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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.25-10-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S FINAL 2028 PLANNING RESERVE MARGIN STUDY AND PROPOSALS

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S FINAL 2028 PLANNING RESERVE MARGIN STUDY AND PROPOSALS

California Community Choice Association[1] (CalCCA) submits these proposals pursuant to the *Assigned Commissioner's Scoping Memo and Ruling,*[2] dated December 12, 2025; *Assigned Commissioner's Amended Scoping Memo and Ruling,*[3] dated August 25, 2026; and *Administrative Law Judge's Ruling Modifying Track 2 Schedule*[4] (Ruling), dated September 25, 2026.

I. INTRODUCTION

CalCCA appreciates the opportunity to submit its Final 2028 Planning Reserve Margin (PRM) Study (CalCCA's Final 2028 PRM Study) and proposals. CalCCA applauds the California Public Utilities Commission (Commission) for providing the opportunity for parties,

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[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, Valley Clean Energy, and WestLight Energy.

[2] *Assigned Commissioner's Scoping Memo and Ruling*, Rulemaking (R.) 25-10-003 (Dec. 12, 2025), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M590/K884/590884355.PDF.

[3] *Assigned Commissioner's Amended Scoping Memo and Ruling*, R.25-10-003 (Aug. 25, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M615/K874/615874564.PDF.

[4] *Administrative Law Judge's Ruling Modifying Track 2 Schedule*, R.25-10-003 (Sept. 25, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M620/K565/620565731.PDF.

along with Energy Division staff, to conduct thorough analysis and have robust conversations about how to set the Resource Adequacy (RA) PRM. Loss-of-Load Expectation (LOLE) modeling, used in CalCCA's, Energy Division's, and SCE's PRM analyses, accounts for the complex interactions among load variability, generator outages, weather conditions, resource availability, and the diversity of resources on the system. It also captures how these factors affect reliability across different hours, seasons, and operating conditions. This complexity requires iterative analysis, review, and discussion among Energy Division and parties to ensure a develop a shared understanding of the methodology and establish a PRM that meets the Commission's reliability standard.

CalCCA's Final 2028 PRM Study, attached hereto as Attachment A, evaluates how the capacity needed to meet the Commission's 0.1 LOLE reliability standard under eight different PRM selection criteria, four of which incorporate cost minimization. Each of the eight PRM selection criteria utilize risk-reserve curves for each month developed from pairing many different portfolios' accredited capacity with their LOLE. The cost-minimizing criteria use the risk-reserve curves to solve an optimization problem that determines how much accredited capacity needs to be shown in each month to meet the 0.1 LOLE reliability standard at least cost. These criteria recognize that the PRM should achieve an established reliability standard while minimizing the cost of maintaining that level of reliability.

CalCCA's Final 2028 PRM Study maintains the core design elements from CalCCA's August 14, 2026, Draft 2028 PRM Study,[5] including generating monthly risk-reserve curves using the same data and tools employed in Energy Division's PRM study process. Through 12

[5] *California Community Choice Association's Track 2 Loss of Load Expectation Study and PRM Proposals*, R.25-10-003 (Aug. 14, 2026) (CalCCA Draft 2028 PRM Study), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M614/K484/614484383.PDF.

different risk-reserve cases, CalCCA's Final 2028 PRM Study explores key uncertainties that impact the risk-reserve curves. It also reflects updates based upon the feedback and questions received from Energy Division and parties in September 2, 2026, informal comments and the September 15, 2026, workshop (Workshop),[6] including using the UCAP EFORd +Ambient Calibration Workbook to align with 2028 resource accreditation rules.[7]

CalCCA's Final 2028 PRM Study overall achieves three objectives by: (1) providing a pathway to lower electricity costs for customers while maintaining reliability; (2) linking PRMs to a transparent and consistent process; and (3) generates datasets, namely risk-reserve curves, that enable stakeholders to evaluate a wide range of alternative PRM selection criteria. The Study demonstrates the process for establishing PRM selection criteria that can be used to inform the PRM when there are multiple options for setting PRMs that produce the same level of reliability. Using this approach, CalCCA's analysis demonstrates that grouping the peak summer month PRMs (July-September) and high-variability months (*e.g.,* April, May) results in higher PRMs in the peak months and higher RA cost, without improving reliability relative to other options for setting the PRM.

With this information, the results of CalCCA's Final 2028 PRM Study confirm CalCCA's primary recommendation: the Energy Division should adopt CalCCA's approach to generating monthly risk-reserve curves and comparing PRMs stemming from different selection criteria in its PRM studies. It also highlights that different modeling assumptions, such as import

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6 *R.25-10-003 Track 2 Workshop* (Sept. 15, 2026), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2026-track-2/r2510003-workshop-on-lole-studies20260915version-2.pdf.

7 September 15, 2026, Workshop: Energy Division Updated PRM Results, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2026-track-2/prm-results-20260915-workshop.zip.

assumptions, can significantly alter the monthly risk-reserve curves and associated PRMs and should be further developed in future PRM studies. In summary and based on CalCCA's Final 2028 PRM Study results, the Commission should:

- Adopt a PRM study methodology that achieves an established reliability standard while minimizing RA costs by developing monthly risk-reserve curves and using CalCCA's RA cost-minimizing PRM criteria as affordability benchmarks;
- Adopt monthly PRMs that separate the peak summer months from high variability spring months based on the CAISO's target LOLE distribution using CalCCA's Case B assumptions, resulting in monthly PRMs that range from 4-16 percent across most months, with PRMs as high as 16-31 percent only in April and May, respectively;
- Use Energy Division's import assumptions and adopt a future workshop process to consider alternative assumptions for future studies; and
- Remove the effective PRM and instead adopt a single set of PRMs for all LSEs.[8]

II. THE PRM STUDY METHODOLOGY SHOULD ACHIEVE AN ESTABLISHED RELIABILITY STANDARD WHILE MINIMIZING RA COSTS

The Commission should adopt CalCCA's proposed PRM study methodology to allow the Commission to set the PRM in a manner that achieves an established reliability standard while minimizing RA costs. This methodology was used in CalCCA's Final 2028 PRM Study to inform the recommendations for the 2028 PRMs in Section III below. Key elements of CalCCA's proposed study methodology are: (1) the development of monthly risk-reserve curves to demonstrate the relationship between the achieved reserve margin and the risk of not having sufficient resources to meet demand; and (2) using the risk-reserve curves to find PRMs that all meet a LOLE of 0.1 events/year using PRM selection criteria, including criteria that minimize RA costs.

[8] CalCCA may include changes or additions to these recommendations in its November 20, 2026, opening comments, if necessary, informed by final LOLE studies filed by other parties.

A. CalCCA's Proposed Methodology for Developing Monthly Risk-Reserve Curves Should Be Adopted

The Commission should adopt CalCCA's methodology for developing monthly risk-reserve curves to demonstrate the relationship between the achieved reserve margin - the amount by which the contracted accredited capacity exceeds the forecasted peak demand - and the risk of not having sufficient resources to meet demand. These risk-reserve curves should be used in conjunction with PRM selection criteria, described in Section II.B. below, to select PRMs that best maintain reliability at the lowest cost to customers.

During the Workshop, it became clear that several key modeling assumptions remain uncertain. Rather than developing a single set of monthly risk-reserve curves, CalCCA's Final 2028 PRM Study includes 12 different risk-reserve cases to demonstrate how different sets of assumptions impact risk and reserves and lead to different sets of curves. The cases address three areas: (1) the source of the peak demand for reserve calculations; (2) the portion of the Baseline that remains uncontracted and therefore unable to contribute to CAISO reliability; and (3) treatment of economic imports (non-RA imports) in probabilistic reliability modeling and reserve calculations.

CalCCA's Final 2028 PRM Study demonstrates the process the Commission should use to quantify tradeoffs between different PRM selection criteria. This approach provides a pathway to lower electricity costs for customers while maintaining reliability, links PRMs to a transparent and consistent process, and generates datasets, namely risk-reserve curves, that enable stakeholders to evaluate a wide range of alternative PRM selection criteria. The Commission should adopt CalCCA's approach to generating monthly risk-reserve curves and comparing PRMs resulting from different selection criteria for its PRM studies going forward.

B. RA Cost-Minimizing Selection Criteria Should Be Used as Affordability Benchmarks to Inform the PRM

The Commission should use PRMs found using RA cost-minimizing criteria as an affordability benchmark to inform PRM proposals. After developing risk-reserve curves, PRM selection criteria are needed to select specific PRMs. As described in Section III.A, below, Energy Division's previous PRM analysis reflects two selection criteria: (1) equivalent PRMs across all months (Annual); and (2) equivalent PRMs across the months of May-September with all unmet demand concentrated in those months and a separate PRM in all other months (Seasonal2). These selection criteria do not result in the most cost-effective PRMs meeting the LOLE of 0.1 events/year reliability standard. Instead, the Commission should benchmark the cost of their proposed PRMs against PRMs resulting from CalCCA's RA cost-minimizing selection criteria, which elect monthly PRMs in a way that minimizes RA costs while meeting a LOLE of 0.1 events/year.

III. MONTHLY PRMS BASED ON THE CAISO'S TARGET LOLE DISTRIBUTION SHOULD BE ADOPTED FOR 2028

The Commission should adopt monthly PRMs based on the "CAISOTargetLOLE" selection criteria for the 2028 RA program.[9] This recommendation is based on the results of CalCCA's Final 2028 PRM Study using the methodology recommended in Section II. above, which finds that: (1) assuming equivalent PRMs across May through September results in higher RA costs than alternative PRM structures that achieve the same level of reliability; and (2) establishing separate PRMs for peak summer and high-variability spring months can reduce RA costs by 4.0 to 5.7 percent under modeling assumptions consistent with Case B. The resulting

[9] The "CAISOTargetLOLE" selection criteria, defined in CalCCA's Final 2028 PRM Study, sets the monthly PRMs to match CAISO Target LOLE distribution used to develop its Default PRM and Qualifying Capacity values. *See* CalCCA's Final 2028 PRM Study, at 15-16.

PRMs for 2028 would range from 4-15 percent across most months with PRMs as high as 17-28 percent only in April and May, as shown in Figure 1, below.[10]

A. Separate Peak-Summer PRMs (July–September) from PRMs in High-Variability Months Such as April and May

The Commission should adopt separate PRMs for peak-summer months and high-variability spring months. Energy Division's Draft PRM Study evaluates a two-season PRM with equivalent PRMs across the months of May-September and a separate PRM for all other months (Seasonal2). Assuming equivalent PRMs across May through September results in higher RA costs than alternative PRM structures that achieve the same level of reliability.[11]

CalCCA's analysis demonstrates that there is no clear justification for grouping peak summer months (July–September) with high-variability spring months (*e.g.,* April and May). Rather, the analysis finds that the lowest-cost PRM structures avoid grouping high-variability months, such as May, with high-cost peak summer months, such as September.[12] Applying the same PRM across these months unnecessarily increases PRMs during peak summer months, raising RA costs without providing additional reliability benefits. The Commission should therefore establish separate PRMs for peak summer and high-variability spring months to achieve its reliability standard at an affordable cost.

B. Set 2028 PRMs Consistent with the CAISO Target LOLE Distribution, Using Case B Assumptions

The Commission should use the CAISOTargetLOLE PRM selection criteria with risk-reserve curves from Case B to set the 2028 PRMs. These assumptions allow Energy Division to continue to identify loss-of-load events by removing perfect capacity, consistent with its existing

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10 CalCCA Final LOLE Study, at 33-34.
11 *Ibid.*
12 *Ibid.*

methodology, and will result in monthly PRMs that range from 4-15 percent across most months with PRMs as high as 16-27 percent only in April and May, as shown in Figure 1, below.

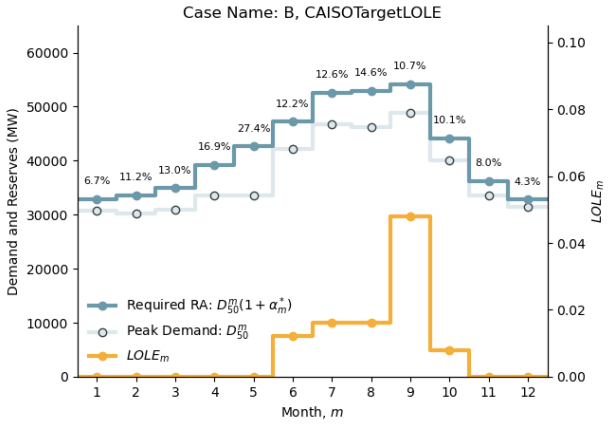


Figure 1. CalCCA recommends 2028 PRMs selected using the CAISOTargetLOLE criteria with risk-reserve curves from Case B.

With these PRMs, 80 percent of the LOLE is concentrated in July, August, and September, the months with the highest RA requirements - exceeding 52 gigawatts (GW). The concentration of LOLE in these months allows the PRMs to stay between 10.7 to 14.6 percent, or 2.8 to 6.7 percentage points lower than it would have otherwise been with an Annual or Seasonal2 PRM. Using the CAISOTargetLOLE selection criteria to set the PRM can reduce RA costs by 4.0 to 5.7 percent under modeling assumptions consistent with Case B.[13]

The resulting PRMs are significantly higher in April and May than they would have been under an Annual or Seasonal2 PRM. However, the moderate 1-in-2 peak loads in the Spring months mean the RA requirements in those months remain below 44 GW. Historical observations of economic imports in April and May suggest that the RA requirements in those months could be lower without sacrificing reliability. Additionally, April and May PRMs were less than 18 percent in April and May of 2025 and 2026 without observed reliability issues.

[13] CalCCA Final 2028 PRM Study, at 33-34.

However, until further data and analysis are available, it is prudent to recommend April and May PRMs that are high enough to avoid unmet energy under the assumptions in Case B.

The combination of moderate PRMs and low 1-in-2 peak demand in the months of November through March keep RA requirements in those months below 37 GW. This period of lower RA requirements creates a contiguous five-month period suitable for planned maintenance of generating resources, without detrimental impacts to reliability. Overall, CalCCA's recommended PRMs achieve significant reductions in consumer costs of complying with RA requirements while still ensuring that the system has sufficient resources to meet a LOLE of 0.1 events/year.

IV. ENERGY DIVISION'S IMPORT ASSUMPTIONS SHOULD BE USED UNTIL A WORKSHOP PROCESS IS CONDUCTED TO DEVELOP ALTERNATIVE ASSUMPTIONS

The Commission should adopt Energy Division's proposed import assumptions for setting the 2028 PRMs and commit to holding additional workshops to further develop import RA assumptions for future PRM studies. Draft studies from CalCCA, SCE, and Energy Division used differing import assumptions without a clear recognition of the implications for PRMs. CalCCA's Final 2028 PRM Study further investigates the impacts of different import assumptions on PRMs and shows that the impacts can be significant. Figure 10 in the CalCCA's Final 2028 PRM Study shows that PRMs can vary, in the most extreme months of April and May, by more than 25 percentage points across different assumptions on import accreditation. While differences in the PRMs are much smaller in the critical months of July through September, only 7 percentage points, these months have historically had the tightest RA supply and highest RA costs. Historical relationships between the capacity of imports shown in RA filings and the observed hourly imports during actual system operations demonstrate that allowing imports to exceed shown RA import capacity, particularly in non-summer months,

reflect likely outcomes.[14] Cases that allow some degree of imports in excess of shown RA imports, including the Energy Division's assumptions in Case B, result in lower PRMs. Alternatively, the most conservative assumptions, used in Case D and Case E, deviate from observed system operations.[15] The Commission should therefore adopt Energy Division's assumptions as a reasonable middle ground and interim solution for import assumptions used for setting 2028 PRMs.

Energy Division should host workshops on import assumptions prior to the next PRM study to further develop the import assumptions for future PRMs. The workshops should directly consider the question of what role energy-only economic imports should play in reliability modeling, especially as the system continues to both better integrate with neighboring regions and incorporate a greater share of energy-limited resources, like battery storage.

V. THE EFFECTIVE PRM SHOULD BE REMOVED

CalCCA continues to recommend that the Commission remove the effective PRM, with no changes to its August 14, 2026, Proposal.[16] The Commission should remove the effective PRM because it: (1) adds demand to the RA market, driving up costs when RA supply is tight; (2) allows the Commission to deviate from the 0.1 LOLE standard in an arbitrary manner; (3) creates an uneven playing field across LSEs by directing the IOUs to procure the effective PRM requirement and allocating the costs of the procurement to all LSEs; (4) does not allow the CAISO to backstop for RA deficiencies; and (5) encroaches on CCA procurement autonomy authorized by statute.

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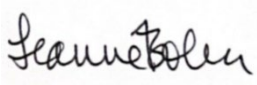
14 CalCCA's Final 2028 PRM Study, at 11-12.
15 *Ibid.*
16 August 14, 2026, Proposal, at 19-22.

CalCCA clarifies its recommendation for the Commission to "establish a single PRM for all LSEs," rather than retaining the effective PRM, in response to a question received during the Workshop. If the Commission adopts monthly or seasonal PRMs rather than an annual PRM, the Commission should adopt *a single set* of monthly or seasonal PRMs for all LSEs. This proposal is not intended to limit the Commission to one PRM for the entire year. Instead, it is intended to apply a uniform PRM or set of PRMs to all LSEs.

VI. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the proposals herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,



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Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

November 2, 2026

ATTACHMENT A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
FINAL 2028 PLANNING RESERVE MARGIN STUDY AND PROPOSALS

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
FINAL 2028 PLANNING RESERVE MARGIN STUDY

ANDREW MILLS, Director of Data Analytics
DESIK SOMASUNDARAM, Senior Data Analyst
November 2, 2026

CALIFORNIA COMMUNITY CHOICE ASSOCIATION FINAL 2028 PLANNING RESERVE MARGIN STUDY

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November 2, 2026

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1. Motivation and Context

The California Public Utilities Commission (CPUC) requires load-serving entities (LSEs) contract with resources sufficient to meet forecasted customer demand on peak days plus a planning reserve margin (PRM). The Energy Division develops tools, data, and studies to recommend a PRM for 2028 and 2029 with the goal of meeting a reliability target of one loss-of-load event in ten years, or equivalently a loss-of-load expectation (LOLE) of 0.1 events/year. To elicit robust discussion and perspectives, the CPUC invited stakeholders to conduct their own PRM studies in parallel to the Energy Division's study.[1] CalCCA's study relies on tools and data provided by the Energy Division, along with CalCCA's probabilistic reliability model in PLEXOS, to recommend PRMs that meet the LOLE of 0.1 events/year.

In the CPUC's Resource Adequacy (RA) program, the role of the PRMs is to determine the portion of online resources that must be available to contribute to reliability. The set of resources expected to be online in 2028, called the Baseline, may not be fully available throughout the year due to maintenance outages or contracts to supply power outside of the California Independent System Operator (CAISO) balancing authority area (BAA). An RA contract ensures that a resource is available and offers its generating capability to the CAISO market through an associated must-offer obligation.

The RA program requires LSEs to show RA contracts for each month of the year. Even though the 0.1 LOLE reliability target is defined as an annual metric, the portion of the Baseline that must be contracted for RA varies by month due to the monthly variability in forecasted peak load and resource accreditation. The process of setting PRMs answers the question: how much accredited capacity of the Baseline should be shown in each month for the system to be reliable (LOLE $\leq$ 0.1)?

In regions with an annual RA program, a single annual PRM, and an annual reliability target, the process of setting the PRM is straightforward. Reductions or additions of resources to the Baseline decrease or increase reliability, respectively. Only one choice of accredited capacity corresponds with a LOLE of 0.1 events/year; only one choice of PRM exactly meets the reliability target.

In the Commission's monthly RA program, the month-to-month variation in peak demand and accredited capacity means that there is no one, unique choice of monthly shown capacity that corresponds with an annual LOLE of 0.1 events/year. Many combinations of monthly PRMs yield a reliable system. This means additional criteria are necessary to select PRMs.

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[1] *Assigned Commissioner's Amended Scoping Memo and Ruling*, Rulemaking (R.) 25-10-003 (Aug. 25, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M615/K874/615874564.PDF; *Administrative Law Judge's Ruling Modifying Track 2 Schedule*, R.25-10-003 (Sept. 25, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M620/K565/620565731.PDF.

Energy Division's previous PRM studies have implicitly included two criteria to recommend PRMs for the monthly RA program. *First*, Energy Division previously assumed an annual PRM,[2] which implicitly requires equivalent monthly PRMs. Requiring equivalent monthly PRMs, coupled with the annual reliability target, allows Energy Division to identify a unique annual PRM. *Second*, Energy Division's 2028 Draft 2028 PRM study[3] assumes a seasonal PRM that can vary between summer and non-summer months, with all of the loss-of-load events occurring in the summer months. This, along with the choice of which months are summer and which are non-summer, allows Energy Division to identify a unique seasonal PRM.

