Loss of Load Expectation Study for 2028: Final Results

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11/05/26
03:13 PM
R2510003

Resource Adequacy Program
Slice of Day Planning Reserve Margin

November 2, 2026
Prepared for CPUC Rulemaking (R.) 25-10-003

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
EDU – Economic and Demographic Uncertainty	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

Purpose and Context

This report presents the final results of the 2028 Loss of Load Expectation (LOLE) study performed by CPUC Energy Division Staff. The information contained in this report will be considered in Track 2 of Rulemaking (R.) 25-10-003 and is intended to inform discussions on the setting of the Planning Reserve Margin (PRM) for the Slice of Day (SOD) Resource Adequacy (RA) program for compliance years 2028 and 2029.

Background

In April 2026, Energy Division Staff published a Proposed Inputs & Assumptions (I&A) document[1] for the 2028 LOLE study. The document was issued by Administrative Law Judge (ALJ) Ruling in RA proceeding R.25-10-003. The Proposed I&A document laid out key updates to the study's modeling inputs, including the baseline generation resource list, operational variables, weather and hydro generation data, and demand forecasts. The document also described the methodological approaches for calibrating the study to a reliability standard of 0.1 LOLE, or one loss-of-load event in ten years and translating study results into the SOD RA Framework. Following review of party comments on the Proposed I&A, Energy Division published a Revised I&A document[2] on June 5, 2026, which established the inputs and methods Staff used to conduct the 2028 LOLE study.

Decision (D.) 26-07-008, Ordering Paragraph (OP) 13 adopted the Unforced Capacity (UCAP) framework as outlined in Appendix B. To this end Staff developed a SOD PRM Calibration Tool that incorporates resource-specified UCAP values for thermal, storage, and co-located resources, and can be used to calculate a PRM consistent with the UCAP framework.

Staff used that SOD PRM Tool to apply UCAP resource counting methodology to the study portfolios. The SOD PRM Calibration Tool incorporates the UCAP derate factors into the *SERVM Units with UCAP* tab to derate resources by their average Equivalent Forced Outage Rate during demand periods (EFORd) and derates due to ambient temperature. Thus, throughout the report Staff presents PRM levels as either Installed Capacity (ICAP) PRM or UCAP-based PRM, meaning without UCAP derate and with UCAP derate.[3] This translation is applied only to the SOD PRM Calibration Tool and does not require additional SERVM runs.

On August 14, 2026, Energy Division published draft results of the 2028 LOLE study and solicited informal feedback from stakeholders, with comments due September 2, 2026. Through that feedback process, an issue related to the solar and wind profiles used in the SOD Calibration Tool was identified. Staff reviewed the issue, confirmed its impact on study results, and resolved the error. Energy Division then hosted a hybrid workshop on September 15, 2026, where Staff presented

[1] Proposed Inputs and Assumptions, SERVM 2026 Data Updates in Support of Resource Adequacy (RA) and Integrated Resource Planning (IRP)

[2] Revised Inputs and Assumptions: SERVM 2026 Updates in Support of RA and IRP

[3] ICAP PRMs are calculated using the current qualifying capacity (QC) methodologies adopted for the RA program.

updated Draft study results reflecting the correction. Southern California Edison (SCE) and the California Community Choice Association (CalCCA) also presented their own analyses at the workshop.

Following the workshop, an ALJ Ruling was issued on September 25, 2026, recognizing that additional time would be beneficial for parties and Energy Division Staff to revise their final 2028 LOLE studies in response to stakeholder feedback received at the September 15 workshop. The ruling revised the LOLE study schedule, establishing a November 2, 2026 deadline for issuance of the final report and setting comment and reply comment deadlines of November 20, 2026, and December 11, 2026, respectively. The final 2028 LOLE study results presented in this report are generally consistent with the updated results discussed at the September 15 workshop, with one exception: the Prorate Capacity scenario was further refined to produce more accurate and robust results comparable to those presented previously. In addition to the finalized study results, this report includes Staff's PRM recommendation.

Methodology

As described in the Revised I&A document issued in June 2026, Energy Division performed extensive updates to the underlying datasets used for the 2028 LOLE study. These updates include incorporating 2023 and 2024 historical weather into the weather-related datasets, like electric demand, wind and solar production, and hydroelectric availability. Staff updated demand forecasts to reflect the California Energy Commission (CEC) 2025 Integrated Energy Policy Report (IEPR), adopted at the beginning of 2026, and the 2034 forecast for other regions from the Western Electricity Coordinating Council (WECC) Anchor Data Set (ADS). Staff refreshed the list of existing generating resources in the CAISO Balancing Authority Area (BAA) and the surrounding BAAs, as well as a refresh of the expected resources that are in development to become online by 2028. Once these updates were incorporated into the modeling dataset, staff performed LOLE studies of the CAISO BAA to determine its 2028 reliability level as-is, to quantify any surplus or shortfall, and to calibrate CAISO reliability to a 1 event in 10 years LOLE target (also referred to as the 0.1 LOLE target). The stochastic production cost model software used by Staff for several years is the Strategic Energy and Risk Valuation Model (SERVM) developed by PowerGEM Consulting[4]. SERVM is a probabilistic system-reliability planning and production cost model designed to analyze the capabilities of an electric system during a variety of conditions under thousands of different scenarios, providing insight into system risks, costs, and the ability to serve peak demands given a range of uncertainty.

Since a primary objective of these studies is to quantify a minimum reserve margin that meets the reliability target considering a range of uncertainties, Energy Division wanted to test different methods of calibrating the CAISO BAA to the 0.1 LOLE target. Results from initial studies of the CAISO BAA showed the system was over-reliable. Thus, Staff focused on testing different methods of increasing LOLE towards 0.1 LOLE. These methods include adding flat blocks of demand, constraining simultaneous import limits, and applying a downward pro rata capacity adjustment to

[4] SERVM | Resource Adequacy Software | PowerGEM

all capacity. Staff translated that LOLE target into a monthly PRM with the current SOD PRM Calibration Tool. Staff also modeled various sensitivity studies to compare results to prior studies and to quantify the impacts of updated data. Specifically, Staff quantified the effects of adding or updating ambient temperature output derating and forced outage (equipment failure) rates. Staff also calculated the effects of economic and demographic uncertainty (EDU) on reliability levels. Separately, Staff also studied an alternative method of calculating PRM: calculating the difference in monthly PRM when using the IEPR 1-in-2 monthly peaks in the denominator of the reserve margin calculation versus using analogous 1-in-2 monthly peaks calculated from the full set of weather year specific hourly profiles used in SERVM.

Key Findings

Final study results suggest the CAISO BAA will be over-reliable in 2028 under the base case assumptions identified in the I&A, with a surplus equivalent to approximately 6,000 MW, quantified by the amount of additional load that could be served with base case assumptions and achieving a 0.1 LOLE reliability target. Quantifying the surplus by adding the same level of demand in each month resulted in a 16.64% ICAP PRM in September, where nearly all the loss-of-load events were concentrated, and higher achieved reserve margins in other months.[5]

In addition to the base case findings, study results from other scenarios and sensitivities yielded a number of other insights:

Monthly Stress Tests

Additional analysis aimed to spread loss-of-load events from the peak month to other months of the year and to test a levelized PRM across the year. This was achieved by increasing demand above 6,000 MW in non-peak months and decreasing it below 6,000 MW in peak months.[6] Stress Test results showed reduced monthly PRMs in non-peak months and a higher monthly PRM in peak months, with monthly LOLE amounts that still total to about 0.1 LOLE across all months of the year. The final tuned monthly stress test scenario achieved an ICAP PRM of 21% for summer months (May – September) and 19% for non-summer months (October -April). The monthly PRMs were calculated with the SOD PRM Calibration Tool using the modeled demand and resources as inputs.

UCAP Resource Derates

D.26-07-008 established the methodology to calculate UCAP resource accreditation and set forth the intent for the Commission to implement UCAP accreditation beginning in compliance year 2028. Applying the UCAP forced outage and ambient temperature resource derates to calculate

[5] These findings refer to the Base Case (Flat Load) scenario where 6,000 MW of flat demand was added to all months to calibrate to 0.1 LOLE, resulting in a 16.64% ICAP PRM in September.

[6] This refers to the Base Case (Stress Test) scenario where 4,430 MW of demand was added to September and between 6,518 – 19,812 MW in other months to calibrate to 0.1 LOLE.

monthly PRM values in the SOD PRM Calibration Tool reduced the monthly stress tested ICAP PRMs to approximately 16% UCAP PRM in May – September and 14% in October -April.[7]

Adding Reserves to Address Ambient Thermal Derates

Staff conducted a sensitivity analysis that indicates an approximately two percentage point increase in summer month reserve margins is required to account for the expected heat related derates on thermal resources in the CAISO BAA.

Updated Forced Outage Rates

Staff conducted a sensitivity analysis to evaluate the impact of using updated forced outage rates in the modeling assumptions. For the current study, outage rates are derived from the CAISO Outage Management System (OMS), whereas previous studies utilized values from NERC's Generator Availability Data System (GADS). Staff found that utilizing the new data source reduces the modeled reliability need and the September PRM by approximately one percentage point.

Economic and Demographic Uncertainty (EDU)

Staff conducted a sensitivity to understand how sensitive system reliability would be to a different distribution of EDU. Most of the scenarios studied used the updated, narrower EDU distribution. A sensitivity of the Base Case (Flat Load) scenario using the prior, wider EDU distribution resulted in a 0.6 percentage point increase in PRMs.

Prorate Capacity

Staff tested prorating capacity as an alternative method for surfacing LOLE. Prorating capacity to 87.6 % for all technologies except hydro achieved a 0.1 LOLE annual result. That translated into a 19.1 % ICAP PRM in September and higher achieved reserve margins in other months. 87.6 % prorating corresponds to about 12.8 GW of removed capacity (nameplate).

Planning Reserve Margin Recommendation

PRM results throughout the report are presented as an ICAP PRM and as an UCAP-based PRM. The purpose of providing PRM values in both contexts is so results can be interpreted in the context of existing PRM (i.e. RA) requirements that are ICAP-based, communicate the recommended UCAP-based PRM that would be adopted for the RA program for compliance years 2028 and 2029, and allow stakeholders to compare Energy Division's results with parties that submit PRM proposals that are either ICAP or UCAP-based.

Based on the 2028 LOLE analysis conducted by Energy Division, Staff recommends adopting a UCAP-based summer PRM of 16% for the months of May – September and a UCAP-based non-summer PRM of 14% for the months of October - April for RA compliance years 2028 and 2029.[8]

[7] In this scenario, the amount of added demand in each month is identical to the Base Case (Stress Test) scenario and UCAP resource accreditation methodology is applied in the SOD PRM Calibration Tool to reflect the UCAP-based PRM.

[8] Results were rounded to nearest percent value for the PRM recommendation.

These PRM levels translate to an ICAP-based summer PRM of 21% in May – September and ICAP-based non-summer PRM of 19% for October- April. Staff's recommendation is based on the Base Case (Stress Test) scenario where Staff sought to levelize the PRM throughout the year, while ensuring that the total LOLE across all months of the year is calibrated to 0.1. This scenario utilized the latest forced outages rates, included derates to thermal power plants due to ambient temperature, applied an updated (narrower) economic and demographic uncertainty distribution, and used the 2025 IEPR 1-in-2 managed CAISO coincident peak demand forecast for 2028 to determine the reserve margin calculation denominator.

