Loss of Load Expectation Study for 2028: Draft Results

Resource Adequacy Program
Slice of Day Planning Reserve Margin

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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 draft report presents the draft results of the 2028 Loss of Load Expectation (LOLE) study performed by CPUC Energy Division Staff. The information contained in this draft report is meant to be considered in Track 2 of Rulemaking (R.) 25-10-003. It is intended to inform a stakeholder-level conversation regarding the eventual setting of and Resource Adequacy (RA) requirements for 2028 and 2029 compliance years, potentially including a new Planning Reserve Margin (PRM) and the translation of needs into the 24-hour Slide of Day (SOD) RA Framework. This paper presents draft results, but it does not constitute or contain a recommendation regarding the setting of those new requirements. Opportunities for stakeholder feedback, including a workshop, comments, and a formal staff proposal building on this content, as well as a schedule for those interactions will be forthcoming.

Background

In April 2026, Energy Division Staff published a Proposed Inputs & Assumptions (I&A) document 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 laid out key updates to the study's modeling inputs, including the baseline generation resource list, operational variables (e.g., outage and maintenance rates), 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 the draft 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 on June 5, 2026, which established the inputs and methods Staff used to conduct the 2028 LOLE study.

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 latest CEC IEPR adopted in 2025, and the latest forecasts for other regions from the 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 a Loss of Load Expectation (LOLE) study of the CAISO BAA to determine the current reliability of the CAISO BAA, how big the surplus or shortfall is, and how to calibrate the dataset 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. SERVM is a 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.

The SERVM model and outputs provide insight into risks and costs during a variety of scenarios, as well as the expectation of being able to meet peak load under various conditions. Since one of the objectives of the exercise is to understand when the system is most at risk to loss of load events, Energy Division utilized several methods to calibrate the CAISO BAA to the 0.1 LOLE target. These methods include adding flat blocks of demand, constraining simultaneous import limits, and applying a downward pro rata capacity adjustment to all capacity. Staff translated that LOLE target into a PRM target with the current SOD PRM Calibration Tool. Staff tested the LOLE study in a range of scenarios both to compare our results to prior studies, and to test the impacts of updated data and alternative methods of calculating PRM that were suggested by parties. Specifically, Staff evaluated key differences in ambient temperature output derating, economic and demographic uncertainty (EDU), and IEPR 1-in-2 monthly profiles versus analogous 1-in-2 monthly profiles calculated from the full set of weather year specific hourly profiles used in the LOLE base case model.

Key Findings

Draft 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 6,150 MW. The surplus represents the amount of additional load that could be served with existing and anticipated resources. Quantifying the surplus by adding the same level of demand in each month results in a 21.9% PRM in September, where all LOLE is concentrated, and higher installed capacity PRMs in other months.

In addition to the base case findings, the draft reliability model results from scenarios and sensitivities yield a number of other insights:

- **Monthly Stress Tests -** Additional analysis aimed to spread LOLE from the peak month to all months of the year and to test a levelized PRM across the year by increasing demand in other months and lowering it a bit in the peak month. These results show a reduced PRM in some months, with a LOLE that still totals 0.1 across all months of the year. The monthly stress tests show PRMs of 25.2% PRM for July-October and 21.8% in other months. These PRM levels are calculated by importing demand and resources into the SOD PRM Calibration Tool.
- **UCAP Resource Derates -** Applying the UCAP forced outage and ambient temperature resource derates adopted in Decision (D.) 26-07-008 to calculate monthly PRM values in the SOD PRM Calibration Tool reduces the PRM to approximately 20.5% in July–October and 17% for all other months.
- **Differences between SERVM Modeled vs. IEPR 1:2 Managed Peak -** Misalignment between the managed peak modeled in SERVM and the IEPR 1-in-2 managed peak used to calculate the PRM in the SOD PRM Tool can lead to a 2 percentage point difference in the PRM results.
- **Adding Reserves to Address Ambient Heat Derates -** Providing reserves sufficient to account for the expected effects of heat related derates on thermal resources in the CAISO

BAA further increases the PRM in summer months by approximately 2 percentage points relative to an Installed Capacity (ICAP) paradigm.

Next Steps

In this draft report, Staff present draft reliability results and monthly PRM values across various modeling scenarios. Importantly, Staff are not presenting results of the Prorate Scenario in this draft report but will share draft results from that scenario in the September workshop. Staff look forward to engaging with stakeholders throughout the upcoming procedural schedule, including workshops and comment periods, and will issue a PRM recommendation in the Final LOLE Study Report, scheduled for release in October 2026.

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.[1] 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.[2]

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 a 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) and procured by the three large investor-owned utilities (IOUs) 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 has scheduled more opportunities for stakeholder engagement in the 2028 LOLE study process. These include comment periods on 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 will host a workshop in mid-September to present draft LOLE study results and solicit stakeholder feedback. The final report will be issued in October 2026, followed by opening and reply comment periods.[3]

Energy Division Staff are not issuing a PRM recommendation in this Draft LOLE Study Report. This draft report focuses on describing the extensive analysis that Staff has conducted to date to revise the LOLE study and inform PRM requirements for 2028 and 2029 RA compliance years. Ahead of the fall workshop and the October final report, Staff will perform additional analyses, including the Prorated Capacity scenario outlined in the Revised Inputs & Assumptions document. Following further discussion of the draft results with parties, Staff will issue a PRM recommendation in its Final LOLE Study Report.

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

[2] 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

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

Model Improvements

Throughout the development of the Proposed and Revised I&A draft documents, Staff developed and incorporated extensive data sets in order to make this study as up-to-date as possible. The updates and improvements are detailed in Revised I&A and the updated modeling datasets have been posted to the CPUC website for review and use by parties in the RA proceeding.[4,5]

These updates are explained in detail in the I&A document and 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 and BTM PV projection from the EIA information and the WECC 2034 ADS
- Updated weather (which determines modeled hourly electric demand, solar generation, and wind generation) and hydroelectric data to include historical years 2023 and 2024
- Updated scheduled and unscheduled 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

In response to party comments on the Proposed I&A, Staff also incorporated additional scenarios into the 2028 study and include the outputs of those scenarios in this draft report. These scenarios evaluate alternative economic and demographic uncertainty levels and differing methods for surfacing LOLE (e.g., capacity pro rata adjustments vs. adding 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 draft study results presented throughout the draft report.

