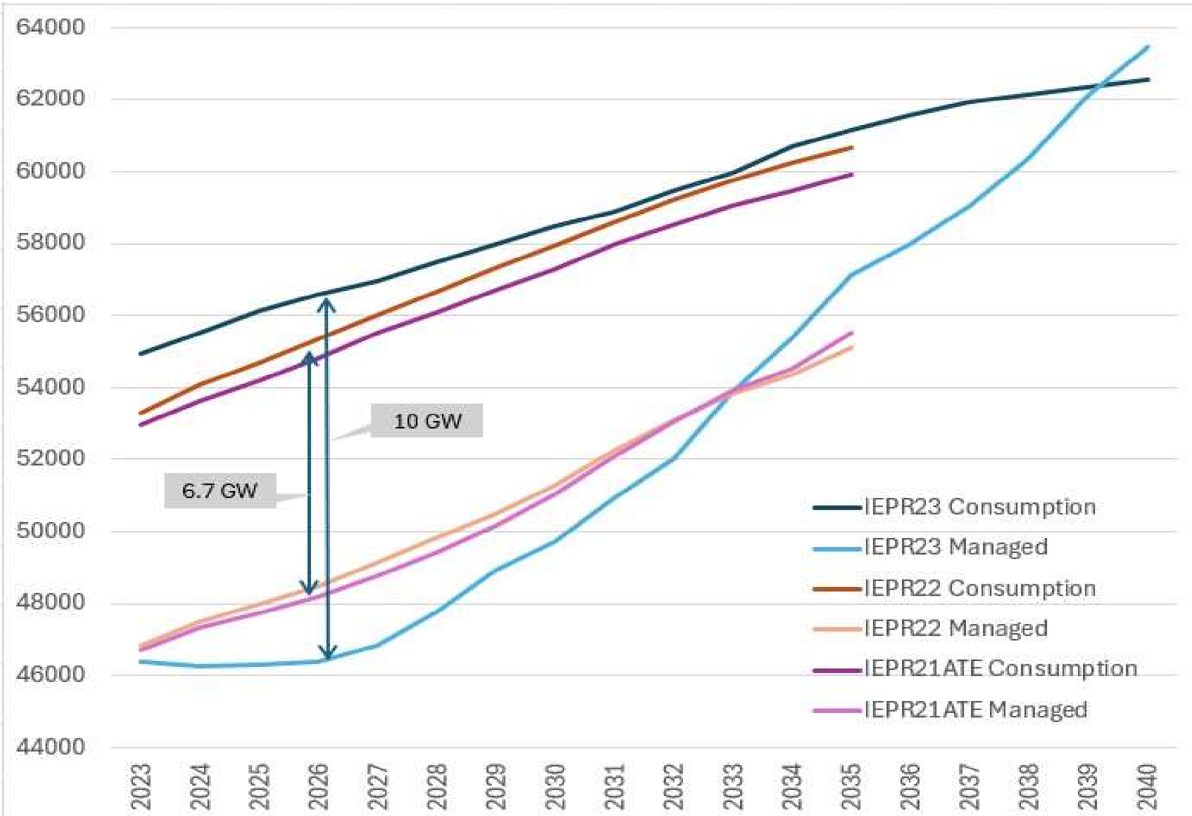
8 https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2023-integrated-energy-policy-report/2023-1

9 More information is available in the CEC presentations from the [IEPR Commissioner Workshop on the California Energy Demand Forecast Results Part II]

Figure 1: CAISO coincident consumption and managed peak MW by IEPR forecast vintage

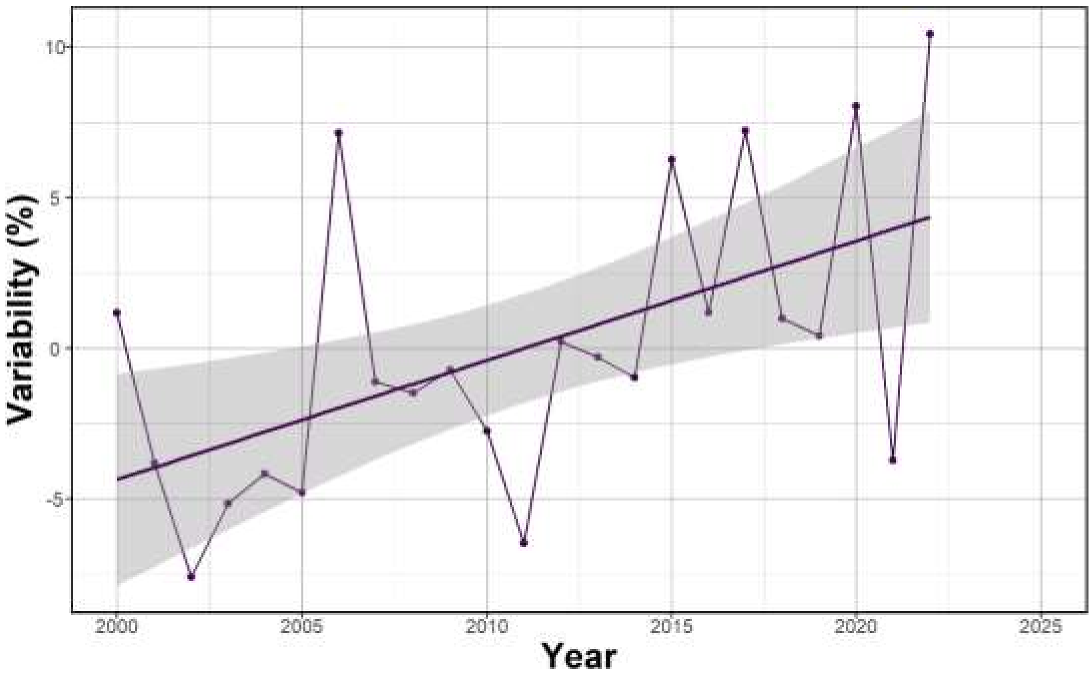


Given these changes, staff decided to benchmark the 2023 IEPR CAISO forecast levels and trends against available historical data. To create a historical consumption peak trend that can be compared to the IEPR forecasted consumption peak trend (which represents 1-in-2 year weather), Staff collected historical consumption data and corrected for natural historical weather variability, a process called weather normalization. We can define the variability for each weather year as:

Variability = (Annual Consumption Peak - Median of Annual Peaks) / Median of Annual Peaks

Staff calculated the variability for weather years 2000-2022 using the equation above with historical CAISO coincident consumption peak data as shown in Figure 2.

Figure 2 The variability of historical CAISO coincident consumption peak for each weather year (points). The straight line and error bars correspond to best linear fits.



The variability represents a comparison of peak demand relative to the median peak demand over the entire group of weather years. The year 2022, for example, has a variability of 12% meaning 2022 peak demand was 12% higher than the median peak demand from 2000 to 2022. Also note that variability is increasing particularly in recent years, likely in part from climate change causing more extreme weather. Going forward the median peak demand meant to represent a "normal" weather year will likely increase.

From the variability we can develop a correction factor to remove the variability from historical consumption data for each year as:

Correction Factor = 1 / (1 + Variability)

Using the 2022 example with 12% variability, we weather normalize 2022 historically observed consumption by multiplying by the correction factor, effectively reducing it by approximately 11%. Correcting historical consumption peaks in this way results in a variability adjusted time series that can be compared to IEPR 1-in-2 year peak forecasts.

Figure 3 shows the 2022 and 2023 IEPR CAISO coincident consumption peak forecast compared to variability adjusted (weather normalized) historical CAISO coincident consumption peaks. Staff observed a significant gap – for 2026 the 2023 IEPR consumption peak is 4 GW higher than the expected peak following the historical trend line. There is also a notable gap between the 2022 and 2023 IEPR vintages consumption peak trend lines, at least in the near-term forecast years.

Figure 3: Weather normalized historical CAISO coincident consumption peaks compared to 2022 and 2023 IEPR forecasted peaks. Points represent data and straight lines and error bars reflect best linear fit.

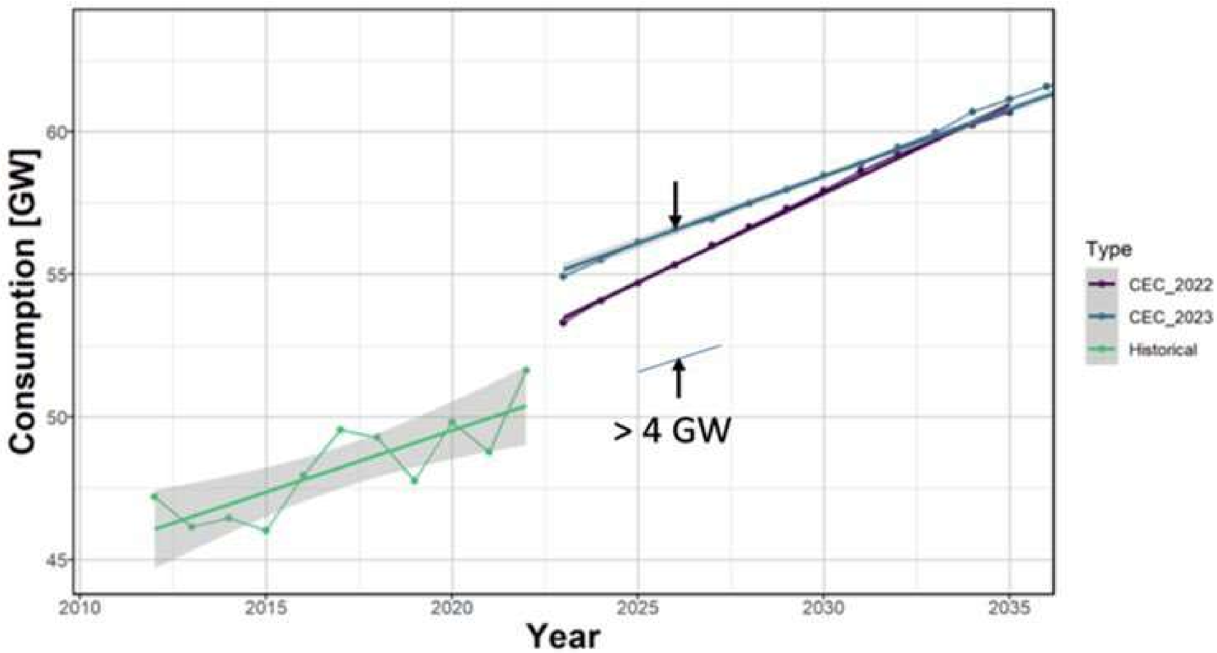


Figure 4: Weather normalized historical CAISO coincident managed peaks compared to 2022 and 2023 IEPR forecasted peaks. Points represent data and straight lines and error bars reflect best linear fit.