The Energy Division's PRM selection criteria are not exhaustive. CalCCA's Inputs and Assumptions document[4] and Draft 2028 PRM Study[5] describe a process for selecting PRMs that minimize RA costs while still achieving the target level of reliability. Additional research and discussions with stakeholders raised additional PRM selection criteria that we evaluate in this study. CalCCA's list of PRM selection criteria is broader than Energy Division's but remains a subset of all the possible criteria.

Key to evaluating any PRM selection criterion is the concept of risk-reserve curves.[6] A risk-reserve curve shows the relationship between achieved reserve margin—the amount by which the contracted accredited capacity exceeds the forecasted peak demand—and the risk of not having sufficient resources to meet demand, resulting in a loss-of-load event. With a monthly RA program, the relationship between achieved reserve margin and risk of loss-of-load events differs by month, requiring twelve monthly risk-reserve curves. Once these curves are specified, it is simple to find monthly PRMs that meet different PRM selection criteria while meeting an annual LOLE of 0.1 events/year.

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[2] Energy Division, *Loss of Load Expectation Study for 2026 Including Slice of Day Tool Analysis: Recommendation for Slice of Day Planning Reserve Margin*,(July 19, 2024) (Energy Division's 2026 PRM Study), at 34, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/2026_lole_final_report_07192024.pdf.

[3] Energy Division, *Loss of Load Expectation Study for 2028: Draft Results* (August 14, 2026) (Energy Division's Draft 2028 PRM Study), at 21, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2026-track-2/energy-division-draft-2028-lole-study.pdf.

[4] *California Community Choice Association's Alternative Inputs & Assumptions Document in Response to Administrative Law Judge's Ruling Modifying 2028 Loss of Load Expectation Study Schedule*, R.25-10-003 (June 5, 2026) (CalCCA I&As), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M608/K216/608216359.PDF.

[5] *California Community Choice Association's Track 2 Loss of Load Expectation Study and PRM Proposals*, R.25-10-003 (Aug. 14, 2026) (CalCCA Draft 2028 PRM Study), https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=614484383.

[6] *See* Brattle and Astrape, *Resource Adequacy Requirements: Reliability and Economic Implications* (2013), at 3-5 (providing a more detailed discussion on determining system reliability as a function of planning reserve margin), https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf.

CalCCA's Input and Assumptions and Draft 2028 PRM Study describes a systematic approach to generating monthly risk-reserve curves using the same data and tools employed in the Energy Division's PRM study process. At the time of publishing CalCCA's Draft 2028 PRM Study, key data and assumptions, affecting both the risk and reserve calculations, remained open-ended. These data and assumptions can significantly shift and change the shape of risk-reserve curves. As such, CalCCA focuses the Final 2028 PRM Study on two areas. *First*, we evaluate how key uncertainties impact the risk-reserve curves. The uncertainties include:

- The source of the peak demand for reserve calculations;
- The composition of the portion of the Baseline that remains uncontracted and therefore unable to contribute to CAISO reliability; and
- Treatment of economic imports (non-RA imports) in probabilistic reliability modeling and reserve calculations.

Second, we use the risk-reserve curves to find PRMs using several different PRM selection criteria that all meet a LOLE of 0.1 events/year. CalCCA's analysis finds that the lowest cost PRMs avoid grouping high variability months, such as May, with high-cost months, such as September. Because Energy Division's annual PRM or seasonal PRMs both start from the premise of equivalency between May and September PRMs, Energy Division's Draft PRM Study results in higher-cost PRMs than alternative PRMs that are just as reliable. From this analysis, we recommend specific PRMs for 2028 and 2029, plus additional changes to the Energy Division's PRM study process to generate risk-reserve curves in future PRM studies.

2. Study Methodology and Assumptions

This section describes CalCCA's systematic approach for: (1) generating monthly risk-reserve curves; and (2) using the curves to select PRMs according to different criteria while meeting a LOLE of 0.1 events/year. In general, the approach relies on tools, data, and assumptions provided by Energy Division to generate the risk-reserve curves consistent with projections of system conditions in 2028. However, because of the uncertainties in modeling the risk of loss-of-load events and calculation of achieved reserve margins, the approach defines several risk-reserve cases and corresponding curves for each case.

a. Generation of Risk-Reserve Curves

Generating risk-reserve curves starts by recognizing that any portfolio of resources, R_i, will have: (1) an achieved reserve margin, α_m, based on the accreditation rules; and (2) a risk of loss-of-load events under realistic power system operating conditions. There is some unknown relationship between achieved reserve margin and risk of loss-of-load events, $f^m(\alpha_m)$, that we can sample by calculating the risk and reserve for that particular portfolio, as shown in Figure 1.

Because the RA program requires monthly showings, we calculate the achieved reserve margin and risk for each month of the year, m. The risk with the portfolio can be measured by the expected number of days with loss-of-load events ($LOLE_m$), the expected number of hours with unmet demand ($LOLH_m$), or the expected unserved energy (EUE_m).

By systematically adding or removing resources from the portfolio, we can sample different points on the risk-reserve curve for each month. In this study, we start with the Baseline portfolio, R_B, then remove capacity in one of two ways. One way is to remove perfect capacity from the baseline portfolio, equivalent to Energy Division's concept of a negative operating unit (NOU). Removing perfect capacity from the Baseline lowers the portfolio's accredited capacity and achieved reserve margin. Removing perfect capacity also increases the risk of loss-of-load events. The second way to remove capacity from the Baseline portfolio is to proportionally decrease the nameplate capacity of all resources in the Baseline portfolio (except for hydropower and pumped hydro storage), following the convention used by Southern California Edison Company (SCE) in its Draft 2028 PRM Study.[7]

[7] SCE, *Draft 2028 Loss of Load Expectation Study Report* (August 14, 2026), at 9, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M614/K587/614587075.PDF.

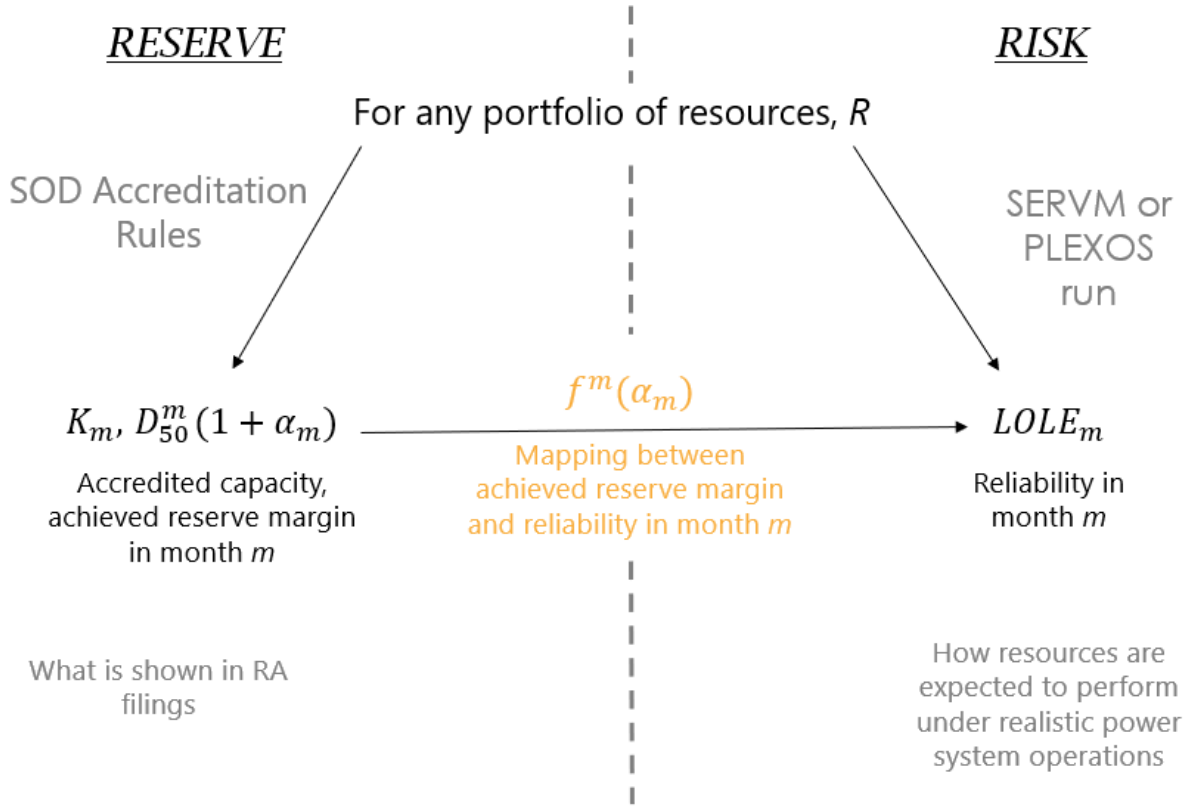


Figure 1. Illustration of the relationship between achieved reserve margin and risk of unmet demand for a particular portfolio of resources.

For each new portfolio, we calculate the corresponding achieved reserve margin and risk. We record the data for each of the risk-reserve cases in a risk-reserve database included with CalCCA's study results available on CalCCA's website.[8] We sampled portfolios that remove 500 megawatts (MW) to 25,000 MW of perfect capacity (in 500 MW increments) and portfolios that scale down the Baseline by 1 percent to 50 percent (in one percent increments).

We interpolate between the sampled portfolios to estimate the continuous risk-reserve curve, $\widehat{f^m}(\alpha_m)$, used in the optimization techniques and other numerical methods for determining PRMs.[9]

[8] CalCCA's final study results are available at: https://cal-cca.org/wp-content/uploads/2026/11/CalCCA_2028_PRM_Study_Final_2026-11-02.xlsx.

[9] Interpolation between datapoints in the risk-reserve curves used the "Piecewise Cubic Hermite Interpolating Polynomial" approach implemented in the Scipy.interpolate package in the PchipInterpolator class. *See* Scipy API, Scipy.interpolate.PchipInterpolator (2008), https://docs.scipy.org/doc/scipy/reference/generated/scipy.interpolate.PchipInterpolator.html. The advantage of this interpolation method over a traditional cubic-spline interpolator is that it preserves monotonicity in the interpolation data and enforces continuity in the slope between points. Monotonicity and continuous slopes make it easier to find the optimum when we use the risk-reserve curves to find cost-minimizing PRMs.

The following sections provide additional details and assumptions used to calculate the risk-reserve curves.

i. Achieved Reserve Margin

To calculate the achieved reserve margin of any portfolio, we calculate the accredited capacity of the portfolio under the SOD accreditation rules using the Energy Division's PRM Calibration Workbooks provided at the September 15, 2026, Draft PRM Study Workshop (Workshop).[10] In all cases, we use the version of the workbook that accredits conventional resources using the UCAP EFORd + Ambient convention that is consistent with the accreditation rules that the Commission will use in the 2028 RA program.[11]

For faster processing, we developed Python code that pulls in the Baseline portfolio from the PRM Calibration Workbook, then reduces the portfolio capacity by removing perfect capacity or proportionally reducing the Baseline. The Python code then dispatches the storage resources across each peak day to maximize the minimum achieved reserve margin within the SOD accreditation rules, consistent with the Excel Solver logic in the PRM Calibration Workbook. The achieved reserve margin in each hour is based on the ratio of the portfolio's accredited capacity, K_m, to the 1-in-2 peak demand, D_{50}^m. In particular, $\alpha_m = \frac{K_m}{D_m^{50}} - 1$.

As noted in CalCCA's Draft 2028 PRM Study,[12] our calculation of achieved reserve margin differs from Energy Division's. CalCCA removes perfect capacity from the portfolio (decreasing the numerator, K_m) and Energy Division instead adds flat load to the demand (increasing the denominator, D_{50}^m). The resulting difference in achieved reserve margins becomes larger the more capacity is removed from the Baseline or the more flat load is added to the forecasted peak demand. The difference is also larger when the forecasted peak demand, D_{50}^m, is smaller. As a result, the differences between reserve margins calculated with CalCCA's convention and Energy Division's convention are most acute in low demand months where significant amounts of perfect capacity can be removed before experiencing loss-of-load events, such as April.

We only report the achieved reserve margin in the tightest hour, where the tightest hour is the hour of the peak day with the lowest achieved reserve margin. When multiple hours have the same

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[10] September 15, 2026, Workshop: *Energy Division Updated PRM Results*, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2026-track-2/prm-results-20260915-workshop.zip.

[11] D.26-07-008, *Decision Adopting Local Capacity Obligations for 2027-2029, Flexible Capacity Obligations for 2027, and Program Refinements*, R.25-10-003 (July 10, 2026), Ordering Paragraph 13, adopts the principles in Appendix B, Unforced Capacity Framework, which includes ambient thermal derates in the accreditation, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M610/K575/610575803.PDF.

[12] CalCCA Draft 2028 PRM Study, n. 29. The achieved reserve margin of a portfolio using CalCCA's convention will exceed the achieved reserve margin of the same portfolio when calculated using the Commission's convention by a factor of $\frac{NOU}{D_{50}^m + NOU}$.

minimum achieved reserve margin, as was commonly observed, we select the hour with the lowest amount of excess capacity from the non-storage resources.[13] Excess capacity is the amount that the accredited capacity of non-storage resources exceeds the hourly demand.

Our Python version of the PRM Calibration Workbook includes two other variable features. First, we can calculate reserves using the 1-in-2 peak demand directly from the 2025 Integrated Energy Policy Report (IEPR) forecast for the CAISO system in 2028 (2025 IEPR) or we can use the 1-in-2 peaks from the 25 weather years of managed load calculated by Energy Division (SERVM). Ideally, the 1-in-2 peak demand of the 25 weather years would match the 2025 IEPR forecast. However, the calibration approach used by the Energy Division matched the 2025 IEPR consumption rather than managed load.[14] Using the 2025 IEPR peak demand in the reserve calculations, while the power system operations are simulated under varying loads that have a different 1-in-2 peak, is inconsistent. Cases with reserves calculated using either the 2025 IEPR or SERVM peaks allow us to quantify the implications of this mismatch on PRMs.

Second, the Python code allows different choices for the accreditation of interchange capacity, representing the amount of imports shown in RA filings. The PRM Calibration Workbooks from the Energy Division assume 4,000 MW of interchange capacity in all hours in the months of June to September and 8,500 MW in all hours for the other months of the year. As described below, stakeholder perspectives differed regarding the amount of interchange capacity to use in calculating the achieved reserve margin of the Baseline portfolio and its variations.[15]

ii. Risk of Unmet Demand

To calculate the risk of loss-of-load events of any portfolio, we simulate the performance of the portfolio in a probabilistic reliability model built by CalCCA in the PLEXOS energy modeling software. Key assumptions and data sources for the final study are summarized in Appendix A.

The probabilistic reliability model uses a detailed hourly representation of resource availability, energy storage dispatch, load, operating reserve requirements, and import availability to quantify probability of unmet demand for each month. From the unmet demand, we calculate the three-risk metrics: $LOLE_m$, $LOLH_m$, and EUE_m. In addition, CalCCA included a limited number of production cost-related parameters to generate a reasonable representation of energy market prices. In

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[13] Our decision to choose the hour with the lowest excess capacity differs from our assumption in the Draft Study, where we chose the first hour with the minimum achieved reserve margin. We adjusted our assumptions simply to better align with the Energy Division's approach where possible.

[14] *Administrative Law Judge's Ruling on Energy Division's Proposed Inputs and Assumptions*, R.25-10-003 (April 10, 2026), Attachment 2 (Energy Division's I&As), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M604/K617/604617992.PDF.

[15] CalCCA described draft study differences during the Workshop, at Slide 80, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2026-track-2/r2510003-workshop-on-lole-studies20260915version-2.pdf.

addition to the three reliability metrics, we now also report the unhedged expected energy market cost to load, defined as the probability-weighted average product of the hourly energy market price and hourly CAISO managed load.

CalCCA mostly aligns the data and assumptions of the PLEXOS model with Energy Division's SERVM model. We chose to deviate from the Energy Division's SERVM model primarily to make the model easier to manage and to make the model run faster. For production cost-related parameters, we also deviate due to the confidential nature of some data used by the Energy Division. Important differences from the Energy Division's SERVM model include:

- Equivalent units rather than unique units: To make the model easier to manage, CalCCA's PLEXOS model represents all of the combined cycle capacity in CAISO, for example, as 44 units with the same capacity, heat rate, forced outage rate, and thermal derates. These units experience unique forced outages and are dispatched individually, but their characteristics are equivalent. Energy Division's SERVM model, on the other hand, includes unit-specific parameters for the same 44 units in the Baseline.
- No intra-CAISO transmission constraints: To make the model easier to manage and run faster, CalCCA's PLEXOS model groups CAISO loads and resources into a single region with no internal transmission limitations. Treating CAISO as a single region also means that we do not need to make decisions about how to spatially allocate Baseline capacity reductions within the CAISO region. Energy Division's SERVM model includes three regions within CAISO, with transmission between PG&E and SCE regions constrained by the Path 26 limit.
- Neighboring region representation: To make the model easier to manage and run faster, CalCCA's PLEXOS model includes simplified representation of availability of resources from neighboring regions and groups non-CA neighbors into a southwest (SW) and northwest (NW) region. Additional details are included in Appendix B. Energy Division's SERVM model includes additional transmission and region granularity for neighboring regions along with dispatching individual units to minimize overall system costs subject to limits.
- Limited representation of dispatch costs: CalCCA originally built the PLEXOS model only to estimate reliability metrics, which are independent of production cost parameters. To estimate expected energy market costs, CalCCA added rough estimates of technology-type heat rates, annual-average fuel costs, fuel-type specific CO2 emission rates, and annual average CO2 emission prices. In addition, CalCCA assumes energy market operators would pay up to $2,000/ megawatt hours (MWh) to avoid shedding load. Energy Division's SERVM model includes significantly more detail on confidential unit-specific heat rates and unit-specific flexibility parameters, both of which can impact emission rates. It also includes location and month-specific fuel prices and transmission line-specific hurdle rates, which CalCCA excludes to make the model easier to manage.

iii. Risk-Reserve Cases

During the Workshop, it became clear that several key modeling assumptions remain uncertain. Rather than presenting a single set of monthly risk-reserve curves, as presented in CalCCA's Draft 2028 PRM Study, CalCCA's Final 2028 PRM Study presents different sets of assumptions impacting risk and reserves that lead to different sets of curves. In this study, CalCCA developed twelve different risk-reserve cases, summarized in Table 1, to address three areas:

- The source of the peak demand for reserve calculations;
- The portion of the Baseline that remains uncontracted and therefore unable to contribute to CAISO reliability; and
- Treatment of economic imports (non-RA imports) in probabilistic reliability modeling and reserve calculations.

Table 1. Risk-Reserve cases used in this study to evaluate the impact of uncertainties on PRMs.

Case	Capacity Adjustment Type	Risk	Reserve		
		Simultaneous Import Limit	Interchange Accreditation	Managed Load 1-in-2	Conventional Accreditation
A	NOU	CPUC Limit	4GW	SERVM	UCAP EFORd + Ambient
B	NOU	CPUC Limit	ED Sep Workshop	SERVM	UCAP EFORd + Ambient
C	NOU	CPUC Limit	SCE Draft	SERVM	UCAP EFORd + Ambient
D	NOU	CPUC Limit	CPUC SIL	SERVM	UCAP EFORd + Ambient
E	NOU	4GW	4GW	SERVM	UCAP EFORd + Ambient
F	NOU	CPUC Limit	ED Sep Workshop	2025 IEPR	UCAP EFORd + Ambient
A'	Scaled	CPUC Limit	4GW	SERVM	UCAP EFORd + Ambient
B'	Scaled	CPUC Limit	ED Sep Workshop	SERVM	UCAP EFORd + Ambient
C'	Scaled	CPUC Limit	SCE Draft	SERVM	UCAP EFORd + Ambient
D'	Scaled	CPUC Limit	CPUC SIL	SERVM	UCAP EFORd + Ambient
E'	Scaled	4GW	4GW	SERVM	UCAP EFORd + Ambient
F'	Scaled	CPUC Limit	ED Sep Workshop	2025 IEPR	UCAP EFORd + Ambient

Cases A through E use progressively more conservative assumptions regarding the treatment of energy-only economic imports, those imports that occur above and beyond the import capacity shown by LSEs in RA filings.

Case A assumes only 4 gigawatts (GW) of interchange capacity in the Baseline portfolio. The probabilistic reliability model in Case A allows any available resources to be imported into CAISO up to the simultaneous import limit (SIL) defined by Energy Division.

Conversely, Case D and E conservatively require any import in the probabilistic reliability model to have been shown in an RA filing, and therefore included in the accredited capacity of the Baseline portfolio.

In the middle, Case B treats imports consistent with the Energy Division's Draft 2028 PRM Study, where the accredited interchange capacity used in reserve calculations is 4 GW in all hours of June-September and 8.5 GW other months, while the SIL in the probabilistic reliability model is sometimes higher. Case C accredits interchange capacity in line with SCE's assumptions in its Draft 2028 PRM Study.