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

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

Table 1 Base Cases and Sensitivity Scenarios

Scenario Name	Method of Annual Calibration / Surface LOLE	Econ-Demo Uncertainty (EDU)	Ambient Temp. Included	Maintenance Schedule Included
Base Case	N/A	Updated	Yes	Yes
Base Case (Flat Load)	Same demand (MW) added to each month to calibrate LOLE.	Updated	Yes	Yes
Base Case (Constrain Imports)	Tighten 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 demand (MW) blocks to calibrate annual LOLE and levelize monthly PRM.	Updated	Yes	No
Prorate Capacity (Stress Test)	Monthly varying capacity reduction to surface LOLE to months.	Updated	Yes	No
Sensitivities				
Base Case (Stress Test w/ Ambient Temp. Removed)	Add monthly varying demand (MW) blocks to calibrate annual LOLE and levelize monthly PRM.	Updated	No	No
Base Case (Flat Load) with Original EDU	Same demand (MW) added to each month to calibrate LOLE.	Original	Yes	Yes

After the Revised I&A was published[6], Staff performed reliability modeling using the datasets created and loaded into SERVM. After stress tests were conducted at the monthly level, 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 draft study results also support the translation of system reliability needs into the 24-hour Slice of SOD RA Framework.

The study addresses the following questions:

- What is the reliability level and implied PRM of the Modeling Baseline[7], 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

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

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

- 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 under the UCAP methodology?

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).[8]

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. 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.[9]

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.

[8] 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.

[9] 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	Inc or 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 Between Aug. 2026 and 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 with groups by 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 50 times, each with a different random outage draw. Increase in the number of random outage draws improves the statistical convergence of the average results of each case and ultimately means that the draft study results are very close 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 draft study results show 0.0 LOLE for the Base Case scenario, meaning that the Modeling Baseline and 2025 IEPR and other study variables provide reliable electric service throughout the year, and no additional capacity is needed to meet reliability needs (Table 4). In other words, the draft study results reflect that the full reliability need can be met with existing resources and resources that are expected to come online ahead of 2028 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 2028.

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

Annual Reliability Metrics		
Metric	**2028**	**Units**
LOLE Total	-	days/year
LOLE Capacity	-	days/year
EUE	-	MWh
LOLH Total	-	hours/year
LOLH Capacity	-	hours/year
LOLH/LOLE (average length of outage)	-	hours/day
Normalized EUE (EUE divided by total electric demand)	0.0000%	percent

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	$MMTCO_2$
CAISO BTM CHP Emissions	-	$MMTCO_2$
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.[10]

- <u>Demand Blocks Added</u>: To surface LOLE when the system is found to be overly reliable, flat blocks of demand were added to yield 0.1 LOLE for the year. For annual LOLE studies, the same amount of load is added each month. For monthly LOLE surfacing, varying amounts of load 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.
- <u>Simultaneous Import Limit:</u> The default assumption applies a CAISO area simultaneous import limit of 11,040 MW year-round, in all hours; additionally, a 4,000 MW limit is 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. Additionally, to address stakeholder feedback regarding potential overreliance on external transfers, Energy Division also modeled a sensitivity scenario with simultaneous import limits reduced to zero in all months.
- <u>Prorate Capacity Reduction:</u> This scenario applies a pro rata capacity reduction to the baseline resources fleet, same across all resource classes except hydro, in order to surface LOLE. This is different from the other scenarios which maintain a static baseline resource fleet—comprising existing and in-development resources.

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

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

- 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.
- 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 SERVM run is over reliable throughout CAISO in 2028, as shown by the zero LOLE result and zero EUE. Table 6 compares the Base Case reliability results with scenarios that sought to surface LOLE using the methods discussed earlier. Results for the Prorate Capacity Reduction scenario are not included in this draft report because the modeling is still underway. Staff will present the results and associated analysis in the September RA workshop or the Final LOLE Study Report.

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	6,150	0	N/A
Simultaneous Import Limit	Default	Default	Restricted	TBD
Capacity Reduction	N/A	N/A	N/A	TBD
LOLE (events/year)	0	0.113	0.028	TBD
EUE (MWh)	0	590	160	TBD
LOLH/LOLE (hours/days)	0	2.0	2.3	TBD

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

To calibrate the 2028 over-reliable portfolio to 0.1 LOLE, Staff added flat load of 6,150 MW for all 12 months. The results of this study reflect a September PRM of 21.9% with the most constrained hour being hour ending (HE) 20:00. Table 7 shows the monthly SOD PRMs including load, supply and most constrained hour. 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 PRMs, 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	Stressed Hour (HE)	Load (MW)	Flat Load Added (MW)	Supply (MW)	PRM
1	19	30,228	6,150	58,408	60.6%
2	19	29,762	6,150	61,319	70.8%
3	19	30,316	6,150	60,840	66.8%
4	19	32,624	6,150	65,673	69.4%
5	20	32,532	6,150	66,112	70.9%
6	20	41,173	6,150	62,022	31.1%
7	20	43,822	6,150	61,806	23.7%
8	20	43,283	6,150	62,612	26.7%
9	20	44,125	6,150	61,271	21.9%
10	20	35,295	6,150	64,247	55.0%
11	19	31,704	6,150	64,657	70.8%
12	19	30,671	6,150	60,946	65.5%

Figure 1 shows the monthly LOLE capacity for each region in CAISO after adding a flat load of 6,150MW. It is seen that SCE and SDG&E are contributing to CAISO LOLE and PG&E has a reliable portfolio. September has the highest LOLE. LOLE is not symmetrical across the CAISO BAA partially due to a constraint on Path 26 in stressed hours.

Figure 1: Monthly LOLE capacity for each region after 6,150 MW flat load is added

