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STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

IN THE MATTER OF: *2025 Integrated Energy Policy Report (2025 IEPR)* *RE: Electricity and Gas Demand Forecast*	DOCKET NO. 25-IEPR-03 COMMENTS ON AUGUST 6, 2025, ENERGY DEMAND FORECAST INPUTS AND ASSUMPTIONS

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE AUGUST 6, 2025, IEPR COMMISSIONER WORKSHOP ON ENERGY DEMAND FORECAST INPUTS AND ASSUMPTIONS

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The California Community Choice Association[1] (CalCCA) submits these comments in response to the August 6, 2025, *IEPR Commissioner Workshop on Energy Demand Forecast Inputs and Assumptions*[2] (Workshop). During this Workshop, the California Energy Commission (Commission) discussed approaches to address energy industry changes and uncertainties impacting the Integrated Energy Policy Report (IEPR) demand forecast.

I. INTRODUCTION

At the conclusion of the Workshop, Vice Chair Gunda emphasized the importance of accurate load forecasting: under-forecasting can lead to reliability and/or clean energy shortfalls, while over-procurement and the resulting system overbuild can lead to significant affordability

[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, 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.

[2] *IEPR Commissioner Workshop on Energy Demand Forecast Inputs and Assumptions*, 25-IEPR-03 (Aug. 6, 2025): https://www.energy.ca.gov/event/workshop/2025-08/iepr-commissioner-workshop-energy-demand-forecast-inputs-and-assumptions. All Workshop presentations referenced in these comments are available at this link.

concerns for customers. CalCCA agrees and encourages the Commission to establish a focused procedural track to improve system demand forecasting and allocation.

The Commission's process for forecasting, which forms the basis of load-serving entities' (LSE) Resource Adequacy (RA) and Integrated Resource Planning (IRP) requirements, could benefit from increased transparency, collaboration, and certainty. Reform could begin with the generation of the "top down" econometric forecast generated by the Commission, which is rooted in historical data adjusted to reflect forecast changes due to a range of drivers. Greater detail on inputs, assumptions, and uncertainties would enable stakeholders to engage more fully and better contribute to the integrity of the final system forecast.

Further improvements could be found in addressing new data centers and other large loads (Large Loads) which have become a key driver today for both developing the forecast and allocating the forecast among LSEs. The process today centers on investor-owned utility (IOU) inputs, despite the growth of Community Choice Aggregation (CCA), and a broader range of input would add to the overall integrity of the forecast and allocations.

The process of allocating the demand forecast among LSEs would also benefit from clarification. It is unclear how each type of LSE is addressed in the process, particularly electric service providers, especially in the face of new Large Loads.

The final area addressed in these comments lies in the treatment of any adjustments requested for individual LSE allocations. Greater certainty on the process, criteria, and consequences for other LSEs should be considered in enhancing the Commission's overall process.

Accordingly, the Commission should initiate a dedicated workstream to address these challenges, focusing on the following objectives:

- Increased transparency, in general, in the development of the IEPR demand forecast to enable a broader understanding of inputs, assumptions, and uncertainties;

- Increased collaboration in developing new large load forecasts for purposes of forecasting and allocating demand;

- Transparent demand allocation procedures that recognize the role each type of LSE plays in serving load; and

- Clear procedures for adjustments to individual LSE demand forecast allocations, including adjustments to the overall forecast.

The Workshop demonstrated the openness of Commission staff to working with IEPR stakeholders to address these hard problems at this moment of potentially extraordinary load growth. CalCCA recommends establishing a separate procedural path to consider these important issues.

II. OBJECTIVE 1: INCREASED TRANSPARENCY IN DEVELOPING THE IEPR DEMAND FORECAST

The IEPR demand forecast serves as the foundation for procurement of resources to meet the State's clean energy and reliability goals, and its importance cannot be overstated. The Commission has a tall task in maintaining an approach that captures the changing balance of LSEs, growing diversity of resources, and the expanding uses of electricity. Greater transparency and collaboration are critical factors in producing a reasonably accurate, reliable demand forecast in this environment.

