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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 COMMENTS ON DRAFT INPUTS & ASSUMPTIONS

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
Lauren Carr,
Senior Manager, Regulatory Affairs and Market Policy
Eric Little,
Director of Market Design
Andrew Mills,
Director of Data Analytics

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9459
E-mail: regulatory@cal-cca.org

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SUMMARY OF RECOMMENDATIONS[1]

The Commission should:

- Convene additional workshops to allow robust discussion regarding how SERVM LOLE modeling will be used to set the PRM;
- Reject party recommendations to assume zero RA imports as that scenario would be overly conservative and negatively impact the accuracy of the analysis;
- Conduct additional analysis to build confidence in the Demand Model given its pronounced variation from historical consumption;
- Account for BTM-PV impact on losses in reconstitution of consumption;
- Update CAISO hydro parameters to reflect increased hydro flexibility observed in recent years; and
- Use past IEPR forecasts of peak demand to validate and, if found to be appropriate, adjust load forecast error assumptions in SERVM.

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[1] Acronyms used herein are defined in the body of this document.

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California Community Choice Association[2] (CalCCA) submits these comments pursuant to the *Administrative Law Judge's Ruling Modifying 2028 Loss of Load Expectation Study Schedule*[3] (Ruling), dated March 30, 2026. The Ruling seeks comments on the April 14, 2026, Draft Inputs & Assumptions Workshop (Workshop).

I. INTRODUCTION

CalCCA appreciates Energy Division's efforts to establish the parameters for and conduct the loss-of-load expectation (LOLE) modeling used to inform the Resource Adequacy (RA) program's planning reserve margin (PRM). Such modeling is a complex undertaking with the potential to significantly impact customer affordability and reliability. Given the critical importance of this modeling, the California Public Utilities Commission (Commission) should

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2 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, Peninsula Clean Energy, 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, and Valley Clean Energy.

3 *Administrative Law Judge's Ruling Modifying 2028 Loss of Load Expectation Study Schedule*, Rulemaking (R.) 25-10-003 (Mar. 30, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M603/K465/603465636.PDF.

modify the schedule to convene additional workshops so that Energy Division and parties can further discuss how Energy Division's inputs and assumptions and LOLE modeling will be used to set the PRM.

In establishing the inputs and assumptions, the Commission should seek to accurately reflect system and resource characteristics. The Commission should therefore decline party recommendations to assume zero RA imports. While it may be worthwhile to explore a lower RA import scenario as a sensitivity to see how fewer imports impact the results, to assume zero imports would be overly conservative and deeply unrealistic at this time. The Commission should also conduct additional analysis of the Demand Model given its pronounced variation from historical consumption.

In addition, the Commission should account for behind-the-meter (BTM) photovoltaic (PV) impact on losses in reconstitution of consumption. The Commission should also update California Independent System Operator (CAISO) balancing authority area (BAA) hydro resource parameters to reflect increased hydro flexibility observed in recent years. Such modifications will ensure the model is reflective of these resources' characteristics.

Finally, accurately characterizing load forecast errors is important in setting the PRM to ensure a 0.1 LOLE. The Commission should seek to validate that its method for establishing forecast error is sound by evaluating past California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) forecasts of peak demand and develop an approach to adjust load forecast error assumptions in SERVM if necessary.

In summary, the Commission should:

- Convene additional workshops to allow robust discussion regarding how SERVM LOLE modeling will be used to set the PRM;
- Reject party recommendations to assume zero RA imports as that scenario would be overly conservative and negatively impact the accuracy of the analysis;

- Conduct additional analysis to build confidence in the Demand Model given its pronounced variation from historical consumption;
- Account for BTM-PV impact on losses in reconstitution of consumption;
- Update CAISO hydro parameters to reflect increased hydro flexibility observed in recent years; and
- Use past IEPR forecasts of peak demand to validate and, if found to be appropriate, adjust load forecast error assumptions in SERVM.