This report also includes sensitivity analyses that isolate the impacts of key modeling inputs and assumptions on the resulting PRM recommendations. These sensitivities help quantify the contribution of individual factors to the PRM, illustrate the tradeoffs associated with including specific elements in the analysis, and provide stakeholders with additional context for evaluating alternative approaches. They also facilitate comparison to the 2026 LOLE study conducted by Staff in 2024 and help explain the differences between that study's findings and the PRM recommendations presented in this report.

Introduction

Staff completed a LOLE study in December 2024, as part of R.23-10-011, and the study was used to inform RA requirements for the 2026 and 2027 RA program years.[9] Results of this previous study suggested that PRMs of 22.5% in peak months and 21% in off-peak months were required to maintain a 0.1 LOLE reliability standard under a specific set of conditions detailed in the report. In February 2025, Energy Division identified an error in the demand forecast due to time adjustments made for Daylight Savings. After correcting this, Energy Division revised its PRM recommendation to 21% for summer months and 20% for off-peak months.[10]

D.25-06-048 noted that the study went through several iterations to address stakeholder feedback and that there was lack of party consensus on what is the appropriate PRM. Ultimately, the Commission adopted an 18% PRM for 2026-2027 and coupled this with a nonbinding effective PRM procurement target of 1,260 – 2,300 MW to support reliability goals. The binding RA requirement of 18% PRM applies to all CPUC jurisdictional load serving entities (LSEs) and the effective PRM procurement targets support the attainment of approximately a 21% PRM. However, the effective PRM is only a target (not subject to RA penalties) whereby the three large investor-owned utilities (IOUs) procure additional resources to support reliability, but with some additional flexibility designed to support a balance of reliability and affordability.

To be responsive to concerns raised in the course of developing and reviewing prior LOLE studies, the Commission scheduled more opportunities for stakeholder engagement in the 2028 LOLE study process. This included comment periods on the Proposed I&A, party submissions of alternative I&A and independently conducted LOLE studies, public workshops, and a defined timeline for draft and final study results.

In accordance with the R.25-10-003 Scoping Memo, Energy Division released Draft LOLE Study results on August 14, 2026, and hosted a workshop on September 15, 2026, to present draft results and solicit stakeholder feedback. The issuance of this final report will be followed by opening and reply comment periods in Track 2 of R.25-10-003.[11]

Following the release of the Draft LOLE Study results, Staff continued modeling efforts on the Prorate Capacity scenario, conducted additional sensitivity analyses, and incorporated stakeholder

[9] Appendix B Loss of Load Expectation Study for 2026 (December 2024): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M549/K797/549797826.PDF

[10] February 2025 Energy Modeling Workshop. Issued via R.23-10-001 Ruling on 2/25/25: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M557/K609/557609748.PDF

[11] R.25-10-003 Scoping Memo (Dec. 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M590/K884/590884355.PDF

feedback. The final Prorate scenario results which achieved 0.1 LOLE with a prorate capacity reduction of 87.6% are presented herein.

A key revision in the final report is a correction to the resource profiles used in the Slice of Day PRM Calibration Tool. An error was identified where the incorrect hourly profiles for solar and wind resources were being used in the Draft Study results. After correcting the error, Staff adjusted the monthly added demand amounts to levelize the PRM and re-ran SERVM to verify that the new demand amounts were calibrated to a 0.1 LOLE reliability target.[12] These corrected results were shared at the September RA workshop and are incorporated in the final report.

Model Improvements

Throughout the development of the Proposed and Revised I&A documents, Staff developed and updated extensive data sets in order to make this study as up to date as possible. The Revised I&A document and the updated modeling datasets have been posted to the CPUC website for review and use by parties in the RA proceeding.[13,14]

The key new or updated input data are summarized below:

- Updated the CAISO baseline generating fleet of existing and under construction resources from the current CAISO Master Generating Capability List (August 2025 vintage) and the CAISO New Generator Interconnection Resource ID
- Report (GIRR) (August 2025 vintage)
- Updated existing or under construction non-CAISO units from the WECC 2034 Anchor Data Set (ADS)
- Incorporated the California Energy Commission (CEC) 2025 Integrated Energy Policy Report (IEPR) California Energy Demand Forecast
- Updated the non-California managed demand forecast from a survey of non-California Integrated Resource Plans, EIA BTM PV information, and the WECC 2034 ADS
- Updated weather (which determines modeled hourly electric demand, solar generation, and wind generation) and hydroelectric data spanning 2000-2024 by adding historical years 2023 and 2024
- Updated scheduled (maintenance) and unscheduled (forced) outage rates for several resource classes based on the revised UCAP proposal adopted in D.26-07-008
- Incorporated ambient temperature output derating for thermal generating units

[12] Correcting the solar and wind profiles in the PRM Calibration Tool reduced the monthly PRM values by 3 to 5 percentage points when comparing draft results to the final study results.

[13] Revised Inputs & Assumptions for 2028 LOLE Study (June 2026): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M608/K310/608310037.PDF

[14] System Reliability Modeling Datasets 2026: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/energy-modeling/servm-inputs-2026

In response to party comments on the Proposed I&A document, Staff also incorporated additional scenarios into the 2028 study and include the outputs of those scenarios in this final report. These scenarios evaluate alternative economic and demographic uncertainty levels and differing methods for surfacing LOLE (e.g., prorating capacity vs. adding flat blocks of demand vs. constraining simultaneous import limits). Including these scenarios will allow stakeholders to compare methodological approaches and foster more informed discussions on the appropriate PRM levels.

Description of Modeling Scenarios

Table 1 below provides an overview of the modeling scenarios that Staff conducted, organizing the model runs in order from Base Case studies to Monthly Stress Tests, and finally additional sensitivity studies to assess impacts on reliability needs. This table serves as a reference for the study results presented throughout this report.

Table 1: Base Cases and Sensitivity Scenarios

Scenario Name	**Method of Annual Calibration / Surface LOLE**	**Econ-Demo Uncertainty (EDU)**	**Ambient Temp. Derate Included**	**Maintenance Schedule Included**
Base Case	N/A	Updated	Yes	Yes
Base Case (Flat Load)	Add uniform flat demand (MW) blocks to each month to calibrate annual LOLE.	Updated	Yes	Yes
Base Case (Constrain Imports)	Tighten simultaneous import constraints to calibrate LOLE.	Updated	Yes	Yes
Prorate Capacity	Reduce capacity by the same proportion in each month to calibrate LOLE.	Updated	Yes	Yes
Base Case (Stress Test)	Add monthly varying flat demand (MW) blocks to calibrate annual LOLE and levelize monthly PRM.	Updated	Yes	No
Sensitivities				
Base Case (Stress Test with Ambient Temp. Derating Removed)	Add monthly varying flat demand (MW) blocks to calibrate annual LOLE and levelize monthly PRM.	Updated	No	No
Base Case (Flat Load) with Prior EDU	Add uniform flat demand (MW) blocks to each month to calibrate annual LOLE.	Prior	Yes	Yes
Base Case (Flat Load) with Prior Forced Outage Rates	Add uniform flat demand (MW) blocks to each month to calibrate annual LOLE.	Updated	Yes	Yes

After the Revised I&A document was published[15], Staff performed reliability modeling of the above scenarios. Annual results with no monthly stress testing were transferred to the SOD PRM Calibration Tool to determine monthly achieved reserve margins in non-peak months and an annual

15 Revised Inputs & Assumptions for 2028 LOLE Study (June 2026): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M608/K310/608310037.PDF

PRM in the peak month. In the monthly Stress Test scenario, modeling results were transferred to the SOD PRM Calibration Tool to determine monthly PRM values.

Study Objectives

Energy Division Staff conducted annual and monthly stress test LOLE studies of 2028 to evaluate the reliability of the CAISO BAA under the Revised I&A to determine the resources needed to meet a 0.1 LOLE reliability standard. The study results also support the translation of system reliability needs into the 24-hour Slice of Day RA Framework.

The study addresses the following questions:

- What is the reliability level and implied PRM of the Modeling Baseline[16], published in June 2026, relative to the 2025 IEPR demand forecast? How long or short is it relative to a 0.1 LOLE standard? How many MWs of effective capacity does the existing modeling baseline provide, and how much demand can it serve?
- What monthly PRM is consistent with the 0.1 LOLE standard under the SOD framework?
- How do different methods of surfacing loss-of-load events affect the PRM?
    - Adding flat demand blocks
    - Constraining simultaneous import limits
    - Applying pro rata capacity reductions
- How do the 2028 results compare with the prior LOLE study? What are the key drivers of differences?
- How much do PRM results change when the UCAP resource accreditation methodology is applied?

Methodology Overview and Input Variables

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 stochastic production cost model software used by Staff is the SERVM developed by PowerGEM (formerly Astrapé). The model calculates probability-weighted expected values for a variety of metrics across thousands of scenarios (different weather conditions and random unit outage draws). Reliability metrics from the model include LOLE as well as Expected Unserved Energy (EUE) and Loss of Load Hours (LOLH).[17]

Staff targeted 0.1 LOLE (equivalent to one loss-of-load event every ten years) to determine the level

[16] SERVM Baseline Generator List (June 2026): https://files.cpuc.ca.gov/energy/modeling/2026_servm_updates/BaselineGeneratorList_CAISO.xlsx

[17] 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.

of RA resources needed for adequate system reliability. Staff configured SERVM to analyze the 2028 study year under a range of uncertainty including weather conditions (25 historical weather and hydroelectric years, 2000-2024), economic & demographic uncertainty, 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 to represent the portion of 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 vintage August 2025 and the Western Electricity Coordinating Council (WECC) 2034 Anchor Data Set (ADS) vintage from July 2024. For additional details on model inputs – including operational variables, weather and hydroelectric data, and electric demand forecasts – please refer to the June 2026 Revised I&A document.[18]

Table 2 below compares the Modeling Baseline from the 2024 data update used for the previous study of 2026 and the current, updated Modeling Baseline used for the 2028 study. Overall, about 18,000 MW of installed capacity were added to the Modeling Baseline since the prior study, reflecting increased investment in resources, particularly storage and solar.

[18] Revised Inputs & Assumptions for 2028 LOLE Study (June 2026): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M608/K310/608310037.PDF

Table 2: Resource Portfolio in 2028 Study Year

SERVM Tech Category	Nameplate MW 2024 Baseline in Service, Dec 2026	Nameplate MW 2026 Baseline in Service, Dec 2028	Incremental Dec Nameplate (MW)	Note
BatteryStorage/Battery_4h	12,124	14,043	1,919	e
Biogas	285	288	3	
Biomass/Wood	542	466	-77	a
CC	19,484	19,369	-115	a
Coal	1,697	476	-1,221	b
Cogen	2,425	3,489	1,063	
CT	8,087	7,260	-828	a
DR	1,688	1,168	-520	
Geothermal	1,630	1,592	-38	
Hybrid_BattStorage	963	1,693	729	e
Hybrid_Solar_1Axis	2,404	2,804	401	d
Hybrid_Solar_Fixed	203	298	95	d
Hydro	9,145	9,149	4	
ICE	255	303	48	
Nuclear	2,935	2,935	0	
Paired_BattStorage	1,433	9,034	7,602	e
Paired_Solar_1Axis	1,905	8,286	6,381	c, d
Paired_Solar_Fixed	870	4,508	3,638	d
PSH	1,483	1,487	4	
Pumping_Load	2,183	2,183	0	
Solar_1Axis	11,999	6,720	-5,280	c. d
Solar_2Axis	11	11	0	d
Solar_Fixed	5,225	5,534	310	d
Solar_Thermal	997	917	-80	d
Steam	2,859	2,859	0	
Wind	8,491	7,727	-764	f
OOS_Wind	-	5,018	5,018	f
Grand Total CAISO	101,322	119,616	18,294	

(a) Net decreases; 1,182 due to changes to Cogen	1,019
(b) Intermountain Coal on 2024 BL, retired by 2025	1,561
Coal with retirement date of 6/1/25 on 2026 Baseline	476
(c) Net increase with some reclassification from other solar to Paired_Solar_1Axis or Solar_1Axis	1,101
(d) Net increase in Solar	5,465
(e) Net increase, including some reclassification from stand alone storage to paired or hybrid storage	10,250
(f) Net increase in Wind and OOS_Wind	4,254

CAISO will continue to rely substantially on storage and solar resources that are currently under development between August 2026 and August 2028. Table 3 provides the nameplate capacity (MW) and number of units that have been added to the Baseline but are currently under development. These projects largely reflect projects that were on the CAISO New Generator Interconnection Resource ID Report as of August 31, 2025.