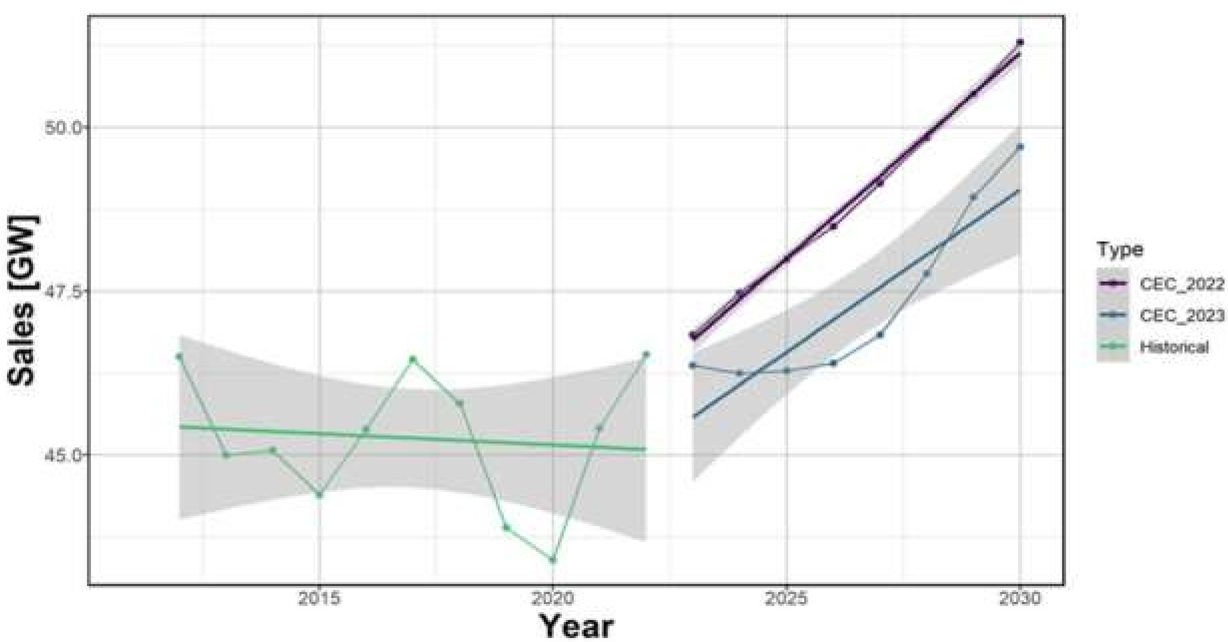
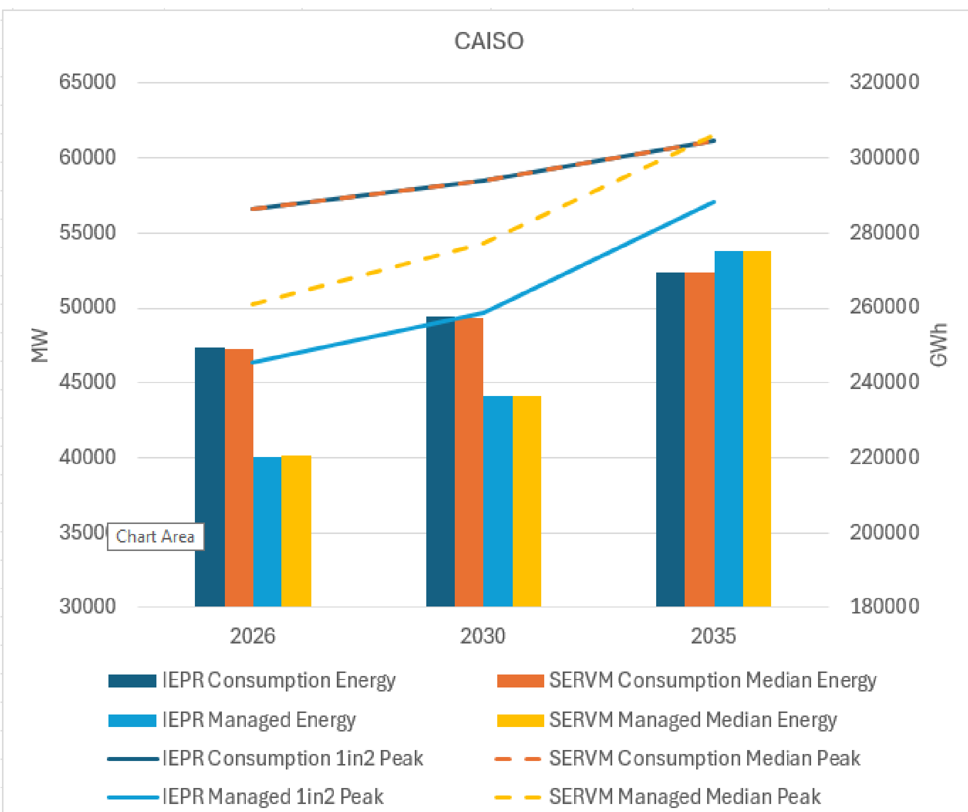


Figure 4 shows the 2022 and 2023 IEPR CAISO coincident managed peak forecast compared to variability adjusted (weather normalized) historical CAISO coincident managed peaks (equivalent to “Sales”, CAISO EMS metered demand). The 2023 IEPR managed peak forecast trend aligns reasonable well with the weather normalized historical managed peak trend, moreso than the 2022 IEPR. Since the 2023 IEPR managed peak forecast aligns better with history than the 2023 IEPR consumption peak forecast, this may imply that the 2023 IEPR managed peak forecast is more appropriate than the consumption peak forecast for calibrating the median peaks in the CPUC model's 23 weather year distribution of hourly electric demand.

Nevertheless, Staff proceeded to calibrate the CPUC model's California consumption shapes such that the median consumption peak matches the 2023 IEPR consumption peak, for each modeled California region. Staff also recreated IEPR-provided hourly load profiles in the CPUC model and calibrated BTMPV installed capacity such that annual energy production matches the amount forecasted in the IEPR. Finally, Staff derived the CPUC model's managed peak for comparison to the 2023 IEPR forecast. Staff found that the CPUC model's CAISO coincident managed peak was significantly higher than the 2023 IEPR forecast, despite matching the IEPR in the manner described above. Figure 5 shows that the CPUC model is calibrated to match the IEPR in the forecast years shown except for the median managed peak (yellow dashed line) being about 4 GW higher then the IEPR (light blue solid line). Median annual consumption peaks are aligned with the IEPR (orange dashed line on top of dark blue solid line) and median annual consumption and managed energy are aligned with the IEPR (dark blue and orange bars match, light blue and yellow bars match).

Figure 5: Results of calibrating CPUC modeled consumption, load modifiers, and BTMPV to match the 2023 IEPR



Staff analyzed in depth the consumption and managed demand shapes provided in the 2023 IEPR and those built into the CPUC model to investigate the reason for the large managed peak gap between the

IEPR and the CPUC model, and to understand why the difference between the 2023 IEPR consumption peak forecast and managed peak forecast is so large relative to prior IEPR vintages. Staff have confirmed that both load modifiers (AAEE, AAFS, electric vehicle charging, BTM storage) and BTMPV in the CPUC model are well calibrated to match the IEPR. This isolates consumption shape differences between the CPUC model and the 2023 IEPR as the likely driver of the managed peak gap.

Figure 6: CAISO Consumption vs Sales – IEPR vintages and CPUC modeling

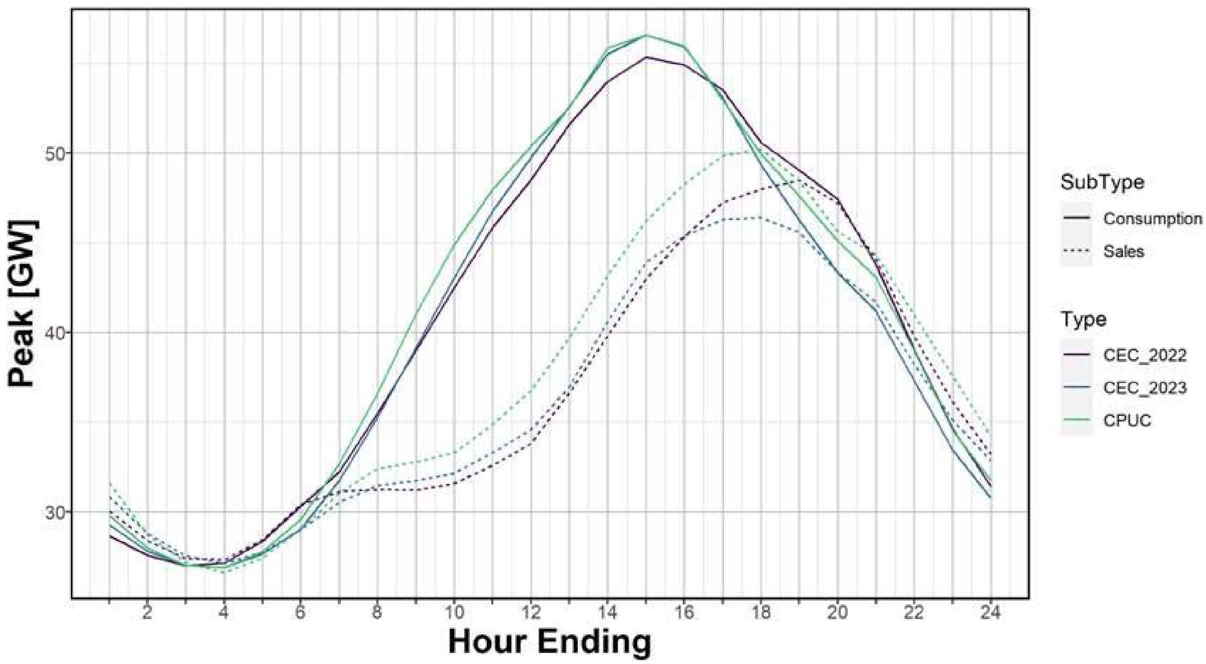


Figure 6 shows average consumption demand shapes between IEPR vintages contrasted with the CPUC model's consumption shapes produced by Staff and calibrated to match the 2023 IEPR's CAISO annual consumption peak and energy. While 2023 IEPR consumption shapes generally overlap with CPUC model consumption shapes through most of the day including peaking on average at Hour Ending 15, the evening hours between Hour Ending 18 and 21 diverge significantly. Staff's consumption shapes rest in between 2022 IEPR shapes (in purple) and 2023 IEPR shapes (in blue) and explains that the managed peak gap comes from a difference in consumption shapes, primarily in later hours of the day, which decline from daily peak much more sharply than the CPUC model demand shapes do. Even though BTMPV capacity and energy is matched between the CPUC model and the IEPR, the same BTMPV would interact much more favorably with the 2023 IEPR consumption shape to create a larger peak impact. In other words, for the same BTMPV, the 2023 IEPR consumption shape would yield a lower managed peak shifted earlier in the evening than the CPUC model's or 2022 IEPR's consumption shapes.

The 2023 IEPR estimates that BTMPV will provide a 54% peak reduction, calculated as:

Peak reduction = (Managed peak without BTMPV present – Managed peak) / BTMPV installed capacity

The managed peak without BTMPV present is defined as the consumption peak plus the effects of all other load modifiers except for BTMPV. The magnitude of peak reduction effect is a large increase fromprevious IEPR cycles and also relative to the peak reduction observed in the CPUC model. Table 3 summarizes the CAISO coincident consumption peaks, managed peaks, and the peak reduction due to BTMPV for the CPUC model (which was calibrated to match 2023 IEPR consumption peak and energy), 2023 IEPR, and 2022 IEPR. Observe that the peak reduction factor from BTMPV for the CPUC model and the 2022 IEPR are relatively consistent while the 2023 IEPR has a significantly larger peak reduction. Peak reduction from BTMPV is calculated as the difference between managed peak without BTMPV present and managed peak.