II. ADDITIONAL WORKSHOPS SHOULD BE CONVENED TO DISCUSS HOW SERVM LOLE MODELING WILL BE USED TO SET THE PRM

The Commission should adopt American Clean Power – California's recommendation at the Workshop to convene additional workshops before LOLE studies and PRM proposals are due on August 14, 2026. This will allow Energy Division and parties to discuss unresolved questions about fundamental modeling approaches (such as differences between adding load and removing generation to develop PRMs in non-peak months). In addition, more discussion would be useful on how Energy Division plans to use its LOLE modeling to set the PRM. During the process for setting the 2026 and 2027 PRMs, stakeholders raised several questions about how the LOLE modeling results translate to the recommended PRM, particularly when the PRM varies by season or by month. Some of these questions were unresolved, not fully evaluated, or only evaluated late in the PRM study cycle without sufficient opportunity for party input. To avoid the same situation in this cycle, CalCCA recommends additional workshops early on in the process to provide parties an opportunity to verify their understanding of Energy Division's planned approach and to discuss the pros and cons of alternative approaches.

The Commission and parties should discuss in a workshop how to incorporate affordability considerations in the decision of how much of the potential RA fleet must be shown in each month. Ideally, the amount of RA shown each month should achieve an annual LOLE of 0.1 at the least cost to consumers. It is not clear how, or whether, Energy Division's process for allocating LOLE across months has historically accounted for the relative cost of RA from month to month. The Commission should therefore explore in a workshop how Energy Division should allocate LOLE across months to result in the most affordable outcome for customers while maintaining the 0.1 LOLE standard.

III. PARTY RECOMMENDATIONS TO ASSUME ZERO RA IMPORTS SHOULD BE REJECTED

The Commission should reject party recommendations to assume zero RA imports in the modeling. While concerns about the future availability of RA imports are legitimate, assuming zero imports is overly conservative. Capacity scarcity in the Western Electricity Coordinating Council (WECC) has been a concern since at least 2022, when entities in the WECC developed the Western Resource Adequacy Program. Since 2022, CAISO data shows that load-serving entities (LSE) in the CAISO balancing authority area (BAA) have shown RA imports from 2019 through 2025. Using this data, the minimum import RA recorded during the most critical summer months of June through September is 3,125 megawatts (MW) in June 2022. Since that year, the amount of imports shown for the same month has been as high as 5,863 MW in 2024 and, most recently, at 5,057 MW for 2025. **Figure 1** shows the amounts of minimum RA import from 2019 through 2025 for June through September of each year.[4]

Minimum RA Showing (2019 - 2025)	MW Import Shown	Year of the Minimum
June Min	3,125	2022
July Min	4,693	2022
Aug Min	4,818	2022
Sep Min	3,784	2022

Figure 1: Minimum RA Imports Shown During the Summer Months

[4] Data for Figure 1 derived from https://www.caiso.com/documents/historicalresourceadequacyaggregatedata.xlsx.

Additionally, data provided by the CAISO demonstrates that the imports not only are *not* approaching zero but have largely been *above* the Commission's assumed value of 4,000 MW. **Figure 2** shows the total shown import RA for the summer months from 2019 to 2025.[5]

Shown RA							
	2019	2020	2021	2022	2023	2024	2025
June	4,689	4,105	4,411	3,125	4,023	5,863	5,057
July	8,290	5,864	5,477	4,693	5,746	6,153	5,704
August	8,804	7,945	5,703	4,818	5,130	6,324	5,399
September	8,587	6,932	4,698	3,784	4,267	5,121	5,297

Figure 2: Summer Shown RA

Finally, a number of LSEs have procured or will own out-of-state resources, some with subscriber financed transmission to bring those resources into California, to meet Integrated Resource Plan (IRP) and Renewables Portfolio Standard (RPS) compliance requirements.[6] Furthermore, the Commission's IRP portfolios include 19 GW of out-of-state resources, suggesting additional procurement of out-of-state resources will be procured in the future.[7] Therefore, if the Commission considers decreasing the assumed RA imports in the modeling used to determine the PRM, at most, it should include reduced RA imports as a sensitivity analysis only. Otherwise reducing imports to zero is highly speculative and not reflective of recent RA import showing trends. If the Commission considers an import value lower than the Commission's assumed 4,000 MW, the Commission should set the minimum no lower than the known contractually obligated resources for the study period.