The different interchange accreditation and import limit assumptions for each Case A-E are summarized in Figure 2.

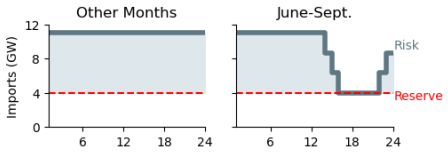
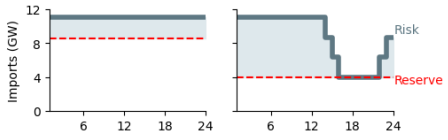
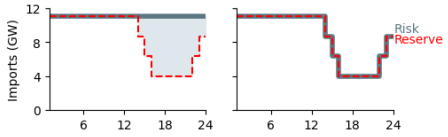
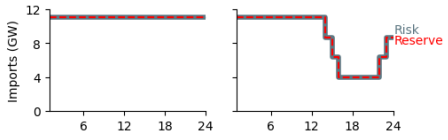
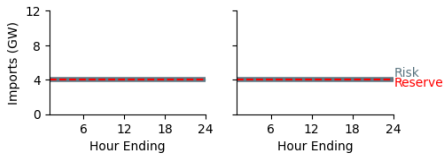
	Risk	Reserve	
Case	Simultaneous Import Limit	Interchange Accreditation	
A	CPUC Limit	4GW	
B	CPUC Limit	ED Sep Workshop	
C	CPUC Limit	SCE Draft	
D	CPUC Limit	CPUC SIL	
E	4GW	4GW	

Figure 2. Differences in assumptions regarding interchange accreditation in reserve calculations and import limits in probabilistic reliability modeling. The light blue shaded area between interchange accreditation and import limits represents the potential for economic imports.

Historical relationships between the capacity of imports shown in RA filings and the observed hourly imports during actual system operations, shown in Figure 3, suggest that Case A is not only reasonable, but it in fact also reflects likely outcomes. In contrast, Case D and E, which assume imports in the probabilistic modeling can never exceed the imports shown in RA filings, are overly conservative relative to recent observations.

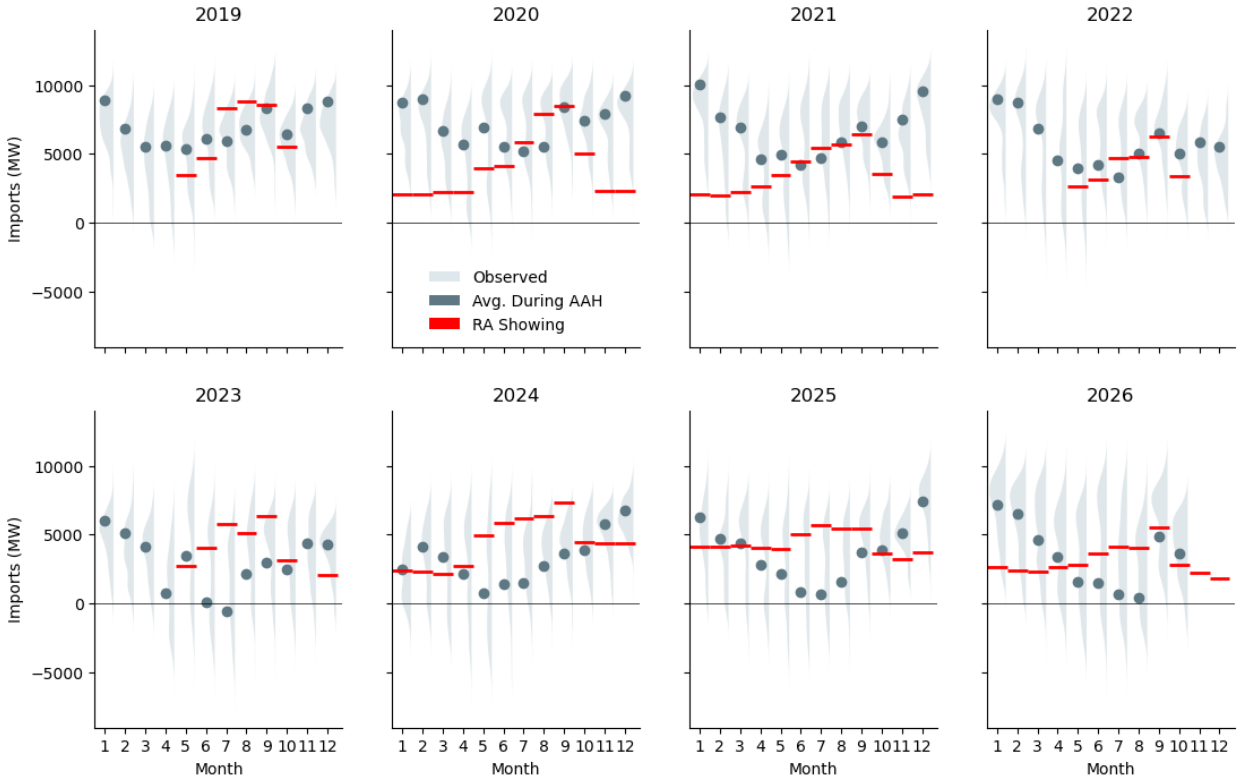


Figure 3. Historically observed imports to the CAISO system often exceed the capacity of import RA shown in LSE filings. [16]

Case F is a sensitivity to Case B to test the importance of the source of peak load data in reserve calculations. In Case F, the peak load used in reserve calculations comes from the 2025 IEPR. In Case B, the 1-in-2 peak managed load is instead derived from the 25-year weather data used in the probabilistic reliability modeling.

Cases A' through F' test the sensitivity of risk-reserve curves to reductions in Baseline capacity by using proportional scaling (Scaled) instead of removing perfect capacity (NOU).

[16] Historical RA import data are primarily obtained from the CAISO Historical Resource Adequacy Aggregate Data Report, https://www.caiso.com/documents/historicalresourceadequacyaggregatedata.xlsx. RA imports from months not covered by this report were obtained from earlier RA import report, https://www.caiso.com/Documents/CaliforniaISOPublishedHistoricalResourceAdequacyImportAggregateData.html (no longer available) or downloaded from the Available Import Capability report at oasis.caiso.com. Observed hourly reports are from the EIA Hourly Electric Grid Monitor report of CISO hourly interchange.

Cases B and F are the closest match to the risk-reserve modeling assumptions used by the Energy Division in the Workshop.

b. PRM Selection Criteria

Risk-reserve curves on their own do not provide sufficient information to recommend PRMs. Additional selection criteria are needed in order to get specific PRMs. Criteria considered in this study are summarized in Table 2. Previous analysis by the Energy Division suggests two criteria: (1) equivalent PRMs across all months (Annual) and (2) equivalent PRMs across the months of May-September with all loss-of-load events concentrated in those months and a separate PRM in all other months (Seasonal2). CalCCA's I&As propose to select monthly PRMs in a way that minimizes RA costs while meeting a LOLE of 0.1 events/year. RA costs can be thought of as varying with each month's required RA capacity (MonthlyRACost) or as varying with the highest RA requirement across any of the months (AnnualRACost).

Table 2. PRM selection criteria used in this study all meet a LOLE of 0.1 events/year.

PRM Selection Criteria	Description
Annual	Set single annual PRM at LOLE=0.1
Seasonal2	Set summer PRM where LOLE_summer=(0.1-0.00001) and nonsummer PRM where LOLE_nonsummer = 0.00001. Summer months are May-September.
Seasonal3	Set summer PRM where LOLE_summer =(0.1-0.00001). Set shoulder and spring PRM each at LOLE_season = 0.000005. Summer months are June-September, Spring months are April and May.
CAISOTargetLOLE	Set monthly PRMs to match CAISO Target LOLE distribution.
MonthlyRACost	Set monthly PRMs to minimize RA costs, where RA costs vary by monthly RA requirement, subject to LOLE<=0.1.
AnnualRACost	Set monthly PRMs to minimize RA costs, where RA costs vary by highest annual RA requirement, subject to LOLE<=0.1.
MonthlyTotalCost	Set monthly RA costs to minimize sum of RA costs, expected unhedged energy market costs, and unserved energy costs at the VOLL, subject to LOLE<=0.1. Energy market costs are product of hourly managed load and hourly energy market price.

Two additional PRM selection criteria that meet a LOLE of 0.1 events/year emerged during research and discussions with stakeholders. *First*, the CAISO sets default monthly PRMs for LSEs whose Local Regulatory Authority (LRA) does not set a PRM. In the CAISO's most recent default PRM study, the CAISO selected monthly PRMs that meet the 0.1 LOLE reliability metric with a specific distribution of loss-of-load events between months.[17] The Commission could set its own monthly PRMs, while using the same monthly distribution of loss-of-load events as the CAISO.

Second, stakeholder questions on CalCCA's proposal to select PRMs that minimize RA costs raised the concern that RA costs are only a subset of the wholesale generating costs faced by customers. These stakeholders stated that energy market costs and the economic cost of any unmet demand can also impact customer costs. If PRMs are set to only minimize RA costs, overall consumer costs could increase if the RA cost minimizing PRMs result in increased energy market costs or economic costs of unmet demand. Another possible PRM section criterion is therefore to minimize total consumer costs, including RA market costs, energy market costs, and economic costs from unmet demand, while meeting a LOLE of 0.1 events/year (MonthlyTotalCost).

For reasons further explored in the Analysis section below, we believe that this last criterion is misguided as it implies that the only way to reduce customer exposure to high energy market prices is through RA contracts. This is not the case: today, an LSE can purchase non-RA fixed price energy market products for delivery in 2028 that insulate the consumer from spot prices in 2028. In fact, most if not all LSEs have some form of risk-management policy that guides LSE hedging decisions to limit exposure to spot market prices. The relevant energy market cost that varies with PRMs is therefore only the unhedged portion, which varies from LSE to LSE in line with their risk-management strategy. Further, the assumption that increased amounts of RA will mitigate energy market prices is predicated on the notion that without the must offer obligation, the resource would have bid a higher price to the energy market or not bid into the energy market at all. This assumption is highly dependent on market competitiveness at any given point in time, the CAISO's rules for market power mitigation, as well as the other contractual circumstances between the resources and LSEs (e.g., energy only resources that do not provide RA but do provide energy at a contractual price). All of these items make it questionable whether changes in RA requirements impact energy prices. We include this criterion only to illustrate the sensitivity of the resulting PRMs to assumptions about the unhedged portion, not as a valid PRM selection criteria.

[17] CAISO Business Practice Manual for Reliability Requirements 13.3.2 "CAISO calibrates the model to an annual loss of load expectation of 0.1, then evaluates the number of unserved energy events occurring in each calendar month and adjusts the individual month LOLE targets, if appropriate. When adjusting the monthly LOLE targets, CAISO considers factors relating to system reliability, including, but not limited to forecasted peaks, load uncertainty, changing load patterns, and impacts on PRMs and QC results. After setting a monthly LOLE target, each calendar month is individually calibrated to that target."

i. Annual PRM Criteria

The Annual PRM selection criteria require the PRM to be equal across all months and that LOLE equal 0.1 events/year. Using monthly risk-reserve curves, the resulting PRM can be found graphically by stacking the curves vertically, which represents the sum of the monthly LOLE for the equivalent achieved reserve margin across all months, and finding the achieved reserve margin where the sum of monthly LOLE equals 0.1. This approach is illustrated in Figure 4.

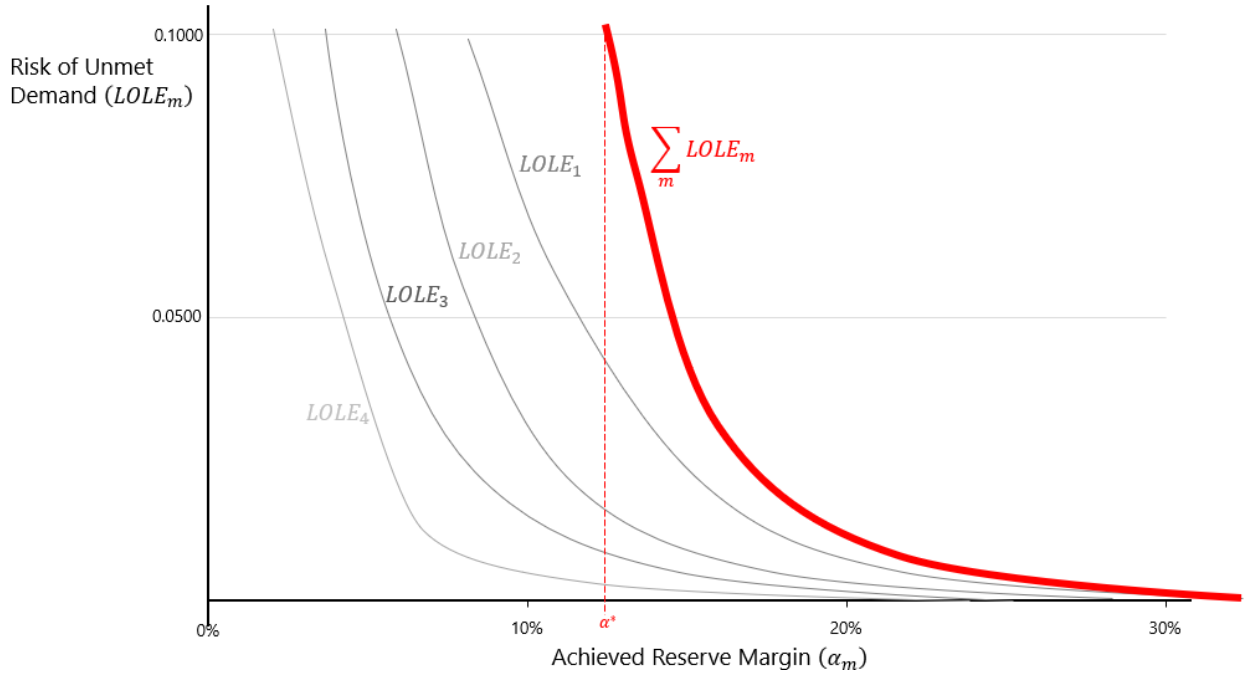


Figure 4. Illustration of the process for using monthly risk-reserve curves to find a single annual PRM that meets a LOLE of 0.1 events/year.

ii. Seasonal2 PRM Criteria

The Seasonal2 PRM selection criteria builds on the same approach as the Annual criteria but separates the risk-reserve curves into two seasons. In the summer season, defined by Energy Division as May-September, a single summer PRM is chosen such that nearly all of the loss-of-load events are in the summer. A summer risk-reserve curve can be found by stacking the summer month risk-reserve curves vertically then finding the achieved reserve margin where the sum of the LOLE in the summer months is just below 0.1. The non-summer risk-reserve curve is made by stacking the non-summer month risk-reserve curves and finding the achieved reserve margin where the sum of the LOLE in the non-summer months just begins to exceed zero. This approach is illustrated in Figure 5.

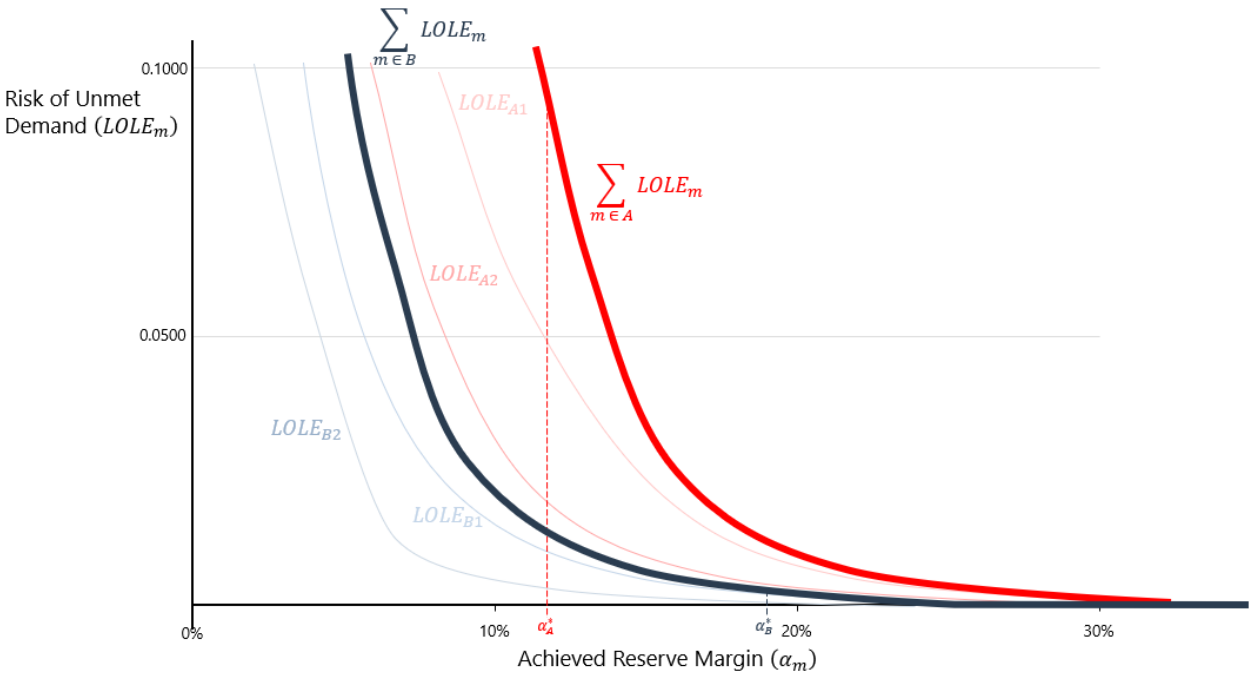


Figure 5. Illustration of the process for using monthly risk-reserve curves to find a seasonal PRM where nearly all of the loss-of-load events are allocated to the summer season (Season A) and very few are allocated to non-summer (Season B), while meeting a LOLE of 0.1 events/year.

iii. Seasonal3 PRM Criteria

The Seasonal3 PRM selection criteria extends the two-season approach from Energy Division to include three seasons. The summer season, with nearly all the loss-of-load events, is narrowed to June-September. The remaining months are divided into a highly-variable spring (April and May) and less variable shoulder season (remaining months). The PRM for the spring and shoulder season is set such that the LOLE just begins to exceed zero in each season.

The purpose of this additional season is to ensure that the high degree of load variability observed around the median 1-in-2 peak load in the spring does not result in higher-than-necessary PRMs in the summer months, where RA costs are typically the highest.

iv. CAISOTargetLOLE PRM Criteria

The CAISOTargetLOLE PRM selection criteria use the risk-reserve curves to find the monthly achieved reserve margin where the resulting LOLE in the month matches the LOLE for the corresponding month in the CAISO target distribution.[18] For example, the CAISO Target LOLE for September allows 24 loss-of-load event days out of 500 equally-weighted samples, equivalent to a September LOLE of 0.048 (24/500). Similar to September, the CAISO Target LOLE distribution

[18] CAISO 2027 Default Resource Adequacy Values: Draft PRM and QC values (September 9, 2026), at Slide 32. https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-2027-Default-Resource-Adequacy-Values-Sep-9-2026.pdf. To set the default PRM such that it achieves a 0.1 LOLE, CAISO targets 6 events in June, 8 events in July, 8 events in August, 24 in September, and 4 in October. In total 50 loss-of-load events out of 500 samples leads to a LOLE of 0.1 events/year.

defines a specific number of loss-of-load events in each month. The target LOLE in each month can be used to find the achieved reserve margin on the corresponding monthly risk-reserve curve, establishing the month's PRM under the CAISOTargetLOLE criteria. This approach is illustrated in Figure 6.