Table 3: Comparing CAISO coincident peaks, and peak reduction due to BTMPV

Model	Description	2026	2030	2035
CPUC	Consumption peak	56,591	58,491	61,162
	Managed peak	50,251	54,343	61,503
	Peak reduction from BTMPV	6,125	7,391	8,735
	Peak reduction factor	0.33	0.30	0.29
2023 IEPR	Consumption peak	56,574	58,474	61,144
	Managed peak	46,395	49,694	57,105
	Peak reduction from BTMPV	10,406	11,597	12,557
	Peak reduction factor	0.54	0.45	0.40
2022 IEPR	Consumption peak	55,330	57,932	60,673
	Managed peak	48,487	51,292	55,118
	Peak reduction from BTMPV	6,392	6,996	8,909
	Peak reduction factor	0.35	0.30	0.30

SERVM Model Aligned with Managed Peak, not Consumption

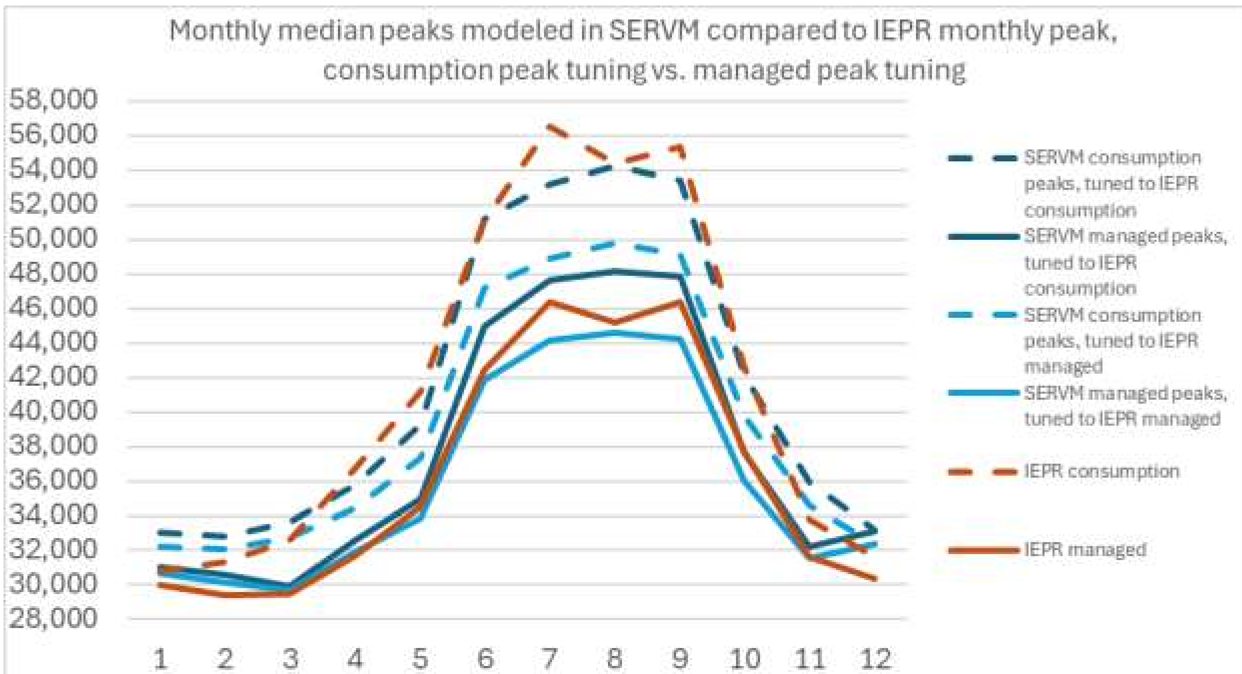
The CEC IEPR forecast is used to calibrate both the consumption and managed electrical demand forecasts used within the CPUC electric grid reliability modeling framework. CPUC used data from the CEC and CAISO as well as weather modeling to simulate BTMPV generation to build a set of demand shapes to target aligning the median demand from our distribution of stochastic data (demand data representing 23 years of historical weather variability). This group of demand shapes usually is scaled to the CEC's consumption forecast of peak and energy. In light of the challenges discussed above, this year, staff instead aligned the median managed peak derived from the consumption shapes and demand modifier data with the CEC 2023 IEPR's managed peak. Staff believe this forecast represents historical temperature and weather patterns better than the consumption forecast. A discussion of the analysis and outcomes follows.

The consumption forecast in IRP usually is the forecast that drives system Total Reliability Need (TRN), while the RA program obligations on LSEs are based off the IEPR 1-in-2 managed load forecast. If we calibrate the model to IEPR consumption peaks, then we find the CPUC model's managed peaks significantly higher than the IEPR, whereas if we calibrate to IEPR managed peaks, we need to significantly decrease the model's consumption peaks relative to the IEPR.

Figure 7 shows the effect of decreasing consumption peaks in SERVM by about 9% in order to adjust the distribution of modeled consumption shapes such that the median of the resulting distribution of managed peaks aligns with the lower 2023 IEPR managed peak. In addition to reducing peak demand forecasts, this also had the effect of significantly decreasing our reliability requirements by about 9%.[10] Median total managed and consumption energy are aligned between the SERVM stochastic shapes and the 2023 IEPR however and needed no adjustment.

The managed peaks from our distribution do not in any one month match the managed peaks from the 2023 IEPR (though August is the closest) but the median annual managed peak from our 23 weather year distribution is the same as the annual managed peak from the IEPR hourly load forecast which is not associated with any specific weather year but is intended to represent a 1 in 2 demand shape. The IEPR Managed forecast shown represents the monthly peak from the 1 in 2 hourly demand forecast, while the peak values shown from SERVM represent the monthly median peak from 23 weather years. Another way of explaining this is that Figure 7 below shows the median monthly peak across all 23 weather year versions of January, all 23 Februarys, etc. The annual peaks across all 23 weather years do not occur in the same month so a monthly median will not reflect an annual median.

Figure 7: Monthly Peaks SERVM Consumption vs. SERVM Managed vs. IEPR



Other Key Input Updates

In addition to the electric demand inputs, Staff, in collaboration with consultants, updated many other portions of the SERVM reliability model in Q1 of 2024. This 2026 study is the first using all updates together. Those updates and modeling methodology are described in the recently published Inputs and

10 If staff had not taken this analytical approach, the PRM would have been higher by 9% or close to 4,000 MW of additional capacity would be needed to achieve a 0.1 LOLE. The adopted analytical approach was not undertaken lightly considering the significant difference in reliability study outcome.

Assumptions document, released March 15, 2024.[11] The model input datasets will be posted to a new link that will be added to the 2024-2026 IRP Cycle Events and Materials webpage.[12]

Several input changes would tend to increase reliability risk. For example, our modeling quantified increased risk due to incorporation of the 2022 weather year and the extreme heat experienced in California that year. Additionally, Staff updated outage rates for storage systems and conventional fossil resources as well as enabling the ambient temperature thermal output derate functionality discussed in previous workshops. These changes would tend to add reliability risk and additional LOLE to the model.

One key update that would decrease reliability risk is the incorporation of an updated resource baseline - which included thousands of MWs of new resources added to the system. These additions are further described later in this section of the report.

As described above, incorporation of the CEC's 2023 IEPR Demand Forecast into the model added complexity to the LOLE analysis. Calibrating the CPUC's model to the consumption forecast resulted in an increase to reliability risk whereas calibrating the model to the managed forecast resulted in a decreased reliability risk. As explained above, Staff proceeded with the LOLE study with demand shapes centered around the managed forecast, rather than the consumption as was done in previous studies.

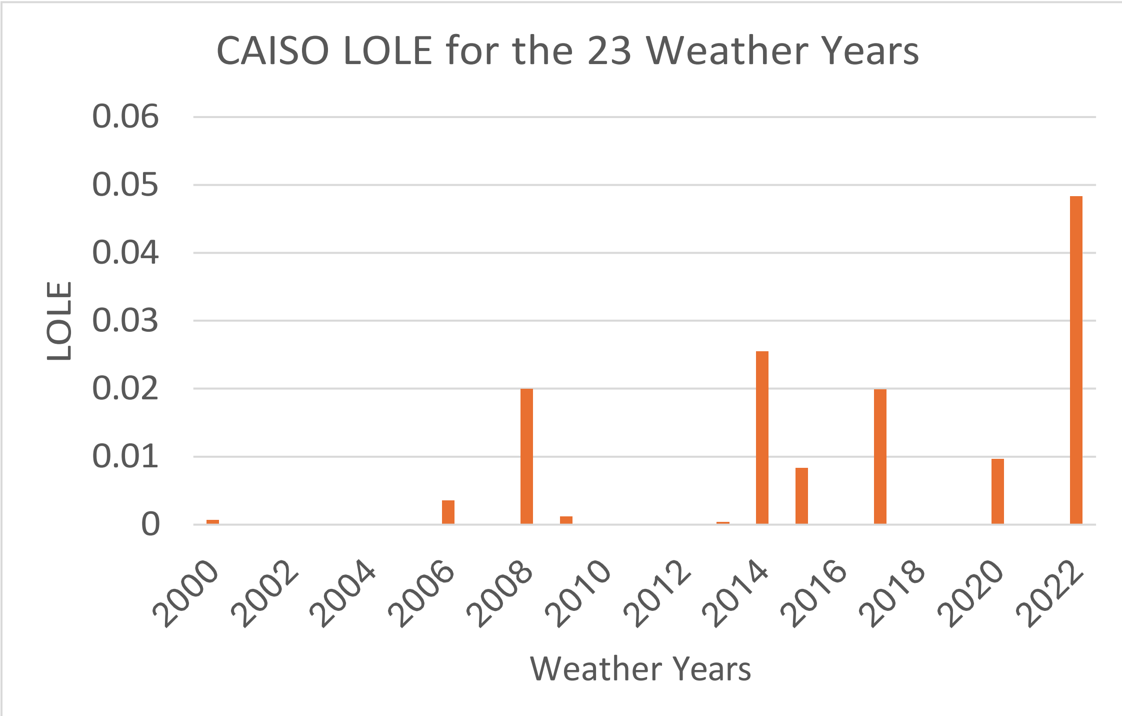
Addition of 2022 Weather Year to SERVM Historical Profile

As mentioned in the Inputs and Assumptions document, the 23 weather year distribution in SERVM was updated to include years 2000 to 2022 (instead of 1998 to 2020) to capture increasingly extreme weather and its effects on reliability. Figure 8 shows CAISO LOLE attributed to weather years from 2000 to 2022. The figure illustrates which weather years have the largest impact on the model's reliability outcome.

11 https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M527/K361/527361341.PDF

12 https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2024-26-irp-cycle-events-and-materials

Figure 8: CAISO LOLE for the 23 weather years incorporated in SERVM for 2026 RA LOLE study



Updated Forced Outage Rates for Batteries and Conventional Units

For battery electric storage systems (BESS) and conventional units including combined cycle, combustion turbine, and diesel, we analyzed historic outage data from 2018 through 2022 to determine applicable Equivalent Forced Outage Rates (EFOR). Forced outages include a wide variety of unplanned events generally outside the control of the unit operator, such as weather, and mechanical, electric, or electronic system failures. The term “equivalent” here indicates that the calculation accounts for unplanned partial outage or deration events that fall into the same category as full outages. This section describes the methodology staff used to determine EFOR values as inputs for SERVM.

Each of the four unit types were subdivided into three categories, based on the overall EFOR across the years under consideration for individual units, with the “Low” EFOR category consisting of units in the zeroth to 35th capacity-weighted percentile of EFOR, “Mid” consisting of the 35th to 65th capacity-weighted percentile, and “High” consisting of the 65th to 100th capacity-weighted percentile. We then calculated capacity-weighted EFOR (WEFOR) values for each of the three EFOR categories within each of the four unit types and across two seasons based on the units within each group, excluding units in the lowest and highest capacity weighted percentiles as outliers. The two seasons are labelled “Summer” and “Non-Summer”, with the former including months June-October and the latter including all other months. Each group’s WEFOR values are applied to all units within each unit type and EFOR category.