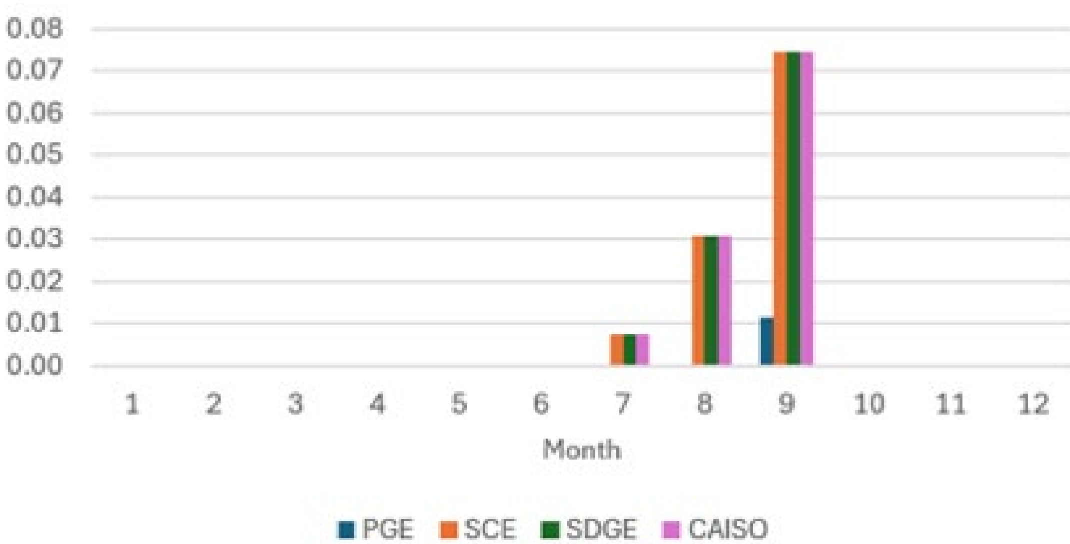
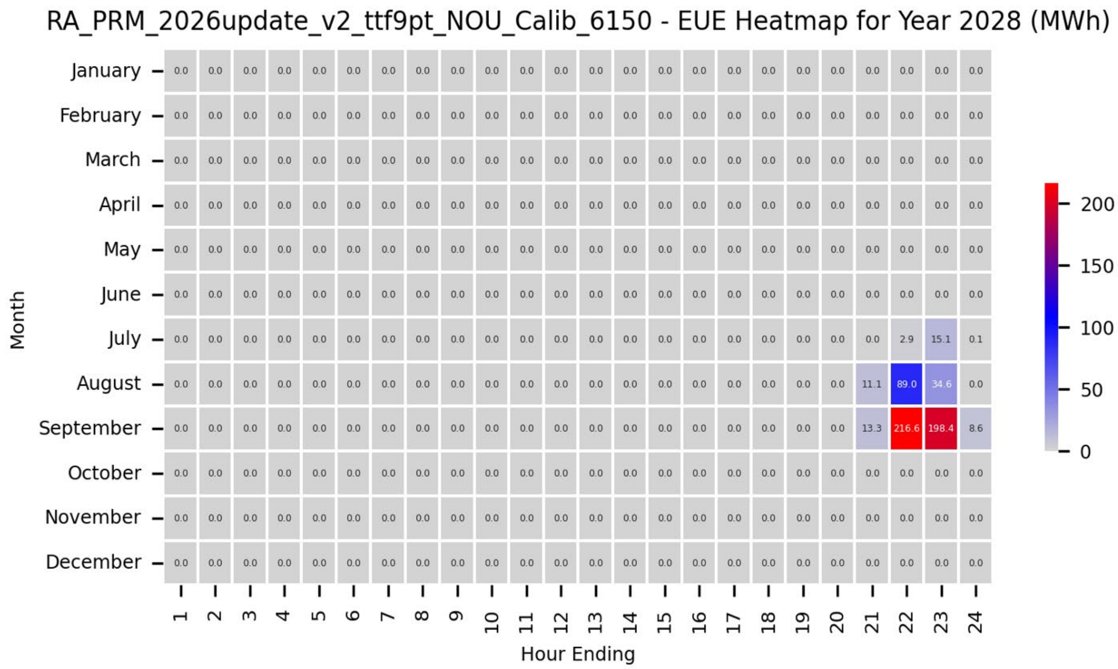


Figure 2 shows a heatmap of EUE across hours of the day and months of the year. This is aggregated to CAISO BAA, not specific to IOU service areas. It is observed that annual LOLE tuning by adding flat load is resulting in EUE being concentrated in months August and September during mostly HE 22:00 and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

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



Annual Loss of Load Draft study 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 0MW during all hours of the year, which still showed a reliable system with 0.028 LOLE.

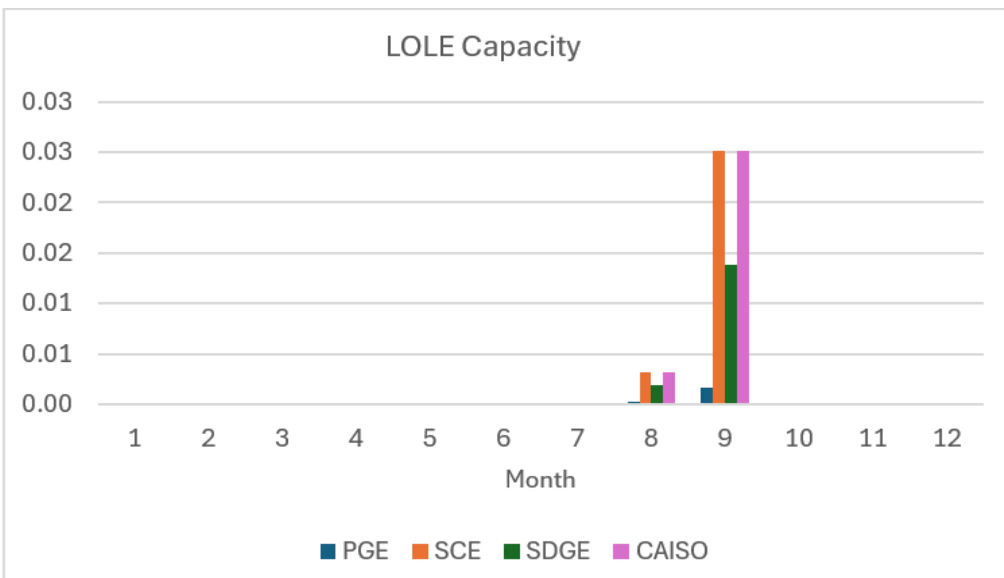
Table 8 shows that with all imports removed, the system exceeds the standard 0.1 LOLE target, achieving a 0.028 LOLE – representing an overly reliable system. This finding is particularly useful to address stakeholders' concerns about evolving supply & demand dynamics in neighboring balancing authority areas and the ability of external regions to continue to provide imports at levels observed historically. Overall, these findings suggest that the CAISO could operate reliability with limited imports, given the current modeling baseline and 2025 IEPR, and that the CAISO is expected to be reliable across all sensitivities in 2028.

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

Annual Reliability Metrics		
Metric	**2028**	**Units**
LOLE Total	0.028	days/year
EUE	159.8	MWh
LOLH Total	0.066	hours/year
LOLH/LOLE (average length of outage)	2.345	hours/day
Normalized EUE (EUE divided by total electric demand)	0.00125%	percent

Figure 3 shows monthly LOLE for each region in our Base Case (Constrain Imports) scenario when imports are constraint 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)



Pending - Annual Loss of Load Draft study results for Prorate Capacity Scenario

This scenario is pending. Instead of adding blocks of demand, Staff will proportionately reduce available capacity across all resource types in the portfolio to calibrate to 0.1 LOLE. This alternative method for surfacing LOLE is currently incomplete. Staff intend to complete the work by September in time to present results to stakeholders at the scheduled public workshop.

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 draft 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.[11] 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

[11] 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.

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.

Monthly Stress Testing

The annual Base Case (Flat Load) LOLE results, presented in Table 7 and Figure 1, show that the minimum PRM of 21.9% occurs in September, with LOLE concentrated in July – September. These results also show that operating 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 9 presents the results of these stress tests which indicate PRMs of approximately 25.2% in July through October and 21.8% in November through June.