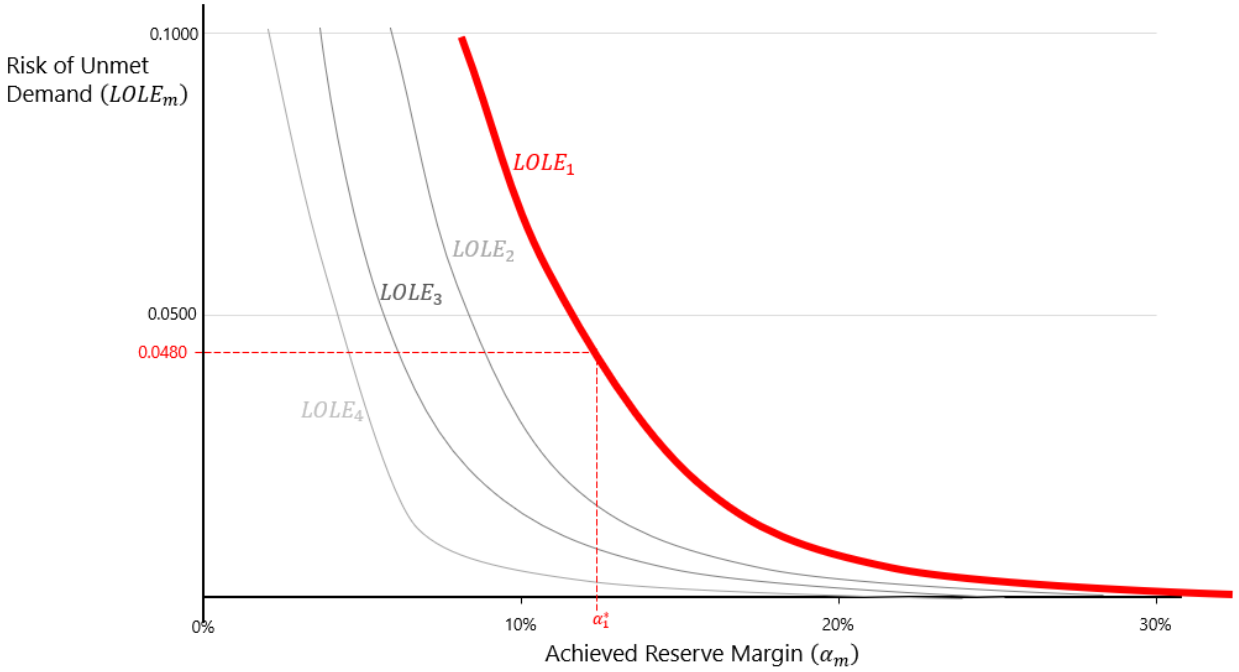


Figure 6. Illustration of the process for using monthly risk-reserve curves to find a monthly PRM where the distribution of loss-of-load events matches the target number of events defined by the CAISO target LOLE. In this case, the CAISO target LOLE for month 1 is 0.048, or 24 out of 500 equally-weighted samples.

v. MonthlyRACost PRM Criteria

The MonthlyRACost PRM selection criteria uses the risk-reserve curves in a constrained optimization that minimizes RA costs subject to the requirement that the total LOLE be less than or equal to 0.1 events/year.[19] RA costs are assumed to vary in proportion to each month's product of the RA requirement and a monthly RA price. The optimization problem chooses α_m^* [PRM in each month] to:

[19] The solver is trying to lower the PRM in all months to reduce RA costs, but as it does so it faces increases in LOLE. At the optimum, the first-order necessary conditions require equal ratios of marginal decreases in monthly RA costs to marginal increases in the monthly LOLE with decreasing achieved reserve margin across all months. Marginal RA costs in any month are the product of peak demand and the RA price ($D_{50}^m p_K^m$), while marginal LOLE is the slope of the risk-reserve curve ($\frac{d\widehat{f^m}}{d\alpha_m}$). At the optimum, months where a reduction in PRM leads to only modest RA cost savings (because of a low peak demand or low RA price) will have a PRM in the shallow part of a risk-reserve curve where changes in LOLE are also modest. Conversely, months where a reduction in PRM can produce large RA cost savings (because of high peak demand or high RA prices), will have PRMs in the steeper part of a risk-reserve curve where using more of the available LOLE budget from lowering the PRM is worth the RA cost savings.

$$minimize \ \sum_m D_{50}^m (1 + \alpha_m) \cdot p_K^m \qquad \text{[Least Cost]}$$

$$such\ that\text{:} \ \sum_m \widehat{f^m}(\alpha_m) \leq 0.1 \qquad \text{[Reliable]}$$

Where:

- D_{50}^m – Peak 1-in-2 managed demand in month m
- α_m– Achieved reserve margin in month m
- p_K^m – Price of accredited capacity in month m
- $\widehat{f^m}(\alpha_m)$ – Estimated risk-reserve curve relating achieved reserve margin in month m to LOLE in m

Actual RA costs in 2028 will depend on 2028 RA prices, which are not yet known. CalCCA recommends that the most-recent publicly available RA prices be used to calculate PRMs using this criteria. Three public RA prices options were available for CalCCA's Final 2028 PRM Study. The prices are summarized in Table 3.

- 2023 RA Market Report: monthly weighted-average prices for all RA transactions for delivery in 2023 reported in the Energy Division's most recent 2023 RA Market Report;[20]
- 2025 FERC EQR: monthly weighted-average prices for capacity product transactions sold to California LSEs for delivery in 2025 reported in FERC Electric Quarterly Reports, as cleaned and organized by CalCCA;[21]
- 2027 MPB forecast: annual weighted average of RA transactions for delivery in 2027 as reported in the Energy Division's PCIA forecast of the 2027 market price benchmark (MPB). We assume the annual average price is equal across all months.[22]

[20] Energy Division, *2023 Resource Adequacy Report* (Aug. 2025), at 27-28, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2023-ra-reportv3.pdf.

[21] Capacity transactions are from FERC electronic quarterly reports (EQR) downloaded from https://eqrreportviewer.ferc.gov/ and cleaned by CalCCA.

[22] *Market Price Benchmark Calculations 2026* (Oct. 1, 2026) https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/2026-market-price-benchmarks.pdf.

Table 3. RA market prices used to calculate monthly RA costs and find PRMs that minimize monthly RA costs.

Month	RA Price ($/kW-mo)		
	2023 RA Market Report	2025 FERC EQR	2027 MPB Forecast
1	5.66	10.19	10.02
2	5.66	9.93	10.02
3	5.36	9.78	10.02
4	5.84	10.23	10.02
5	7.13	11.66	10.02
6	10.80	12.81	10.02
7	17.50	14.60	10.02
8	21.43	15.47	10.02
9	24.07	16.40	10.02
10	11.37	11.63	10.02
11	6.51	10.55	10.02
12	7.01	9.79	10.02

vi. AnnualRACost PRM Criteria

In some cases, LSEs procure RA contracts in annual strips, rather than monthly quantities. In this circumstance, RA costs depend on the highest RA requirement across the entire year. RA contracts that can meet the highest month are therefore available to meet RA requirements in any other month too. This changes the objective function in the RA cost minimization problem, but uses the same risk-reserve curves and constraint requiring that the total LOLE be less than or equal to 0.1. Changing the RA cost definition changes the problem to choosing α_m^* [PRM in each month] to:

$$minimize \ \max_m\{D_{50}^m(1+\alpha_m)\} \cdot p_K \qquad \text{[Least Cost]}$$

$$such\ that\text{:}\ \textstyle\sum_m \widehat{f^m}(\alpha_m) \leq 0.1 \qquad \text{[Reliable]}$$

Where:

- p_K – Annual price of accredited capacity

vii. MonthlyTotalCost PRM Criteria

The MonthlyTotalCost PRM selection criteria expands the costs considered in the objective function to include unhedged expected energy market costs and expected unserved energy costs, in addition to the monthly RA costs. The monthly unhedged expected energy market costs and unserved energy depend on the portfolio of resources available to the CAISO market. These change with the achieved reserve margin, similar to the way that monthly LOLE changes with the achieved reserve margin. The expected unserved energy costs are the product of the expected unserved energy and an assumed value of lost load (VOLL).

The VOLL is difficult to observe,[23] and therefore highly uncertain. A recent U.S. estimate of customer interruption costs estimated a VOLL of $5,030/MWh for residential customers associated with a 2-hour duration event and $100,000/MWh for non-residential customers.[24] With roughly 66 percent of CPUC-jurisdictional retail sales being non-residential,[25] we use a sales-weighted average VOLL of $67,710/MWh.

The PRMs that meet this selection criteria can again be expressed as a constrained optimization that minimizes total costs while meeting a LOLE of 0.1 events/year. With this optimization, we choose α_m^* [PRM in each month] to:

$$minimize\ \sum_m D_{50}^m(1+\alpha_m)\cdot p_K^m + U\cdot \widehat{g^m}(\alpha_m) + VOLL\cdot \widehat{h^m}(\alpha_m) \qquad \text{[Least Cost]}$$

$$such\ that\text{:}\ \sum_m \widehat{f^m}(\alpha_m) \le 0.1 \qquad \text{[Reliable]}$$

Where:

- U – Portion of energy market costs that are unhedged
- $\widehat{g^m}(\alpha_m)$ – Estimated curve relating achieved reserve margin in month m to unhedged expected energy market costs in m
- $VOLL$ – Value of lost load
- $\widehat{h^m}(\alpha_m)$ – Estimated curve relating achieved reserve margin in month m to EUE in m

The fraction of energy market costs that are unhedged, U, is a risk-management decision directly in the control of each individual LSE. The results in CalCCA'sPRM_problem_solution_database show the worst case, in which LSEs are 100 percent unhedged for 2028 energy market purchases (MonthlyTotalCostUnhedged) or a best case where LSEs are 100 percent hedged (MonthlyTotalCostHedged). The hedging fraction can be directly chosen by each individual LSE independent of the achieved reserve margin. The MonthlyTotalCost PRM selection criteria should therefore not be used to set PRMs, and is only included in the analysis for completeness.

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[23] Will Gorman, "The quest to quantify the value of lost load: A critical review of the economics of power outages", *The Electricity Journal*, Volume 35, Issue 8, 2022, 107187, https://doi.org/10.1016/j.tej.2022.107187.

[24] Larsen, P.; Carney, K.; Eto, J.; Jiang, G.; Joshi, D.; LaCommare, K., et al. (2026). *ICE Calculator 2: Final Report for Phase 1 and 2 of the National Initiative to Update the Interruption Cost Estimate (ICE) Calculator.* Lawrence Berkeley National Laboratory. OSTI ID: 3021993. Retrieved from https://escholarship.org/uc/item/3s61v105.

[25] EIA-861 retail sales to bundled and unbundled customers for PG&E, SCE, and SDG&E in 2024, from https://www.eia.gov/electricity/data/eia861/.

3. Results

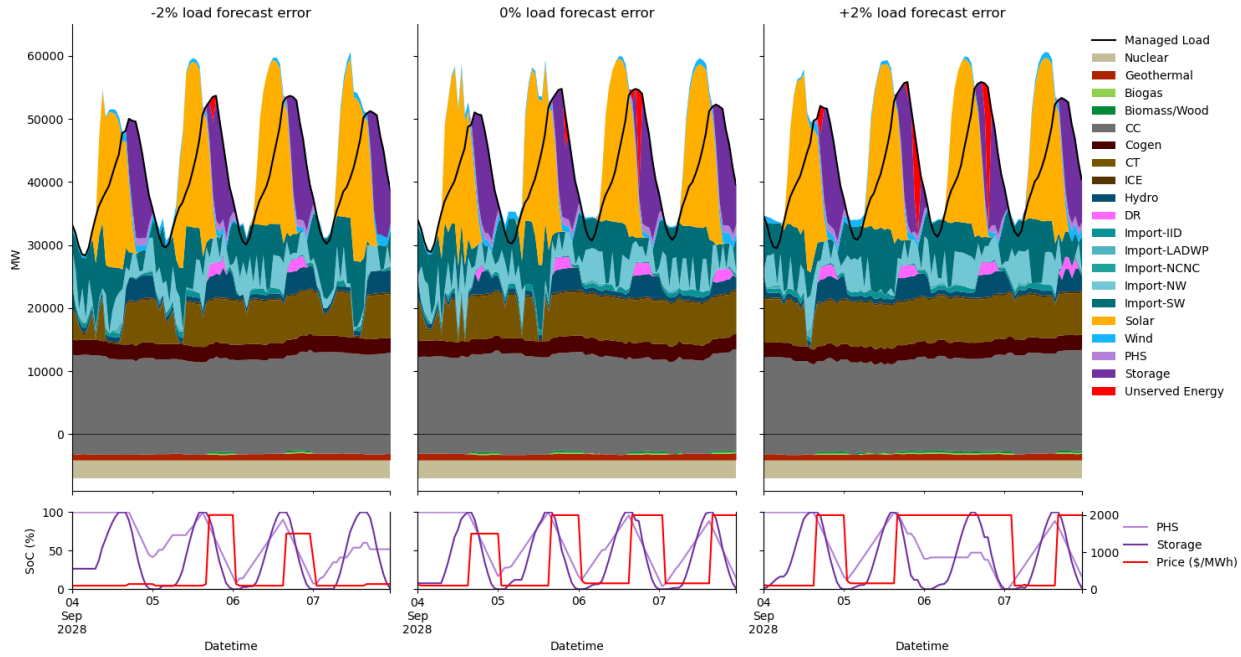
To reflect the wide range of modeling uncertainties and alternative PRM selection criteria, we calculated risk-reserve curves for twelve risk-reserve cases and used the resulting risk-reserve curves to calculate PRMs under eight different selection criteria. For each set of PRMs, we calculated the resulting RA costs using three sources of RA prices, each under two different assumptions of how RA costs vary (i.e., with monthly RA requirements or based on the highest annual requirement). The full set of results are available to stakeholders through an Excel file posted to CalCCA's website.[26]

The Baseline portfolio never experiences loss-of-load events under all risk-reserve cases. Not all the Baseline resources need to be committed to the CAISO market in all months to meet a LOLE of 0.1 events/year. Some portion of the Baseline can therefore go offline for maintenance or be committed to other markets without compromising reliability.

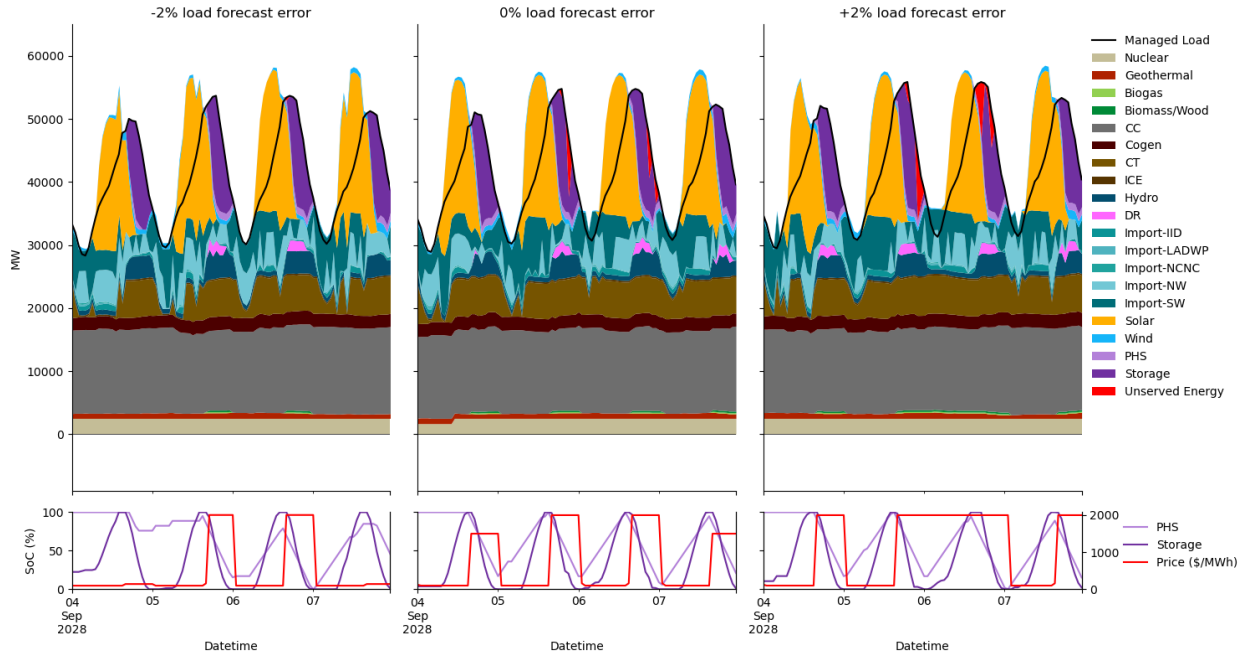
In all risk-reserve cases that set the SIL consistent with Energy Division's definition in the probabilistic reliability modeling (i.e., all cases except E and E'), roughly 6,500-7,000 MW of perfect capacity could be removed or 14 percent of each of the Baseline resources could be removed, before observing roughly a LOLE of 0.1 events/year. Cases with the SIL restricted to 4 GW in all hours and months, Cases E and E', start with less resources in the Baseline and therefore reach a LOLE of 0.1 events/year after removing 3,500 MW of perfect capacity or 8 percent of each of the Baseline resources, respectively.

In all cases, the loss-of-load events happen first in September, primarily under the load and resource characteristics consistent with the 2022 weather year. To illustrate the realistic power system operations reflected in the probabilistic reliability model, we show a dispatch report from PLEXOS for a series of stressful September days under the 2022 weather year, Figure 7. In one configuration, we remove 7,000 MW of perfect capacity from the Baseline. Mechanically, this removal of perfect capacity is achieved by creating a market object in the PLEXOS model that purchases 7,000 MW in all months and hours with higher priority than serving CAISO demand. The model allows imports up to the SIL defined by the Energy Division. In the other configuration, we scale the accessible nameplate capacity of the Baseline resources down by 14 percent, including a proportional reduction in the SIL.

[26] CalCCA's final study results in Excel: https://cal-cca.org/wp-content/uploads/2026/11/CalCCA_2028_PRM_Study_Final_2026-11-02.xlsx.



(a)



(b)

Figure 7. Example dispatch report from the probabilistic reliability model created in PLEXOS showing dispatch results on stressful days in September from the 2022 weather year with resources removed from the Baseline portfolio equivalent to (a) 7,000 MW of perfect capacity and (b) 14 percent of all non-Hydro and non-pumped hydro storage resources.

Both configurations see unserved energy in the evening after sunset and before the end of the period with restricted imports. Energy market prices rise to the assumed maximum CAISO bid cap of $2,000/MWh during times with unserved energy and other surrounding hours where battery dispatch is limited by the amount of stored energy. Unserved energy and energy market prices increase with load forecast error under the same stressful weather conditions. Eventually, with the highest load forecast error, energy prices rise to the bid cap throughout the night when resources are insufficient to fully charge energy storage between consecutive days with unserved energy. In essence, the high energy market prices in the early morning of September 6 indicate that a reduction in managed load, even when managed load is already at its lowest, could free up generating capacity to charge storage and avoid some unserved energy in the evening hours later in the same day.[27]

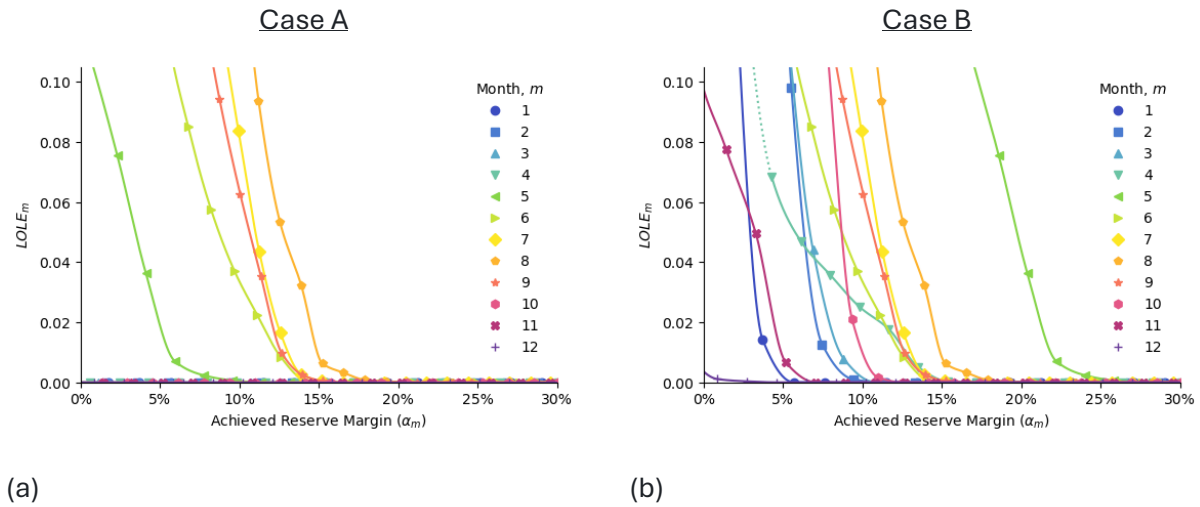


Figure 8. Risk-reserve curves change with modeling assumptions, particularly around accreditation of imports in non-summer months, as illustrated by comparing curves for Case A, assuming 4 GW of accredited imports in all hours and months, and Case B, which increases accreditation of non-summer months to 8.5 GW in all hours.[28]

Identifying a set of PRMs that meet reliability requirements requires calculation of a portfolio's achieved reserve margin to go along with the loss-of-load events found in the probabilistic reliability modeling of the portfolio. The results indicate that decisions about how to accredit

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[27] Random spikes in output occur when multiple resources could meet constraints with the same costs, resulting in the model seeing no advantage to dispatching one resource over another. Under these conditions the solution can bounce between equivalent options without otherwise affecting the objective of minimizing production costs. Similarly, nothing in the model indicates a preference for concentrating all loss-of-load in individual hours or spreading the event across multiple hours when it otherwise does not change the total amount of unmet energy. As a result, the spikes in unmet energy could presumably be mitigated if customers or system operators have a preference for longer-duration but less severe events over shorter-duration events with more customers affected.