The North American Electric Reliability Corporation’s (NERC’s) Generating Availability Data System (GADS) is the source dataset for all combined cycle, combustion turbine, and diesel units. This data set provides event-level outage data for individual units, as well as various aggregate EFOR calculations, and the GADS manual provides the definition and formulas for EFOR and WEFOR used in our analysis.

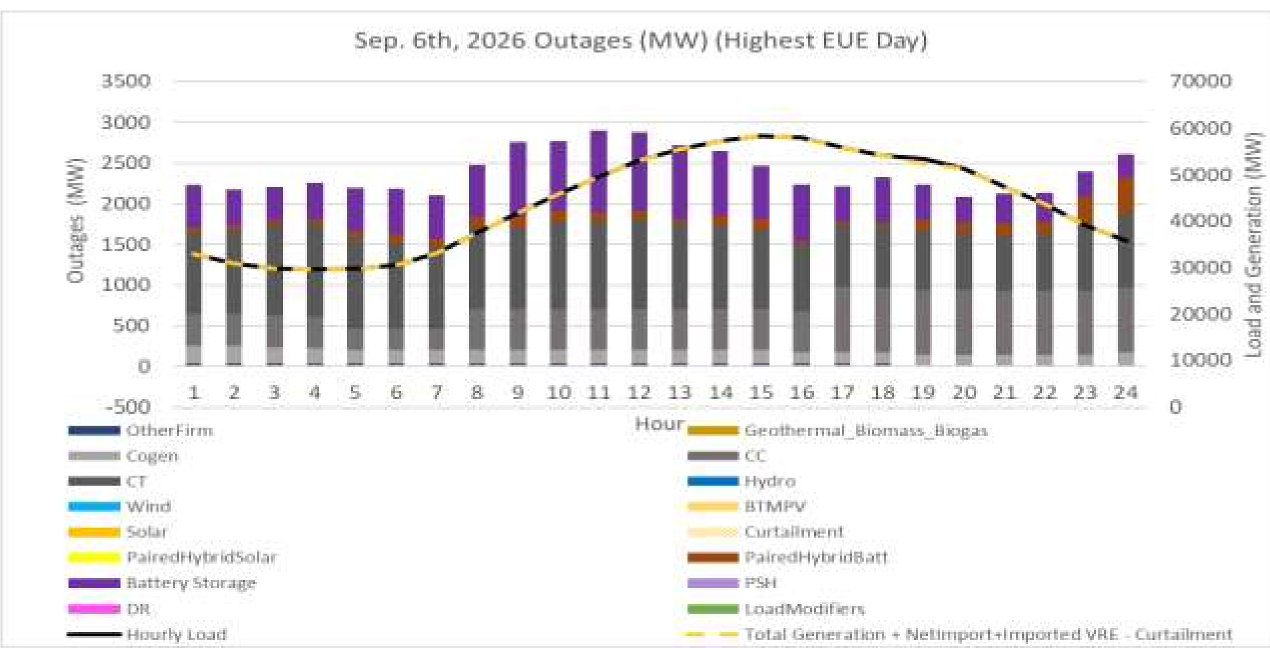
However, NERC does not yet publish reliability data for BESS resources. Instead, we sought to calculate an analogous EFOR value using a combination of Prior Trade-Day Curtailment Reports and Economic Bidding Data, both provided by the California Independent System Operator (CAISO). Once forced outage hours and service hours were derived from the two data sets, the remaining steps of the analysis are similar to the other unit types; however, the resulting EFOR values for storage are ultimately divided by two because the reported outages correspond to discharging times, while SERVM models that outage rate in both charging and discharging periods, effectively doubling the outage rate. The resulting WEFOR values for each group, as applied in SERVM, are shown below in Table 4.

Table 4: WEFOR Values by Season, Unit Type, and EFOR Category

		EFOR Category		
Season	Unit Type	Low	Mid	High
Non-Summer	Storage	1.39%	2.68%	6.64%
	Combined Cycle	2.18%	7.58%	17.37%
	Combustion Turbine	9.92%	20.82%	61.09%
	Diesel	1.88%	2.57%	4.05%
Summer	Storage	1.12%	3.82%	7.85%
	Combined Cycle	1.30%	3.08%	8.60%
	Combustion Turbine	4.35%	20.01%	51.79%
	Diesel	2.02%	2.35%	8.31%

Figure 9 shows typical modeled outages in MW for different unit categories for 2026 on the day with the most unserved energy. Outages tend to increase with a resource's usage intensity. The hourly amounts on outage (left axis) are compared to the hourly load and total generation (right axis).

Figure 9: Outage during highest EUE day (Sep. 6th 2026)



Updated Scheduled Outage Factors for Batteries and Conventional Units

SERVM uses a Scheduled Outage Factor (SOF) which, as defined in the GADS manual, includes maintenance and other planned outages. The inclusion of planned outages distinguishes SOF from a simpler Maintenance Outage Rate (MOR). This section describes staff's analysis to update the SOF values for SERVM.

The same four unit types considered in the EFOR analysis were also assessed for SOF, and, while we again relied upon the GADS manual for the definition of SOF, the manual does not specify a preferred methodology for weighting scheduled outage factors. We therefore applied the same capacity-weighting methodology defined for WEFOR to produce capacity-weighted SOF (WSOF) values, which are not explicitly defined in the GADS manual but we believe are consistent with NERC's overall approach.

Again, GADS does not include data for BESS units, so we relied instead upon planned outages in CAISO's Curtailment Reports. The definition of ESOF uses Period Hours (e.g., total hours in a given month), rather than unit availability, so unlike the EFOR analysis, bidding data was not required.

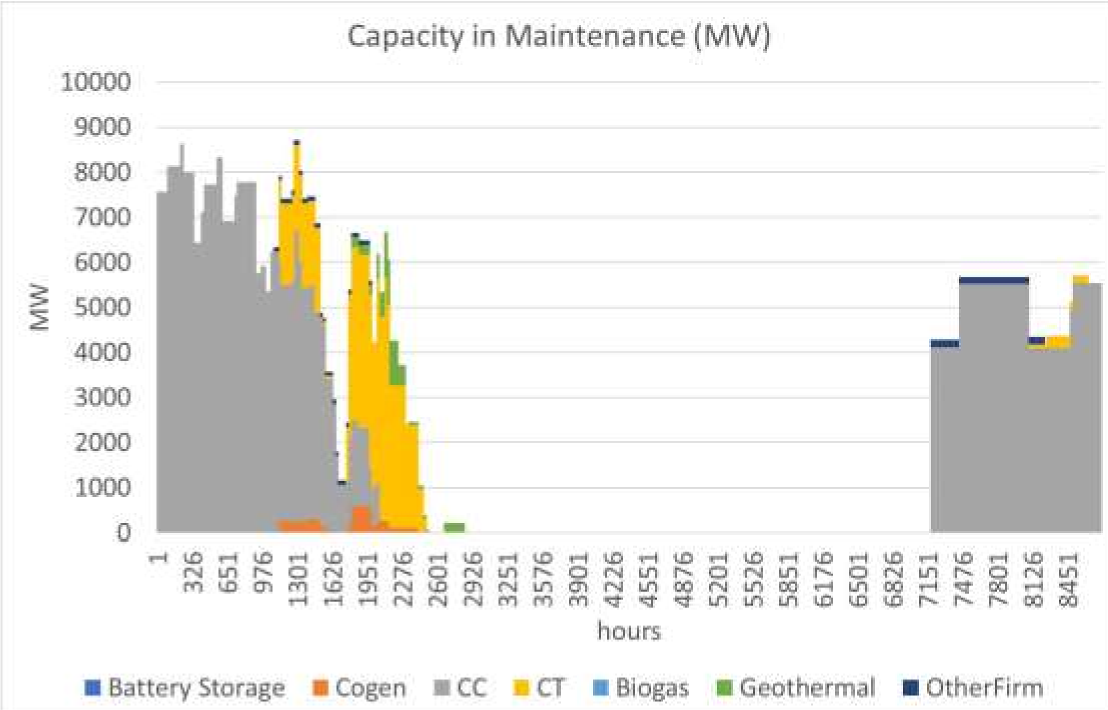
As with the EFOR analysis, we subdivided each of the four unit types into three ESOF categories with the same weighted percentiles of 0^{th}-35^{th}, 35^{th}-65^{th}, and 65^{th}-100^{th}, and evaluated WSOF for each unit type, SOF category, and the same two seasons defined for EFOR. The results are presented below in Table 5. Note that the WSOF values for storage are not divided by two, in contrast to the WEFOR values in the previous section.

Table 5: WSOF by Season, Unit Type, and SOF Category

		Schedule Outage Factor (SOF) Category		
Season	Unit Type	Low	Mid	High
Non-Summer	Storage	2.77%	5.36%	13.27%
	Combined Cycle	3.56%	10.68%	21.89%
	Combustion Turbine	2.19%	4.38%	8.54%
	Diesel	4.09%	10.54%	12.36%
Summer	Storage	2.25%	7.64%	15.69%
	Combined Cycle	0.55%	1.68%	3.63%
	Combustion Turbine	0.37%	1.20%	3.41%
	Diesel	5.01%	9.26%	19.43%

Figure 10 shows typical capacity in maintenance for different unit categories in 2026. The model schedules maintenance according to the expected load and available generating capacity for the whole year. Maintenance happens during off-peak periods and months to be able to maintain reliability during critical days.

Figure 10: Capacity in maintenance for different unit categories



Thermal Derate for Combined Cycle and Combustion Turbine Unit Types

The maximum power capacities of combined cycle and combustion turbine units are capacities dependent upon the ambient or inlet air temperatures, with high temperatures corresponding to decreased capacities. While the thermodynamics of combustion reactions and steam expansion are well-understood, and mechanical dynamics of turbines can be modelled with high precision in isolation, the countless externalities in the complex systems that constitute a modern generation units necessitate a more wholistic approach to predicting derates. We have kept this in mind while developing a methodology for forecasting unit performance based on correlating prior observations of thermal derations with historic weather. The resulting model maps capacity as a continuous piecewise-linear function of ambient temperature.

The model is predicated on the assumption that the capacity for each unit does not exceed its rated maximum, regardless of ambient conditions, and that capacity decreases linearly with ambient temperature above a certain threshold. Humidity was considered for inclusion in the model but determined to have little explanatory value. For each unit type, the regression model is defined by the following formula:

$$DD_{ii} = \beta\beta_1 T_{ii}T^* + \beta\beta_{3.1}WW_1 + \beta\beta_{3.2}WW_2 + \cdots + \beta\beta_{3.nn}WW_{nn} + \beta\beta_4$$

Where:

- DD_{ii} is the reported or actual deration corresponding to observation ii;
- $T_{ii}T^*$ is the recorded temperature at the nearest available weather station at the time of the observation;

- WW_{jj} is a Boolean variable indicating a data point is associated with weather station jj; and
- $\beta\beta_{kk}$ is a linear regression parameter applied to the kk^{th} of the $2 + nn$ variables, with nn being the total number of weather stations used in the study.

The first regression parameter, $\beta\beta_1$, is the slope of the relationship between ambient temperature and deration, while the remaining regression parameters allow the intercept of the best-fit line to float within each weather station. The regression model is strictly linear and unbounded, while the prediction model applies the regression parameters to a piecewise linear model, bounded within 0% and 100% of each unit's maximum capacity, as indicated in the following formula:

$$\square_{ii} = mmmmmm(mmiinn(100\% - \beta\beta_1(TT_{ii} - TT_0), 100\%), 0\%)$$

Where:

- $\square_{ii}$ is the deration factor;
- $\beta\beta_1$ is the first linear regression parameter, representing the rate at which capacity decreases with increased temperature;
- TT_0 is the threshold temperature above which the deration term falls below 100%, determined through the regression analysis; and
- TT_{ii} is the temperature variable.