Table 3: Nameplate Capacity (MW) In Development Aug. 2026 to Aug. 2028 in CAISO

Unit Category	In Development Units (MW)					Number of Units				
	IID	PG&E	SCE	SDG&E	Total	IID	PG&E	SCE	SDG&E	Total
Battery Storage	100	55	2,262	379	2,796	1	1	15	3	20
Biogas		3			3		1			1
Geothermal			13		13			1		1
Pumped Storage			44		44			1		1
Solar	100		1,785	90	1,975	1		13	1	15
Wind			25		25			1		1
Grand Total	**200**	**58**	**4,129**	**469**	**4,856**	**2**	**2**	**31**	**4**	**39**

Revised Buildup of Study Cases

In the prior LOLE study, Staff introduced stochastic variation into the range of SERVM cases by varying the weather year, hydro year, and probability-weighted point from the economic-demographic uncertainty distribution. Each case was simulated 3 times, each with a different random unit outage draw. Thus, 23 weather years times 23 hydro years times 5 points of economic-demographic uncertainty yielded 2,645 cases simulated in a SERVM study with each case run 3 times with a random unit outage draw. Staff experience from the prior study has shown that multiple combinations of weather and hydro years create very little variation in LOLE when varying hydro years are paired with a given weather year. Staff concluded that weather year variation is a much stronger driver of results than hydro year variation. Furthermore, each case's average results were not stable since each case was only run with 3 random outage draws, meaning the average case results could change significantly by running the case additional times with different random outage draws until the case reaches convergence.

For the 2028 study, Staff revised their approach to developing the range of SERVM cases by reducing the number of cases and increasing the number of times each case is simulated. This tradeoff allows SERVM studies to be completed within a reasonable amount of time while improving statistical convergence of the results. Each case is defined by a weather/hydro year pair and a point from the economic-demographic uncertainty distribution. The weather/hydro years are paired using the same historical year of data, for example year 2000 weather is paired with year 2000 hydro availability. Thus, the number of cases simulated in SERVM is 25 times 5, yielding 125 cases. Each case is simulated 30 times, each with a different random outage draw. The increase in the number of random outage draws improves the statistical convergence of the average results of each case and ultimately means that the study results are much closer to the true expected values.

Reliability Results Baseline and 2025 IEPR Annual Study

Staff completed a LOLE study of the 2028 RA compliance year to determine the amount of resources needed to maintain reliability in the CAISO BAA. The study results show 0.0 LOLE for the Base Case scenario, meaning that the Modeling Baseline and 2025 IEPR and other study variables substantially exceeded the reliability target of 0.1 LOLE and no additional capacity is needed for reliability (Table 4). In other words, 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 2028 with existing resources and resources expected to come online by 2028.

Table 4: Annual Reliability Metrics for 2028 Base Case Study showing 0 LOLE and 0 EUE

Annual Reliability Metrics		
Metric	**2028**	**Units**
LOLE	0	days/year
EUE	0	MWh
LOLH	0	hours/year
LOLH/LOLE (average length of outage)	0	hours/day

Table 5 shows the GHG emissions results for the 2028 Base Case Scenario. The results reflect a total of 24.45 MMT for the CAISO BAA, comprised of 17.29 MMT from CAISO generator emissions and 7.16 MMT from unspecified emissions.

Table 5: Annual GHG Emissions in 2028 for Base Case scenario

Annual GHG Emissions (SERVM)		
Category	2028	Units
CAISO emitting generation	40,554	GWh
CAISO Generator Emissions	17.29	$MMTCO_2$
Imports (unspecified)	16,717	GWh
Unspecified emissions	7.16	$MMTCO_2$
Total CAISO Emissions	24.45	$MMTCO_2$

Results of Alternative Methods to Quantify Surplus or Shortfall in Annual LOLE Study

In the prior 2026 LOLE study, completed in December 2024, Staff also encountered a Base Case that was overly reliable and thus needed to surface LOLE to determine an annual reliability level, and perform a similar operation each month for the monthly stress tests. In the prior study, Staff

performed the annual study by raising or lowering the level of simultaneous import constraints into CAISO. To perform the monthly stress tests, Staff added demand blocks in each month to surface LOLE rather than constraining the simultaneous import constraint. While Staff achieved a stable result and were satisfied with the final recommendation, parties commented that this may have caused inadvertent inconsistency between the annual LOLE study and the monthly stress tests.

In the current 2028 study, Staff are avoiding this potential inconsistency by surfacing LOLE for both annual and monthly studies in the same way and are further exploring reliability in the CAISO area by surfacing LOLE with different methods.

Consistent with the June 5, 2028 Revised I&A Document, Staff calculated the reliability of the baseline existing resource fleet against the 2025 IEPR planning forecast and assessed surplus or deficit relative to the LOLE target using three key scenarios.[19]

- Demand Blocks Added: To surface LOLE when the system is found to be overly reliable, flat blocks of demand were added until 0.1 LOLE was achieved. For annual LOLE studies, the same amount of flat demand is added to each month. For monthly Stress Testing, varying amounts of flat demand were added to each month so that the sum of the annual LOLE is close to 0.1. For additional details on this methodology please refer to the "Surfacing Annual and Monthly LOLE" section of the Revised I&A document.
- Simultaneous Import Limit: The default assumption applied a CAISO area simultaneous import limit of 11,040 MW year-round, in all hours; additionally, a 4,000 MW limit was applied in the months of June through September during peak hours (5pm – 10pm). In this scenario, Staff constrained import levels below the default values to surface LOLE.
- Prorate Capacity Reduction: This scenario applied a pro rata capacity reduction to the baseline resources fleet; the same pro rata reduction is applied across all resource classes, except for hydro, in order to surface LOLE. The prorating was also applied to both the peak hour and non-peak hour simultaneous import limits. This is different from the other scenarios which maintain a static baseline resource fleet comprised of existing and in-development resources.

Staff assessed reliability across these three scenarios and reported the results by frequency, magnitude and duration. These metrics are defined as:

- Loss of Load Expectation (LOLE): Frequency – expected number of loss-of-load events, regardless of length, in a given year.
- Expected Unserved Energy (EUE) in MWh: Magnitude – total expected MWh of unserved energy in a year.

19 Revised Inputs & Assumptions for 2028 LOLE Study (June 2026): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M608/K310/608310037.PDF

- Loss of Load Hours (LOLH)/LOLE (hours/events): Duration – number of hours with Loss of Load divided by number of events, resulting in average expected duration of each event.

The Base Case results project an over-reliable CAISO system in 2028, as shown by the zero LOLE and zero EUE results. Table 6 compares the Base Case reliability results with scenarios that sought to surface LOLE using the methods discussed earlier.

Table 6: LOLE, EUE, and LOLH/LOLE results for each modeling scenario

Scenario	Base Case	Base Case (Flat Load)	Base Case (Constrain Imports)	Prorate Capacity
Demand Blocks Added (MW)	0	6,000	0	N/A
Simultaneous Import Limit	Default	Default	Constrained to 0	87.6% prorate
Capacity Reduction	N/A	N/A	N/A	87.6% prorate (12.8 GW capmax reduction)
LOLE (events/year)	0	0.100	0.014	0.103
EUE (MWh)	0	483.5	77	468.6
LOLH/LOLE Average Length of Outage (hours/day)	0	1.96	2.3	1.8
GHG emissions (MMT)	24.45	43.27	33.55	31.15

Annual Loss of Load results – Base Case (Flat Load)

To calibrate the 2028 over-reliable portfolio to 0.1 LOLE, Staff added flat load of 6,000 MW[20] for all 12 months. Using the SOD PRM Calibration Tool, this translates to a September ICAP PRM of 16.64% with the most constrained hour being hour ending (HE) 18:00. Table 7 shows the monthly SOD PRMs including load, supply and most constrained hours. The most constrained hour equals the hour in each month during which storage units are utilized at their highest aggregate MWh value. The lowest PRM is September, and other months have higher achieved reserve margins, reflecting that LOLE observed in this study is concentrated mostly in September.

Table 7: Initial Monthly SOD PRMs resulting from Annual LOLE Portfolio to achieve a 0.1 LOLE – Base Case (Flat Load)

Month	Constrained Hour (HE)	Load (MW)	Flat Load Added (MW)	Supply (MW)	ICAP PRM	UCAP PRM
1	19	30,228	6,000	55,123	53.32%	46.74%
2	19	29,762	6,000	58,904	63.59%	55.91%
3	19	30,316	6,000	60,330	66.13%	58.43%

[20] In the August 14, 2026 Draft Report published by Energy Division, Staff reported that 6,150 MW of flat load added would calibrate the system to about 0.1 LOLE. Since then, Staff noticed some anomalous annual energy results in that set of studies that suggested a need to rerun studies to confirm results. The reruns now have annual energy results in line with expectations and the calibration to 0.1 changed to 6,000 MW of flat load.

Month	Constrained Hour (HE)	Load (MW)	Flat Load Added (MW)	Supply (MW)	ICAP PRM	UCAP PRM
4	19	32,624	6,000	65,720	68.64%	61.10%
5	20	32,532	6,000	66,303	70.93%	63.51%
6	20	41,173	6,000	63,442	34.49%	28.61%
7	19	45,806	6,000	63,976	23.49%	18.80%
8	19	45,211	6,000	62,720	22.47%	17.70%
9	18	48,200	6,000	63,217	16.64%	11.95%
10	18	39,139	6,000	63,597	40.56%	35.03%
11	18	32,636	6,000	58,585	52.04%	45.67%
12	18	30,849	6,000	54,338	48.42%	42.04%

Figure 1 shows the monthly LOLE capacity for each region in CAISO after adding a flat load of 6,000 MW. The SCE and SDG&E regions drive CAISO LOLE while PG&E does not. September has the highest LOLE. LOLE is not symmetrical across the CAISO BAA partially due to Path 26 flow limits in stressed hours.