[28] The dashed line in April represents an extrapolation of the risk-reserve curve, as opposed to the interpolation represented by the solid lines. Ideally, the systematical removal of capacity from the Baseline will include points on the risk-reserve curves that include up to 0.1 events/year. However, even removing 25 GW of perfect capacity or scaling the Baseline by 50 were insufficient to get to 0.1 events/year in April.

imports in the Baseline portfolio have significant implications for achieved reserve margins, particularly in the non-summer months. As a result, these decisions can dramatically shift risk-reserve curves, even while maintaining the same SIL assumptions in the probabilistic reliability modeling. To illustrate this point, we show the risk-reserve curves for Case A and B in Figure 8. Case A uses assumptions proposed by CalCCA to accredit imports with 4 GW of interchange capacity in all hours and months in the reserve calculations. Case B used Energy Division's proposal from the Workshop to accredit imports with 8.5 GW of interchange capacity in all hours of non-summer months and 4 GW in all hours of summer months.

To assess the implications of modeling assumptions on the risk-reserve curves, and therefore on PRMs, we start by analyzing results with a single PRM section criteria. Of all of the options, the CAISOTargetLOLE is unique in that the PRMs resulting from these criteria all have the same monthly distribution of LOLE, no matter the unique character of the risk-reserve curves. A change in a particular month's PRM, found using the CAISOTargetLOLE criteria, directly reflects a change to that same month's risk-reserve curve without any confounding interaction from changes in other month's curves. The same cannot be said for any of the other PRM selection criteria analyzed in this report. Such a characteristic does not make the CAISOTargetLOLE selection criteria more or less attractive from a policy perspective, but it does make it more useful from an analytical perspective when evaluating implications of uncertain assumptions. We first present the PRMs resulting from the CAISOTargetLOLE (PRM_{ISO}) in each of the twelve risk-reserve cases, Table 4. The monthly PRMs translate into monthly RA requirements, shown in Table 5. In the next section, we use these PRM_{ISO} results to analyze three primary sources of modeling uncertainty: the source of peak demand in reserve calculations, approach to removing capacity from the Baseline portfolio, and treatment of economic imports in reserve accreditation.

Finally, we use the full set of results to compare PRM selection criteria. All criteria meet a LOLE of 0.1 events/year, but they differ in terms of administrative complexity, distribution of LOLE across months, RA compliance costs, and relative performance on other reliability metrics. The comprehensive set of results inform CalCCA's PRM recommendations and can potentially help stakeholders understand reasons for differences across PRM studies.

Table 4. PRMs resulting from the CAISOTargetLOLE selection criteria (PRM_{ISO}) applied to each of the twelve risk-reserve cases.

Month	A	B	C	D	E	F	A'	B'	C'	D'	E'	F'
1	0.0%	6.7%	7.6%	16.6%	16.9%	6.2%	0.0%	8.9%	5.6%	14.1%	15.5%	9.0%
2	0.0%	11.2%	9.2%	21.0%	20.9%	10.8%	1.2%	10.2%	7.5%	15.3%	15.9%	10.4%
3	0.0%	13.0%	10.5%	22.8%	23.3%	12.7%	5.6%	14.7%	10.8%	19.7%	20.7%	15.0%
4	0.3%	16.9%	13.5%	26.3%	26.3%	17.1%	14.4%	23.6%	17.6%	28.8%	27.8%	24.9%
5	11.2%	27.4%	23.8%	36.6%	36.4%	28.1%	21.7%	31.4%	25.2%	36.7%	35.8%	32.9%
6	12.2%	12.2%	17.0%	17.0%	23.1%	14.3%	10.0%	10.0%	12.2%	12.2%	18.1%	12.7%
7	12.6%	12.6%	18.2%	18.2%	17.1%	15.2%	14.0%	14.0%	16.9%	16.9%	16.2%	16.7%
8	14.6%	14.6%	19.3%	19.3%	21.1%	17.2%	15.7%	15.7%	18.5%	18.5%	19.6%	18.7%
9	10.7%	10.7%	14.7%	14.7%	17.6%	13.2%	11.7%	11.7%	14.6%	14.6%	17.0%	14.3%
10	0.0%	10.1%	4.9%	18.3%	18.1%	11.8%	2.9%	11.7%	6.0%	16.7%	17.6%	14.4%
11	0.0%	8.0%	5.3%	17.6%	17.5%	8.1%	0.6%	9.7%	4.8%	14.9%	16.3%	11.0%
12	0.0%	4.3%	5.6%	13.8%	13.7%	4.5%	0.0%	6.8%	5.9%	12.3%	11.3%	7.0%

Table 5. RA requirements (i.e., $D_{50}^{m}(1+\alpha_m^*)$) resulting from the CAISOTargetLOLE selection criteria applied to each of the twelve risk-reserve cases.

Month	A	B	C	D	E	F	A'	B'	C'	D'	E'	F'
1	30,755	32,809	33,105	35,855	35,967	32,114	30,755	33,499	32,472	35,105	35,537	32,962
2	30,213	33,587	33,000	36,562	36,516	32,966	30,572	33,293	32,470	34,830	35,008	32,843
3	30,859	34,879	34,094	37,898	38,058	34,168	32,581	35,385	34,204	36,954	37,262	34,862
4	33,625	39,203	38,070	42,342	42,347	38,205	38,371	41,454	39,431	43,194	42,870	40,750
5	37,197	42,640	41,427	45,713	45,631	41,677	40,723	43,972	41,902	45,738	45,440	43,250
6	47,214	47,214	49,258	49,258	51,820	47,043	46,287	46,287	47,221	47,221	49,696	46,420
7	52,616	52,616	55,236	55,236	54,733	52,752	53,253	53,253	54,619	54,619	54,291	53,463
8	52,961	52,961	55,141	55,141	55,958	53,001	53,487	53,487	54,779	54,779	55,273	53,658
9	54,162	54,162	56,078	56,078	57,531	54,579	54,634	54,634	56,069	56,069	57,202	55,106
10	40,036	44,096	41,996	47,346	47,295	43,758	41,207	44,734	42,449	46,710	47,078	44,789
11	33,561	36,257	35,326	39,460	39,450	35,268	33,767	36,832	35,170	38,557	39,039	36,230
12	31,434	32,800	33,204	35,780	35,733	32,230	31,434	33,566	33,290	35,287	34,991	32,994

4. Impact of Risk-Reserve Modeling Assumptions

Different modeling assumptions alter the monthly risk-reserve curves and associated PRMs. In this section, we analyze the impact of various risk-reserve modeling assumptions, as reflected in the risk-reserve case definitions, on the PRMs from the CAISOTargetLOLE selection criteria.

a. Using 1-in-2 Peaks for Reserves That Differ from 1-in-2 of Peaks in Risk Modeling Overstates PRMs

The Energy Division's Draft 2028 PRM Study calculated reserves using both the 1-in-2 peak managed load from the IEPR 2025 forecast and from the 25 weather-year dataset used in the probabilistic reliability model. The 1-in-2 peaks used to calculate the achieved reserve margin of a portfolio should correspond to the load data used to assess the risk of loss-of-load events in the probabilistic reliability model. To do otherwise breaks the connection between the risk and reserves that is fundamental to CalCCA's methodology.

To quantify the implications of using mismatched loads between the risk and reserve sides, we compare the PRM_{ISO} in Case F, which uses the IEPR 2025 peaks to calculate reserves, and Case B, which uses the 1-in-2 managed load peaks from the 25 weather-year dataset used in the probabilistic reliability model. We make the same comparison for Case F' and B', where the ' indicates that capacity is removed from the Baseline by proportional scaling rather than perfect capacity.

Table 6. Using managed peak loads from the IEPR 2025 in reserve calculations, as in Case F and F', overstates PRMs relative to using the 1-in-2 managed peak load from the 25 weather-year data that is used in probabilistic reliability modeling, as in Case B and B'.

Month	F	B	F-B	F'	B'	F'-B'
1	6.2%	6.7%	-0.4%	9.0%	8.9%	0.1%
2	10.8%	11.2%	-0.4%	10.4%	10.2%	0.2%
3	12.7%	13.0%	-0.3%	15.0%	14.7%	0.3%
4	17.1%	16.9%	0.2%	24.9%	23.6%	1.3%
5	28.1%	27.4%	0.7%	32.9%	31.4%	1.5%
6	14.3%	12.2%	2.1%	12.7%	10.0%	2.8%
7	15.2%	12.6%	2.5%	16.7%	14.0%	2.7%
8	17.2%	14.6%	2.6%	18.7%	15.7%	2.9%
9	13.2%	10.7%	2.5%	14.3%	11.7%	2.6%
10	11.8%	10.1%	1.7%	14.4%	11.7%	2.7%
11	8.1%	8.0%	0.0%	11.0%	9.7%	1.3%
12	4.5%	4.3%	0.1%	7.0%	6.8%	0.2%

The difference in the PRMs, as shown in Table 6, shows that using the mismatched IEPR 2025 peak load in the reserve calculations tends to shift the risk-reserve curves to the right (i.e., suggests higher achieved reserve margins are needed to have the same risk of loss-of-load events). Using the mismatched IEPR 2025 peaks therefore overstates the PRMs needed to meet a LOLE of 0.1

events/year by at least 2 percentage points in the months of June-September and as high as 2.9 percentage points in August with the proportional scaling of the Baseline portfolio.

b. Scaling Portfolio or Removing Capacity (NOU) Often Produce Similar Risk-Reserve Curves

Risk-reserve curves differ depending on whether capacity is removed from the Baseline portfolio by removing perfect capacity (Cases A through F) or by proportionally reducing all capacity (Cases A' through F'). However, in most cases we do not see a systematic bias moving all monthly risk-reserve curves one direction or the other. The exception is in the months of April and May, where risk-reserve curves generated from the removal of perfect capacity are shifted to the left relative to risk-reserve curves from proportionally scaling all resources in the Baseline portfolio. The implication is that April and May PRMs calculated by removing perfect capacity will tend to be lower than PRMs calculated by proportionally scaling the Baseline portfolio, as shown in Figure 9.

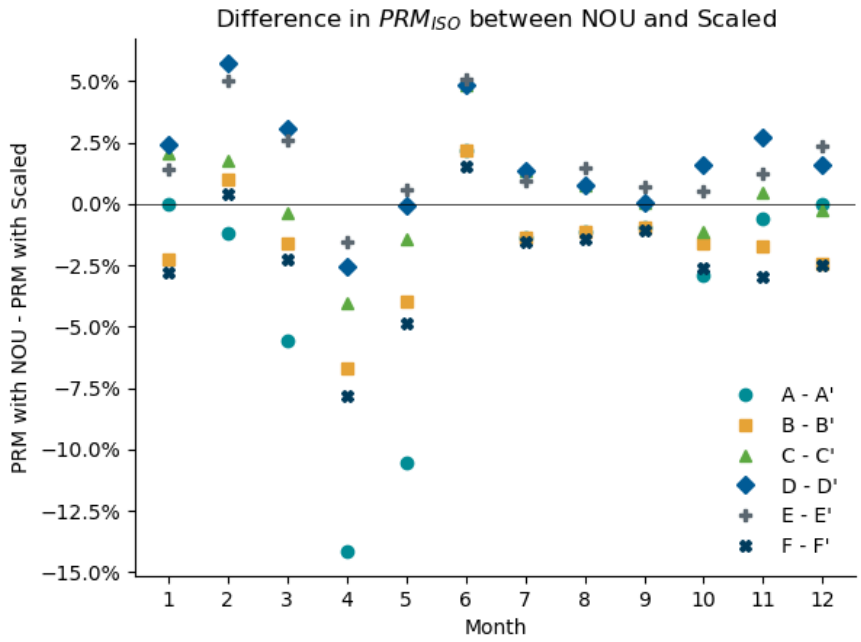


Figure 9. Proportional scaling of the Baseline portfolio or removing perfect capacity (NOU) often produce similar risk-reserve curves, with the exception of April and May.

No matter what level of PRMs are used in the RA program, no element of the RA program design determines whether the uncontracted Baseline capacity will tend to look more like perfect capacity or more like a proportional share of the Baseline portfolio. Consequently, the risk-reserve curves have an inherent uncertainty related to which portion of the Baseline would be shown to meet a given PRM. This analysis helps to bound that uncertainty: the choice likely impacts monthly PRMs by +/- 2.5 percentage points in most cases, with larger impacts in April and May. It does not, however, provide a clear recommendation for how to resolve the inherent uncertainty.

c. Lower PRMs Are Needed if Imports Can Exceed Shown Import RA

Diverse perspectives on the way to handle imports in risk and reserve modeling led to a variety of assumptions in the Draft 2028 PRM studies, particularly for assumptions outside of the peak hours of the summer months. For the peak hours in the summer months, all studies consistently assume that accredited imports in reserve calculations are 4 GW and that the SIL in the probabilistic reliability model is capped at 4 GW (with appropriate scaling of the accredited imports and SIL when using SCE's proportional scaling approach). Outside of this narrow window, however, disagreement stems from whether imports in the probabilistic reliability model can ever exceed the accredited imports shown in RA filings.

Figure 10 shows the PRM_{ISO} can vary, in the most extreme months of April and May, by more than 25 percentage points across different assumptions on import accreditation. While differences in the PRMs are much smaller in the critical months of July through September, only 7 percentage points, these months have historically had the tightest RA supply and highest RA costs.

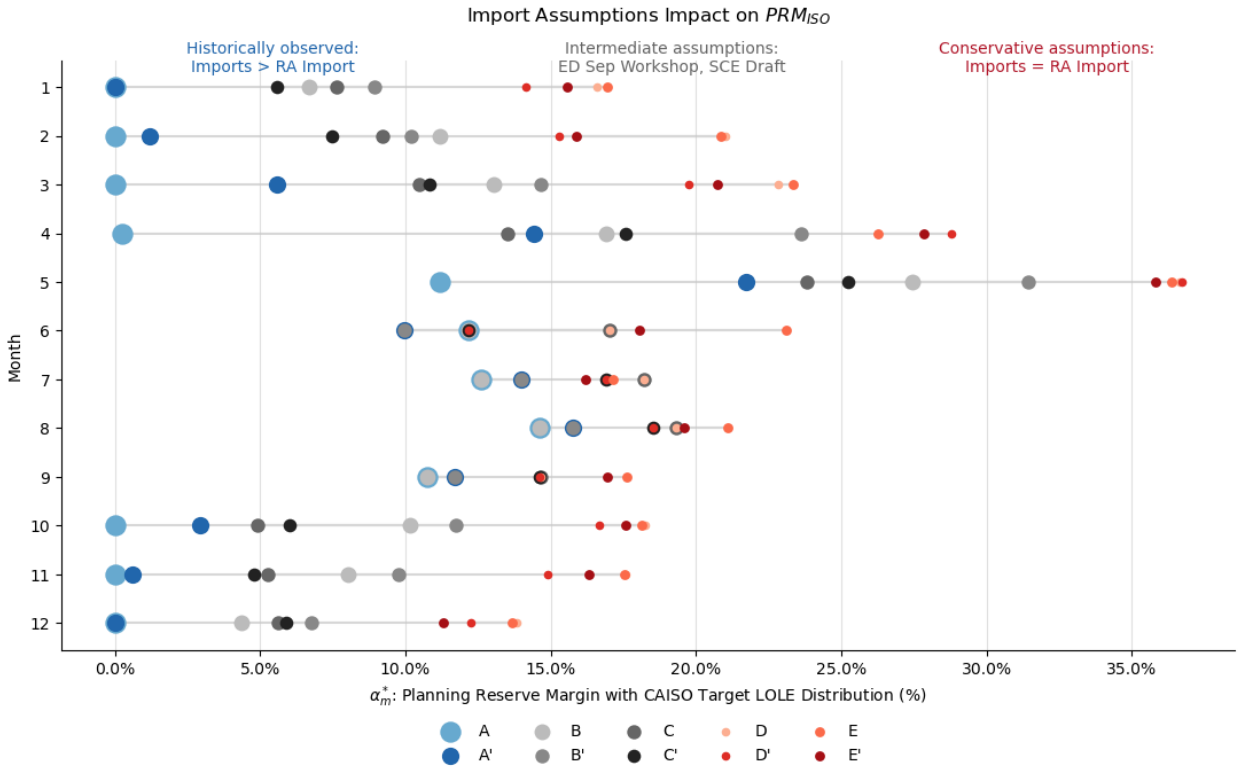


Figure 10. Lower PRMs are needed when risk-reserve curves recognize economic imports—imports that can exceed shown import RA.

Assuming imports in the probabilistic reliability model can never exceed the accredited import RA capacity, as in Cases D, D', E, and E', consistently results in the highest PRM_{ISO}. In contrast, the lowest PRM_{ISO} stems from assuming that available resources outside of the CAISO can be

imported up to Energy Division's SIL even if the shown RA imports are only 4 GW in all months and hours, as assumed in Case A. Case A' does not always lead to as low of a PRM as Case A simply because Case A' scales down both the SIL in the probabilistic reliability model and the accredited import RA capacity in reserve calculations. Scaling lowers the relative impact of imports on achieved reserve margin and risk in portfolio's that define the shape of the risk-reserve curves.

In the summer months, the differences in PRMs across import assumptions are smaller in part because all assumptions agree on limiting the SIL to 4 GW and accrediting import RA capacity at 4 GW in the peak summer hours between HE17 and HE22. Even with this agreement for summer peak hours, however, the summer PRMs still differ across cases. The reason is that off-peak imports play an important role in providing charging energy for storage, which is energy-limited when responding to stressful conditions that drive summer loss-of-load. In the summer, Cases A, A', B and B' allow for some off-peak imports in summer that can, when resources are available in neighboring regions, exceed the shown RA imports and help charge energy storage for stressful conditions during peak hours. Economic imports (i.e., imports that exceed shown RA imports and do not have a CAISO must-offer-obligation) outside of peak hours, are a regularly observed part of the CAISO system. Their importance in supporting CAISO's reliability will only grow as the CAISO system comes to depend more on energy-limited resources. That said, the other reason for the smaller range of PRMs in the summer months is that imports are a relatively smaller portion of the overall portfolio of resources used to keep the CAISO system reliable.

In the non-summer months, however, the 11 GW simultaneous import limit can be roughly a third of the 1-in-2 peak demand, making import assumptions critical to determining PRMs. PRMs are lower in cases that allow some degree of economic imports (i.e., Cases A, A', B, B', C, and C' all allow varying degrees of imports that can exceed shown RA imports). CalCCA's modeling found that surplus resources outside of CAISO could be available to import up to the Energy Division's SIL in all non-summer hours under all weather years (see Appendix B). Relying on the availability of these surplus resources, even LSEs only show 4 GW of RA imports, as in Case A, results in negligible loss-of-load events and non-summer PRMs of 0 percent. Suggesting that economic imports would be sufficient to handle loads above the 1-in-2 peak, variable generation below the exceedance profiles, forced outages, and operating reserve requirements.

While the 0 percent PRMs in non-summer months resulting from Case A are an interesting and thought-provoking result, CalCCA does not recommend using Case A to set non-summer PRMs at this time. Rather, we present these results to highlight the important role of import assumptions in setting PRMs and recommend further discussion and workshops among stakeholders and experts. In the interim, the import assumptions in Case B and B', consistent with the Energy Division's assumptions at the Workshop, appear to be a reasonable middle ground.

A second insight from this analysis is that PRM_{ISO} in April in May should be the highest across all months under that condition that imports can never exceed shown RA imports (i.e., as assumed in

Cases D, D', E, and E'). April and May have moderate 1-in-2 peaks, with a high degree of variability of loads and renewable profiles across weather years. Reliably managing that variability requires high PRMs. However, April and May are also times of the year when surplus resources could be expected to be available in regions outside of the CAISO, increasing the comfort level for reliance on economic imports. The need for high PRMs in April and May quickly disappears when recognizing imports that can exceed shown import RA.

5. Comparison of PRM Selection Criteria

In an RA program that has monthly RA showings, there are many ways to meet the requirement that the annual LOLE be less than or equal to 0.1 events/year. The previous section focused on PRMs that match the CAISO Target LOLE distribution in order to explore the risk-reserve modeling assumptions. In this section we turn to comparing PRM different selection criteria. All of the criteria considered here maintain reliability by meeting a LOLE of 0.1 events/year.

a. PRMs and LOLE for Case B

The differences between PRM selection criteria are easiest to observe with a fixed set of risk-reserve curves, derived from a single set of risk and reserve modeling assumptions. Here we present results using assumptions from Case B, which uses the Energy Division's proposal for accreditation interchange capacity and the SERVM 1-in-2 peak loads in reserve calculations. The PRMs resulting from the eight different PRM selection criteria, applied to the risk-reserve curves from Case B, are shown in Table 7. The corresponding LOLE in each month, which always sums to 0.1 events/year or less, is shown in Table 8.