The results of the regression analysis are presented below:

Table 6: Regression Parameters for Ambient Deration

Unit Type	$\beta\beta_1 \square^{\%}\square_{°CC}\square$
Combustion Turbine	-1.44
Combined Cycle	-1.10

Updated Baseline Resource Portfolio

A key update to the CPUC's model includes an update to the baseline resource portfolio. CAISO will rely heavily on large amounts of storage, solar and other hybrid generators that are currently under development between January 2024 and August 2026. Table 7 provides the MW nameplate and number of units that have been added to the Baseline but are currently under development. These projects largely reflect contracted projects reported by LSEs in their December 1, 2023, IRP filings.

Table 7 Capacity (MW nameplate) In Development Between Jan. 2024 and Aug. 2026 for CAISO only

Unit Category	In Development Units (MW)				Number of Units				Percentage of Total Portfolio
	PG&E	SCE	SDG&E	Total	PG&E	SCE	SDG&E	Total	
Battery Storage	1,046	4,336	640	6,023	19	45	17	81	42.97%
Biomass/Wood	2			2	2			2	0.40%
CC	48			48	1			1	0.27%

Geothermal	18			18	1			1	1.19%
Solar	1,843	1,266	581	3,691	19	27	6	52	15.81%
Wind	230	57		287	1	2		3	3.71%
Grand Total	**3,188**	**5,659**	**1,222**	**10,068**	**43**	**74**	**23**	**140**	**9.52%**

Whereas the previous table shows resources modeled in 2026 that are still in development (as of January 2024), Table 8 shows the delta between resources modeled in the prior LOLE study for 2024 and this report's 2026 LOLE study by unit category in SERVM. The total increase of 12.7 GW from the prior study to the current study is mostly because of an increase in battery and solar resources. SCE has the highest amount of capacity increase relative to PG&E and SDG&E.

Table 8: Delta (MW nameplate) in resources modeled in the prior 2024 LOLE study vs. the current 2026 LOLE study, by unit category

Unit Category	PG&E	SCE	SDG&E	CAISO
Battery Storage	919	4,206	467	5,592
Biogas	(1)	(5)	(6)	(12)
Biomass/Wood	(60)	(29)	-	(88)
BTMPV	254	1,526	104	1,884
CC	54	(2)	(12)	40
Coal	-	(480)	-	(480)
Cogen	18	(3)	-	16
CT	6	(18)	(3)	(15)
Geothermal	28	(14)	-	14
Hybrid_BattStorage	(77)	305	200	427
Hybrid_Solar_1Axis	479	1,479	132	2,090
Hybrid_Solar_Fixed	3	-	-	3
Hydro	(86)	(4)	-	(90)
ICE	(4)	-	-	(4)
Nuclear	-	-	-	-
Paired_BattStorage	136	330	-	466
Paired_Solar_1Axis	(150)	516	-	366
Paired_Solar_Fixed	-	-	-	-
PSH	-	-	-	-
Solar_1Axis	1,114	653	554	2,322
Solar_2Axis	-	-	(2)	(2)
Solar_Fixed	100	(53)	-	47
Solar_Thermal	-	-	-	-
Wind	198	(97)	(1)	100
Grand Total	2,931	8,310	1,433	12,674

Staff also estimated the effective capacity change since 2024. By itself, each additional MW of solar nameplate capacity provides less reliability because of saturation. Similarly, each additional MW of storage nameplate capacity provides less reliability because it does not produce energy itself. Table 9 shows that 6,709 MW of solar has been added since 2024 and that the Effective Capacity of these resources is 302 MW; 6,485 MW of batteries have been added since 2024 and have an Effective Capacity of 5,901 MW. The additional solar and battery resources total 6,203 MW of Effective Capacity. Additionally, 1,070 MW of solar and storage MWs have been removed, retired, or have not been developed since 2024. In ELCC terms, this is 691 MW of effective capacity subtracted since 2024, resulting in only 5,512 MW of Effective Capacity increase.

Table 9: Estimate of Effective Capacity Change between the prior 2024 study and the current 2026 study

	Solar total (MW)	Battery Total (MW)	Total
Total in 2026	40,340	14,028	
New since 2024	6,709	6,485	
Category total in 2024	33,630	7,543	
EffCap added since 2024	302	5,901	6,203

ELCC added since 2024	MW removed since 2024	EFF CAP change
6,203	(691)	5,512

Study Results and Slice of Day Translation

This section details the results from the annual LOLE study and their translation into the SOD PRM tool. This section also discusses the recommendation for PRM requirements for 2026 RA compliance year.

Annual Loss of Load Study Results

Staff completed a LOLE study of the 2026 RA compliance year to determine the amount of resources needed to maintain reliability in the CAISO area. The study results show that the baseline dataset provides reliable electric service throughout the year, and no additional capacity is needed to meet reliability needs. In other words, the study results reflect that the full reliability need can be met with market resources that are existing and resources that are expected to come on-line ahead of 2026 needs. Within the bounds of modeled weather and demand variability, the results reflect that CAISO's BAA is prepared to manage reliability risk that is reasonably expected to occur in 2026.

Compared to the 2024 LOLE study, the current study finds significantly less reliability need, largely due to the lower IEPR managed peak which centers the distribution of the model's stochastic demand shapes. Other updates staff implemented also affected reliability in this study compared to the 2024 LOLE study. For example, the addition of the 2022 weather year increases need, with more extreme weather adding LOLE risk. Other updates such as outage rates and incorporation of thermal derate modeling also increase LOLE risk. On the other hand, the total baseline resource increase between the 2024 LOLE study and this 2026 LOLE study lowers LOLE risk. This is true even though most of the added resources are renewable energy and batteries which are expected to have lower reliability benefit than the traditional resource mix. Table 10 summarizes the portfolio by resource technology that was used in the 2026 LOLE study. These values reflect the net dependable capacity (capmax) for both existing and under-construction/planned resources.

Table 10: Resource Portfolio in 2026 Study Year

	Fleet Summary 2026	
Unit Category	**Capmax**	**Unit**
Battery Storage	14,018	MW
Biomass	786	MW
BTMPV	18,098	MW
CC/CT/ICE/Stea	26,013	MW
Coal	-	MW
Cogen	2,664	MW
DR	2,377	MW
Geothermal	1,513	MW
Hydro	5,835	MW
Nuclear	2,935	MW
OffshoreWind	-	MW
OOSWind	-	MW
PSH	1,483	MW
Solar	23,339	MW
Wind	7,730	MW

Initial results of the annual LOLE study centered on the managed peak forecast resulted in LOLE of 0, and no reliability risk was seen at all. A result of 0 LOLE does not let us know what level of capacity is required however, and likely would lead to economically unnecessary over procurement. To reach the proper necessary PRM and RA program requirement, staff calibrated LOLE to be equal to 0.1 by reducing the evening hour CAISO Simultaneous Import Constraint (initially set at 4,000 MW) in steps until we reached the LOLE results described here. The CAISO area reached a LOLE of 0.1 at 1,700 MW of Import Constraint. At this level, staff determined that the 0.1 LOLE target was met. This signals that the lower RA requirement created by the lower managed peak provides for a margin of surplus in excess of the

Baseline Portfolio of about 2,300 MW effective capacity. Our final annual reliability metrics (LOLE, EUE, LOLH) are listed by month in Table 11 and annual energy balance (without SOD PRM tuning of individual months) is shown in Table .

Table 11: Monthly Reliability Metrics, Base case tuned to 0.1 annual LOLE

Month	LOLE	EUE	LOLH
1	0.0000	0.0000	0.0000
2	0.0000	0.0000	0.0000
3	0.0000	0.0000	0.0000
4	0.0000	0.0000	0.0000
5	0.0000	0.0000	0.0000
6	0.0000	0.0000	0.0000
7	0.0001	0.0003	0.0001
8	0.0004	0.0671	0.0004
9	0.1121	160.1	0.1402
10	0.0000	0.0000	0.0000
11	0.0000	0.0000	0.0000
12	0.0000	0.0000	0.0000
Total	0.1126	160.2	0.1407

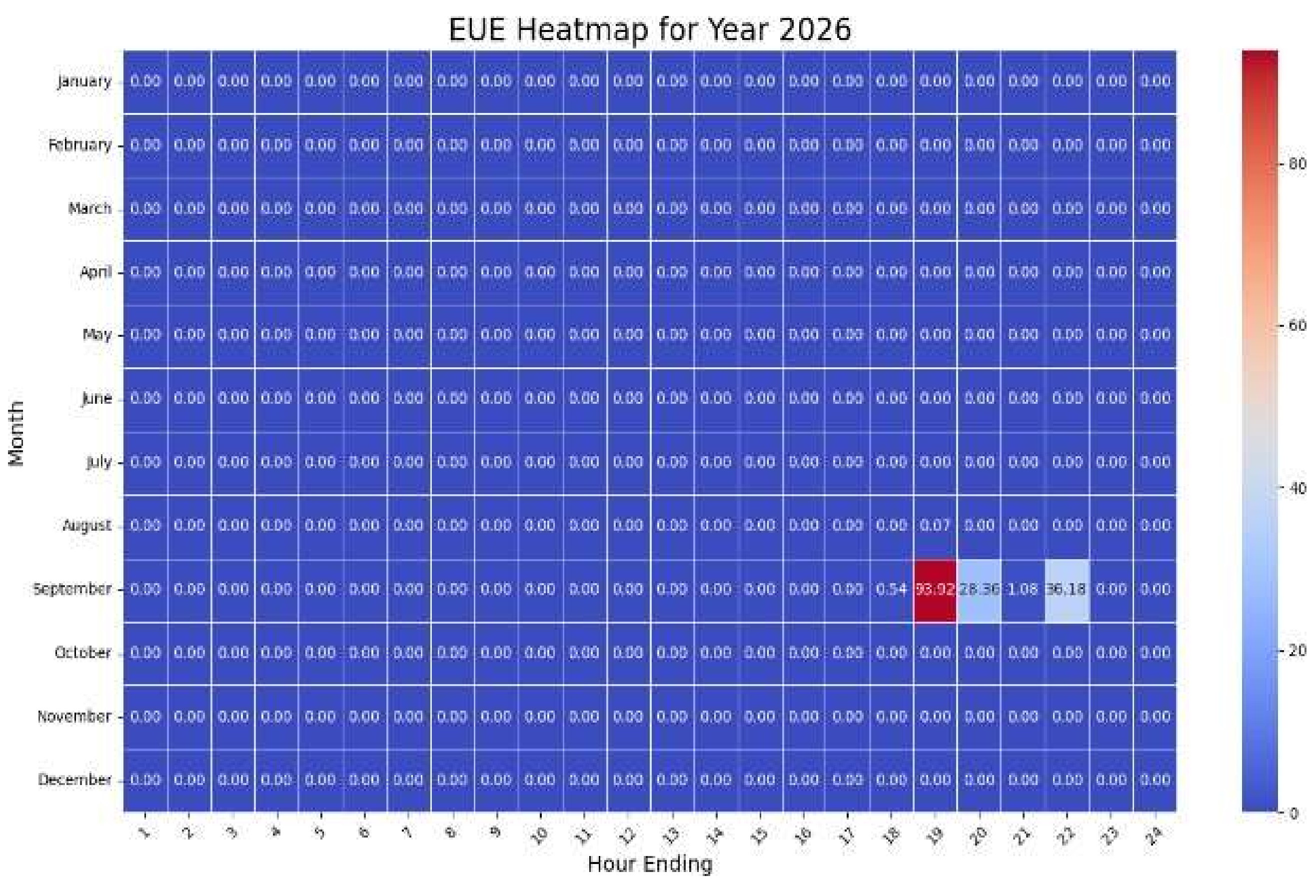
Table 12 Annual Energy Balance, Base case tuned to 0.1 annual LOLE

Annual Energy Balance		
	SERVM	
Category	**2026**	Units
Battery Storage	(2,701)	GWh
Biomass	5,049	GWh
BTMPV	34,944	GWh
Gas	76,673	GWh
Coal	-	GWh
DR	7	GWh
Geothermal	12,103	GWh
Hydro	26,898	GWh
Nuclear	25,711	GWh
OffshoreWind	-	GWh
OOSWind	-	GWh
PSH	(729)	GWh
Solar	65,287	GWh
Wind	19,177	GWh
Curtailed Energy	(3,711)	GWh
Net Imports	(2,803)	GWh

Total Demand Modifiers	5,925	GWh
Load	255,906	GWh
Total Generation	255,906	GWh

Figure 11 shows that when the system is balanced at 0.1 LOLE in the near term, LOLE is still seen during the net peak hours, particularly HE 19, and does not yet stretch to overnight hours. EUE is highly concentrated in September, reflecting the lower relative PRM and higher relative demand peak in that month. Overall, 2026 study year is reliable with available resources, and given the uneven LOLE across the year, the PRM levels are likely uneven. September is the riskiest month of the year in an annual LOLE study though that risk is limited.