Figure 1: Monthly LOLE capacity for each region after 6,000 MW flat load is added

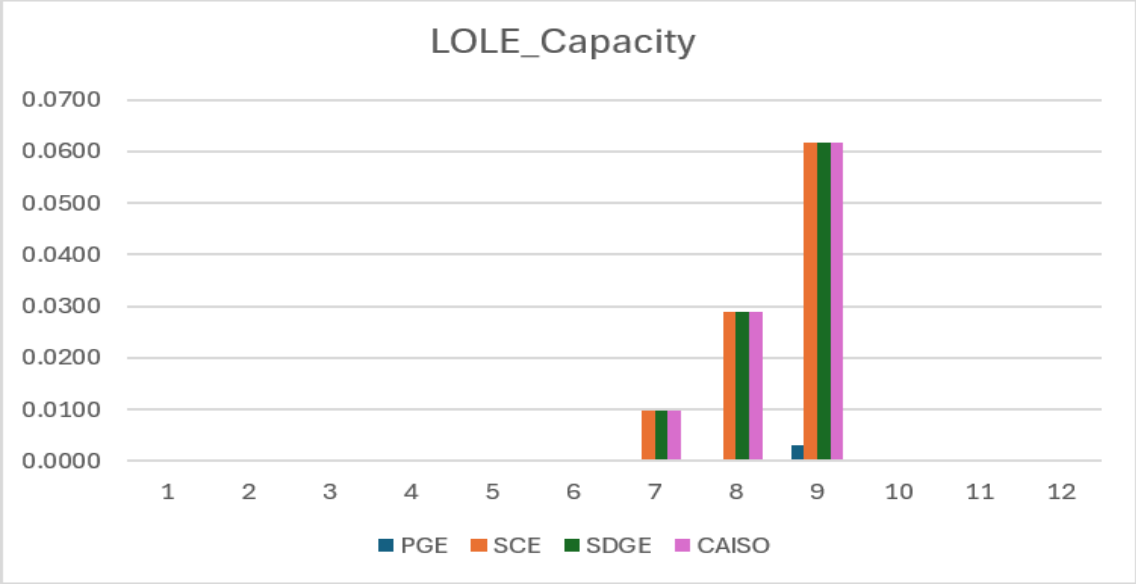
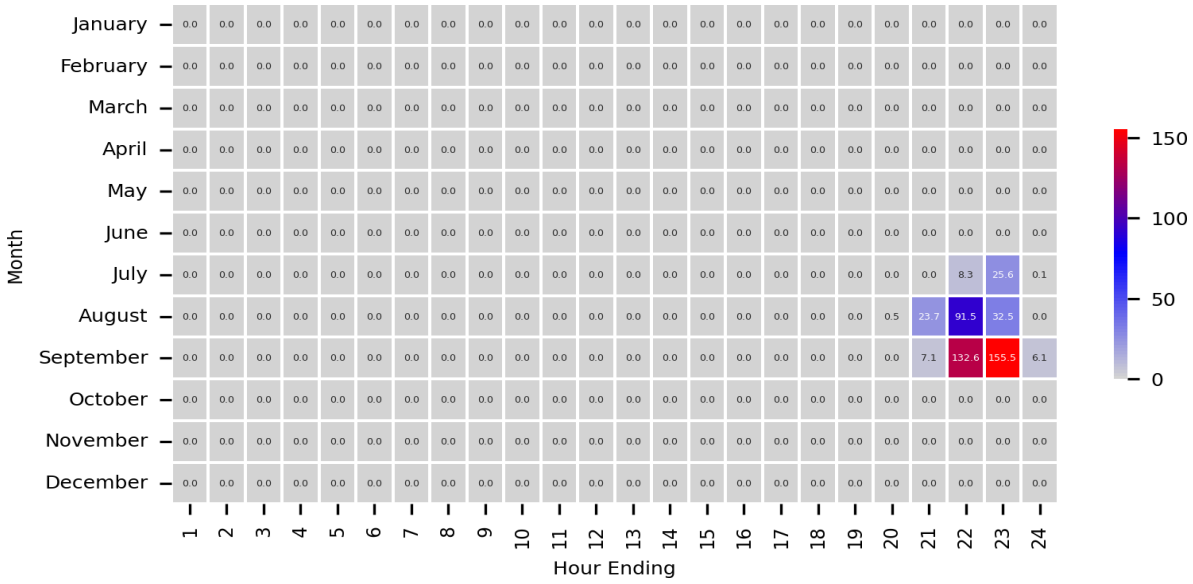


Figure 2 shows a heatmap of EUE across hours of the day and months of the year. This is aggregated to the CAISO BAA, not specific to IOU service areas. It is observed that annual LOLE tuning by adding flat load results in EUE being concentrated in months August and September mostly during HE 22:00 and 23:00.

Figure 2: EUE Heatmap – Base Case (Flat Load)



Annual Loss of Load results – Base Case (Constrain Imports)

In the prior 2026 LOLE Study a primary method for surfacing LOLE was to constrain import levels. For the current study, Staff sought to compare reliability and PRM results using an import constraint to surface LOLE against the other methods. In this scenario, Staff initially restricted simultaneous import levels to 2,000 MW across all hours of the year. Modeling results indicated the system remained over-reliable even with this restriction. Staff subsequently reduced available imports to 0 MW during all hours of the year, which was still over-reliable system with 0.014 LOLE.

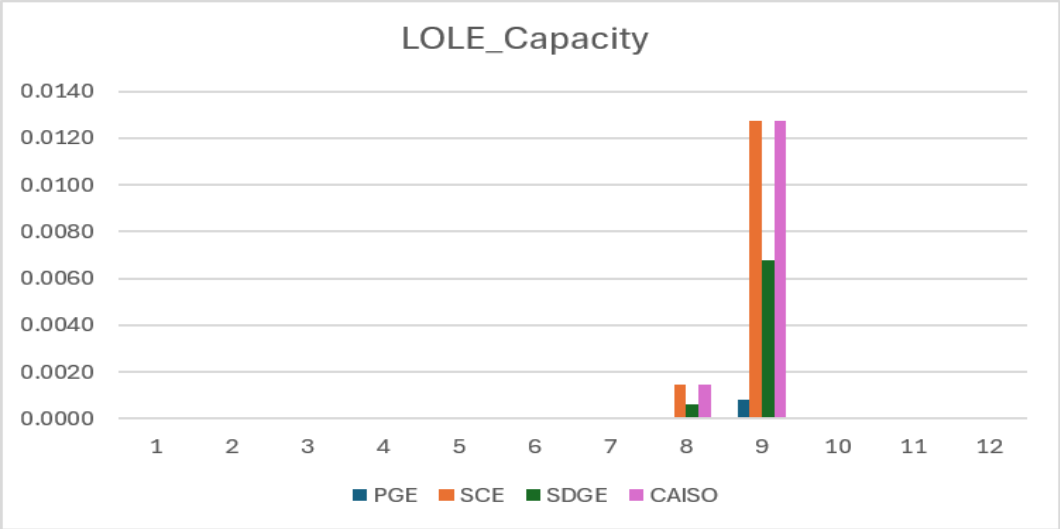
Table 8 below shows the reliability metrics with all imports removed. The finding of over-reliability even with no imports addresses stakeholders' concerns about evolving supply & demand dynamics in neighboring balancing authority areas and the ability of external regions to continue to provide imports at levels observed historically, at least for the next few years. These findings suggest that the CAISO system could operate reliably for the next few years with limited imports, given the current modeling baseline and 2025 IEPR forecasted demand.

Table 8: Annual Reliability Metrics for Base Case (Constrain Imports) scenario showing an over-reliable system

Annual Reliability Metrics		
Metric	**2028**	**Units**
LOLE	0.014	days/year
EUE	77.0	MWh
LOLH	0.033	hours/year
LOLH/LOLE (average length of outage)	2.303	hours/day

Figure 3 shows monthly LOLE for each region in the Base Case (Constrain Imports) scenario when imports are constrained to "0" for all 8,760 hours. It is observed that PGE and SDG&E are more reliable than SCE which may be due to Path 26 limitations.

Figure 3: Monthly and Regional LOLE – Base Case (Constrain Imports)



Annual Loss of Load results – Prorate Capacity

When the 2028 Draft Study results were released in August 2026, modeling efforts on the Prorate Capacity scenario were still underway and results were not yet available. Prior to the September RA workshop Staff completed initial runs using the prorate capacity method and shared results at the workshop. Initial results showed a 5% reduction in capacity resulted in 0.1 LOLE. However, Staff noted these counter-intuitive results required further investigation. This investigation uncovered a bug in SERVM which resulted in significantly larger prorating for storage than the prorate programmed into model inputs. This bug was confirmed by PowerGEM and Staff worked with them to develop a solution. Staff repeated the prorate capacity studies with the updated SERVM configuration and found that a 12.4% reduction in capacity (i.e., 87.6% prorate) resulted in a 0.1 LOLE reliability target.

Due to time constraints, Staff only ran one annual prorate capacity study that calibrated all the way to 0.1 LOLE and translated results into an annual PRM using the SOD Calibration Tool. Staff did not perform stress tests (varying the amount of prorating by month to levelize LOLE across months). For this study, Staff included EDU and enforced Path 26 flow limits, same as the Base Case (Flat Load) scenario and most of the other scenarios/sensitivities described in this report, so that annual PRM results could be more directly compared across all of Staff's scenarios/sensitivities. Table 9 below illustrates the reliability metrics for this annual prorate capacity study.

Table 9: Annual LOLE Results Prorate Capacity Scenario – 87.6% prorate, with EDU and with Path 26 flow limits enforced

Annual Reliability Metrics		
Metric	**2028**	**Units**
LOLE	0.103	days/year
EUE	468.62	MWh
LOLH	0.188	hours/year
LOLH/LOLE (average length of outage)	1.827	hours/day

Table 10 shows ICAP PRMs calculated from translating the Prorate Capacity scenario into the SOD PRM Calibration Tool. It is comparable to Table 7 above which shows the Base Case (Flat Load) scenario ICAP PRM results. September is indicative of the annual ICAP PRM with LOLE concentrated in that month. The other months have higher (likely excessive) achieved reserve margins since there is no stress testing (no varying of prorating percent by month) to levelize LOLE across months.