Table 9: Monthly PRM and LOLE Results – Base Case (Stress Test)

Month	Demand Added (MW)	PRM	LOLE
1	16,333	21.7%	0
2	18,969	21.7%	0
3	17,659	21.8%	0
4	18,784	21.8%	0
5	19,301	21.9%	0.0039
6	9,133	21.9%	0
7	5,642	25.2%	0.0018
8	6,665	25.1%	0.0640
9	5,008	25.2%	0.0185
10	14,957	25.1%	0.0201
11	19,284	21.8%	0
12	17,944	21.9%	0
Total			**0.1083**

Table 10 presents the aggregate reliability metrics for the Base Case (Stress Test) scenario. The stress test results in a total LOLE of 0.108, indicating that the resulting PRM levels are consistent with the 0.1 LOLE reliability standard.

Table 10: Annual Reliability Metrics – Base Case (Stress Test)

Annual Reliability Metrics		
Metric	**2028**	**Units**
LOLE Total	0.108	days/year
EUE	502.3	MWh
LOLH Total	0.208	hours/year
LOLH/LOLE (average length of outage)	1.918	hours/day
Normalized EUE (EUE divided by total electric demand)	0.00392%	percent

Figure 4 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 5 presents the EUE results for the Base Case (Stress Test) and shows EUE most concentrated in August through October in HE 21:00 – 23:00.

Figure 4: Monthly LOLE for PGE, SCE and SDG&E – Base Case (Stress Test)

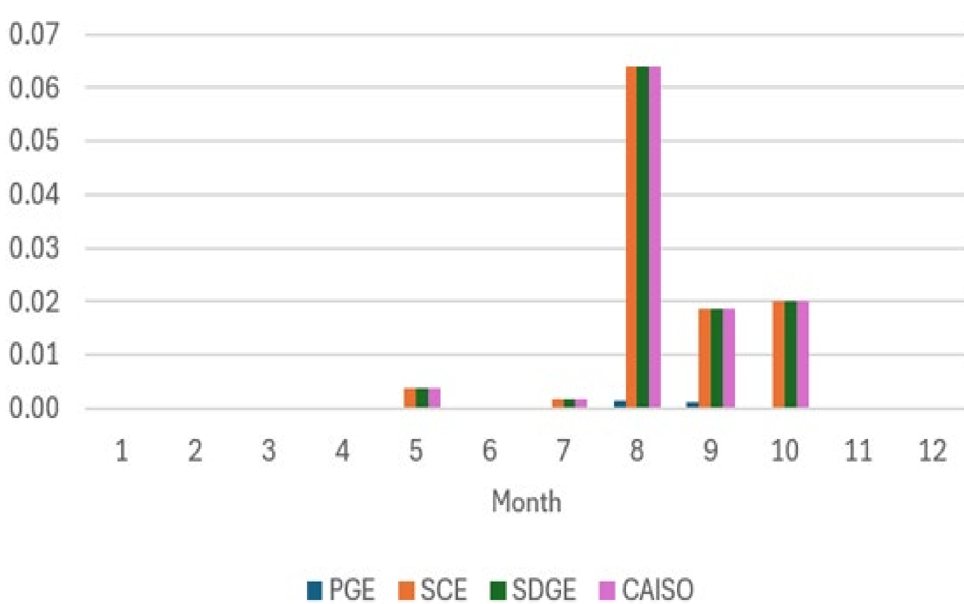
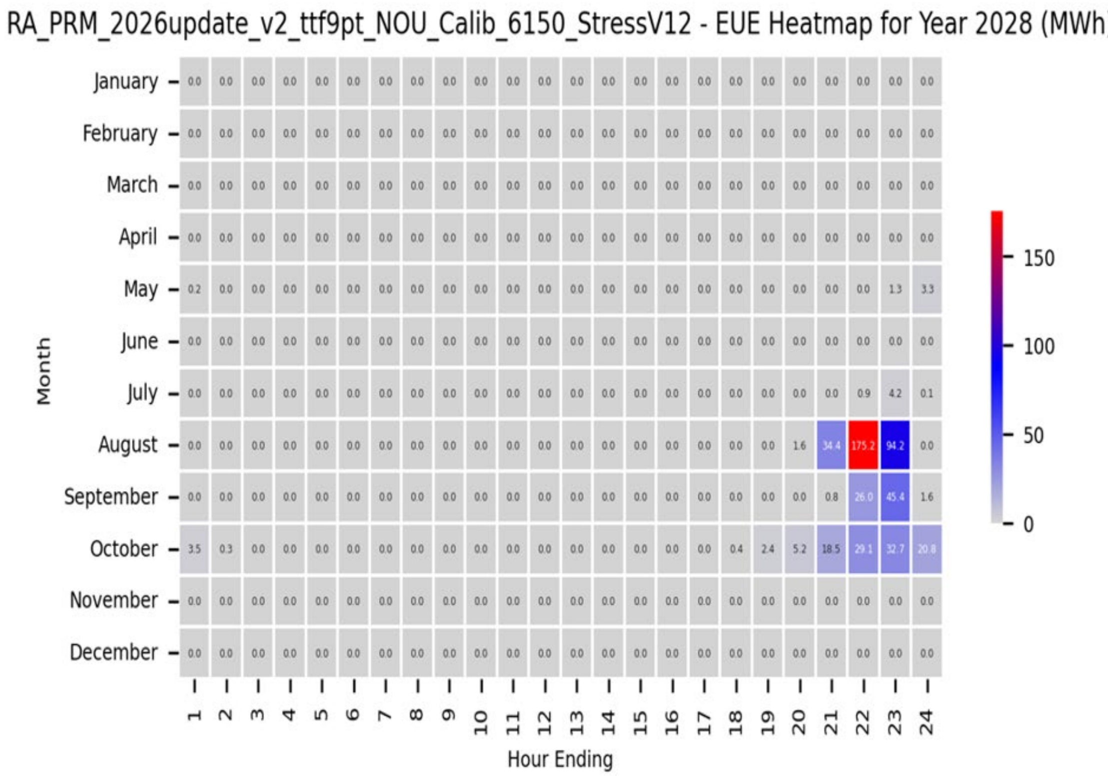


Figure 5: EUE heat map – Base Case (Stress Test)



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, PRM levels 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 monthly PRMs as high at 70%, with LOLE concentrated in September. These results indicate that the annual draft study results translated by month do not provide appropriate monthly PRMs. Staff performed additional stress tests to levelize the PRM across the summer months and reduce the PRM in off-peak months. In 2028, LOLE results show that October behaves more like a summer month by requiring a higher margin of reserves, while June now appears to be like a non-summer month with a lower PRM. Staff grouped months into summer and non-summer to reflect June moving out of the summer months and October moving into the 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 a PRM of approximately 22% in off-peak months and 25% PRM in summer. Table 11 summarizes and compares the annual Base Case Flat Load monthly PRM results to the Base Case Stress Test monthly PRM results.