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5 Data for Figure 2 derived from https://www.caiso.com/documents/historicalresourceadequacyaggregatedata.xlsx.

6 Slide 16 of the Workshop Presentation indicates that even owned or contracted import resources are addressed within SERVM. It is not completely clear how this designation translates to the recommendation that imports be counted as zero. Regardless, it is clear that some imports will occur and should not be discounted for purposes of calculating the PRM.

7 D.26-02-057, *Decision Requiring 2029-2032 Electric Resource Procurement and Transmitting Portfolios for 2026-2027 Transmission Planning Process,* R.25-06-019 (Feb. 26, 2026), at 56: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M600/K854/600854771.pdf.

IV. ADDITIONAL ANALYSIS SHOULD BE CONDUCTED TO BUILD CONFIDENCE IN THE DEMAND MODEL

During the Workshop, Energy Division demonstrated that the Electric Demand Model's estimated hourly CAISO consumption closely matches the consumption over the weather years 2022-2024.[8] Because these years are used to train the Demand Model, based on the relationship between weather data and electricity consumption, a close match is expected. The hourly consumption patterns from the Demand Model, however, have a dramatically different shape than the historical consumption when the comparison is extended outside of the training years to include the period of 2010-2024.[9] Energy Division indicates that it expects the consumption patterns outside of the training period to vary because the response of load to weather in recent years likely differs from the response of load to weather a decade or more ago. That said, additional scrutiny of the Demand Model is warranted for two reasons. *First*, the magnitude of the difference between the model and historical consumption warrant investigation into why the variation from historical consumption is so pronounced. *Second*, consumption used for the Demand Model is not actually observed; it is instead "pseudo-consumption" reconstituted from the observed managed load by adding in estimates of behind-the-meter PV and other demand modifiers.

CalCCA recommends the following three actions to help build confidence in the Demand Model. *First*, with the Demand Model trained on 2022-2024 data, the Commission should predict the consumption in 2025 and compare the prediction to the actual 2025 consumption. While relationships between weather and demand from the training period may differ from those relationships a decade or more ago, they should not differ from 2025. The difference between the

[8] Workshop Presentation, at 38.
[9] Workshop Presentation, at 39.

2025 predicted consumption and 2025 actual consumption should serve as a good out-of-sample validation of the Demand Model. Such validation can assuage concerns that the Demand Model is over-fit to the limited training period.

Second, the Commission should test the Demand Model using regression techniques that are robust to outliers.[10] The training period of 2022-2024 includes the extreme heat wave experienced in 2022. On the one hand, having extremes included in the data helps anchor the relationship between high temperatures and demand in actual data, avoiding possible extraneous results based on extrapolation. On the other hand, outliers can have significant leverage in a model, running the risk that a particular heat wave in one year unduly influences Demand Model parameters that are then applied to 25 years of weather data.

Third, the Commission should provide any independent evidence of device adoption or customer behavior changes that will provide intuition behind changes in the consumption patterns in the decade preceding the training period. This will help instill confidence in the assumptions used to calculate consumption from observations of weather and managed load.

V. THE COMMISSION SHOULD ACCOUNT FOR BTM-PV IMPACT ON LOSSES IN RECONSTITUTION OF CONSUMPTION AT THE BULK SYSTEM LEVEL

The Commission should provide additional details on how consumption at the bulk system level is reconstituted from managed load after removing the impact of demand modifiers like BTM PV. The Commission modeling quantifies demand at the generator busbar, where demand at the customer meter is "grossed up" to account for transmission and distribution

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[10] Robust regression techniques that minimize the impact of outliers on regression parameters include quantile regression or the random sample consensus algorithm included in Python's scikit.learn package (as described by Fischler, M. A., and R. C. Bolles. "Random sample consensus: a paradigm for model fitting with applications to image analysis and automated cartography," *Communications of the ACM 24,* no. 6 (1981): 381-395, https://doi.org/10.1145/358669.358692).

losses.[11] In addition, the Commission indicates that it uses proprietary CEC BTM-PV vendor data to calibrate system level solar profiles.[12] Calculating consumption at the bulk system level from managed load at the bulk system level means that the BTM-PV production must also be "grossed up" to the bulk system level. It is not clear what loss factor, if any, the Commission applies to bring BTM-PV production from the customer level to the BTM-PV at the system level. The Commission should clarify its approach and provide an explanation for how its assumptions regarding the effect of BTM-PV are reasonable.