Table 10: Initial Monthly SOD PRMs resulting from Annual LOLE Portfolio to achieve a 0.1 LOLE – Base Case (87.6% Prorate Scenario)

Month	Constrained Hour (HE)	Load (MW)	Flat Load Added (MW)	Supply (MW)	ICAP PRM
1	19	30,228	0	50,442	66.87%
2	19	29,762	0	52,900	77.74%
3	19	30,316	0	54,673	80.34%
4	19	32,624	0	59,285	81.72%
5	20	32,532	0	59,917	84.18%
6	20	41,173	0	56,850	38.08%
7	19	45,806	0	58,146	26.94%
8	19	45,211	0	57,045	26.17%
9	18	48,200	0	57,399	19.08%
10	18	39,139	0	57,697	47.41%
11	18	32,636	0	53,614	64.28%
12	18	30,849	0	49,488	60.42%

Figure 4: Monthly LOLE for PGE, SCE and SDG&E – 87.6% Prorate Scenario

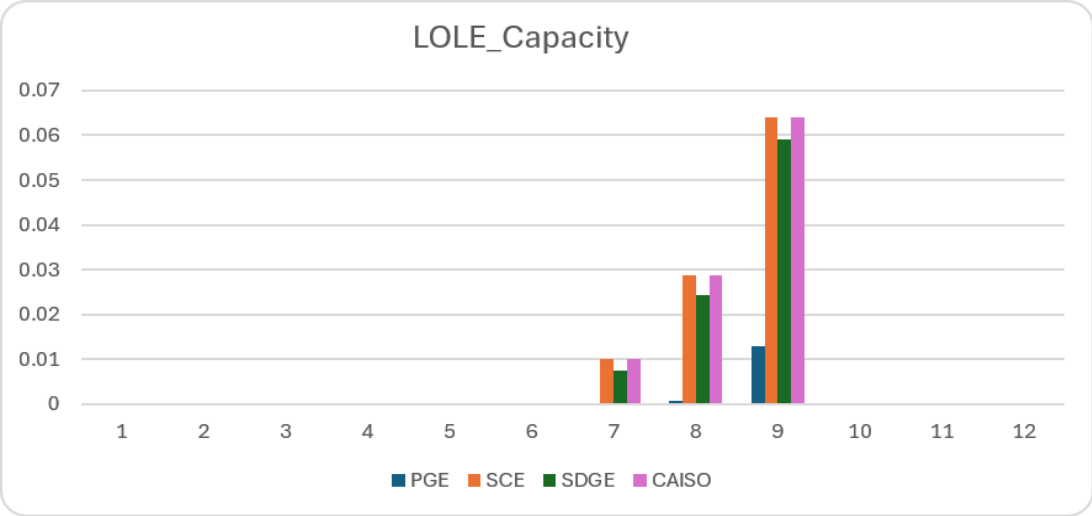
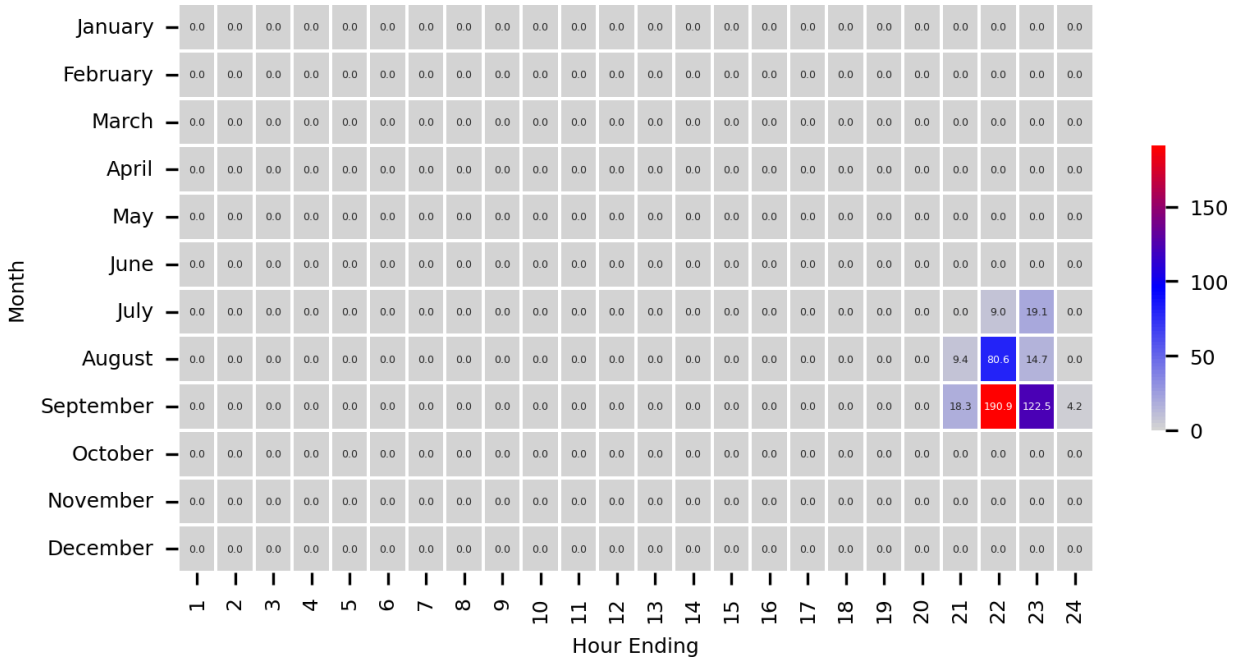


Figure 5: EUE heatmap for 87.6% prorate scenario. EUE is concentrated in August and September, HE 22:00 and 23:00



Monthly Stress Testing and Translation of LOLE Portfolio to PRM

Translation of Annual LOLE Study into SOD PRM

This section details how the annual LOLE study results are translated to a Slice of Day PRM using the PRM Calibration Tool. The main elements of the PRM Calibration Tool include:

1. Managed Peak Demand Worst Day (day coinciding with the monthly Managed Peak)
    - The CEC IEPR Hourly Load Model is used to identify the day with the Managed Peak in each month and then the 24-hour demand profile is entered into the *Managed Load* tab.
2. The resource portfolio for each month is extracted from SERVM and is entered into the *SERVM Units* tab.
3. The total capacity from each technology category is quantified according to RA QC calculation guidelines. The *Profiles* tab contains hourly SOD profiles for each resource type, with solar and wind profiles based on the exceedance values.[21] The PSH and DR profiles follow RA rules, and the simultaneous import constraint is a flat 24-hour profile.
    - Depending on the technology category, the hourly profile coefficients are applied to individual resources' QC or Nameplate.
4. The *Capacities by Unit Category* tab sums the total applicable monthly QC or Nameplate capacities for each month.
5. The *Supply* tab applies the hourly SOD coefficients from the *Profiles* tab to the monthly capacities in the *Capacities by Unit Category* tab to calculate the hourly supply provided by each unity category.
6. The *PRM Setting* tab calculates the PRM using Excel's Solver tool to seek the PRM across 24 hours (without storage being shown).
    - Storage capacity is deployed to meet hourly capacity requirements unmet by non-storage units according to assumed physical constraints on state-of-charge, charge and discharge rates, stored energy, and excess non-storage capacity required for charging.
    - The PRM for each month, along with the hourly SOD managed load forecasts, factor into the hourly capacity requirements, labeled "Total Load with PRM (MW)" in the table on the right side of the sheet.
    - Solver determines the PRM that uses storage resources as much as possible, subject to the constraints above, while ensuring all hourly capacity requirements are met.
7. The *Dashboard* tab presents hourly supply & demand profiles by month and provides data visualizations.
    - Supply is shown as a stacked bar chart representing the hourly capacity by a unit category.
    - Demand is shown as two-line charts, representing the managed load and the hourly capacity requirement including with the PRM.

The primary differences in inputs across the months are the managed load and resource values. The hourly resource values for each month are derived from the draft 2027 Master Resource Database. 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 PRM Calibration Tool are reflective of the RA values that will be used for the 2027 RA compliance year.

[21] Exceedance profiles represent expected energy generation during each hour of the day for different technologies and regions. Exceedance levels vary by month and are applied to six years of historical data, removing all values outside exceedance bounds. For example, an exceedance level of 70% means that we remove 70% of high production days, equating to a production profile of the 30th percentile.

Monthly Stress Testing

The annual Base Case (Flat Load) LOLE results, presented in Table 7 and Figure 1, show that the minimum ICAP PRM of 16.64% occurs in September, with LOLE concentrated in July – September. These results also show that achieved reserve margins are higher in non-summer months, resulting in higher reliability in these months. To find the appropriate monthly PRM levels, Staff conducted monthly stress tests by adding varying amounts of demand in each month to surface LOLE in non-summer months and identify a single lower PRM for those months. This method for surfacing LOLE produces a PRM requirement for each month of the year that keeps the total annual LOLE at 0.1 or below. Table 11 presents the results of these stress tests which indicate ICAP PRMs of approximately 21% in May through September and 19% in October through April. When UCAP resource accreditation is applied the UCAP-based PRM is approximately 16% in May through September and 14% in October through April.

Table 11: Monthly PRM and LOLE Results – Base Case (Stress Test)

Month	Flat Load Added (MW)	ICAP PRM	UCAP PRM	LOLE
1	15,158	19.01%	13.90%	0.0
2	17,832	19.03%	13.73%	0.0
3	18,640	19.03%	13.60%	0.0
4	19,784	19.04%	13.72%	0.0
5	19,812	21.05%	15.79%	0.0039
6	10,577	21.00%	15.54%	0.0009
7	6,891	21.00%	16.40%	0.0367
8	6,518	21.00%	16.28%	0.0525
9	4,430	21.00%	16.14%	0.0042
10	12,669	19.00%	14.32%	0.0
11	15,050	19.01%	14.02%	0.0
12	14,098	19.01%	13.89%	0.0
Total				0.0981

Table 12 presents the aggregate reliability metrics for the Base Case (Stress Test) scenario. The stress test results in a total LOLE of 0.098, indicating that the resulting PRM levels are consistent with the 0.1 LOLE reliability standard.

Table 12: Annual Reliability Metrics – Base Case (Stress Test)

Annual Reliability Metrics		
Metric	**2028**	**Units**
LOLE	0.098	days/year
EUE	458.3	MWh
LOLH	0.183	hours/year
LOLH/LOLE (average length of outage)	1.86	hours/day

Figure 6 presents the Base Case (Stress Test) LOLE results by month and IOU service area. The results show that levelizing the PRM across the summer months shifts the most constrained month from September, which had the highest LOLE in the Base Case (Flat Load) annual study, to August. The distribution of LOLE by month across the IOU service areas shows that SCE and SDG&E are contributing to CAISO LOLE and PG&E has a reliable portfolio.

Figure 6: Monthly LOLE for PGE, SCE and SDGE, Base Case (Stress Test)