Table 11: Monthly LOLE and PRM Results derived with Slice of Day PRM Calibration Tool

	Base Case (Flat Load)		Base Case (Stress Test)	
Month	PRM	LOLE	PRM	LOLE
1	60.6%	0.0	21.7%	0.0
2	70.8%	0.0	21.7%	0.0
3	66.8%	0.0	21.8%	0.0
4	69.4%	0.0	21.8%	0.0
5	70.9%	0.0	21.9%	0.0039
6	31.1%	0.0	21.9%	0.0
7	23.7%	0.0076	25.2%	0.0018
8	26.7%	0.0309	25.1%	0.0640
9	21.9%	0.0744	25.2%	0.0185
10	55.0%	0.0	25.1%	0.0201
11	70.8%	0.0	21.8%	0.0
12	65.5%	0.0	21.9%	0.0
Total		0.1129		0.1084

UCAP Application

D.26-07-008 at ordering paragraph 17 adopted the UCAP framework and adjusted PRM 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 11 compares the monthly Unadjusted PRM and UCAP-adjusted PRM results across the study scenarios. The UCAP-adjusted 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 expected outage rates.

Table 12: Unadjusted PRM and UCAP PRM Comparison – Base Case (Flat Load) and Base Case (Stress Test) Scenarios

	Base Case (Flat Load)				Base Case (Stress Test)			
Month	Unadjusted PRM	UCAP PRM (EFORd Only)	UCAP PRM (EFORd & Ambient)	Diff. Percentage Points	Unadjusted PRM	UCAP PRM (EFORd Only)	UCAP PRM (EFORd & Ambient)	Diff. Percentage Points
1	60.6%	55.5%	54.0%	-6.6%	21.7%	17.9%	16.8%	-4.9%
2	70.8%	64.6%	63.1%	-7.7%	21.7%	17.5%	16.5%	-5.2%
3	66.8%	61.6%	60.1%	-6.7%	21.8%	18.0%	16.9%	-4.9%
4	69.4%	63.3%	62.0%	-7.4%	21.8%	18.2%	17.2%	-4.6%
5	70.9%	65.0%	63.6%	-7.3%	21.9%	18.3%	17.3%	-4.6%
6	31.1%	27.9%	25.9%	-5.2%	21.9%	19.0%	17.1%	-4.8%
7	23.7%	20.8%	19.0%	-4.7%	25.2%	22.3%	20.4%	-4.8%
8	26.7%	23.8%	21.9%	-4.8%	25.1%	22.3%	20.4%	-4.7%
9	21.9%	19.0%	17.2%	-4.7%	25.2%	22.2%	20.4%	-4.8%
10	55.0%	51.7%	49.5%	-5.5%	25.1%	22.4%	20.6%	-4.5%
11	70.8%	65.2%	63.8%	-7.0%	21.8%	17.8%	16.8%	-5.0%
12	65.5%	59.5%	58.1%	-7.4%	21.9%	17.7%	16.6%	-5.3%

Table 12 above shows the UCAP-adjusted PRM results. Staff are providing two sets of adjusted values: one reflecting only EFORd derates, and another reflecting both EFORd and ambient temperature derates. The reason for this is because the SOD UCAP-Adjusted PRM Calibration Tool released in January 2026 applied only EFORd derates while staff refined the ambient derate methodology.[12] Staff intends to present final PRM recommendations that include both types of UCAP derates, however providing both sets of values ahead of the September RA workshop allows stakeholders to compare results against party proposals that are utilizing the January 2026 tool. Staff are publishing the updated UCAP PRM Calibration Tool alongside the 2028 LOLE draft results.

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

In order to be assured that the observed results bore relation to previous studies and previous analysis, Staff identified three major methodological differences that are likely to have had an impact on the overall resulting PRM levels. These major differences could explain the increase in the summer PRM requirement from 21.5% found in the previous 2026 LOLE study, compared to the PRM findings of 25.2% found in the current study. Two new methods are likely to increase

[12] UCAP-Adjusted PRM Calibration Workbook from January 23, 2026: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-history

requirements, meaning the overall approach is becoming more conservative and potentially raising reliability requirements, while one approach is expected to reduce requirements. Staff attempted to quantify the impacts of these three methods individually in terms of their impact (increase or decrease) to the PRM.

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

As explained in the Revised I&A document,[13] 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 IEPR forecast perfectly. While Staff calibrated to the consumption forecasts, lack of data prevented analysis of the impacts of demand modifiers other than BTMPV and staff could not properly match the impacts on the forecast of weather dependent demand modifiers. The resulting lack of calibration between the managed peak modeled in SERVM and the IEPR 1-in-2 managed peak (IEPR 1-in-2) used to calculate the PRM in the SOD PRM Calibration Tool can lead to different PRM results. Staff therefore evaluated the PRM under both the IEPR 1-in-2 managed peak and the 1-in-2 managed peak model in SERVM.

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 6 shows the SERVM 1-in-2 managed-demand profile in orange and the IEPR 1-in-2 demand profile in blue. Both profiles peak at Hour Ending 17. The SERVM 1-in-2 managed-demand peak is 49,388 MW, compared with an IEPR peak of 48,356 MW. The SERVM 1-in-2 peak is approximately 1,032 MW, or 2.1%, higher than the IEPR 1-in-2 peak.