VI. CAISO HYDRO PARAMETERS SHOULD BE UPDATED TO REFLECT INCREASED HYDRO FLEXIBILITY OBSERVED IN RECENT YEARS

The Commission should modify its hydro assumptions to reflect increased in-state hydro flexibility. Energy Division's Workshop presentation described important updates to the hydropower modeling parameters for SERVM, with a focus on refinement to modeling hydro in the Pacific Northwest.[13] The limited import transmission capacity assumed in the SERVM model may reduce the importance of Pacific Northwest hydro on the ability of California to avoid loss-of-load events. In this case, the parameters used to model hydropower within the CAISO system, not subject to the import limitations, are more impactful on the state's ability to avoid loss-of-load events. CalCCA therefore recommends that Energy Division review recent CAISO hydropower production data to ensure that modeling assumptions are consistent with its evolving capabilities.

CalCCA analysis of historical 5-min hydropower and net load data from the CAISO,[14] shown in **Figure 3**, indicates that large hydro was considerably more flexible in 2023 than in 2018, even though both years had similar annual hydropower production (21.9 TWh and 21.3

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11 Draft I&A document, at 12.
12 Workshop Presentation, at 33.
13 Workshop Presentation, at 56.
14 CAISO Production and Curtailment Data, downloaded from https://www.caiso.com/library/production-curtailments-data.

TWh, respectively).[15] While in 2018 the large hydro production never dropped below 1,000 MW, 2023 saw periods of low net load in which large hydro production was well below even 500 MW. As a result, energy from hydropower could be reallocated from low value periods with low net load to higher value periods. The increased ability to reallocate hydro to higher value periods will likely also increase its ability to reduce loss-of-load events. As such, CalCCA recommends Energy Division ensure CAISO hydro parameters in SERVM modeling reflect its full capability.

2018 (21.3 TWh/year from Large Hydro)	2023 (21.9 TWh/year from Large Hydro)