The Commission's electricity demand forecast is composed of three primary elements:

- The baseline consumption, which tracks end use consumption;

- The baseline sales, which nets out the portion of end use consumption met by behind-the-meter (BTM) generation; and

- Managed sales, which adjusts the baseline sales according to policy goals for additional achievable transportation electrification, energy efficiency, and fuel switching.

The forecast of baseline consumption is more of a "top-down" econometric forecast based on historically observed relationships of sales with factors like weather, demographics, and the economy. In contrast, forecasts of BTM generation and additional achievable policy goals are "bottoms-up" forecasts. Peak demand forecasts (PDF) are driven by developing hourly profiles for components of the forecast that are then scaled to the annual consumption forecast. The Commission allocates the retail sales forecast down to individual LSEs. Through a process established with the California Public Utilities Commission (CPUC), the IEPR forecast is used to allocate RA obligations to LSEs and to establish energy and PDFs for the IRP process.

Because of the importance of the IEPR forecast to system planning and setting LSE requirements, the forecasting process should be as transparent and reproduceable as possible. For the "top-down" elements of the baseline consumption, increased transparency means reporting the independent variables and coefficients included in the econometric model to establish historical relationships. In addition, the uncertainty in the relationships should be conveyed through statistics on the standard errors along with details on the process for choosing the final econometric model.[3] For the "bottoms-up" forecasts, increased transparency could come from documenting the models and sensitivity of the forecasts to key uncertainties.

Examples of more transparent models can guide improvements to the Commission's process. Earlier versions of the IEPR demand forecast provided tables of regression coefficients and statistics, along with summaries of the forecast models.[4] While some of these same approaches may still be in use today, the choices of variables, the coefficients, and statistics of

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[3] CalCCA raised a similar point in comments on the 2024 IEPR: *California Community Choice Association's Comments on the Forecast in Electricity System Planning Workshop*, 24-IEPR-03 (Oct. 16, 2024), at 6: https://efiling.energy.ca.gov/GetDocument.aspx?tn=259570&DocumentContentId=95699.

[4] *Final California Energy Demand Updated Forecast, 2017-2027*, 16-IEPR-05 (Feb. 2, 2017): https://efiling.energy.ca.gov/getdocument.aspx?tn=215745.

the regressions fit to the data have likely changed over time as the electricity sector has evolved. Another example of detailed reporting of forecasting methodologies is the Electric Reliability Council of Texas (ERCOT) long-term load forecast.[5] The LTH provides detail on how planners partition historical data to build various alternative forecast models, select models, and test models on data not used in model building or selection. Such transparency can help stakeholders understand the level of uncertainty in forecasts, identify alternative approaches, and align internal practices with Commission practices.

With myriad resources, electricity uses, and LSEs in play, the Commission's overall system demand forecasting would benefit from review with an eye toward greater clarity and detail.

III. OBJECTIVE 2: INCREASED COLLABORATION IN FORECASTING NEW LARGE LOADS

As California faces potentially significant load growth after years of relatively flat demand, accuracy in load forecasts presents a challenge, particularly with the advent of unprecedented Large Load growth. Increased transparency and definition are needed for the load forecasting process, especially as the Commission moves toward incorporating Large Loads into the planning scenario with potential impacts on RA, RPS and IRP planning. In addition, increased input from all LSEs on Large Load forecasting is required to verify and validate the accuracy of proposed increases in the demand forecast. In particular, consideration must be given to non-IOU LSE input in developing the forecast, given the material growth in CCAs over the past 15 years.

A. New Large Loads are Uncertain

The Large Load challenge is unique and rapidly evolving, and the current IEPR process is not structured to adequately address those challenges. PG&E acknowledged at a recent

[5] 2025 ERCOT System Planning, *Long-Term Hourly Peak Demand and Energy Forecast* (Apr. 08, 2025) (LTH Forecast): https://www.ercot.com/files/docs/2025/04/08/2025_LTLF_Report.docx.