Several key results with Case B extend to other cases and will be described further in the following sections:

- Annual and Seasonal2 PRMs can go no lower primarily because of the increasing risk of loss-of-load events in May. Loss-of-load events are concentrated in May with these PRM selection criteria.
- Seasonal3 PRMs decouple the PRMs in May and April from other seasons, allowing PRMs in other months to decrease by 3.4 to 5 percentage points relative to the Seasonal2 or Annual PRMs. The May and April Seasonal3 PRMs, on the other hand increase by 11.1 to 11.6 percentage points relative to Seaonal2 or Annual PRMs. The Seasonal3 PRMs shift all of the risk of loss-of-load events to June through September, with the highest concentration in August.
- The MonthlyRACost, AnnualRACost, and MonthlyTotalCostHedged PRMs roughly follow a similar shape to the monthly PRMs from the CAISOTargetLOLE criteria (PRM_{ISO}). Across these criteria and RA price scenarios, PRMs in the months of June through September are in the range of 8.9 to 15.1 percent; which is always lower than the corresponding 17.4 percent Annual or Seasonal2 PRM applicable to the same months. PRMs in May are much higher than the Annual and Seasonal2 PRMs, in the range of 22.1 to 27.5 percent.
- Cost minimizing PRMs are similar to the PRM_{ISO} becasue, for the most part, they concentrate LOLE in the more expensive summer months. The distribution of LOLE most closely matches the CAISO Target LOLE distribution for the PRMs from AnnualRACost and MonthlyRACost with RA prices from the 2023 RA Market Report, featuring severely peaked RA prices in September.

- An exception is that as the shape of RA prices flatten, with the 2027 MPB Forecast assuming equal RA prices across all months, the LOLE also becomes more widely distributed. In fact with the completely flat prices assumed with the 2027 MPB Forecast, the MonthlyRACost PRM selection criteria finds greatest cost savings by lowering the PRM in April, a month with a shallow risk-reserve curve, and as a result, increasing the concentration of loss-of-load events in April.

Table 7. Comparison of PRMs selected from different criteria, but all meeting a LOLE of 0.1 events/year or less, using risk-reserve curves from Case B.

PRM Selection Critera	RA Prices for PRM Problem	1	2	3	4	5	6	7	8	9	10	11	12
Annual		17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%
Seasonal2		16.9%	16.9%	16.9%	16.9%	17.4%	17.4%	17.4%	17.4%	17.4%	16.9%	16.9%	16.9%
Seasonal3		13.5%	13.5%	13.5%	27.5%	27.5%	12.4%	12.4%	12.4%	12.4%	13.5%	13.5%	13.5%
CAISOTargetLOLE		6.7%	11.2%	13.0%	16.9%	27.4%	12.2%	12.6%	14.6%	10.7%	10.1%	8.0%	4.3%
AnnualRACost		5.7%	11.3%	11.7%	16.9%	27.5%	15.4%	14.0%	15.2%	8.9%	12.5%	7.1%	4.4%
MonthlyRACost	2023 RA Market Report	5.3%	9.1%	10.2%	14.1%	22.3%	12.4%	12.6%	14.9%	11.0%	10.5%	6.1%	0.3%
	2025 FERC EQR	5.0%	8.6%	9.5%	9.1%	22.1%	12.1%	13.2%	15.0%	12.5%	10.5%	5.2%	0.0%
	2027 MPB Forecast	5.0%	8.6%	9.5%	6.9%	22.1%	12.5%	13.6%	15.1%	12.7%	10.6%	5.4%	0.0%
MonthlyTotalCostHedged	2023 RA Market Report	5.2%	8.9%	10.0%	13.5%	22.6%	12.0%	12.4%	14.6%	11.9%	10.5%	5.3%	0.1%
	2025 FERC EQR	4.9%	8.4%	9.1%	13.1%	22.1%	11.6%	12.5%	14.9%	12.4%	10.5%	5.1%	0.0%
	2027 MPB Forecast	4.7%	8.1%	8.8%	12.9%	22.1%	11.7%	12.8%	15.0%	12.5%	10.5%	5.1%	0.0%
MonthlyTotalCostUnhedged	2023 RA Market Report	81.3%	91.0%	94.2%	94.5%	96.9%	45.4%	34.1%	32.9%	25.5%	56.0%	75.6%	73.5%
	2025 FERC EQR	38.1%	42.8%	36.1%	94.4%	96.8%	45.4%	34.2%	32.9%	25.6%	56.0%	75.5%	73.5%
	2027 MPB Forecast	38.2%	42.7%	94.0%	94.4%	96.8%	45.5%	34.2%	33.0%	25.6%	56.0%	75.5%	35.4%

Table 8. Comparison of the monthly distribution of loss-of-load events, as measured by $LOLE_m$, corresponding to PRMs selected from different criteria using risk-reserve curves from Case B.

PRM Selection Critera	RA Prices for PRM Problem	1	2	3	4	5	6	7	8	9	10	11	12
Annual		0.0000	0.0000	0.0000	0.0000	0.0985	0.0000	0.0000	0.0015	0.0000	0.0000	0.0000	0.0000
Seasonal2		0.0000	0.0000	0.0000	0.0000	0.0985	0.0000	0.0000	0.0015	0.0000	0.0000	0.0000	0.0000
Seasonal3		0.0000	0.0000	0.0000	0.0000	0.0000	0.0100	0.0194	0.0571	0.0133	0.0000	0.0000	0.0000
CAISOTargetLOLE		0.0000	0.0000	0.0000	0.0000	0.0000	0.0120	0.0160	0.0160	0.0480	0.0080	0.0000	0.0000
AnnualRACost		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0025	0.0063	0.0911	0.0000	0.0000	0.0000
MonthlyRACost	2023 RA Market Report	0.0006	0.0017	0.0010	0.0030	0.0065	0.0098	0.0169	0.0100	0.0421	0.0039	0.0020	0.0025
	2025 FERC EQR	0.0019	0.0035	0.0037	0.0292	0.0077	0.0122	0.0080	0.0079	0.0118	0.0039	0.0066	0.0036
	2027 MPB Forecast	0.0018	0.0035	0.0039	0.0415	0.0074	0.0090	0.0045	0.0068	0.0092	0.0033	0.0055	0.0036
MonthlyTotalCostHedged	2023 RA Market Report	0.0008	0.0022	0.0017	0.0052	0.0056	0.0131	0.0197	0.0162	0.0224	0.0038	0.0059	0.0033
	2025 FERC EQR	0.0026	0.0048	0.0063	0.0071	0.0077	0.0171	0.0173	0.0095	0.0131	0.0039	0.0070	0.0036
	2027 MPB Forecast	0.0041	0.0072	0.0082	0.0087	0.0078	0.0164	0.0135	0.0082	0.0110	0.0040	0.0073	0.0036
MonthlyTotalCostUnhedged	2023 RA Market Report	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	2025 FERC EQR	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	2027 MPB Forecast	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

b. PRMs Based on Minimizing RA Costs Are Similar to PRMs from CAISO's Target LOLE Distribution

The resemblance between the PRMs from the RA-cost-minimizing criteria and the PRM_{ISO} means that the total RA costs are similar. As a corollary, the divergence of the Annual and Seasonal2 PRMs from the RA-cost-minimizing PRMs means that the total RA costs will be different. Table 9 shows how much more expensive it is to meet RA requirements with PRMs set without consideration of RA costs relative to the cost of RA with the MonthlyRACost premium using the risk-reserve curves for Case B. In this table RA costs are expected to vary with monthly RA requirements. Table 10 shows

the RA cost premium under the assumption that RA costs instead vary with the highest annual RA requirement, again showing results only for Case B.

Table 9. Increase in RA cost with risk-reserve curves from Case B when selecting PRMs using various non-cost-minimizing criteria compared to the RA cost of PRMs selected using the MonthlyRACost criteria, assuming that RA costs vary with monthly RA requirements.

PRM Selection Criteria	2023 RA Market Report	2025 FERC EQR	2027 MPB Forecast
Annual	5.0%	5.6%	6.1%
Seasonal2	4.9%	5.4%	5.9%
Seasonal3	1.9%	3.2%	4.1%
CAISOTargetLOLE	0.6%	1.2%	1.6%

Table 10. Increase in RA cost with risk-reserve curves from Case B when selecting PRMs using various non-cost-minimizing criteria compared to the RA cost of PRMs selected using the AnnualRACost criteria, assuming that RA costs vary with the highest RA requirement across the year.

PRM Selection Criteria	2023 RA Market Report	2025 FERC EQR	2027 MPB Forecast
Annual	7.8%	7.8%	7.8%
Seasonal2	7.8%	7.8%	7.8%
Seasonal3	3.2%	3.2%	3.2%
CAISOTargetLOLE	1.7%	1.7%	1.7%

The higher summer PRMs with the Annual and Seasonal2 selection criteria require more RA contracts in the summer than the RA-cost-minimizing PRMs and the PRM_{ISO}. As a result, overall RA costs are 4.9 to 7.8 percent higher with the Annual and Seasonal2 PRMs even though all of the PRM criteria meet the same level of reliability, as reflected by the LOLE of 0.1 events/year or less. In absolute terms, the Annual and Seasonal2 PRMs could have RA costs that are $290-597 million/year higher than RA-cost-minimized PRMs.

The CAISOTargetLOLE selection criteria also results in RA costs that are higher than the RA-cost-minimized PRMs. However, the closer resemblance of the PRMs means that the RA cost premium of PRM_{ISO}, using risk-reserve curves from Case B, is only 0.6 to 1.7 percent, or $33-130 million/year, above the RA cost for the RA-cost-minimized PRMs.

These results: (1) that the RA costs from the PRM_{ISO} are most similar to the RA-cost-minimizing PRMs; and (2) that the Annual and Seasonal2 PRMs are higher cost, extends to nearly all risk-reserve cases and combinations of RA prices, as shown in Figure 11. At worst, the PRM_{ISO} result in RA costs that are 2 percent higher than the RA-cost-minimizing PRMs. In contrast, the cost of PRMs using the Annual or Seasonal2 criteria can be up to 12 percent higher than the RA-cost-minimizing PRM.

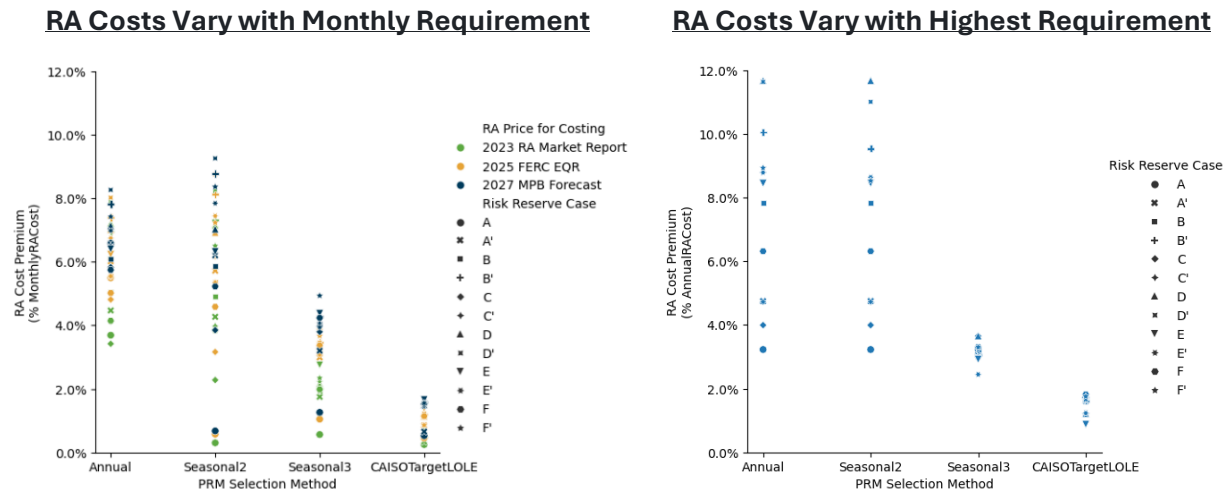


Figure 11. Increase in RA cost with risk-reserve curves from all cases when selecting PRMs using various non-cost-minimizing criteria assuming costs vary with (a) monthly RA requirements or (b) with the highest RA requirement across the year.

c. PRMs with Lower Cost Avoid Grouping High-Variability Months with Summer Months

The high RA cost of the Annual and Seasonal2 PRMs across a wide range of cases is often driven by a fact observed earlier with the risk-reserve curves from Case B. The high variability in the spring months of April and May, reflected by risk-reserve curves that are shifted to the right relative to other months, often restricts how low PRMs can go before hitting the 0.1 events/year limit. Energy Division's choice to group the high variability month of May with the other summer months in the Seasonal2 PRM selection criteria means that September's PRM is influenced more by conditions in May than it is conditions in September.

The Sesaonal3 selection criteria reduce RA costs by decoupling the PRMs in the high-variability months from the PRMs in the high RA cost months. The PRMs in the spring season are now free to be set a level high enough to avoid loss-of-load events, while PRMs in the more-narrow definition of the summer season are independently reduced to the point where nearly all loss-of-load is concentrated in the summer.

Continuing this logic, why stop at three seasons? Why not go to monthly PRMs where the unique characteristic of each month's risk-reserve curve can be used to inform the choice of monthly PRMs? The monthly RA-cost-minimizing PRMs do just that, resulting in the lowest possible RA costs while still meeting a LOLE of 0.1 events/year. It is worth noting, however, that the annual reliability constraint still couples the decision each month's PRMs together, just in a way that makes tradeoffs more explicit.

d. Exposure to Energy Market Costs Is Managed By LSEs; Should Not Be Used to Set Reliability-Based PRMs

To this point we have focused primarily on RA-cost-minimizing PRMs. We could also consider a broader definition of consumer costs that adds expected energy costs and expected unserved energy costs to the RA costs.

Energy market prices depend on the set of resources participating in the CAISO market. Keeping the managed load constant while removing resources from the Baseline portfolio, either through removal of perfect capacity or proportional reduction of all resources, can increase energy market prices, inclusive of Cap-and-Invest GHG emission costs, if the affected resources are infra-marginal. As such, a reduction in the achieved reserve margin not only increases the risk of unmet energy it also increases the expected energy market costs. Expected energy market costs, defined as the product of energy market prices and managed load, can be two to three times higher than RA costs. Valuing expected unmet energy at a VOLL of over $67,000 MWh similarly provides a strong signal to not lower PRMs too much, though this is already a consideration when requiring that PRMs achieve a LOLE of 0.1 events/year.

If we were to assume that consumers are fully exposed to energy market prices, in other words completely unhedged, then the PRMs from the MonthlyTotalCostUnhedged selection criteria would be set so high that all or nearly all of the Baseline portfolio would have to participate in the CAISO market throughout the year. Under such high PRMs, no loss-of-load events would occur, and LOLE would be zero in all months.

Figure 12 illustrates how assuming energy market costs are unhedged drives the total-cost-minimizing PRM in September to over 25 percent, well above the achieved reserve margin where loss-of-load events would begin to occur.

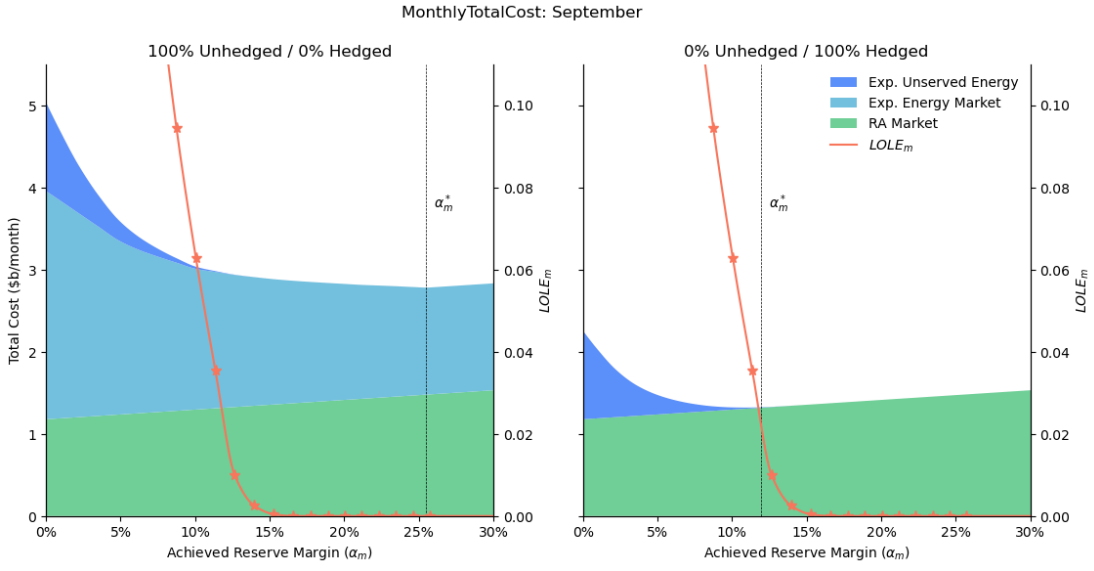


Figure 12. The unreasonable assumption that energy market costs are completely unhedged leads to high PRMs, with no loss-of-load events even in September, under the MonthlyTotalCostUnhedged selection criteria.

The reality is that LSEs use risk-management strategies to limit customer exposure to energy market prices, and these strategies can include financial, energy-only contracts. The achieved reserve margin is therefore not a direct determinant of customer energy market costs, at least in the short term between PRM study and RA program filings,[29] whereas it is more directly linked to expected unserved energy and RA costs.

In as much as LOLE and EUE are related, the MonthlyRACost PRM selection criteria already accounts for the relationship between achieved reserve margin and RA costs along with the relationship between achieved reserve margin and expected unserved energy costs. As such, we would expect that PRMs from the MonthlyRACost and MonthlyTotalCostHedged to be nearly equivalent. Figure 13 shows that across almost all months, risk-reserve cases, and RA price assumptions the PRMs from the MonthlyTotalCostHedged criteria are within +/- 2 percentage points of the PRMs from the MonthlyRACost. Exceptions to this finding primarily occur in April, where the MonthlyRACost criteria sometimes finds RA cost savings from the shallow risk-reserve curve, and to a lesser extent in June. The higher April PRMs with the MonthlyTotalCostHedged criteria indicate that the potential for reducing April RA cost are not worth the potential higher cost of unserved energy in other months like September.

[29] In the long-run, where existing generators may retire or new generators may be built, even the cost of financial (non-RA) energy products may be influenced by PRM decisions. In such a case, a more comprehensive examination of investment and retirement decisions could be used to evaluate PRM selection criteria, similar to a 2014 Brattle study of PRMs for ERCOT (*Estimating the Economically Optimal Reserve Margin in ERCOT*, https://www.ercot.com/files/docs/2017/05/16/Estimating_the_Economically_Optimal_Reserve_Margin_in_ERCOT_Revised.pdf). California's RA program is different, however, in that PRMs under consideration for this study would only be in effect for 2028 and 2029, arguably too short of a horizon for long-run effects to impact the cost of financial products to hedge energy market costs.

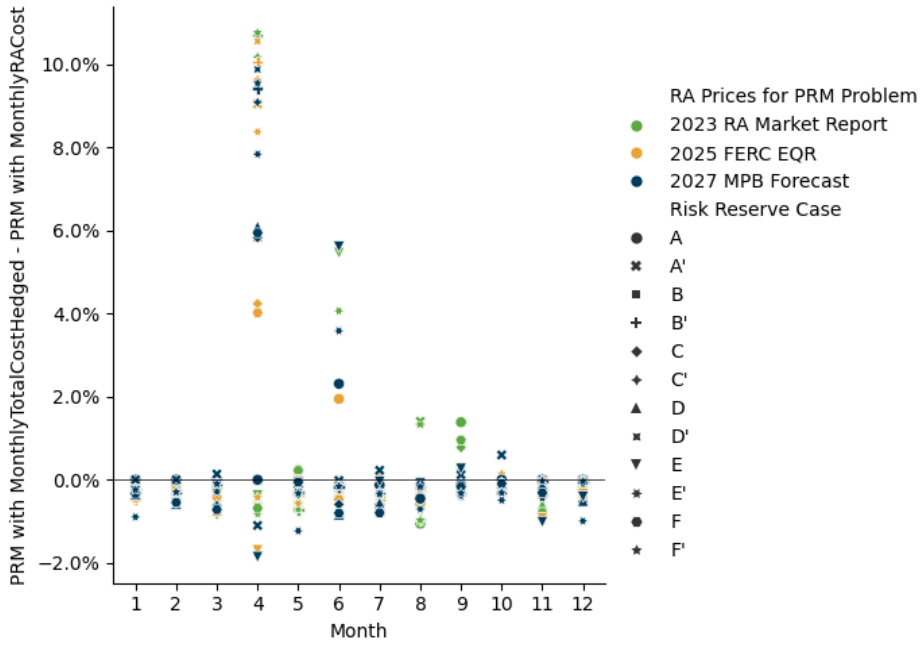


Figure 13. PRMs selected with consideration of RA costs and expected unmet energy costs, following the MonthtlyTotalCostHedged criteria, are similar to the PRMs that only minimize RA costs, MonthlyRACost, because both are required to meet a LOLE of 0.1 events/year.

e. All PRMs Meet 0.1 LOLE But Produce Mixed Results with Other Reliability Metrics

By design, all of the PRM selection criteria meet a LOLE of 0.1 events/year but that does not mean they perform equally when measured with other reliability metrics like the expected loss-of-load hours (LOLH) or expected unserved energy (EUE). Slight differences between LOLE and EUE metrics, coupled with differences in RA costs and the VOLL, in part explain the variation in PRMs selected with the MonthlyRACost and MonthlyTotalCostHedged criteria in the previous section. Table 11 shows the average and maximum of the annual risk metrics across all cases and RA price scenarios for each PRM selection criteria. While the PRM selection criteria are equivalent in meeting a LOLE of 0.1 events/year, the CAISOTargetLOLE criteria and MonthlyTotalCostHedged criteria produce the lowest LOLH and EUE.