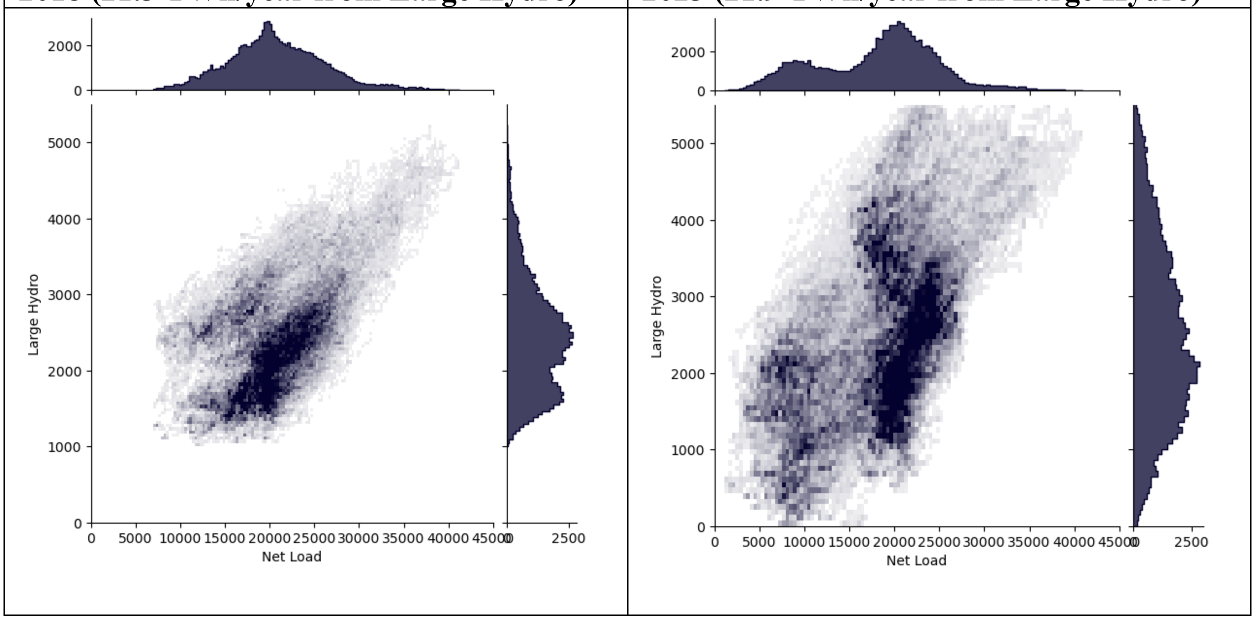

Figure 3. Observed Relationship Between Large Hydro and Net Load in CAISO Shows Increased Hydro Flexibility in 2023

VII. ENERGY DIVISION SHOULD USE PAST IEPR FORECASTS OF PEAK DEMAND TO VALIDATE AND ADJUST LOAD FORECAST ERROR ASSUMPTIONS IN SERVM

Load forecast errors are an important component to setting the PRM to ensure a 0.1 LOLE. LSE RA requirements add up to a system-wide requirement that is based on a 1-in-2 peak

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15 CalCCA observed improved hydro flexibility in 2025 consistent with what is shown in 2023 while again having similar annual hydropower production.

demand forecast using data from as recent as two years before the operating year. After the IEPR load forecast is adopted, overall system-wide RA requirements do not change, and actual load can be higher (or lower) than the load forecast. As a result, maintaining a reliable system requires a portion of the PRM to include resources needed to cover load forecast errors.

In the LOLE modeling, load forecast errors are sampled from a distribution and used to adjust the load from an independently sampled weather year. Energy Division's distribution of load forecast errors in SERVM, shown in **Table 1** and taken from Energy Division's Workshop presentation,[16] is based on a paper analyzing the Euro Area Gross Domestic Product (GDP) growth forecasts collected from the European Central Bank Survey of Professional Forecasters (SPF).[17]

Table 1. Energy Division's Current Assumption for Distribution of Load Forecast Errors in SERVM

Load Forecast Error (%)	Probability
-2.5	0.0668
-1.5	0.2417
0	0.3829
1.5	0.2417
2.5	0.0668

While the SERVM distribution appears reasonable, there is no documentation demonstrating that the ability to forecast GDP growth in the Euro Area is a good approximation of California's ability to forecast 1-in-2 peak demand for the RA program.[18] CalCCA

[16] Workshop Presentation, at 69.

[17] Bowles, C., R. Friz, V. Genre, G. Kenny, A. Meyler, and T. Rautanen, "An evaluation of the growth and unemployment forecasts in the ECB Survey of Professional Forecasters." *Journal of Business Cycle Measurement and Analysis* 2, no. 4 (2010), at 1-28: http://dx.doi.org/10.1787/jbcma-v2010-2-en.

[18] The only documentation of the load forecast errors that CalCCA could find states: "The load forecast multipliers used in Energy Division modeling are based on analysis of near term forecasting that was available from the OECD Journal. Staff evaluated projections of 1 year ahead and 2 year ahead GDP growth, noting the magnitudes of GDP uncertainty and their probabilities. These figures were entered as a basis for the load forecast uncertainty variables in SERVM." *See* Energy Division "Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions– Guidance for Production Cost Modeling and Network Reliability Studies," (Feb. 20, 2018), at 29, https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/utilitiesindustries/energy/energyprograms/electpowerprocurementgeneration/irp/2018/1unified-ia-main-draft-20180220.pdf.

recommends that the Commission use past 1-in-2 peak demand forecasts from the IEPR planning forecast to validate, and possibly adjust, the load forecast errors in SERVM. The remainder of this section provides a framework for how Energy Division staff can conduct this validation and propose adjustments.