Demand Analysis Working Group (DAWG) meeting that "[f]or multiple forecast cycles, forecasts will likely be highly uncertain due to the nascency of the data center technology [and] markets and due to the complexity of data center projects."[6] The number, size, and characteristics of Large Loads, as well as the urgency of interconnection, are unlike traditional load growth for which the existing load forecasting methodologies were developed.

As an initial matter, submission of interconnection requests to the IOU does not guarantee those loads will materialize. A recent report highlighted incentives for data center customers to "shop around": "Some estimate that speculative interconnection requests could be five to ten times more than the actual number of data centers, as data centers "shop around" for the fastest interconnection opportunities and cancel data center projects in oversupply."[7]

For load that does materialize, the Commission needs to examine whether assumptions to determine estimated peak load based on data centers in general are reasonable. Different data centers have different functions such as providing reduced latency for financial markets or supporting artificial intelligence or cryptocurrency. The use case for the data center will define the energy and reliability needs for the facility. Accordingly, Commission staff identified that assuming new data centers use energy similar to existing data centers may not be the correct approach.[8] Lessons learned from jurisdictions with significant Large Loads should inform how these loads inform the California demand forecast. For example, system planners at the ERCOT adjust Large Load projections based on patterns observed for recent projects, including an 180-

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[6] *PG&E Data Center Forecasting*, Jenny Conde, 25-IEPR-03 (July 16, 2025), at 14: https://efiling.energy.ca.gov/GetDocument.aspx?tn=264914.

[7] *Fast, Flexible Solutions for Data Centers*, Rocky Mountain Institute (July 17, 2025): https://rmi.org/fast-flexible-solutions-for-data-centers/.

[8] *See 2024 IEPR Data Center Forecast Recap*, Heidi Javanbakht, 25-IEPR-03 (July 16, 2025) (listing data center forecasting challenges and a recap of methods used for the 2024 IEPR data center forecast): https://www.energy.ca.gov/media/11748.

day delay to expected energization dates and the observation that average peak loads were 49.8 percent of the requested interconnection capacity.[9] The North American Electric Reliability Corporation (NERC) recently formed a Large Loads Task Force to examine the impact and risks to the grid of data centers and other large loads, working first to evaluate the unique technical operating characteristics of large loads.[10]

B. Large Load Demand Forecast Should Include Input from all Interested Stakeholders

The Commission has acknowledged that the IOUs and municipal utilities, and not other stakeholders such as CCAs, electric service providers (ESP), or data center customers, provide the bulk of the input to inform Large Load forecasting. As the amount of CCA load has grown materially, the Commission's forecasting methodology has not been modified to incorporate their insights early in the process. CalCCA appreciates Commission Staff's comments during the Workshop that during the 2025 IEPR process, they "should have time to build in more collaboration" from all LSEs. Given the significant uncertainty, the Commission should solicit early input from a wide variety of stakeholders to help validate the IOUs forecasts of demand. Increased collaboration will improve the ability of the Commission to validate IOU inputs and develop an accurate forecast.

Commission staff stated during the Workshop that for the 2024 demand forecast, determinations regarding large load interconnections were made with input from the IOUs. During the recent DAWG workshop, PG&E and SCE highlighted significant variability in the likelihood of the new load energizing. Heidi Javanbakht also noted during the Workshop that even during the week prior to the Workshop, that Commission staff was working with the IOUs

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9 LTH Forecast, at 9.

10 *See* NERC Large Loads Task Force: https://www.nerc.com/comm/RSTC/Pages/LLTF.aspx.

to make adjustments based on the "latest and greatest information." The IOUs noted that their Large Load forecasting was done through their own modeling and consultations with their "internal subject matter experts." Other LSEs do not have visibility into these models and subject matter expertise, and other LSEs and data center customers, were not mentioned as contributing to the Large Load analysis.