Table 11. PRM selection criteria all meet a LOLE of 0.1 events/year but differ on performance on other reliability metrics on average across cases (a) and in the maximum across cases (b).

Average Across Cases and RA Price Scenarios

PRM Selection Criteria	LOLE events/year	LOLH hours/year	EUE GWh/year
Annual	0.1000	0.2226	0.9159
Seasonal2	0.1000	0.2285	0.9639
Seasonal3	0.1000	0.1516	0.5689
CAISOTargetLOLE	0.0994	0.1410	0.4349
AnnualRACost	0.1000	0.1882	0.8316
MonthlyRACost	0.1000	0.1905	0.7894
MonthlyTotalCostHedged	0.0997	0.1444	0.3297
MonthlyTotalCostUnhedged	0.0000	0.0000	0.0000

(a)

Maximum Across Cases and RA Price Scenarios

PRM Selection Criteria	LOLE events/year	LOLH hours/year	EUE GWh/year
Annual	0.1000	0.2818	1.3663
Seasonal2	0.1000	0.2987	1.4252
Seasonal3	0.1000	0.1898	0.8726
CAISOTargetLOLE	0.1001	0.1887	0.7372
AnnualRACost	0.1000	0.2831	1.3065
MonthlyRACost	0.1000	0.2605	1.3958
MonthlyTotalCostHedged	0.1000	0.1746	0.5031
MonthlyTotalCostUnhedged	0.0000	0.0000	0.0000

(b)

Overall differences in risk metrics across PRM selection criteria are likely smaller than differences in PRMs that would arise if a reliability target other than a LOLE of 0.1 events/year were to be used. Brattle and Astrape (2013),[30] for example, shows how PRMs change if the reliability standard is a LOLE of 0.1 events/year, an LOLH of 2.4 hours/year, or a normalized EUE of 0.0010 percent. In the context of the current study, the maximum EUE of 1.4252 GWh/year in Table 11 translates to a normalized EUE of 0.0007 percent. Had we used a normalized EUE of 0.0010 percent as the reliability target in the PRM selection criteria, rather than a LOLE of 0.1 events/year, then all of the PRMs would be lower and all of the resulting LOLEs would exceed 0.1 events/year. Hence, defining a consistent reliability target is more impactful than evaluating PRM selection criteria on differences in off-design risk metrics.

[30] *See* Brattle and Astrape, *Resource Adequacy Requirements: Reliability and Economic Implications* (2013), at 38-41, https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf.

6. Recommendations

At the outset of this effort, CalCCA set out not to identify a specific PRM for 2028, but instead to ask Energy Division to include affordability in its consideration of PRMs when multiple options produce the same level of reliability. In CalCCA's I&As, we developed a consistent framework for explicitly including RA costs in the PRM selection criteria, along with a step-by-step process for implementing the framework using tools and data already in use by the Energy Division. With this Final 2028 PRM Study, CalCCA has now demonstrated the process and used the results to quantify tradeoffs between different PRM selection criteria.

a. Adopt CalCCA's Approach to Generating Monthly Risk Reserve Curves and Cost-Minimizing PRM Selection Criteria

CalCCA's approach provides a pathway to lower electricity costs for customers while maintaining reliability, links PRMs to a transparent and consistent process, and generates datasets, namely risk-reserve curves, that enable stakeholders to evaluate a wide range of alternative PRM selection criteria. With this, we come back full circle to our primary recommendation: the CPUC should adopt CalCCA's approach to generating monthly risk-reserve curves and comparing PRMs stemming from different selection criteria in its PRM studies. PRMs from CalCCA's cost-minimizing selection criteria (*e.g.*, MonthlyRACost, AnnualRACost, or MonthlyTotalCostHedged) can then be used to provide an affordability benchmark for any other PRM proposals.

While cost-minimization should not be the only criteria driving PRM selection, it should be one consideration included among other insights or factors driving PRM selection. We acknowledge that determining PRMs is an art as well as a science. However, if proposed PRMs drive up RA costs, well above the cost-minimizing benchmark, there should be clear reasoning for why paying that higher cost is justified. Across a wide range of scenarios and assumptions, we see no clear justification for using the Annual or Seasonal2 PRM selection criteria as they are currently defined. The peak summer month PRMs (July-September) should not result from an approach that arbitrarily ties those PRMs to the PRMs needed to manage high-variability months (e.g., April, May). Grouping May with the peak summer months results in an increase in the PRMs in the peak months and higher RA cost, without improving reliability relative to other options.

Our study also reveals an area that feels a little too much like art without enough science: the choice of import assumptions in probabilistic reliability modeling and reserve calculations. Draft studies used differing import assumptions without a clear recognition of the implications for PRMs. This study shows that different assumptions can have significant impacts on PRMs and that the most conservative assumptions deviate from observed system operations. We see that the Energy Division's proposal is a reasonable middle ground as an interim solution, and recommend Energy Division host workshops on import assumptions prior to the next PRM study. The workshops should directly consider the question of what role energy-only economic imports, a mainstay of

CAISO operations, should play in reliability modeling, especially as the system continues to both better integrate with neighboring regions and incorporate a greater share of energy-limited resources like battery storage.

Other outstanding modeling questions affect PRMs in meaningful ways, but do not need to wait for future workshops to resolve. The Commission should accredit conventional resources when setting PRMs using the UCAP EFORd+Ambient approach, rather than installed capacity (ICAP). The UCAP EFORd+Ambient approach aligns accreditation in reserve calculations with the accreditation rules that will be in place for the 2028 RA program. The Commission should also use the 1-in-2 peak load of the 25-weather year dataset (SERVM) instead of 2025 IEPR peaks to calculate reserves in the PRM setting process. Establishing a relationship between a portfolio's risk of unmet demand and its achieved reserve margin expects that the managed load used in probabilistic reliability modeling corresponds to the 1-in-2 peak managed loads used to calculate reserves. While we appreciate the engagement of ED staff raising the question of whether energy market costs should be considered on par with RA costs when considering affordability, we've now shown why the unique ability of LSEs to hedge exposure to energy market costs through non-RA products means it is not appropriate to set PRMs using unhedged expected energy costs.

Independent of the particular modeling assumptions, the CAISOTargetLOLE PRM criteria performed well in terms of affordability. Other advantages of using the CAISOTargetLOLE PRM criteria include using criteria defined by the grid operator, being relatively easy to understand, and being easy to implement once risk-reserve curves are defined. It also keeps the distribution of the LOLE across the year fixed, even across different modeling assumptions, and concentrated in the peak summer months. For now, the PRMs from the CAISOTargetLOLE tend to agree with the cost-minimizing PRMs. In future years, as RA prices, demand, and supply evolve, it is possible PRMs will not agree to the same degree. At which point benchmarking to cost-minimizing PRM selection criteria could reveal the need to change the target LOLE distribution or shift to other criteria altogether.

b. Select PRMs Using CAISO Target LOLE Criteria with Assumptions Consistent with Case B

For the 2028 PRMs, CalCCA recommends using the CAISOTargetLOLE PRM selection criteria in conjunction with risk-reserve curves from Case B. These assumptions allow Energy Division to continue to identify loss-of-load events by removing perfect capacity, consistent with its existing methodology, and will result in monthly PRMs that range from 4-15 percent across most months with PRMs as high as 16-27 percent only in April and May. The final recommended PRMs are shown in Figure 14.

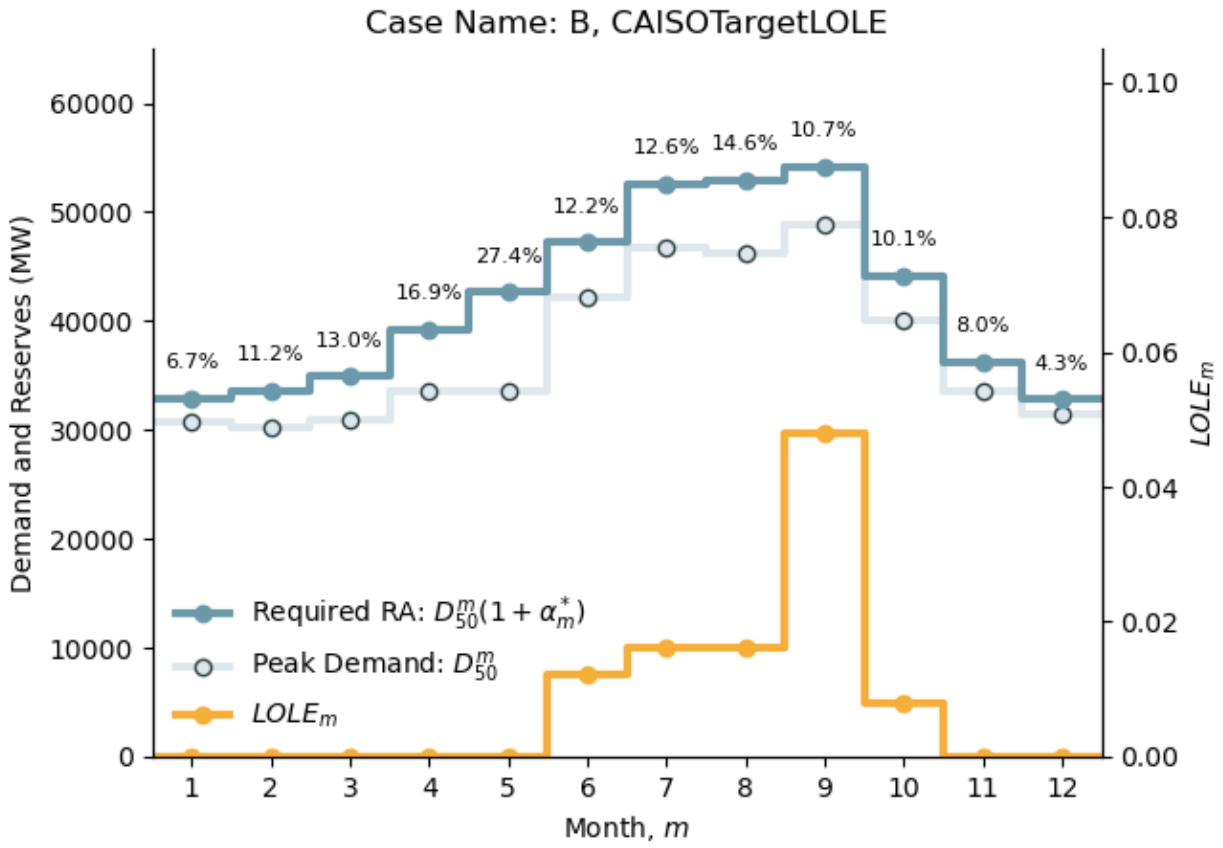


Figure 14. CalCCA recommends 2028 PRMs selected using the CAISOTargetLOLE criteria with risk-reserve curves from Case B.

With these PRMs, the RA requirements are highest, exceeding 52 GW during the tightest hours, in the months of July, August, and September due to the high 1-in-2 peak managed load. According to the CAISO Target LOLE distribution, 80 percent of the LOLE is concentrated in these high-requirement months. The concentration of LOLE allows the PRMs to stay between 10.7 to 14.6 percent, or 2.8 to 6.7 percentage points lower than it would have otherwise been with an Annual or Seasonal2 PRM that meets the same LOLE of 0.1 events/year across the year. Even though RA cost is not directly considered in the CAISOTargetLOLE criteria, choosing PRMs with the CAISOTargetLOLE selection criteria can reduce RA costs by 4.0 to 5.7 percent under modeling assumptions consistent with Case B.

The recommended PRMs are significantly higher than Annual or Seasonal2 PRMs in April and May. However, the moderate 1-in-2 peak loads in the spring mean the RA requirements in those months remains below 44 GW. Historical observations of economic imports in April and May suggests that the RA requirements in those months could be lower without sacrificing reliability. Additionally, April and May PRMs were less than 18 percent in April and May of 2025 and 2026, without any obvious reliability concerns, though we do not yet know what the achieved reserve margin was for those months under the SOD accounting rules. Until further data and analysis are available, it is

prudent to recommend April and May PRMs that are high enough to avoid unmet energy under the assumptions in Case B.

The combination of moderate PRMs and low 1-in-2 peak demand in the months of November through March keep RA requirements in those months below 37 GW. This period of lower RA requirements creates a contiguous five-month period suitable for planned maintenance of generating resources, without detrimental impacts to reliability.

Overall, CalCCA's recommended PRMs achieve significant reductions in consumer costs of complying with RA requirements while still ensuring that the system has sufficient resources to meet a LOLE of 0.1 events/year.

Appendix A. Probabilistic Reliability Model Assumptions

- Load:
    - CAISO hourly net managed load profiles based on the Commission's 25 weather years;[31] and
    - Load forecast uncertainty represented by five discrete outcomes spanning -2 percent to +2 percent, with probability of each outcome from a Midcontinent Independent System Operator (MISO) study.[32]
- Operating Reserves:
    - Operating reserves include 3 percent of hourly net managed load for spinning reserves and 3 percent for regulation up reserves, load shed to maintain reserves;[33] and
    - Storage must maintain sufficient energy to sustain spinning reserve deployment for one hour and regulation up reserves for ten minutes.[34]
- Conventional Resources and Energy Storage:
    - Resource categories represented by sets of identically sized units, with each unit having a unique forced outage profile;.[35]

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[31] CAISO net managed load created by summing the "NetLoad" columns for the "PGE", "SCE", and "SDGE" regions. Data included Hourly load components for California regions only, 2000-2024 weather, medians consistent with 2025 IEPR demand forecast Planning Scenario, 2028. *See* CPUC System Reliability Modeling Datasets, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/energy-modeling/servm-inputs-2026.

[32] *See* CalCCA Alternative I&A Document, at 23, Table 2 (Load forecast error based on U.S. economic forecast errors from MISO PRM study).

[33] CalCCA's assumption that load shedding is used to preserve operating reserves equivalent to 6 percent of the managed net load is consistent with the Commission's modeling requirement that resources must maintain regulating reserves at 3 percent of load in addition to spinning reserves at 3 percent of load. *See* Revised Inputs & Assumptions SERVM 2026 Data Updates in Support of Resource Adequacy (RA) and Integrated Resource Planning (IRP) (June 5, 2026) (CPUC I&A), at 39-40, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M608/K310/608310037.PDF.

[34] CalCCA's requirement that storage must have energy stored sufficient to maintain the provision of operating reserves is similar to the Commission's definition that "[f]or storage resources, the operational range from the current operating level to maximum output (headroom) and maximum charging (footroom) is available, subject to constraints on energy availability." *See* CPUC I&A, at 38. However, the Commission does not define the time period over which the reserves must be able to be deployed to calculate the energy availability.

[35] The capacity of each identical unit is the total January NQC capacity of the category divided by the number of units in the category. The capacity and count of units are from the "Value" column in the "SERVM Units" tab of the Commission's PRM Calibration Workbook for September 15, 2026 (PRM Calibration Workbook), downloaded from: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-history. CalCCA used the NQC value for conventional resources rather than nameplate to emulate Energy Division's suggestion that some generation, particularly cogen units, cannot operate at their nameplate. Energy Division's Draft 2028 PRM Study, at 12.

    - Forced outages simulated using category-specific forced outage rates from the Commission[36] and assuming 24-hour mean repair time;
    - 3,125 random samples of forced outages (25 for each weather year and load forecast error combination);
    - Category-average thermal derates modeled using hourly weather-dependent derate profiles based on Commission's 25 weather years;[37] and
    - Battery duration based on the average duration of all CAISO battery storage in the Commission's June 2026 Baseline Generating List, with pumped hydro storage duration assumed to be 10 hours.
- Variable and Hydro Resources:
    - Variable Energy Resource (VER) output represented through weather-dependent production profiles without separate forced outage modeling, based on Commission's 25 weather years;[38]
    - Hydro constrained by weather-dependent capacity, monthly energy budgets, and minimum flow requirements;[39] and
    - Emergency hydro, additional hydro capacity that can be called on for limited events, has a maximum capacity that varies with month and year based on the Commission's 25 weather years.[40]
- Transmission:
    - Internal CAISO transmission constraints not modeled;
    - Imports from neighboring regions limited by a Simultaneous Import Limit (SIL) that depends on the case, as described in the next section; and

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[36] Category-average forced outage rates are from the "EFFECTIVE EFORD EXCLUDING AMBIENT DUE TO TEMPERATURE" column of the "Resource Type UCAP" tab in the PRM Calibration Workbook.

[37] CalCCA used the nameplate capacity of each unit to create a capacity-weighted average of the thermal derate by category. Individual unit thermal derates by year are from the Commission's Ambient Temperature Output Derating, 2000-2024 weather, downloaded from https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/energy-modeling/servm-inputs-2026.

[38] VER profiles are consistent with the PRM Accreditation Workbook categories created by summing the columns for the "PGE", "SCE", and "SDGE" regions. See Variable Gen Hourly Profiles, 2000-2024 weather, Baseline Generator List, 2028, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/energy-modeling/servm-inputs-2026.

[39] Hydro parameters created by summing each variable for the "PGE_Hydro_V0024", "SCE_Hydro_V0024", and "SCE_Hoover_Hydro_V0024" unit names in SERVM Hydro Variables, 2000-2024 hydro conditions, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/energy-modeling/servm-inputs-2026. PLEXOS uses a mid-term (MT) schedule to create a coarse plan for allocating hydro across the month based on a load duration curve with 15 blocks. The short-term (ST) schedule then refines the hydro dispatch based on observed hourly conditions.

[40] Emergency hydro capacity created by summing the "capmax" variable for "PGE_Emergency_Hydro_V0024" and "SCE_Emergency_Hydro_V0024" unit names. The maximum energy that can be used by emergency hydro each month is from the corresponding "max_flex" global variable. To model the "borrowing" of emergency hydro energy from the normal hydro budget, CalCCA imposed a constraint that the normal and emergency hydro generation must not exceed the total monthly energy in the "hydro_energy" variable.

    - Imports from neighboring regions dependent on the availability of residual supply after meeting the neighbor's own demand, with additional details in Appendix B.
- Reliability Assessment:
    - Risk of unmet demand quantified through probabilistic simulation of weather, load uncertainty, resource availability, and operating reserve requirements;
    - Risk metrics include expectations of loss-of-load event days[41], loss-of-load hours, and unmet energy.

[41] Consistent with our understanding of the Commission's approach, we assume that any day with unserved energy counts as one loss-of-load event. The monthly LOLE is the probability-weighted average count of events across all days of the month. The LOLE across the year is the sum of each month's LOLE. The reliability standard is to meet a 0.1 LOLE across the year.

Appendix B. Simplified Representation of Neighboring Regions

CalCCA's Draft Study assumed 4 GW of imports in every hour and month, with no consideration of whether resources outside of CAISO could supply the imports. Energy Division's SERVM model instead explicitly represents supply, demand, and transmission constraints for neighboring regions, then applies a simultaneous import limit (SIL) that caps available impots. CalCCA's Final Study modifies PLEXOS to include a simplified representation of supply availability in neighboring regions and then caps available imports with a SIL.

To maintain reasonable solution times and a simple model structure, CalCCA's simplified representation of neighboring regions uses heuristics to estimate residual supply—an hourly accounting of resource availability in excess of the region's demand—instead of directly incorporating unit-by-unit dispatch decisions into PLEXOS. As shown below, the residual supply is suitable for modeling reliability metrics in CAISO, because residual supply is often far greater than the SIL. This implies assumptions about the SIL are likely more important than details on individual generator dispatch decisions. The four sections that follow describe CalCCA's definition of neighboring regions, approach to calculating residual supply, adjustments to residual supply through a regional reliability calibration, and the treatment of unmet demand outside CAISO.