A. Observations of IEPR 1-in-2 Peak Demand Forecast Errors Should Be Used to Validate SERVM Assumptions

The Commission should validate SERVM load forecast error assumptions using IEPR 1-in-2 peak demand forecast errors. The IEPR 1-in-2 peak demand forecast for the CAISO system is the primary input into the RA requirements. RA requirements are set using the vintage of IEPR forecast from two years before the operating year (*i.e.,* the 2023 IEPR Planning Forecast was used to set the 2025 RA program requirements), as illustrated in **Figure 4**, below.

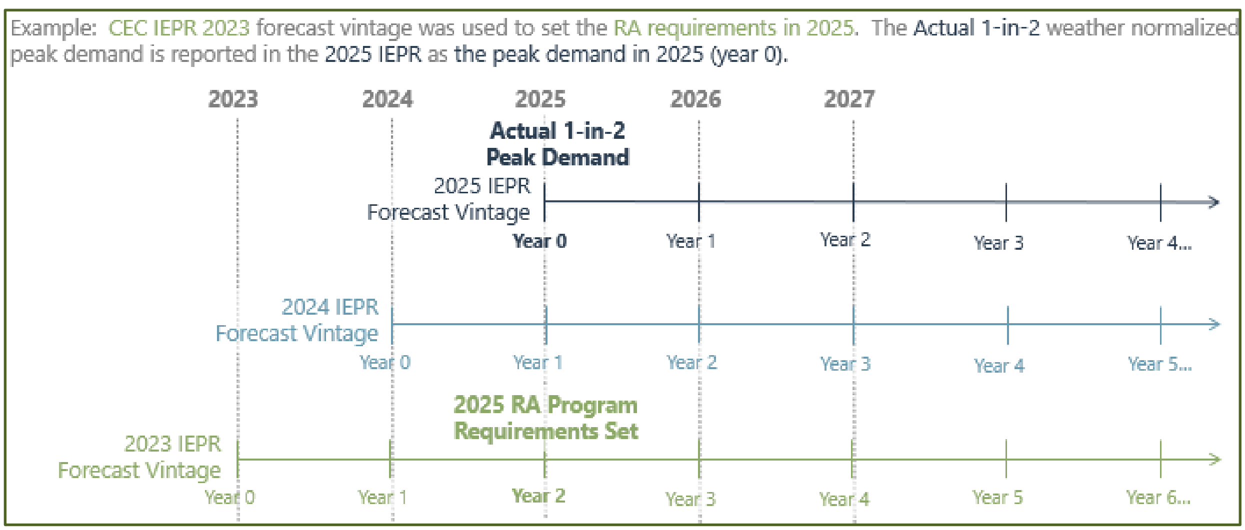

Figure 4. Relationship of IEPR Forecast Vintage to RA Program Requirements and Actual 1-in-2 Peak Demand.

The observed forecast error for each RA program year is the difference between the 1-in-2 peak demand forecast and the actual 1-in-2 peak demand. CalCCA understands, and CEC forecasting staff confirmed, that the actual 1-in-2 peak demand for a particular year is reported as the 1-in-2 demand for the year of the IEPR vintage (*i.e.,* the actual 1-in-2 peak demand in 2025 is the same as the 2025 value in the IEPR 2025 Planning Forecast files). Alternatively, the CPUC could develop a method to independently calculate the actual 1-in-2 demand for any historical year.

Based on the assumption that the actual 1-in-2 demand was the reported 1-in-2 demand for the year of the IEPR vintage, CalCCA calculated the forecast error for nine years of the RA program using IEPR forecasts between 2015-2025, as shown in **Figure 5**, below. The extreme forecast error for the 2022 RA program year is likely related to COVID-related complications with forecasting recovery from a major macroeconomic shock. The extreme forecast error for the 2024 RA program year could be due to a reported decline in the temperature sensitivity of PG&E daily peak load which resulted in a lower weather-normalized peak load in 2024.[19] These, or independently calculated, observations of the IEPR 1-in-2 peak demand forecast error should be used to validate the SERVM assumptions.