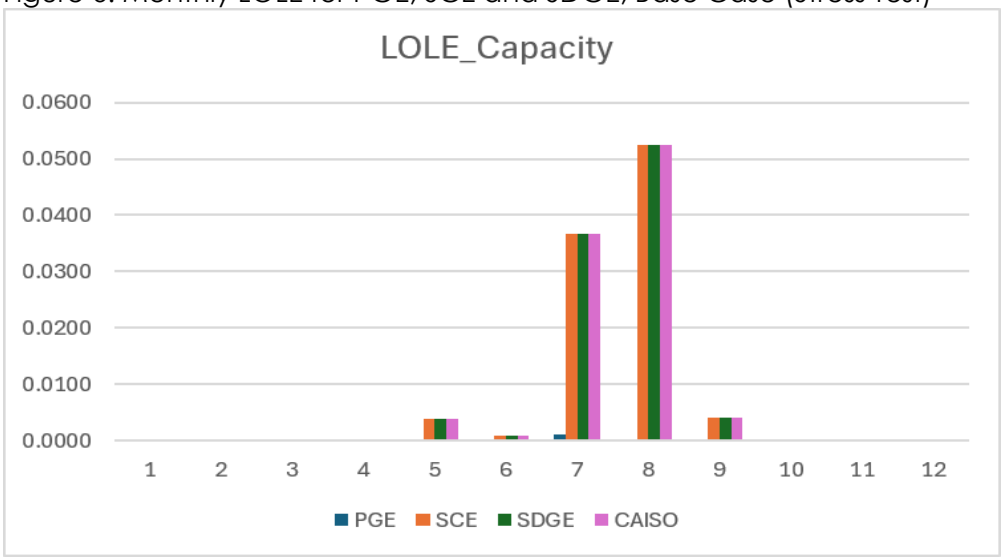
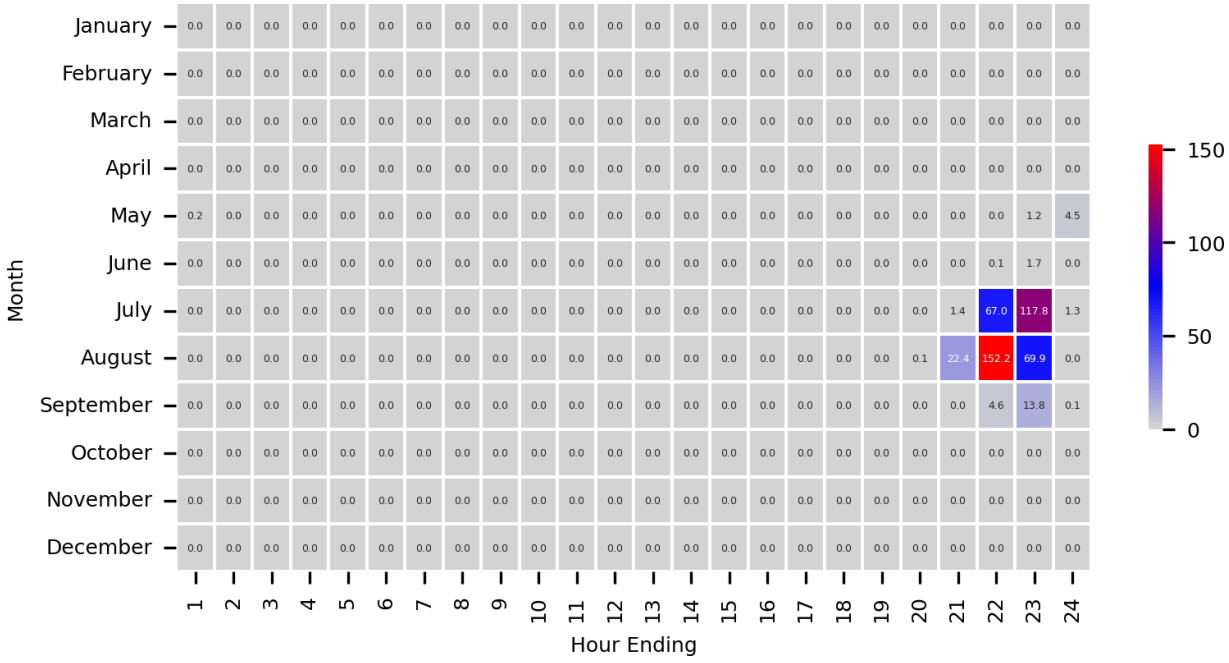


Figure 7 presents the EUE results for the Base Case (Stress Test) and shows EUE most concentrated in July and August, consistent with Figure 6, mostly at HE 21:00 – 23:00.

Figure 7: EUE heat map – Base Case (Stress Test)



Translation into the SOD PRM Calibration Tool - PRM Results

Staff translated the annual portfolio of resources resulting from the LOLE analysis into the SOD PRM Calibration Tool and calculated monthly required PRMs. As expected, with a static fleet of resources across the year and demand that is highest in the summer months, achieved reserve margins in off-peak months were substantially higher when more capacity was available than was needed to meet the reliability standard. The Base Case (Flat Load) study resulted in achieved reserve margins as high at 70% when LOLE was concentrated in September. Furthermore, in this scenario Staff did not seek to reduce the PRMs in off-peak months to the threshold where LOLE would surface. To identify the appropriate monthly reserve margins, Staff performed additional stress tests to levelize the PRM across the summer months and reduce the PRM in off-peak months. Since May showed higher PRMs due to high variability, Staff grouped May through September as summer months and October to April as non-summer months. By adding demand in the off-peak months to surface LOLE, Staff found that the CAISO BAA could meet the 0.1 LOLE standard with an ICAP PRM of approximately 19% in off-peak months and 21% PRM in summer. Table 13 summarizes and compares the annual Base Case (Flat Load) monthly PRM results to the Base Case (Stress Test) monthly PRM results.

Table 13: Monthly LOLE and PRM Results derived with Slice of Day PRM Calibration Tool

	Base Case (Flat Load)		**Base Case (Stress Test)**	
Month	ICAP PRM	LOLE	ICAP PRM	LOLE
1	53.32%	0.0	19.01%	0.0
2	63.59%	0.0	19.03%	0.0
3	66.13%	0.0	19.03%	0.0
4	68.64%	0.0	19.04%	0.0
5	70.93%	0.0	21.05%	0.0039
6	34.49%	0.0	21.00%	0.0009
7	23.49%	0.0097	21.00%	0.0367
8	22.47%	0.0288	21.00%	0.0525
9	16.64%	0.0617	21.00%	0.0042
10	40.56%	0.0	19.00%	0.0
11	52.04%	0.0	19.01%	0.0
12	48.42%	0.0	19.01%	0.0
Total		0.1002		0.0981

UCAP Application

D.26-07-008 at Ordering Paragraph 13 adopted the UCAP framework as outlined in Appendix B. To this end Staff developed a SOD PRM Calibration workbook that incorporates resource-specified

UCAP values for thermal, storage, and co-located resources, and can be used to calculate a PRM consistent with the UCAP framework.

Table 14 compares the monthly ICAP PRMs and UCAP-based PRM results across two study scenarios. The UCAP-based PRMs reflect the application of the UCAP resource counting methodology to the study portfolios in the SOD PRM Calibration Tool. This translation is applied only to the SOD PRM Calibration Tool and does not require additional SERVM runs. The SOD PRM Calibration Tool incorporates the UCAP derate factors into the *SERVM Units with UCAP* tab to derate resources by their average Equivalent Forced Outage Rate during demand periods (EFORd) and derates due to ambient temperature.

Table 14: ICAP PRM and UCAP PRM Comparison – Base Case (Flat Load) and Base Case (Stress Test) Scenarios

	Base Case (Flat Load)			**Base Case (Stress Test)**		
Month	ICAP PRM	UCAP PRM (EFORd & Ambient)	Diff. Percentage Points	ICAP PRM	UCAP PRM (EFORd & Ambient)	Diff. Percentage Points
1	53.3%	46.7%	6.6%	19.0%	13.9%	5.1%
2	63.6%	55.9%	7.7%	19.0%	13.7%	5.3%
3	66.1%	58.4%	7.7%	19.0%	13.6%	5.4%
4	68.6%	61.1%	7.5%	19.0%	13.7%	5.3%
5	70.9%	63.5%	7.4%	21.1%	15.8%	5.3%
6	34.5%	28.6%	5.9%	21.0%	15.5%	5.5%
7	23.5%	18.8%	4.7%	21.0%	16.4%	4.6%
8	22.5%	17.7%	4.8%	21.0%	16.3%	4.7%
9	16.6%	12.0%	4.7%	21.0%	16.1%	4.9%
10	40.6%	35.0%	5.5%	19.0%	14.3%	4.7%
11	52.0%	45.7%	6.4%	19.0%	14.0%	5.0%
12	48.4%	42.0%	6.4%	19.0%	13.9%	5.1%

Previous LOLE study vs. Current LOLE Study - Key Drivers of PRM Increase or Decrease since 2024 Study of 2026 RA Year

To check for consistency between this report's study results and previous studies and analyses, Staff identified three methodological or input differences that would likely drive changes in the PRM levels needed to achieve the reliability target. Through sensitivity testing described in this section, Staff found that the effects of these differences mostly netted themselves out. This would explain

why the summer 21% ICAP PRM finding in the current study (Base Case Stress Test with month-varying flat demand added) is basically unchanged from the summer 21% ICAP PRM requirement found in the previous 2026 LOLE study. Staff attempted to quantify the impacts of these model changes individually in terms of how much they increase or decrease the PRM. Table 15 below summarizes the findings from sensitivity testing each of these model updates. The expected net change is a 0.4 percentage point increase in PRM, which is small enough that Staff propose no change to the summer 21% ICAP PRM from the prior 2026 LOLE study. This is reasonable given that there are other input differences that can contribute to PRM changes such as expanding the weather range from 23 to 25 years and changes in the mix of resources between the portfolios modeled in 2026 and 2028.

Table 15: Factors Impacting Change in ICAP PRM

	ICAP PRM Result	ICAP PRM Impacts
2026 LOLE Study	21%	
2028 LOLE Study	21%	
Ambient Thermal Derate Effect		+2%
Updated Forced Outage Rates		-1%
Updated Econ-Demo Uncertainty		-0.6%
Total Net Changes		**0.4%**

Sensitivity Analysis – Ambient Thermal Derate

To be comparable with the 2026 RA LOLE study, which did not include ambient thermal derates, Staff conducted a sensitivity similar to the Monthly Stress Test scenario by adding demand to individual months of 2028 with ambient thermal derates removed. Results shown in Table 17, reflect a 2 percentage point decrease in the ICAP PRM relative to the Base Case (Stress Test) scenario. The non-summer month ICAP PRMs show little change since the ambient thermal derate effect mainly happens in the summer months when the weather is hotter.

Table 16: Annual Reliability Metrics - Base Case (Stress Test) without Ambient Thermal Derate

Annual Reliability Metrics		
Metric	**2028**	**Units**
LOLE	0.091	days/year
EUE	414.6	MWh
LOLH	0.160	hours/year
LOLH/LOLE (average length of outage)	1.75	hours/day

Table 17: Monthly ICAP PRM for Base Case (Stress Test) Ambient Thermal Derate Sensitivity

	Base Case (Stress Test) with Ambient Thermal Derate			Base Case Stress Test Sensitivity (No Ambient Thermal Derate)		
Month	Demand Added (MW)	ICAP PRM	LOLE	Demand Added (MW)	ICAP PRM	LOLE
1	15,158	19.01%	0.0	15,158	19.01%	0.0
2	17,832	19.03%	0.0	17,832	19.03%	0.0
3	18,640	19.03%	0.0	18,640	19.03%	0.0
4	19,784	19.04%	0.0	19,784	19.04%	0.0
5	19,812	21.00%	0.0039	20,604	19.05%	0.0094
6	10,577	21.00%	0.0009	11,328	19.00%	0.0011
7	6,891	21.00%	0.0367	7,633	19.00%	0.0311
8	6,518	21.00%	0.0525	7,242	19.00%	0.0442
9	4,430	21.00%	0.0042	5,136	19.00%	0.0055
10	12,669	19.00%	0.0	12,669	19.00%	0.0
11	15,050	19.01%	0.0	15,050	19.01%	0.0
12	14,098	19.01%	0.0	14,098	19.01%	0.0
Total			0.0981			0.0914

Figure 8: Monthly LOLE for PGE, SCE and SDG&E for Base Case (Stress Test w/ Ambient Thermal Derate Removed)