Figure 11: Heatmap of EUE concentrated in Evening Hours



Translation of Annual LOLE Study into SOD PRM

This section details how the LOLE study results documented in the previous section were translated to a SOD PRM. As documented in the background section, the Commission adopted a SOD PRM calibration tool for use in translating the results of a LOLE study to a RA SOD PRM. To use the SOD PRM tool, the following inputs are needed.

1. Managed Worst Day (Day containing the Managed Peak) – Staff uses the California Energy Commission IEPR Hourly Load Model to identify the day with the Managed Peak in it, then

entered that entire 24 hour day into the SOD tool. A SOD PRM tool is created for each month, meaning staff identifies the 24 hour worst day and managed peak by month.

2. The portfolio for each month is extracted from SERVM and entered into the SOD PRM tool. Each technology category of resources is quantified according to either exceedance or QC calculation guidelines. The profiles tab contains QC values by unit category and profiles for each resource type, with solar and wind profiles based on the exceedance values for each month. The PSH and DR shapes and counting follow RA rules, and the simultaneous import constraint is entered into the SOD PRM tool across all 24 hours of the day flat.
3. The final output tab calculates the NQC MW by hour based on the profiles by unit category.
4. The Dashboard tab reflects the MW values of each unit category, as well as managed load and supply with and without storage.
5. The PRM_setting tab calculates the PRM using a solver by first seeking the minimum PRM across 24 hours without storage, then optimizing by adding storage to this lowest PRM while ensuring that the overall capacity of storage is not exceeded in any given hour and that the available energy in the batteries is not exceeded in any given day while guaranteeing there is sufficient energy to charge the batteries.

Staff translated the initial resulting annual portfolio of resources into the SOD tool and calculated monthly required PRMs. As expected, off-peak PRM levels were excessive due to lower electric demand relative to the annual capacity portfolio (calculated for each month using hourly SOD NQC values). As expected, LOLE equaled zero outside of September presenting an opportunity for levelizing PRM across the months to remove some of that excess. Table 12 illustrates the initial SOD PRM results showing that the required PRM in September is the minimum for the whole year and is equal to 17.8%. The other months show significant excess capacity relative to their much lower managed peak demand, which explains their minimal or zero LOLE.

Exceedance Values – Exceedance values are profiles for different technology types calculated for variable renewable energy resources based on six years of historical energy production. These values are based on exceedance levels, which provide the likelihood that a resource will produce more energy than the value given. Exceedance levels indicate the output of a resource (% nameplate) on at least X% of observations (e.g. 70%) for each month-hour pair are the reverse of percentiles, with 70% exceedance meaning that the number given is the 30th percentile of production (i.e., a higher exceedance level is a more conservative number). Staff use historical CAISO settlement quality data and/or modeled data where historical data is insufficient to derive both exceedance levels and values. To derive exceedance levels staff use historical production data during the top five CAISO load days, as well as days where a Flex Alert, EEA 1-3, or Emergency Alerts are called. Staff also uses a solver function to identify the exceedance level that minimizes LOLE in the worst days to identify unique exceedance levels for each month and for each technology type. The exceedance levels are then applied historical monthly production and a production profile for each technology type by region is produced and can then be applied hourly to the variable resource's nameplate MW

Table 12: Initial Monthly SOD PRMs resulting from Annual LOLE Portfolio

Month	Stressed Hour (HE)	Load	Supply (MW)	PRM
1	19	30,003	41,080	36.9%
2	20	29,165	45,511	56.0%
3	20	29,412	46,756	59.0%
4	19	31,688	53,716	69.5%
5	1	25,183	40,154	59.5%
6	20	40,117	54,904	36.9%
7	20	43,347	53,558	23.6%
8	19	44,125	54,893	24.4%
9	19	44,885	52,873	17.8%
10	18	37,720	51,035	35.3%
11	18	31,645	46,628	47.3%
12	19	30,392	41,387	36.2%

The primary differences in inputs across the months are the managed load and resource values. The managed load forecast input is derived from the CEC's hourly managed system (1-in-2) demand forecast and uses the worst day hourly load shape for each month. The hourly resource values for each month are derived from the draft 2025 master resource database (which will be published later this month or early next). Wind and solar values are derived from monthly exceedance production shapes using the updated exceedance methodology adopted in D.24-06-004. Hydro and non-dispatchable resources also vary by month and have been derived using the most recent historical data. The resource values used in the SOD tool are reflective of the RA values that will be used for the 2025 RA compliance year.

The translation of the annual LOLE study resulting in monthly SOD PRMs shows September as having the lowest PRM due to having the highest peak demand and the lowest exceedance production levels for solar and wind. However, other summer months (June, July and August) are fairly similar in overall reliability despite higher PRM levels. The other summer months are supported by the same portfolio of resources, despite the differing exceedance production profiles, and have only slightly different managed demand levels.

As reflected in Table 12, the PRM levels for the most stressed summer months (July-September) varied significantly. The PRM at the most constrained hour was around 17.8% in September and 24.4% in August. This variation between August and September is primarily driven by monthly variations in resource NQC values. On the demand side, while there is about 1,500 MW of variation in load between July and September, there is only about 700 MW of variation between August and September. On the supply side, however, we see over a 2,000 MW difference between August and September resource values during the most constrained hour and less than a 700 MW difference between July and September.

Table 13 reflects the NQC values used in the SOD PRM Tool by month and resource technology across the most constrained hour of the month (as reflected by the initial SOD PRM Tool results). Iin the most constrained hours of HE 20 in July and HE 19 in August and September, there is a significant decrease in production from variable renewable recourses. Between July and September, there is a drop off of over

1,700 MW of QC for wind production. Between August and September, there is a drop off of thousands of MW of QC for solar resources. The wind difference between July and September and the solar difference between August and September drive much of the supply difference leading to the small PRM in September.

Table 13 Monthly NQC used for SOD

Month	June	July	August	September	October
Constrained Hour	20	20	19	19	18
Biogas	206	204	202	202	197
Biomass/Wood	426	420	410	411	396
CC	17,138	17,110	17,113	17,129	17,188
Cogen	1,878	1,875	1,913	1,886	1,908
CT	8,012	8,025	8,023	8,031	8,037
DR	2,299	2,299	2,377	2,377	2,498
Geothermal	1,276	1,302	1,297	1,297	1,247
Hydro	3,082	3,313	3,118	2,905	2,190
ICE	255	255	255	255	255
Interchange	1,700	1,700	1,700	1,700	1,700
Nuclear	2,280	2,280	2,280	2,280	2,280
PSH	1,459	1,458	1,458	1,457	1,458
Solar Fixed_Norcal	197	161	401	152	342
Solar Fixed_Socal	144	111	506	114	428
Solar Thermal_Socal	149	122	291	104	249
Solar Tracking_Norcal	805	611	1,369	434	899
Solar Tracking_Socal	779	657	2,309	485	1,734
Wind_Norcal	900	961	552	554	128
Wind_Socal	2,380	2,743	1,929	1,407	624
Total Supply Without Storage (MW)	45,365	45,607	47,503	43,180	43,758
Load	40,117	43,347	44,125	44,885	37,720

Table 14 provides a heat map of the exceedance production profile differences between August and September. Every red space is a decrease in production of greater than five percentage points. The most constrained hours in September and August consistently have significant decreases in production from August to September. This means that all else being equal, the PRM level from the SOD PRM tool will be lower in September than in July or August, even if the capacity or nameplate margin of resources in excess of electric demand were the same. The decrease in exceedance production profiles contributes to significant variability in PRM during the summer months and explains the wide fluctuation in PRM across the summer months. It would be easier to use the SOD tool to set requirements for RA if exceedance production profiles were set for the whole summer, possibly taking an average of each monthly profile to make a comparison easier.

Table 14 Exceedance production profile differences between August and September

Hour	Solar Fixed_Norcal	Solar Fixed_Socal	Solar Thermal_Norcal	Solar Thermal_Socal	Solar Tracking_Norcal	Solar Tracking_Socal	Wind_Norca	Wind_Socal
1	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.12
2	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.14
3	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.11
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07
5	0.00	0.00	0.00	0.00	0.00	0.00	-0.02	0.07
6	0.00	0.00	0.00	0.00	0.00	0.00	-0.01	0.05
7	0.01	0.02	0.00	0.00	0.01	0.03	-0.02	0.03
8	0.06	0.05	0.00	0.05	0.11	0.11	-0.05	0.02
9	0.02	0.02	0.00	0.08	0.04	0.05	-0.10	0.00
10	-0.01	-0.01	0.00	0.04	0.02	0.04	-0.10	-0.01
11	-0.03	0.00	0.00	0.04	0.02	0.03	-0.08	-0.02
12	-0.01	0.02	0.00	0.06	0.04	0.04	-0.06	-0.03
13	0.00	0.02	0.00	0.06	0.05	0.03	-0.05	-0.03
14	0.01	-0.01	0.00	0.05	0.04	0.03	-0.04	-0.01
15	0.01	0.00	0.00	0.02	0.03	0.01	-0.04	-0.01
16	0.01	0.01	0.00	-0.02	0.02	0.03	-0.05	0.00
17	0.03	0.05	0.00	0.00	0.03	0.04	-0.04	0.03
18	0.11	0.16	0.00	0.07	0.15	0.20	-0.01	0.09
19	0.12	0.09	0.00	0.19	0.18	0.17	0.00	0.09
20	0.01	0.00	0.00	0.05	0.01	0.01	-0.02	0.10
21	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.10
22	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.12
23	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.12
24	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.13

Due to the expectation that the LOLE will be uneven across the summer, even with an annual portfolio, Staff proposes to levelize LOLE across the summer months as part of evaluating the overall monthly SOD calculate PRM needed to meet 0.1 LOLE. To do this, Staff first raised the import constraint from 1,700 MW to 2,500 MW to raise the PRM in September from 17.8% to 18.5%. Less LOLE occurred in September as a result. Staff increased PRM by increasing the Simultaneous Import Constraint to raise the PRM in September and relieve some of the LOLE in September in case other summer months produce LOLE when their PRM is lowered. Staff then added blocks of demand to the other months (including July and August) to increase their LOLE and lower their PRM levels until LOLE again totaled 0.1. This avoids the confusion of having to select resources to remove and is an optimal way to balance LOLE risk across CAISO. It is very important to calculate needed demand blocks using the SOD tool and record the PRM levels and what hour becomes the stressed hour. This is necessary since as batteries are optimized, energy is shifted around the day and what was a constraint on one hour can become a constraint on a different hour as optimization is refreshed . PRM levels are confirmed by running the SOD PRM tool for that month using that month's specific managed demand day profile and exceedance values. Staff repeated this calibration until annual aggregate monthly LOLE equaled 0.1.[13]

Monthly Stress Test Results

Staff will be posting the monthly (12 in total) calibrated PRM workbooks on the CPUC website that support the results of the monthly PRM SOD results. Those workbooks will demonstrate how we implemented the stress tests as proposed by adding blocks of load to each month to levelize the PRM across the year and LOLE risk across the summer. Proposed SOD PRM levels as well as blocks of demand added in each month are shown below in Table 15.