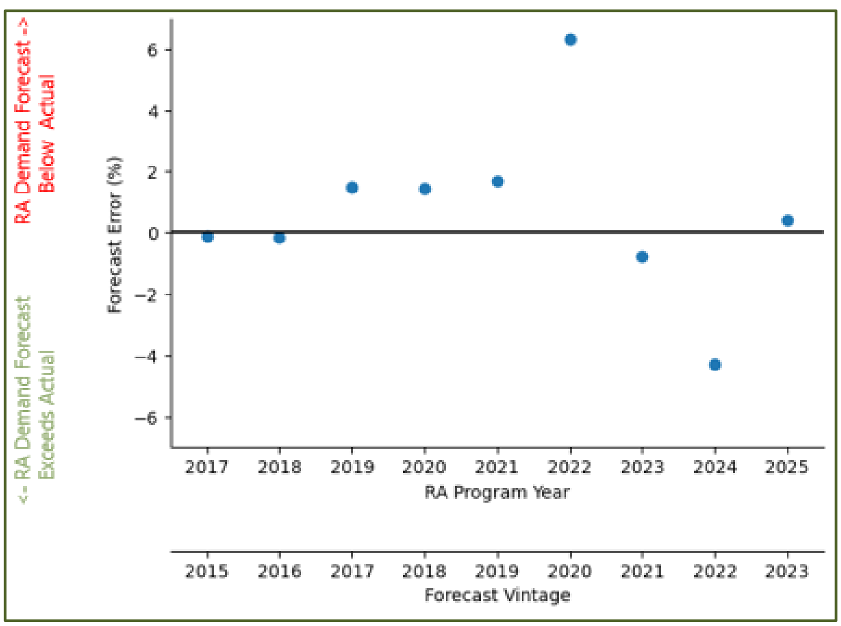

Figure 5. CalCCA Calculations of IEPR 1-in-2 Peak Demand Forecast Errors for CAISO

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19 CEC Hourly Electricity Demand presentation for 2024 IEPR Draft Results, at 12, https://efiling.energy.ca.gov/GetDocument.aspx?tn=260597.

B. The Commission Should Validate Whether Observed Errors Could Plausibly Be Generated by the SERVM Distribution

The Commission should validate whether observed load forecast errors could plausibly be generated by the SERVM distribution. One approach to validating the SERVM load forecast error distribution is to use a statistical test with the observed forecast errors. In particular, the Chi-squared test, which checks for a significant difference between observed and expected frequencies in categorical data, can be used to evaluate the plausibility that the observed forecast errors were generated by the SERVM distribution of load forecast errors.

The first step is to map the observed forecast errors, which are continuous, to the categories representing discrete intervals corresponding to the SERMV distribution. Energy Division's Inputs and Assumptions Document does not specify the intervals for each of the five discrete forecast error values, shown previously in **Table 1**. CalCCA was able to estimate the intervals from the forecast error parameters in the original ECB SPF paper, along with the following assumptions:

- The SPF forecast errors are normally distributed;
- The SPF forecast errors have a mean of 0 (unbiased); and
- The standard deviation of the SPF forecast errors is the reported root-mean-square error for the 2-year ahead GDP forecasts (*i.e.,* a 1.3 percent forecast error).[20]

Using those assumptions, CalCCA was able to back into a discrete distribution that reasonably recreates the SERVM distribution from the SPF paper, as shown in **Table 2**.

[20] Root-mean-square error for 2-year ahead forecasts of real GPD from Table 2 in Bowles, *et al.* (2010).

Table 2. CalCCA Calculation of the Forecast Error Intervals from the Survey of Professional Forecasters (Bowles et al. 2010).