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

Figure 6: Comparison of 1-in-2 Worst Day Demand Profiles - SERVM vs. 2025 IEPR

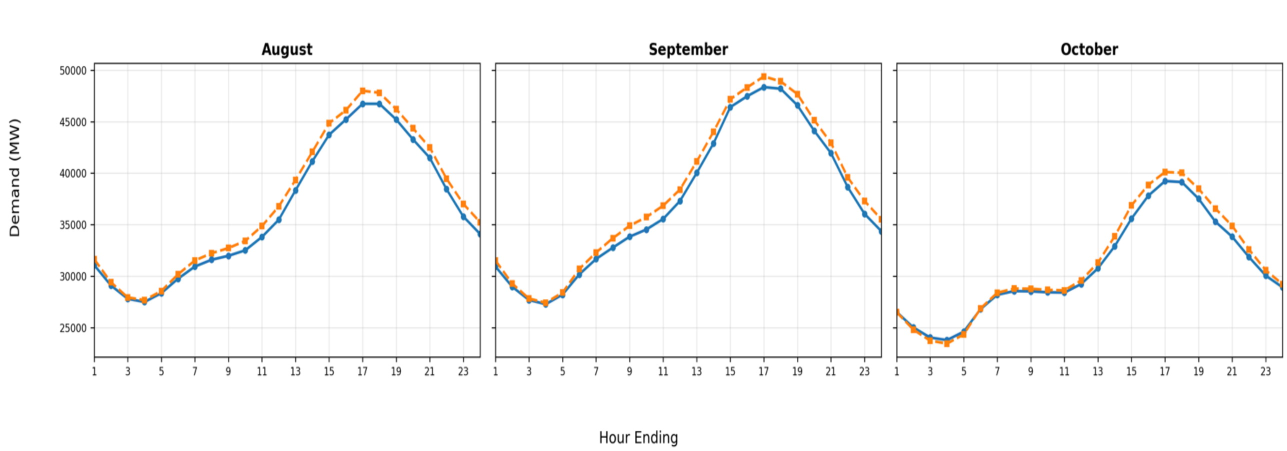


Table 13 compares PRM results of the SERVM 1-in-2 demand profiles vs. the IEPR 1-in-2 demand profiles. This table shows that, in the summer months, the higher SERVM demand reduces the PRM from approximately 25.2% to 22.7% (a decrease of about 2.5 percentage points). Additionally, there was no significant effect in the off-peak months, which is likely due to very similar 1-in-2 Worst Day shapes in off-peak months.

Table 13: Comparison of SOD PRM Calibration Results - SERVM 1-in-2 vs IEPR 1-in-2

Month	PRM SERVM 1-in-2 Shapes	PRM IEPR 1-in-2 Shapes	Demand Added (MW)	Constraining Hour Ending
1	22.0%	21.7%	16,333	19
2	22.2%	21.7%	18,969	19
3	22.2%	21.8%	17,659	19
4	22.0%	21.8%	18,784	19
5	22.0%	21.9%	19,301	20
6	20.0%	21.9%	9,133	20
7	22.7%	25.2%	5,642	20
8	22.8%	25.1%	6,665	20
9	22.7%	25.2%	5,008	20
10	23.9%	25.1%	14,957	20
11	21.8%	21.8%	19,284	19
12	21.8%	21.9%	17,944	19

PRM Increase from Ambient Thermal Derate Methodology

To be comparable with 2026 RA LOLE study, which didn't include ambient thermal derates, Staff conducted a sensitivity similar to the Monthly Stress Test scenario by adding demand to individual months of 2028 without ambient thermal derates. Results shown in Table 14, reflect a 2 percentage point decrease in the PRM relative to the Base Case (Stress Test) scenario.

Table 14: Monthly PRM for Base Case (Stress Test w/ Ambient Temp. Removed)

Month	Demand Added (MW)	PRM	LOLE
1	16,333	21.7%	0
2	18,969	21.7%	0
3	17,659	21.8%	0
4	18,784	21.8%	0
5	19,301	21.9%	0.00027
6	9,133	21.9%	0
7	6,339	23.1%	0.00272
8	7,366	23.1%	0.05569
9	5,700	23.1%	0.01595
10	15,699	23.1%	0.02461
11	19,284	21.8%	0
12	17,944	21.9%	0
Total			**0.099246**

Table 15: Annual Reliability Metrics for Base Case (Stress Test w/ Ambient Temp. Removed)

Annual Reliability Metrics		
Metric	**2028**	**Units**
LOLE Total	0.099	days/year
EUE	447.0	MWh
LOLH Total	0.190	hours/year
LOLH/LOLE (average length of outage)	1.913	hours/day
Normalized EUE (EUE divided by total electric demand)	0.0035%	percent
Total CAISO Emissions	72.63	MMT CO2

Figure 7 shows the monthly LOLE for each region without thermal derate. As can be seen, even without thermal derates, October is added to LOLE months. August is showing higher LOLE than September.

Figure 7: Monthly LOLE for PGE, SCE and SDG&E for Base Case (Stress Test w/ Ambient Temp. Removed)

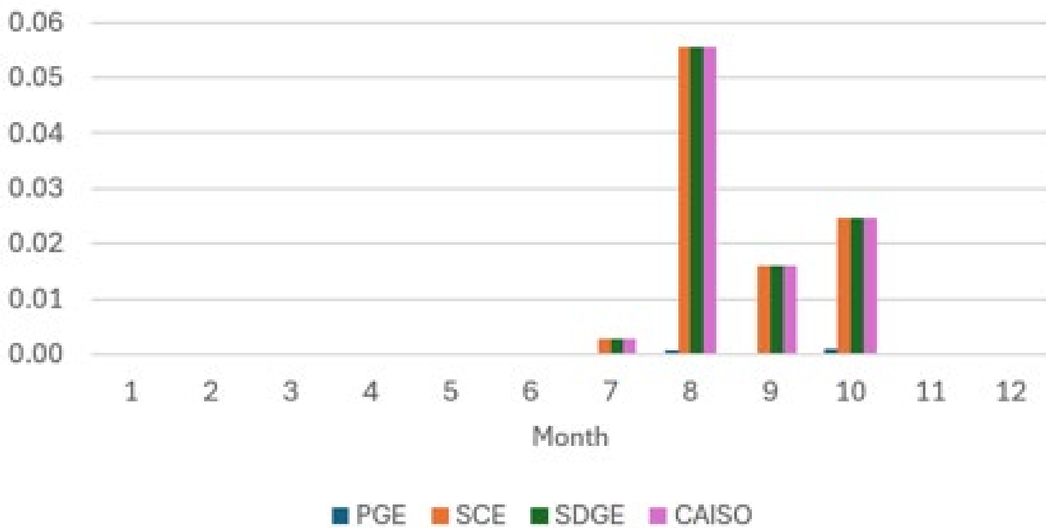
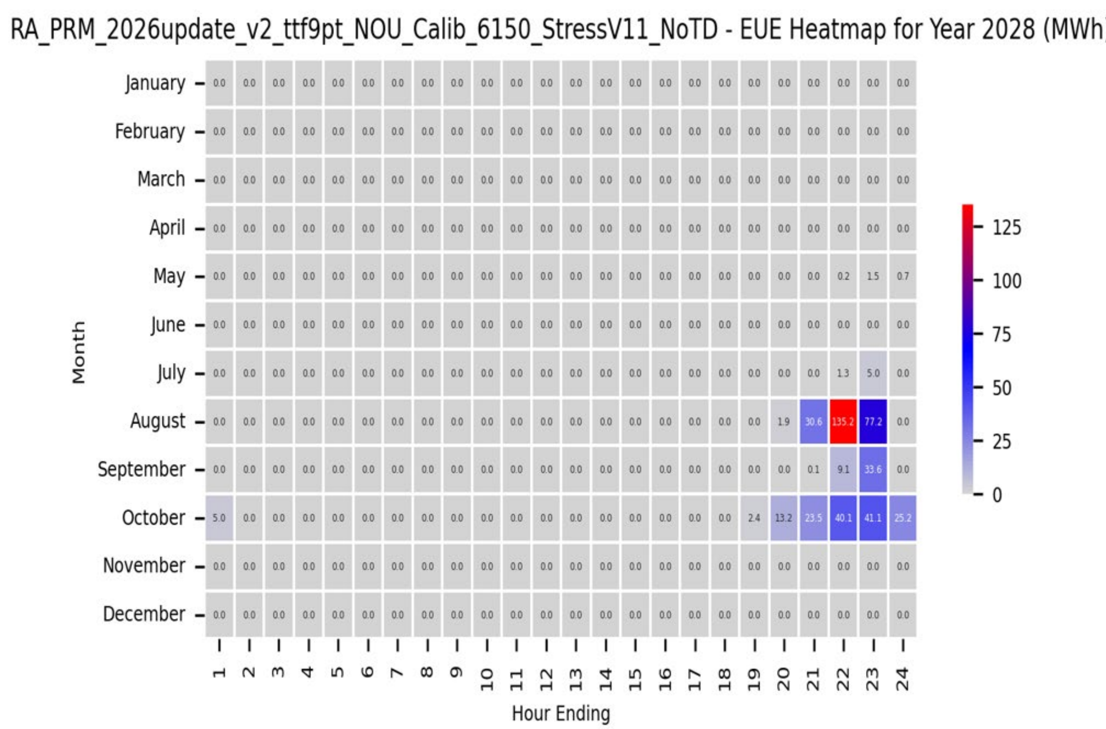