Staff arrived at a levelized PRM that resulted in LOLE at 0.1 with a PRM of about 18.5% in each month. Only February was unable to reach acceptable LOLE at an 18.5% PRM, and the SOD PRM tool did not achieve a successful solution in the optimizer at a PRM below 20%. Staff will investigate that one month

[13] RA proposals from January 2024 are discussed in this slide deck. SOD Stress Test proposals begin on slide 81. [ra-oir-track-1-workshop-022924.pdf (ca.gov)]

further. The other months showed acceptable LOLE, and across the whole year totaled 0.12 (excluding February). Staff will continue to investigate the anomalous February results.

Table 15 Levelized Proposed SOD PRM levels

Month	Stressed Hour	Load	Total Supply	Demand block added to levelize PRM	Target PRM
1	19	30,003	41,139	4,750	18.37
2	20	29,165	44,668	8,000	20.19
3	20	29,412	45,376	9,000	18.13
4	2	26,182	41,017	8,900	16.92
5	1	25,183	40,954	9,400	18.42
6	20	40,117	54,350	5,842	18.25
7	20	43,347	54,012	2,200	18.58
8	20	41,769	52,354	2,425	18.46
9	19	44,885	53,756	400	18.71
10	19	35,905	48,289	4,800	18.63
11	18	31,645	45,752	6,950	18.54
12	19	30,392	41,504	4,650	18.44

Table 16 illustrates the LOLE, EUE and LOLH levels by month from this study. The results show that all months, except for February have minimal or zero LOLE at a 18.5% PRM. This confirms that this is the correct PRM level, and though this is higher than the bare minimum annual PRM, this level is sufficient to impose on each month as the SOD PRM for the RA obligations in 2026. As noted above, LOLE results in February continue to be elevated even at a 18.5% PRM (.048 LOLE for February), and staff will continue to investigate why that is the case. Also, April's PRM is below 18.5% as the most constrained hour is HE2, which has very low demand. At this PRM, however, LOLE in April is minimal so it is reasonable that a 18.5% PRM is sufficient for that month. Excluding February's LOLE value, the total LOLE for the year equals 0.12 and is close to the 0.1 target.

Table 16 LOLE and EUE levels in each month at 18.5% PRM

Month	LOLE	EUE	LOLH
1	0.000316	2.39	0.000758
2	0.048531	337.02	0.081850
3	0.001954	4.63	0.002371
4	0.000362	0.23	0.000362
5	0.014898	18.78	0.024597
6	0.017539	17.79	0.017539
7	0.00298	1.82	0.003651
8	0.007954	10.60	0.012335
9	0.075206	98.09	0.089358
10	0.000000	0.00	0.000000
11	0.000063	0.17	0.000063
12	0.000000	0.00	0.000000
Total	**0.169802**	**491.52**	**0.232884**

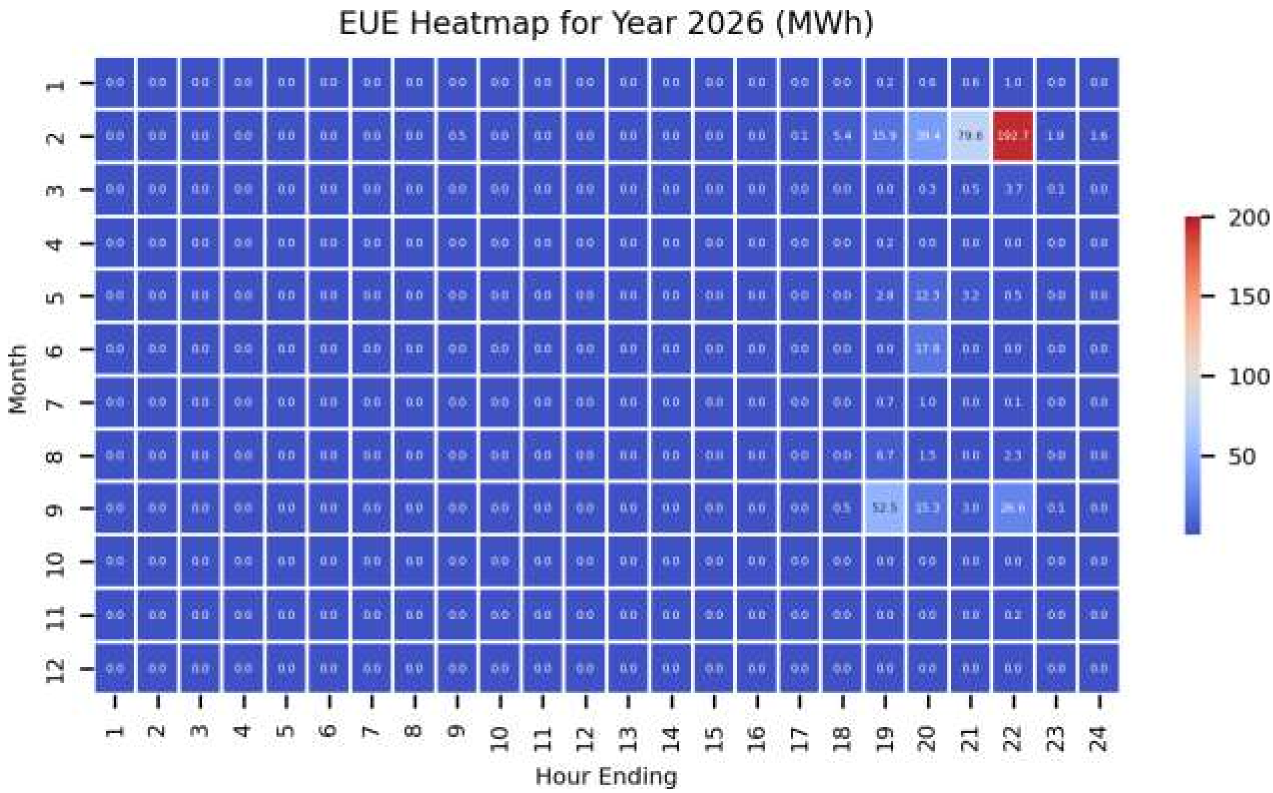
Table 17 shows the amount of energy (in GWh) generated by each unit type. Battery storage and PSH are net negatives, as they require more energy to charge than they discharge. Larger negative numbers illustrate heavier use. See that the BTMPV GWh of energy generated is substantial, more than 15% of total CAISO energy to meet load (255,910 GWh). See that total generation equals total demand and that total demand modifiers net out to a positive number (meaning more demand reducing modifiers than demand increasing). In future years, that number becomes negative as EV load begins to grow substantially.

Table 17 Annual Energy Generated by Unit Type in 2026

Annual Energy Balance		
	SERVM	
Category	**2026**	Units
Battery Storage	(2,698)	GWh
Biomass	5,166	GWh
BTMPV	34,944	GWh
CC	81,713	GWh
Coal	-	GWh
Cogen	16,299	GWh
CT	9,232	GWh
DR	10	GWh
Geothermal	12,489	GWh
Hydro	16,746	GWh
Hydro_NW_CAISO	10,152	GWh
ICE	356	GWh
Nuclear	25,711	GWh
OffshoreWind	-	GWh
OOSWind	-	GWh
PSH	(638)	GWh
Solar	65,317	GWh
Steam	-	GWh
Wind	19,178	GWh
Curtailed Energy	(427)	GWh
Net Imports	18,136	GWh
Total Demand Modifiers	5,925	GWh
Load	255,910	GWh
Total Generation	255,910	GWh

Figure 12 illustrates what hours and what times of year LOLE occurs. The figure reflects that when PRM is levelized across the year, additional LOLE events occur outside of the summer and outside of September. A levelized PRM would potentially reduce risk in September relative to the lower September PRM in the Annual LOLE Base case, but the exchange is increased LOLE risk in other summer months. It is unlikely that offpeak months will be binding in reality though a levelized PRM would theoretically be the minimum level needed to prevent LOLE events. Levelizing the PRM in offpeak months create Increased LOLE risk in offpeak months relative to the much higher PRM levels in the Annual LOLE base case.

Figure 12 LOLE events Throughout the year - SOD Monthly Stress Test



Path 26 and Simultaneous Imports Stress Tests

To test the effect of constraints on either imports or Path 26, staff performed a series of sensitivity tests. In the first set of sensitivities, Staff used a case with high LOLE to test the effect of raising or lowering the evening CAISO Simultaneous Import Constraint or Path 26 limits on LOLE. Staff performed two sensitivities with this high LOLE case (High LOLE cases), one where the Import Constraint was increased by 1000 MW (From 4,000 MW to 5,000 MW), and the other where Path 26 in the PGE flowing to SCE direction (North to South) was increased by 1000 MW (from 4,000 MW to 5,000 MW). Staff recorded the LOLE for each High LOLE case and captured dispatch results that show how resources were dispatched, and whether the Import Constraint or Path 26 constraint were binding in a given hour.

In a second set of sensitivities, Staff used the final Annual LOLE study case (the Annual Base Case calibrated to 0.1 LOLE at 1,700 MW of evening CAISO Simultaneous Import constraint) to test the LOLE reducing impacts of changing the Import Constraint or the Path 26 North to South direction limit. The Import Constraint was first reduced by 500 MW and the LOLE result recorded. Then, the Path 26 limit was increased by 500 MW and the LOLE result recorded.

In the High LOLE case sensitivities, increasing Path 26 produced almost no effect on LOLE while increasing the Import Constraint reduced LOLE significantly. Staff concluded that relaxing Path 26 constraints are not impactful to reduce LOLE when it is already high. On the other hand, the Import Constraint was a useful lever of LOLE risk. Even more interesting, staff observed that when the Import

Constraint binds, one region in CAISO will attempt to import capacity from another region in CAISO to alleviate LOLE. In short, the region that is short tries to resolve LOLE risk by either importing more from neighboring regions or from other parts of the CAISO. It is when other regions cannot provide more help that we see Path 26 being constrained.

Figure 13 shows Path 26 North to South during HE 17:00-22:00 in 2026. In a system constrained such that no more capacity is available from imports, we see LOLE coinciding with Path 26 constraint. In other hours less constrained, Path 26 does not bind. This shows that the first order constraint is the Simultaneous Import constraint. In a system without excessive LOLE driven by shortages and constraints on import capacity, Path 26 does not cause additional reliability risk on its own.

The results of this analysis show that the SCE area will first attempt to import additional energy or capacity from outside CAISO, and only when that import ability is constrained will SCE attempt to pull down energy or capacity from the PG&E area across Path 26. For that reason, during peak periods or times of reliability risk, any reduction or constraint on Path 26 will likely exacerbate or increase reliability risk. Any wheeling contracts or other transfers across Path 26 become critical in peak or constrained times.