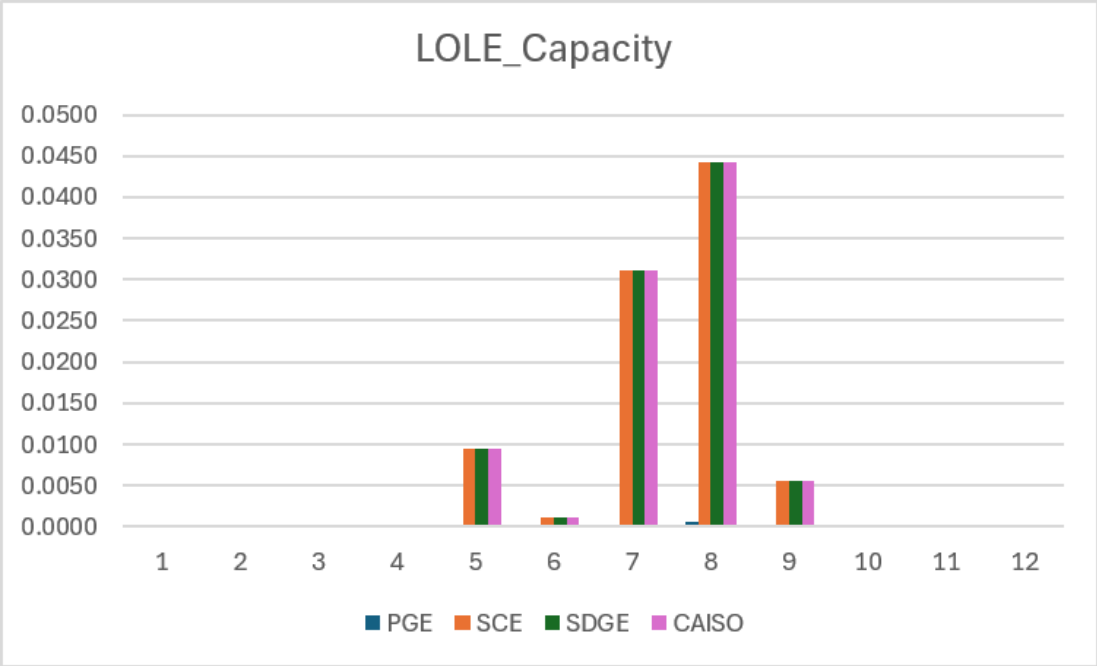
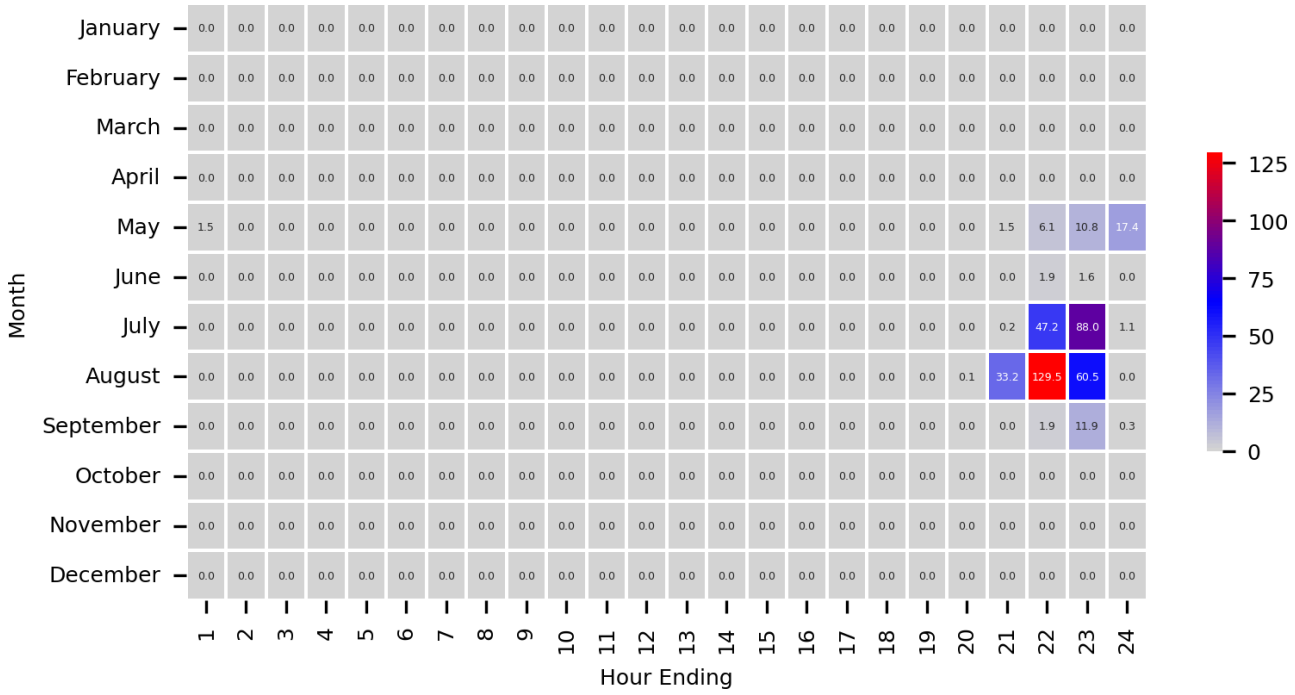


Figure 9: EUE heat map for Base Case (Stress Test w/ Ambient Thermal Derate Removed). Total annual EUE is less than the scenario including thermal derates



Sensitivity Analysis – Economic and Demographic Uncertainty

SERVM incorporates a 5-point probability-weighted economic and demographic uncertainty (EDU) distribution to represent electric demand uncertainty in future study years based on demographic and economic drivers. During the prior 2026 LOLE Study, parties suggested that the distribution utilized by Staff was too wide and that the upward load deviations were unnecessarily inflating the PRM. For this study stakeholders recommended utilizing a narrower distribution based on a 2025-2026 Midcontinent Independent System Operator (MISO) LOLE Study.[22]

As shown in Table 18, the updated EDU distribution has both lower overall variance (+/- 2.0% vs. +/- 2.5%) and significantly reduced tail risk. For example, the probability of +2.5% upward load deviation drops from 6.7% under the prior EDU assumptions to 0.9% for a +2.0% deviation under the updated EDU assumptions. For the current 2028 LOLE Study, Staff implemented the updated EDU distribution across all study scenarios and conducted an additional sensitivity analysis to evaluate the reliability and PRM impacts of the change in EDU distributions.

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MISO 2025-2026 LOLE Study Report: https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401

Table 18: Comparison of Economic & Demographic Uncertainty (EDU) Distributions

Prior Econ & Demo Uncertainty		Updated Econ & Demo Uncertainty	
Forecast Error	Probability	Forecast Error	Probability
2.5%	0.067	2.0%	0.009
1.5%	0.242	1.0%	0.205
0%	0.383	0%	0.573
-1.5%	0.242	-1.0%	0.205
-2.5%	0.067	-2.0%	0.009

To evaluate the impact of the EDU assumptions, Staff compared the amount of added demand that was necessary to calibrate SERVM to 0.1 LOLE, holding all else equal:

> Base Case (Flat Load) with Prior EDU: Utilizing the prior EDU values required an additional 5,800 MW of flat demand blocks across all months to calibrate to 0.1 LOLE.
>
> Base Case (Flat Load): Utilizing the updated EDU distribution required an additional 6,000 MW of flat demand to calibrate to 0.1 LOLE. (This is the same Base Case (Flat Load) scenario already discussed earlier in the report.)

Results show that using the updated EDU distribution reduces reliability risk since more flat demand could be added to the CAISO system while still achieving the 0.1 LOLE reliability target. Updating the EDU factors allows an additional 200 MW of demand to be met by the CAISO BAA while still meeting the 0.1 LOLE target. The observed differences can be attributed to the updated EDU distribution having a lower frequency and magnitude of demand above the average in the SERVM simulations, thus making the modeled system appear more reliable. Staff found that using the updated EDU reduces the PRM by about 0.5 percentage point as compared to using the prior EDU distribution. As shown in Table 20 the September PRM is 16.64% for the Base Case (Flat Load) scenario, compared to a 17.18% PRM in the Base Case (Flat Load) Prior EDU sensitivity.

Table 19: Annual Reliability Metrics – Base Case (Flat Load) with Prior EDU

Annual Reliability Metrics		
Metric	**2028**	**Units**
LOLE	0.092	days/year
EUE	441.5	MWh
LOLH	0.183	hours/year
LOLH/LOLE (average length of outage)	1.98	hours/day

Table 20: Annual PRM Results – Base Case (Flat Load), comparing Prior and Updated EDU Impact

	Base Case (Flat Load) Prior EDU			Base Case (Flat Load)		
Month	Demand Added (MW)	PRM	LOLE	Demand Added (MW)	PRM	LOLE
1	5,800	54.30%	0.0	6,000	53.32%	0.0
2	5,800	64.62%	0.0	6,000	63.59%	0.0
3	5,800	67.17%	0.0	6,000	66.13%	0.0
4	5,800	69.67%	0.0	6,000	68.64%	0.0
5	5,800	71.96%	0.0	6,000	70.93%	0.0
6	5,800	35.13%	0.0	6,000	34.49%	0.0
7	5,800	24.07%	0.0084	6,000	23.49%	0.0097
8	5,800	23.05%	0.0253	6,000	22.47%	0.0288
9	5,800	17.18%	0.0586	6,000	16.64%	0.0617
10	5,800	41.33%	0.0	6,000	40.56%	0.0
11	5,800	52.98%	0.0	6,000	52.04%	0.0
12	5,800	49.33%	0.0	6,000	48.42%	0.0
Total			0.0923			0.1002

Sensitivity Analysis – Updated Forced Outage Rates

For the 2028 LOLE study, Staff updated all forced outage rates used in SERVM. In prior cycles, Staff sourced outage data from the NERC Generating Availability Data System (GADS) database. For this cycle, staff switched to using the CAISO Outage Management System (OMS) Curtailment data as laid out in the Revised I&A. The result of this change is that forced outage rates generally are lower than in previous cycles. A possible explanation for this is that the GADS data comingled thermal ambient derates together with equipment failure, and Staff were able to better distinguish and separate these two causes by using the CAISO OMS data. The result was the overall forced outage rates tied to equipment failure are lower, but when combined with inclusion of thermal ambient derates, results show that their effects on reliability somewhat offset each other.

Similar to isolating the impact of thermal ambient derates added in this 2028 LOLE study, Staff isolated the impact of moving from the previous GADS derived outage rates to the CAISO OMS Curtailment data. This sensitivity test found that using the new outage rates allowed about 400 MW more of annual flat demand to be added to the CAISO system while still achieving the 0.1 LOLE reliability target. In summer months, this equated to about a one percentage point reduction in reserve margin.

Table 21: Annual Reliability Metrics – Base Case (Flat Load) Comparison of Forced Outage Rates

Annual Reliability Metrics	Base case (Flat Load) with prior EFOR & 5.6 GW flat load added	Base case (Flat Load) with updated EFOR & 6 GW flat load added	
Metric	**2028**	**2028**	**Units**
LOLE	0.098	0.100	days/year
EUE	551.4	483.5	MWh
LOLH	0.190	0.196	hours/year
LOLH/LOLE (average duration)	1.93	1.960	hours/day

Table 22: Comparison of Previous and Updated Forced Outage Rates

	Prior EFOR	Updated EFOR
Region	**System EFOR (%)**	**System EFOR (%)**
CAISO	2.40	2.01
Unit Category	**EFOR (%)**	**EFOR (%)**
Battery_4h	3.50	4.44
Biogas	1.09	0.52
CC	7.24	5.64
CT	20.69	7.49
Cogen	10.10	10.57
Geothermal	0.91	5.95
Hybrid_BattStorage	3.13	3.32
ICE	3.07	3.21
PSH	0.70	4.25
Paired_BattStorage	3.64	3.08

Table 23: Monthly PRM using Prior and Updated Forced Outage Rates

	Base Case (Flat Load) with Prior Forced Outage Rates			Base Case (Flat Load)		
Month	Demand Added (MW)	PRM	LOLE	Demand Added (MW)	PRM	LOLE
1	5,600	55.28%	0.0	6,000	53.32%	0.0
2	5,600	65.67%	0.0	6,000	63.59%	0.0
3	5,600	68.23%	0.0	6,000	66.13%	0.0
4	5,600	70.71%	0.0	6,000	68.64%	0.0
5	5,600	73.00%	0.0	6,000	70.93%	0.0
6	5,600	35.78%	0.0	6,000	34.49%	0.0
7	5,600	24.64%	0.0043	6,000	23.49%	0.0097
8	5,600	23.64%	0.0344	6,000	22.47%	0.0288
9	5,600	17.72%	0.0596	6,000	16.64%	0.0617
10	5,600	42.10%	0.0	6,000	40.56%	0.0
11	5,600	53.93%	0.0	6,000	52.04%	0.0
12	5,600	50.25%	0.0	6,000	48.42%	0.0
Total			0.0983			0.1002

SERVM Managed Peak vs. IEPR 1-in-2 Managed Peak Shapes

As explained in the Revised I&A document,[23] Staff calibrated SERVM consumption demand peak and annual energy inputs to match the corresponding forecast values in the CEC's 2025 IEPR demand forecast. Staff also replicated in SERVM the demand modifiers that come from the 2025 IEPR such as AAEE, AAFS, BTM PV, EV charging, and BTM storage profiles. This differs from the previous 2026 LOLE study, which calibrated directly to the IEPR managed forecast.