Figure 8: EUE heat map for Base Case (Stress Test w/ Ambient Temp. Removed). Total annual EUE is less than the scenario including thermal derates.



Summer Months Shift to July-October during Stress Tests

As seen in the monthly stress test scenarios, summer months shifted from June – September, to July – October. Staff analyzed the dispatch reports for a high October LOLE case and concluded that due to added blocks of load, October's power system is under higher stress than normal which results in batteries being unable to fully charge. This effect is even more pronounced when the system is under stress for several consecutive days. This effect may be related to the method of surfacing LOLE in a particular month, so Staff will discuss this dynamic when contrasting with the Prorate Capacity scenario in the September workshops.

Figure 9: Monthly Stress Test Scenario Highest October EUE Day, Dispatch and SOC.

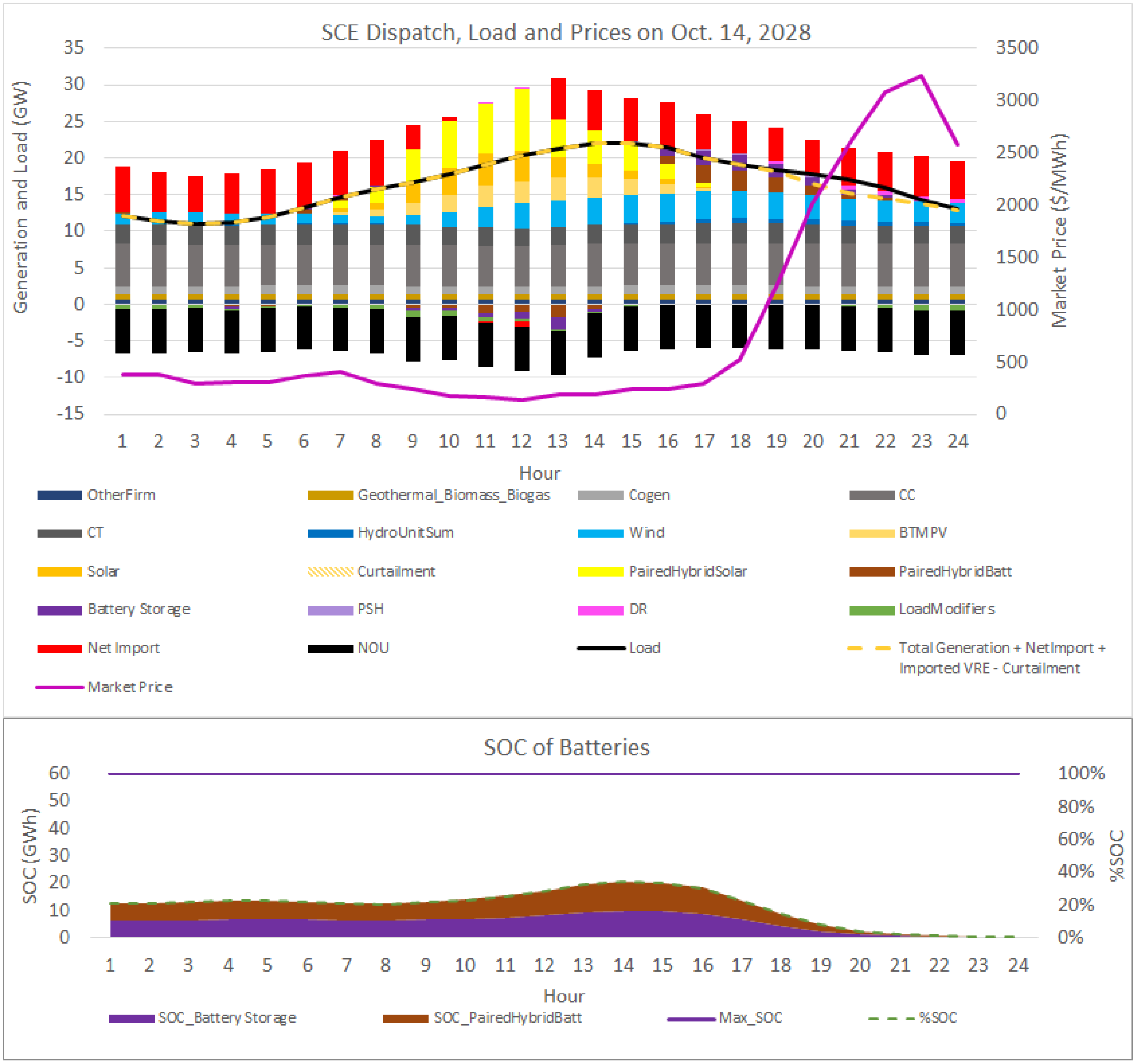
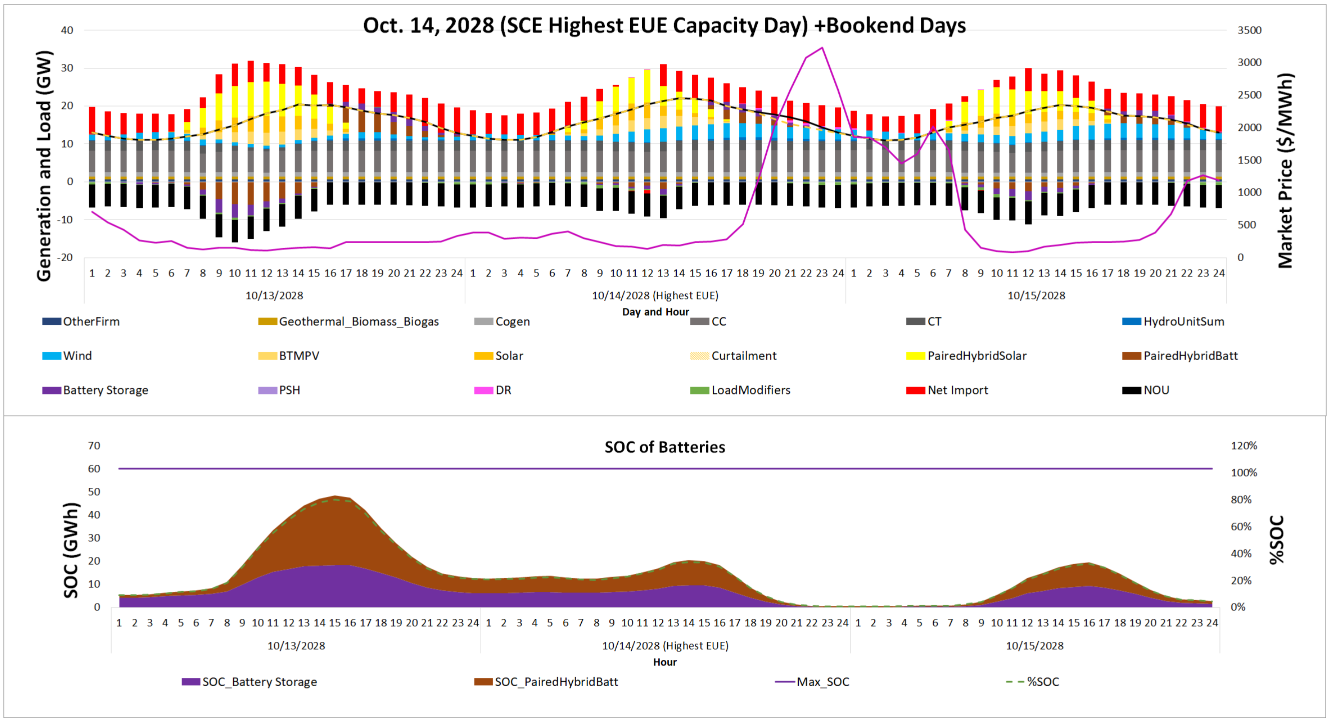