Figure 13: Path 26 North to South and SCE EUE during hours ending 17:00 – 22:00 in 2026

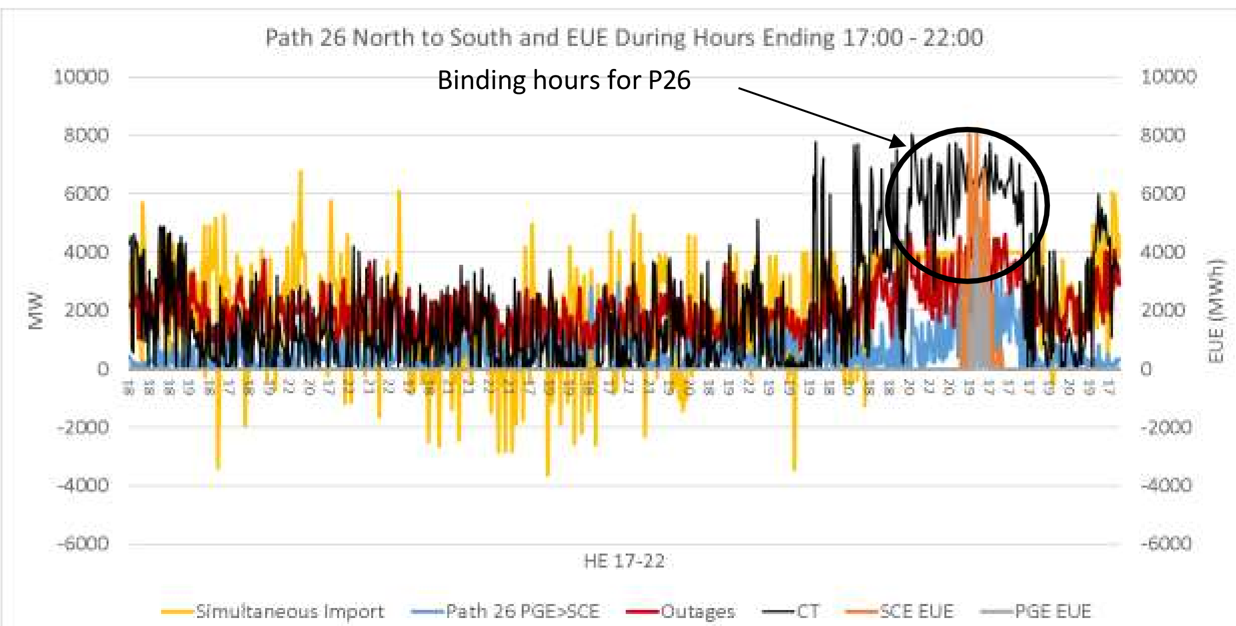


Figure 14 below further zooms in on the previous figure showing the High LOLE Case, showing the four hours in September that the North to South Path 26 is binding. During these four hours, simultaneous imports and Path 26 North to South are at their maximum constraint (4,000MW) and LOLE at SCE also is happening in one of these hours. Total outages of all resources (in red) are also elevated during this period as more conventional resources are dispatched.

Figure 14 Binding hours and EUE during HE 17:00-22:00

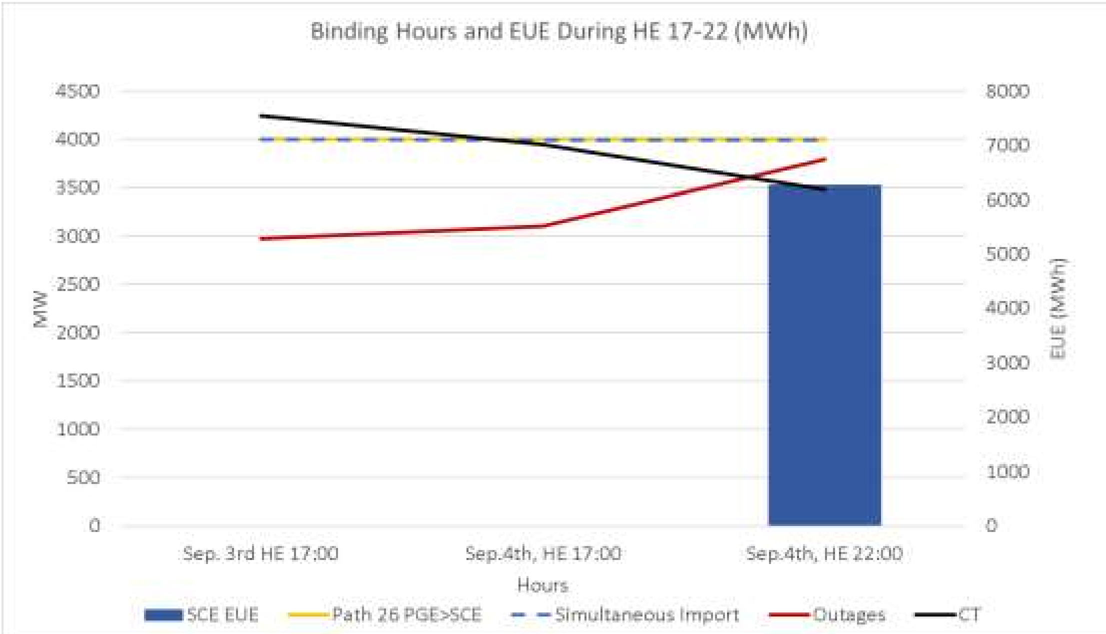
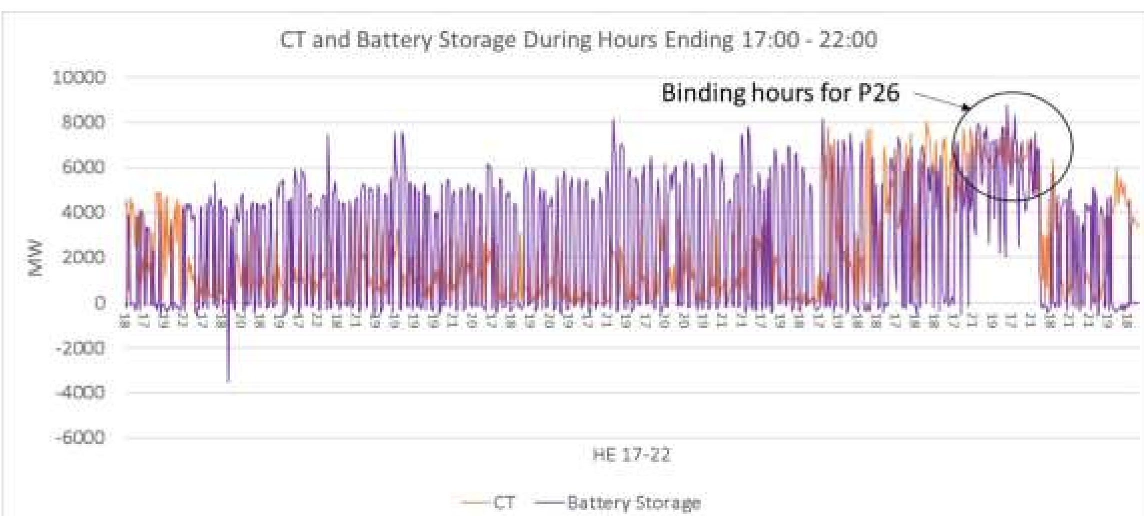


Figure 15 again zooms in on the High LOLE case to show how CT and Batteries increase their dispatch significantly during LOLE hours. This figure is another look at the same time period as Figure 13, showing just CT and battery dispatch during the LOLE hours where both Path 26 and the Simultaneous Import constraints are binding. See that previous to the LOLE hours in the right side of this chart, dispatch patterns on batteries and CTs appear stable but become strained (never letting batteries charge) during the most critical hours.

Figure 15 CT and Battery Storage during HE 17:00-22:00



The Annual Base Case sensitivity also showed that the Import Constraint played a greater role in LOLE than Path 26. In this sensitivity, staff started with the Simultaneous Import Constraint level from the Annual Base Case (1,700 MW) and decreased it by 500 MW (to 1,200 MW) and LOLE increased from

0.11 to 0.15. Next, staff increased Path 26 from 4,000 MW to 4,500 MW to see if that would reduce LOLE back to 0.11. Results showed that LOLE remained the same with additional room on Path 26, showing that Path 26 is not a significant remedy for LOLE when already constrained. This is potentially due to shortages of excess capacity in other regions of CAISO to transfer, even if Path 26 had room to accommodate it.

Staff concludes from these sensitivities that the Simultaneous Import Constraint is a more important driver of reliability need than Path 26, and that Path 26 is only binding when there is already a preexisting import constraint. In other words, when CAISO's BAA is binding due to simultaneous imports, SCE leans on PG&E to alleviate LOLE. Therefore, Path 26 is critical for CAISO reliability mostly in a time of regional resource constraints.

PRM Recommendation

Based on studies performed both for an annual LOLE study and for Monthly PRM results, staff propose a PRM of 18.5% implemented across all 12 months of the RA compliance year. This translates to the existing baseline fleet plus 2,500 MW of simultaneous Import Constraint and reflects reliability needs for the 2026 RA compliance year. For purposes of CPUC jurisdictional RA PRM requirements, we recommend implementing the monthly SOD PRM resulting from the stress tests, not the annual LOLE study that only focused on the peak month.

The CPUC jurisdictional LSEs subject to any CPUC adopted PRM only account for roughly 90% of the load in CAISO. Since non-CPUC jurisdictional LSEs are not subject to the CPUC's PRM (and historically have demonstrated less than 15% PRM for their own loads), used non-RA eligible resources to meet their PRM, and not all use the IEPR load forecasts), it is possible that reliability could be eroded due the uneven application of a PRM. For example, this study provides that there is surplus/cushion identified if a 18.5% PRM is applied to the CAISO, such that the resource portfolio plus 2,500 MW of resources can maintain a 0.1 LOLE. (If imports are a bit higher or built resources are a bit lower – LOLE can be maintained, thus there is a cushion.) However, if non-CPUC jurisdictional LSEs do not provide a 18.5% PRM alongside CPUC jurisdictional LSEs, the effect is also to lower the reliability cushion of the entire system. Furthermore, some resources in the baseline fleet may be resources dedicated to non-CPUC jurisdictional entities and not performed as modeled.

Questions for Stakeholders and Parties

1. Does an 18.5% PRM for all hours and months of the year appear reasonable given the study results, the application of the SOD PRM tool, and the stress tests performed?
2. Is the application of the SOD PRM tool sufficient in translating LOLE portfolio results and setting monthly PRM requirements for the SOD Framework?
3. What future modifications are needed to the SOD PRM tool to make it more accurate at translating LOLE study results?
4. The 18.5% PRM being proposed is for use in the 2026 RA compliance. This PRM level is based on the 2023 IEPR for the 2026 compliance year. However, the 2024 IEPR will be used to develop LSE SOD load forecasts for the 2026 RA compliance year. The vintage of the IEPR used to set the PRM and used to set the RA load forecast will only align if the PRM is updated annually after the

annual IEPR is adopted.   Please provide your comments on how best to address the timing gap between the IEPR vintages used to set the SOD PRM and used for the RA load forecast.

5. Are the EFOR methodologies Staff used to update the forced outage rates for batteries and conventional units appropriate and what recommended changes to these methodologies should be made in the future?
6. What additional stress tests of Path 26 should Energy Division perform in the future to better understand how priority wheel throughs could impact grid reliability and future RA and IRP procurement?
7. Provide your feedback on Staffs use of the 2023 IEPR managed peak demand (rather than the IEPR consumption peak), to calibrate the CPUC model? In future LOLE studies should the same analysis of the IEPR consumption and managed forecast be done in deciding how best to calibrate the CPUC LOLE model?