For this reason, the median managed peak modeled in SERVM does not perfectly match the corresponding IEPR 1-in-2 managed peak forecast or worst-day demand shapes used in the SOD PRM Calibration Tool. As described in the Revised I&A document, it is not possible to calibrate both the consumption and managed peaks to match the IEPR 1-in-2 forecast perfectly. This imperfect matching between the managed peaks modeled in SERVM and the IEPR 1-in-2 managed peak used in the SOD PRM Calibration Tool can lead to different PRM results. To assess this potential difference, Staff calculated the PRM in the SOD PRM Calibration Tool using the implied

[23] Revised Inputs & Assumptions for 2028 LOLE Study (June 2026): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M608/K310/608310037.PDF

1-in-2 CAISO coincident managed peak calculated from the full distribution of weather-varying hourly demand profiles used in SERVM, as well as calculated the PRM using the IEPR 1-in-2 CAISO coincident managed peak.

To develop the SERVM 1-in-2 managed peak, Staff downloaded the entire 25-year ensemble of demand shapes from SERVM and calculated a 1-in-2, 8,760-hour demand profile from the SERVM dataset using the same methodology as the CEC uses to create a 1-in-2 demand profile in their model. This is to harmonize the methods and create demand shapes from the underlying weather dataset.

From that, Staff created the 1-in-2 worst day profiles, loaded them into the SOD PRM Calibration tool, and ran the SOD PRM Calibration Tool to compare the effect on PRM with different demand shapes. For this analysis no new SERVM modeling runs were performed; the only difference was the demand profile that was loaded into the SOD PRM Calibration Tool.

Figure 10 shows the SERVM 1-in-2 managed demand profile in orange and the IEPR 1-in-2 managed demand profile in blue. Both profiles peak at Hour Ending 18. The SERVM 1-in-2 managed peak is 49,388 MW whereas the IEPR 1-in-2 managed peak is 48,356 MW. The SERVM 1-in-2 managed peak is approximately 1,023 MW, or 2.1%, higher than the IEPR 1-in-2 managed peak in 2028.

Figure 10: Comparison of 1-in-2 Worst Day Demand Profiles - SERVM vs. 2025 IEPR

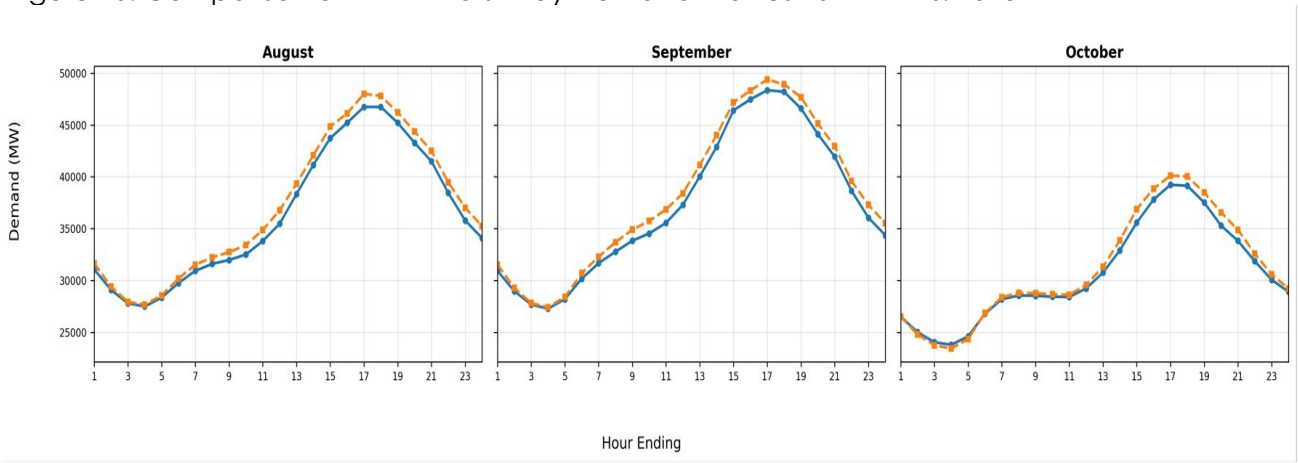


Table 24 compares monthly PRM results when the SERVM 1-in-2 managed peaks are used vs. when the IEPR 1-in-2 managed peaks are used. This table shows that, in the summer months, the higher SERVM demand reduces the PRM from approximately 21% to 18.7% (a decrease of about 2.3 percentage points). Additionally, there was no significant effect in the off-peak months, which is likely due to very similar 1-in-2 Worst Day shapes in off-peak months.

Table 24: Comparison of SOD PRM Calibration Results - SERVM 1-in-2 managed peak vs IEPR 1-in-2 managed peak

Month	Constrained Hour (HE)	Demand Added (MW)	ICAP PRM SERVM 1-in-2 Shapes	ICAP PRM IEPR 1-in-2 Shapes
1	19	15,158	19.32%	19.01%
2	19	17,832	19.53%	19.03%
3	19	18,640	19.32%	19.03%
4	19	19,784	18.92%	19.04%
5	20	19,812	20.68%	21.05%
6	20	10,577	19.21%	21.00%
7	19	6,891	18.73%	21.00%
8	19	6,518	18.70%	21.00%
9	18	4,430	18.60%	21.00%
10	18	12,669	17.73%	19.00%
11	18	15,050	18.97%	19.01%
12	18	14,098	18.89%	19.01%

Although calculating monthly ICAP PRMs using SERVM 1-in-2 managed peaks might be an acceptable assumption because it reinforces consistency between the LOLE model and PRMs calculated from model results, Staff decided to keep using the IEPR 1-in-2 managed peaks in the SOD PRM Calibration Tool to calculate monthly PRMs as was done in previous years. This errs on the side of being conservative in system reliability planning since it will increase PRM requirements by about 2 percentage points. It also stays consistent with the language in the joint-agency Single Forecast Agreement[24] that system RA requirements shall be based on the 2025 IEPR Planning Forecast with no Known Loads.

Recommended PRM Value

The results presented herein have been informed by multiple rounds of stakeholder input, including formal comments on modeling inputs and assumptions, informal comments on August 2026 draft results, and discussions at the September 2026 RA workshop. After thorough evaluation of the available results, Energy Division Staff recommend adopting UCAP-based PRMs derived from the Base Case monthly Stress Test scenario. This scenario calibrates reliability to an annual 0.1 LOLE target by adding varying amounts of uniform demand to each month, rather than prorating capacity, and utilizes monthly stress tests to levelize planning reserve margin requirements and reliability risks

[24] https://efiling.energy.ca.gov/GetDocument.aspx?tn=269506

throughout the year. The monthly stress test results indicated that reliability risks are concentrated during the summer period, with August producing the highest LOLE and May exhibiting elevated variability relative to the other non-summer months. Based on these results an ICAP-based PRM of 21% for the months of May through September and an ICAP based non-summer PRM of 19% for the months of October through April collectively maintains the 0.1 LOLE reliability standard

Applying the UCAP accreditation methodology adopted in D.26-07-008 translates these values to a UCAP-based summer PRM of 16% for May through September and a UCAP-based non-summer PRM of 14% for October through April. Accordingly, Staff recommends the adoption of these UCAP-based PRMs for RA compliance years 2028 and 2029.

It is noted once more that Staff are not recommending using the SERVM 1-in-2 managed peaks in the SOD PRM Calibration Tool and are using the IEPR 1-in-2 managed peaks as was done in previous years.

Table 25: Proposed PRM values for 2028 and 2029

Month	ICAP PRM – Base Case (Stress Test) Result	UCAP PRM (EFORd & Ambient)	Diff. Percentage Points	Proposed PRM for 2028 & 2029
1	19.0%	13.9%	5.1%	**14%**
2	19.0%	13.7%	5.3%	**14%**
3	19.0%	13.6%	5.4%	**14%**
4	19.0%	13.7%	5.3%	**14%**
5	21.1%	15.8%	5.3%	**16%**
6	21.0%	15.5%	5.5%	**16%**
7	21.0%	16.4%	4.6%	**16%**
8	21.0%	16.3%	4.7%	**16%**
9	21.0%	16.1%	4.9%	**16%**
10	19.0%	14.3%	4.7%	**14%**
11	19.0%	14.0%	5.0%	**14%**
12	19.0%	13.9%	5.1%	**14%**

Conclusions

The studies performed suggest the following conclusions can be made from these study results:

1. The study results indicate that CAISO BAA has significantly increased the amount of capacity over the last few years. The study shows that the CAISO BAA is over-reliable in 2028 by an amount equivalent to a 6,000 MW surplus, as measured by additional flat demand

that could be met by the resources online or expected to be online by 2028 and the adopted 2025 IEPR forecast.

2. The study shows an installed capacity fleet of resources equivalent to a 16.64% ICAP PRM in September translates to a Loss of Load Expectation of 0.1, or one LOLE event in ten years.
3. The study results show that implementing LOLE monthly stress test results would lead to a monthly ICAP PRM with varying amounts of monthly demand, such as a 21% PRM for May – September and 19% in other months.
4. The study results show that applying the resource derates adopted in the UCAP resource counting methodology to the monthly stress-tested PRM values in the SOD PRM Tool reduces the PRM to approximately 16% in May – September and 14% for all other months.
5. The study results show that providing reserves sufficient to account for the expected effects of heat related derates on thermal resources in the CAISO BAA increases the PRM in summer months by approximately 2 percentage points under an ICAP paradigm.
6. The study results show that utilizing the updated economic and demographic uncertainty distribution relative to the prior LOLE study could decrease reliability needs by about 200 MW, decreasing the PRM requirement by approximately 0.5 percentage point.
7. The Prorate Capacity scenario results show that calculated annual ICAP PRM is 19% in September with higher achieved reserve margins in other months.

Based on the above conclusions, Energy Division Staff recommend a 16% UCAP-based PRM for the months May through September and a 14% UCAP-based PRM for the months October through April for RA compliance years 2028 and 2029. Results of Energy Division's 2028 Loss of Load Expectation analysis will be considered in Track 2 of R.25-10-003, with opening and reply comments scheduled for November 20, 2026, and December 11, 2026, respectively.