Figure 9 and Figure 10 highlight this dynamic over a three-day period, showing EUE occurring on October 14, 2028, during HE 20:00 to 23:00. Due to additional EUE already occurring on October 11th and 12th, the batteries were unable to fully charge between those four days, and the highest achieved state of charge was 33% on October 14th resulting in additional EUE.

Figure 10: Monthly Stress Test Scenario Highest October EUE Day, plus/minus one day, Dispatch and SOC.



Economic and Demographic Uncertainty (EDU) Impacts on PRM

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 large 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.[14]

As shown in Table 16, 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 original 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 EDU distributions.

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

Table 16: Comparison of Economic & Demographic Uncertainty (EDU) Distributions

Original 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 Original EDU: Utilizing the original 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 6,150 MW of flat demand to calibrate to 0.1 LOLE.

Results show that using the updated EDU distribution reduces reliability risk, as measured in the amount of demand that can be met in CAISO. Updating the EDU factors requires an additional 350 MW of demand to be added to calibrate to 0.1 LOLE. The observed differences can be attributed to the updated EDU distribution having a lower frequency of demand variance in the SERVM simulations, thus making the modeled system appear more reliable. Staff find that using the updated EDU reduces the PRM by about 1 percentage point as compared to using the original EDU distribution. As shown in Table 18 the September PRM is 22.9% for the Base Case (Flat Load) Original EDU sensitivity, compared to a 21.9% PRM in the Base Case (Flat Load) scenario.

Table 17: Annual Reliability Metrics – Base Case (Flat Load) with Original EDU

Annual Reliability Metrics		
Metric	**2028**	**Units**
LOLE Total	0.101	days/year
LOLE Capacity	0.101	days/year
EUE	464.7	MWh
LOLH Total	0.188	hours/year
LOLH Capacity	0.188	hours/year
LOLH/LOLE (average length of outage)	1.866	hours/day
Normalized EUE (EUE divided by total electric demand)	0.00402%	percent

Table 18: Comparison of Annual PRM Results – Base Case (Flat Load) with Original EDU & Base Case (Flat Load)

	Base Case (Flat Load) Original EDU			Base Case (Flat Load)		
Month	**Demand Added (MW)**	**PRM**	**LOLE**	**Demand Added (MW)**	**PRM**	**LOLE**
1	5,800	62.3%	0	6,150	60.6%	0.0
2	5,800	72.6%	0	6,150	70.8%	0.0
3	5,800	68.7%	0	6,150	66.8%	0.0
4	5,800	71.2%	0	6,150	69.4%	0.0
5	5,800	72.7%	0	6,150	70.9%	0.0
6	5,800	32.2%	0	6,150	31.1%	0.0
7	5,800	24.7%	0.01165	6,150	23.7%	0.0076
8	5,800	27.7%	0.02822	6,150	26.7%	0.0309
9	5,800	22.9%	0.06113	6,150	21.9%	0.0744
10	5,800	56.5%	0	6,150	55.0%	0.0
11	5,800	72.7%	0	6,150	70.8%	0.0
12	5,800	67.3%	0	6,150	65.5%	0.0
Total			0.10099			0.113

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 6,150 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 21.9% 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 PRM with varying amounts of monthly demand, such as a 25.2% PRM for July-October and 21.8% 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 20.5% in July–October and 17% for all other months.

5. The study results show misalignment between the managed peak modeled in SERVM and the IEPR 1-in-2 managed peak used to calculate the PRM in the SOD PRM Tool can lead to a 2 percentage point difference in the PRM results.
6. 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.
7. The study results show that relaxing the expected uncertainty caused by economic and demographic uncertainty relative to the prior LOLE study could decrease reliability needs by about 350 MW, decreasing the PRM requirement by approximately 1 percentage point.

Next Steps for 2028 LOLE Study

Energy Division Staff intend to implement the next steps for the 2028 LOLE Study as follows:

1. For this draft report, Staff reduced the number of random outage draws (iterations) from 50 to 30 to accelerate review times and complete this phase of the study. For the final report, Staff will perform the full 50 iterations across all scenarios in order to increase convergence and the stability of results.
2. Modeling the Prorate Capacity scenario is in progress. Staff will complete this analysis and incorporate the results in the final report.
3. Since Staff is not proposing a firm PRM recommendation for the 2028–2029 RA compliance years in this draft report, next steps include holding a September workshop to present results to stakeholders, followed by a PRM recommendation in the final report.