Neighboring Regions

CalCCA's representation of neighboring regions is as follows:

- CalCCA starts with the balancing authority areas (BAAs) modeled by Energy Division, then combines strongly interconnected BAAs into larger aggregated regions;
- CalCCA retains NCNC, IID, and LADWP; and aggregates the remaining BAAs into a NW and SW region shown in Table 12;
- CalCCA aggregates the Energy Division's 25 weather year data for each of the members of a region.

Table 12. CalCCA aggregation of neighboring regions

Aggregate Region	Member Balancing Authority Areas
NW	BPAT, PACW, PortlandGE
SW	AZPS, SRP, NEVP, WALC
NCNC	NCNC
IID	IID
LADWP	LADWP

In PLEXOS, transmission capacity limits transfers between neighboring regions, including the CAISO SIL. Transmission limits are shown in Figure 15.

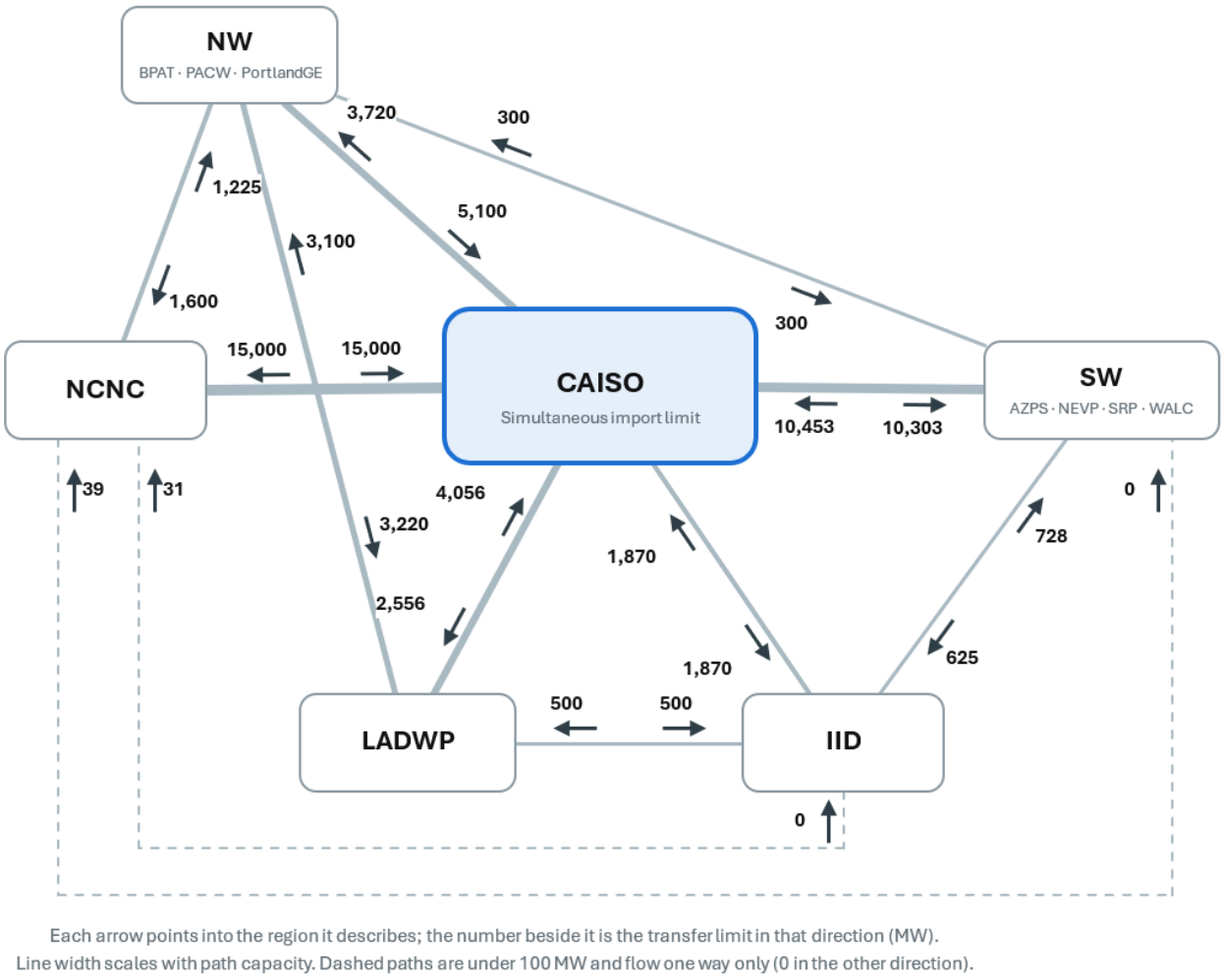


Figure 15. Transmission topology and directional transfer limits between CAISO and the non-CAISO aggregate regions represented in PLEXOS. Total imports into CAISO are further limited by the simultaneous import limit.

Residual Supply

Outside of PLEXOS, CalCCA uses the Energy Division's data along with simple heuristics to calculate residual supply---the supply remaining after meeting each region's weather-dependent managed load and operating reserves. This residual supply, adjusted with a calibration step described in the next section, is incorporated into PLEXOS as an hourly profile for a regional generator that varies over the 25 weather years. The residual supply from one region can supply unmet demand in other regions or can be imported into CAISO, subject to transmission limitations.

Residual supply is the difference between the calibrated firm capacity and the region's managed load and operating reserve requirement, net of any variable energy resources (VER), hydro, and storage. An example calculation of the residual supply for the SW region is shown in Figure 16.

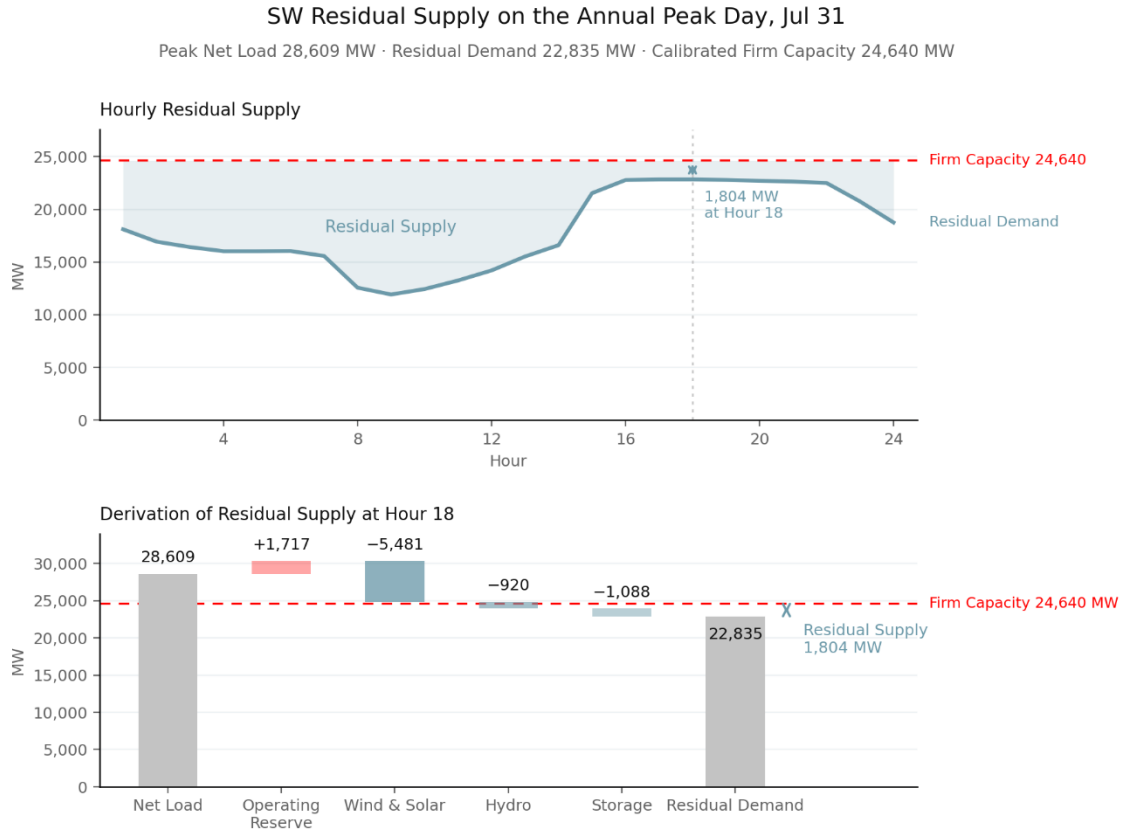


Figure 16. Residual supply on the SW peak day (July 31, weather year 2000), with the peak-hour calculation shown as waterfall. At hour 18, SW's 28,609 MW managed load plus a 1,717 MW operating reserve, less 5,481 MW of wind and solar, 920 MW of hydro, and 1,088 MW of storage, leaves 22,835 MW of residual demand. Against 24,640 MW of calibrated firm capacity with 7.4 percent derate applied, 1,804 MW remains as residual supply.

Each of the components of the residual supply are described below.

- Managed Load:
  - Use Energy Division 2028 25-weather year, hourly managed load by balancing authority, net of behind-the-meter photovoltaics and adjusted for additional achievable energy efficiency and fuel substitution, consistent with CAISO.
- Operating reserve:
  - 6 percent of the hourly managed load.
- Wind and Solar:
  - Reduce managed load by Energy Division's 25 weather year, hourly wind and solar profiles for each region.

- Hydro:
    - Use heuristic to dispatch hydro within the Energy Division's monthly energy budgets and minimum/maximum flows by weather year.
    - Use a simple search algorithm to find a monthly threshold where hydro is at the min flow when the load less wind/solar is below the threshold, and at its max flow (or the max needed to meet demand) when load less wind/solar is above the threshold. Choose the threshold such that the hydro dispatch matches the monthly energy budget. The heuristic is illustrated in Figure 17.

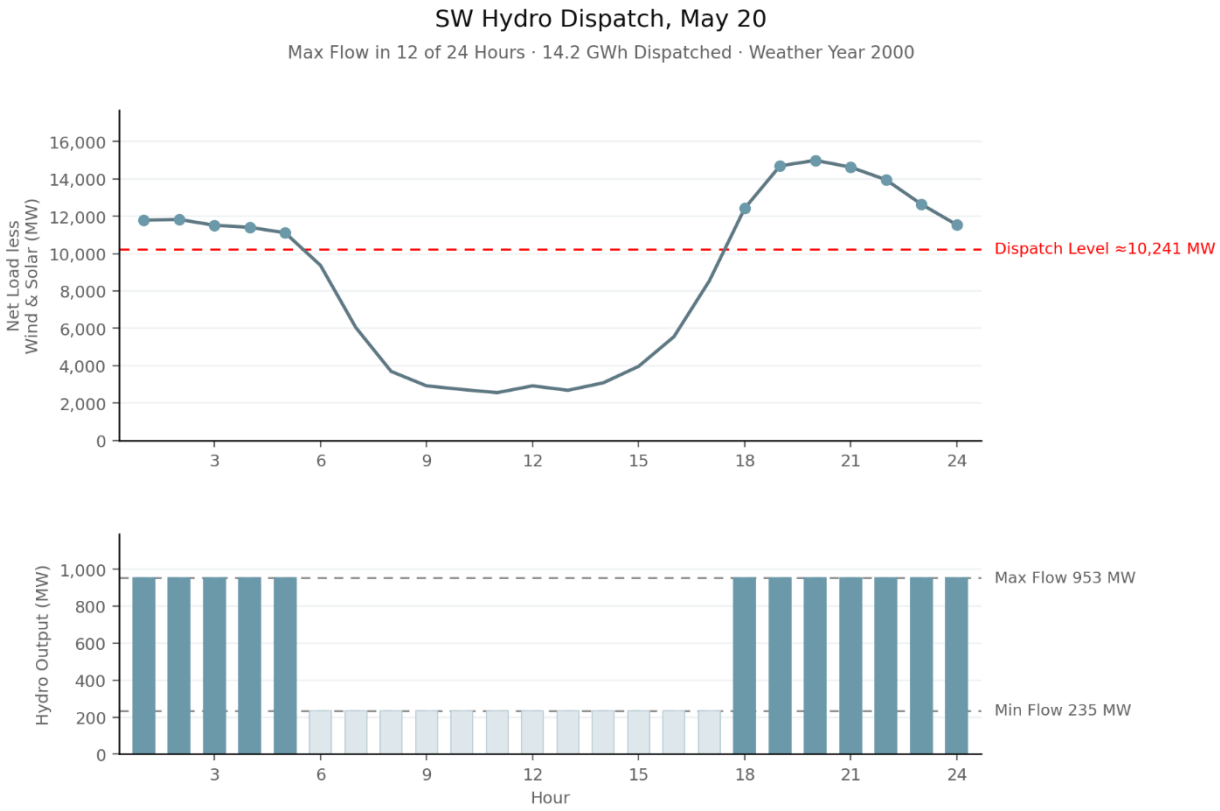


Figure 17. Illustration of heuristic used to dispatch hydro in each region within min flow, max flow, and monthly energy budget constraints.

- Storage:
    - Use a peak-shaving heuristic to dispatch storage to minimize peaks in the load less wind, solar, and hydro profile.
    - Dispatch is constrained by power and energy limits and accounts for an 81 percent round-trip efficiency. An example of storage dispatch is shown in Figure 18.
    - Peak-shaving algorithm is based on a five-day window that is rolled forward one day at a time, and only the dispatch of the middle day of the window is kept. The surrounding days establish state of charge, which reduces boundary effects for the

middle day. Using a rolling window limits processing time across the five regions and 25 weather years.

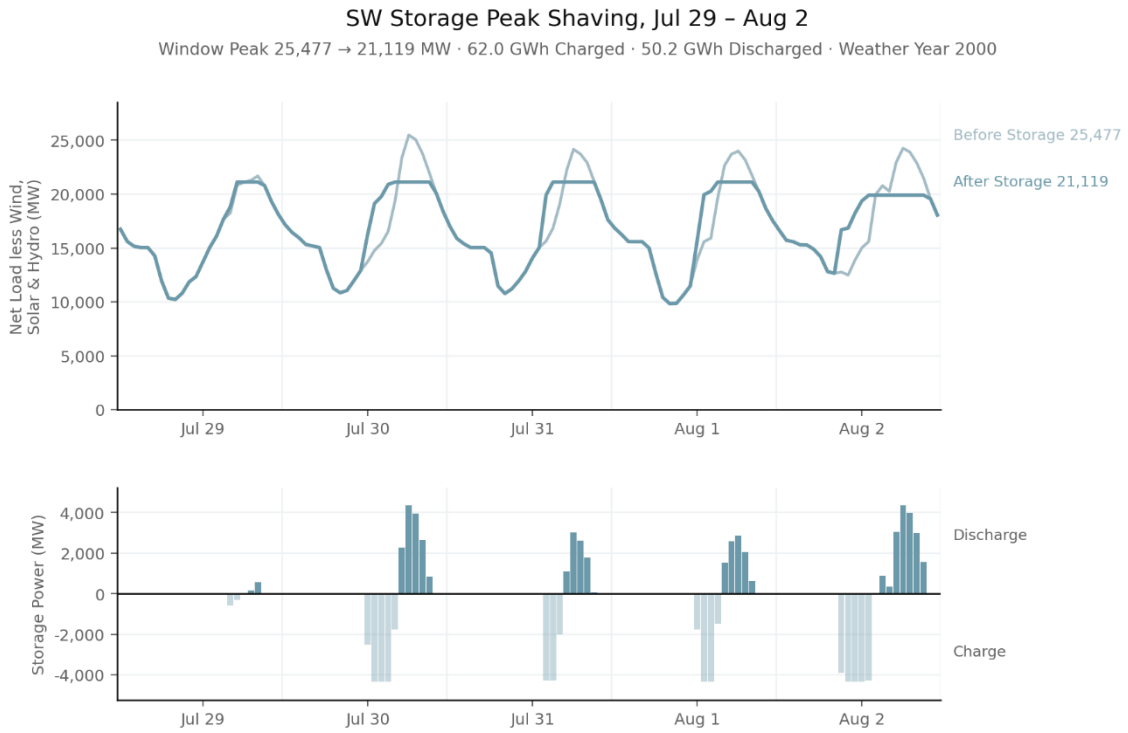


Figure 18. Example of storage dispatch in the SW region with weather data from 2000.

- Firm capacity:
    - Total of thermal capacity in the region, excluding any capacity already included in the CAISO Baseline.
    - No explicit modeling of forced outages, instead reduce nameplate capacity by a 7.4 percent weighted-average forced-outage rate. No ambient derate applied.

Regional Calibration

In some hours a region's generation capacity may not be sufficient to meet the managed load and operating reserves, leading to a residual supply of zero and positive unmet demand. CalCCA counted the number of days with an unmet demand across the 25 weather years to roughly estimate the LOLE in neighboring regions. Three of the regions (IID, LADWP, and SW) saw few unmet demand events leading to a LOLE less than 0.1 events/year. In these three regions we scaled down the firm capacity until the LOLE rose to 0.1 events/year. The calibration reduced firm capacity in these three regions by 15 to 19 percent.

In the two remaining regions, NCNC and NW, the LOLE was already above 0.1 events/year. In these regions we made no further changes to the firm capacity.

Unmet Demand

Hours where the region's calibrated supply was insufficient to meet managed load and operating reserves had unmet demand rather than residual supply. CalCCA represented unmet demand in PLEXOS as a load in the neighboring region with an hourly profile across the 25 weather years. Unmet demand could be met by imports from residual supply, subject to the transmission limits.

Residual Supply Relative to Energy Division's Simultaneous Import Limit

CalCCA used the residual supply, unmet demand, and transmission limits to illustrate how often available imports would be below Energy Division's SIL. Figure 19 shows that available imports almost always exceed the SIL, except for afternoon hours between June and September. In those hours, available imports can be below the SIL at most 5 percent of the time.

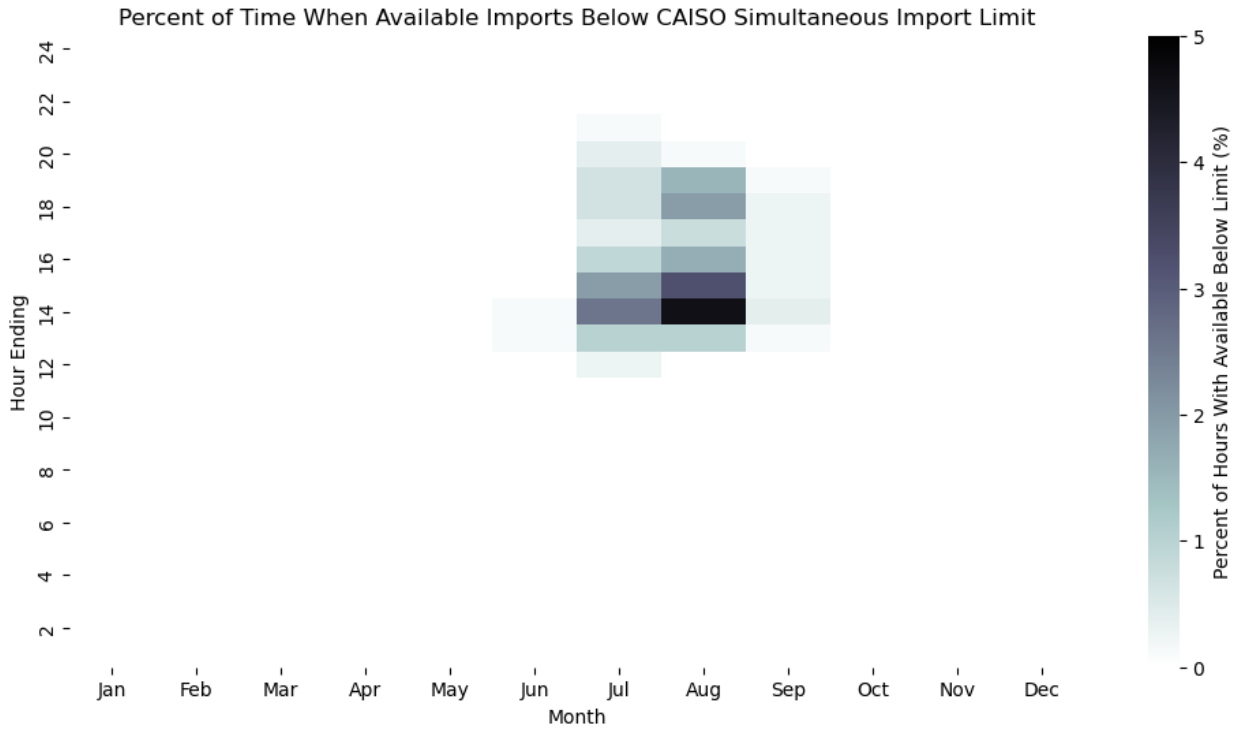


Figure 19. Percentage of hours with available imports less than Energy Division's SIL.