Interval	Mid-interval quantile	Forecast error at mid-interval quantile if σ=1.3	Probability of being in interval
(-inf, -1.5] *σ	-1.83*σ	-2.382	0.0668
(-1.5, -0.5] *σ	-0.89*σ	-1.152	0.2417
(-0.5, 0.5] *σ	0	0.000	0.3829
(0.5, 1.5] *σ	0.89*σ	1.152	0.2417
(1.5, inf) *σ	1.83*σ	2.382	0.0668

Note: σ is the standard deviation of a normal distribution. We assume the normal distribution has a mean of zero.

Once the intervals are defined, counting the number of observed forecast errors, from the IEPR forecast data, can be done within each interval. The Chi-squared test compares the count of observed forecast errors to the count expected if the observations came from the assumed distribution. **Table 3**, below, shows the intervals, the observed count of IEPR forecast errors within the intervals, and the expected count from the distribution (assuming nine draws).

Table 3. Chi-Squared Test Compares Observed Count in Each Interval to Expected Count from Assumed Distribution

Interval	**Interval if σ=1.3**	**Count of Observed IEPR Forecast Errors in Interval (n=9)**	**Expected Count from SPF Distribution (n=9)**
(-inf, -1.5] *σ	(-inf, -1.95]	1	0.6013
(-1.5, -0.5] *σ	(-1.95, -0.65]	1	2.1756
(-0.5, 0.5] *σ	(-0.65, 0.65]	3	3.4463
(0.5, 1.5] *σ	(0.65, 1.95]	3	2.1756
(1.5, inf) *σ	(1.95, inf)	1	0.6013

The Chi-squared test statistic is 1.5343 which results in a p-value of 0.82056,[21] well above a reasonable significance level of 0.05 or 0.10. This means that we cannot reject the null hypothesis that the observed forecast errors were generated by the SPF distribution. In other

[21] CalCCA used the *scipy.stats.chisquare* module in the Python language to calculate the Chi-squared test statistic and p-value. These indicate the likelihood of observing the IEPR forecast errors under the null hypothesis that the errors were generated by the SPF distribution.

words, this test supports the contention that the observed IEPR forecast errors are consistent with the SERVM forecast error distribution.

One limitation of this approach, however, is that the limited sample size (nine load forecast error observations) means that the power of the test, or its ability to detect a true effect, is quite low.[22] One way to increase the power of this test is to increase the sample size by continuing to collect additional observations of forecast error or to go back further in the IEPR forecast records to collect older forecast errors. With limited observations, another way to increase the power of the test is to reduce the number of intervals from five intervals to three or four, though a different number of intervals would be inconsistent with the current distribution assumed in SERVM.

C. Bayesian Updates to the Load Forecast Error Distribution with Observations Could Incorporate IEPR Load Forecast Errors into the Distribution

Apart from validating the SERVM load forecast error distributions, an open question is whether the information in the observed IEPR load forecast errors can be incorporated into an updated distribution. Bayesian analysis formalizes this approach in which a *prior distribution*, in this case the SERVM assumptions developed from the SPF distribution, is updated to a *posterior distribution* based on the likelihood of the new observations, in this case the IEPR forecast errors. The large forecast errors associated with the 2022 and 2024 RA program years are both larger than 3 times the standard deviation of the SPF distribution, making them unlikely from the perspective of the prior distribution and consequently could shift the posterior distribution.

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22 A simple calculator for the sample size needed to achieve a desired level of statistical power is available. *See* Abdul Rahman, H., A. A. Noraidi, A. N. H. Khalid, A. Z. Mohamad-Adam, N. H. Zahari, and N. E. Tuming, "Practical guide to calculate sample size for chi-square test in biomedical research," *BMC Medical Research Methodology* 25, no. 1 (2025), 144, https://doi.org/10.1186/s12874-025-02584-4.

CalCCA will continue to investigate the Bayesian framework[23] as an option for refining load forecast error assumptions in SERVM and encourages Commission staff to do the same.

VIII. CONCLUSION

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

Respectfully submitted,

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

April 24, 2026

[23] An in-depth description of a Bayesian approach is in Bolstad, W. M., and J. M. Curran. *Introduction to Bayesian Statistics*. John Wiley & Sons, 2016.