Ultimately, some of these new loads will be served by the CCAs, the default provider of customers within their service areas. As such, the default assumption should be that any new large loads located within a CCA's service area will be served by the CCA. In regards to new Large Loads, progress is already being made through the CPUC's PG&E Rule 30 proceeding in which PG&E is now required to share information about large loads that are planning interconnection to the transmission system in a CCA service area.[11] With this information, CCAs will be empowered to connect with new customers, and use these new relationships to provide informed feedback to the Commission forecast on the likelihood, timing and operating characteristics of new loads. The Commission process should build in sufficient time for this check on the process.

IV. OBJECTIVE 3: TRANSPARENT DEMAND ALLOCATION PROCEDURES

The Commission must allocate, for the purposes of establishing CPUC RA requirements, its system demand forecast to individual LSEs. The allocation process, however, remains somewhat opaque and no doubt requires judgment in allocating demand among dozens of LSEs. Since these allocations can materially impact the compliance obligations, and reflect a financial impact on an LSE, the process should be sufficiently transparent for the LSE to understand and validate their allocation. Given the default role of CCAs discussed in section III.B above, CCA

[11] *See* D.25-07-039 (requiring PG&E to provide all pending and future transmission interconnection applications to CCAs in which customers are seeking interconnection).

input should be solicited to ensure that the increases in load allocated to that CCA reflect the CCA's own internal forecasts.

Further, the allocation should reflect the fact that certain new loads will be served by ESPs. The size of the new Large Loads will have a material impact on compliance requirements, so it is crucial that the load is properly allocated to the correct LSE. As Commission Baker noted at the Workshop, any shifting of obligations to serve load will result in a cost shift that should be avoided. To do this, LSEs need transparency on how the new loads are being allocated to ensure that their allocation accurately reflects the loads they expect to serve. This is particularly critical where the amount of new load from a large data center can cause a doubling if not more of the load the LSE would otherwise expect to be served. The ultimate provider for new loads may not, in all cases, be known at the time the load allocation is completed. The dedicated process CalCCA recommends should also consider how to address those situations where the provider is uncertain. For example, that process could determine that it is best to share allocation between LSEs pending a final decision or if any load increase should reasonably be included if there is so much lack of certainty that the LSE is unknown.

V. OBJECTIVE 4: CLEAR PROCEDURES FOR RESOLVING PROPOSED ADJUSTMENTS TO ALLOCATED FORECASTS

Following the allocation of the "top down" system demand forecast to individual LSEs for the purposes of setting RA requirements, LSEs may propose adjustments to the Commission to better align with their individual load forecasts from the "bottom up." LSEs seek these adjustments to avoid imposing unreasonable costs on their customers in procuring RA to meet their needs.

The process for reconciling the top-down allocation with the bottom-up forecast is somewhat opaque. Commission Staff described the process for finalizing this reconciliation in a

recent CPUC workshop on the 2026 Slice-of-Day RA workshop, but many of the steps in the process are not entirely clear, particularly the Commission's weather normalization process and development of LSE-specific targets for peak demand.[12] Understanding that some amount of judgment will necessarily be applied, a broader understanding of this process may lead to a better outcome for the LSE and the Commission and lower costs for customers.

It is also unclear whether and how an adjustment based on the bottom-up forecast affects the overall system forecast. If an allocation for an LSE is reduced, a reduction in the overall system forecast may be due rather than a "peanut butter spread" of the difference. Or if the difference is spread back to other LSEs, the process for spreading the adjustment to other LSEs is unclear. Again, a broader understanding of this process could lead to a better outcome for the Commission staff noted at the Workshop that in the future the Commission could "explore models/tools to develop a more granular forecast."

VI. RECOMMENDATION: ESTABLISH A DEDICATED PATH TO DEVELOP AN IEPR FORECAST FRAMEWORK

CalCCA recommends that the Commission establish a dedicated procedural path to develop a more granular, transparent, and certain framework for demand forecasting, taking into account the unique challenges presented by Large Loads. The scope should include the following issues:

- How can the Commission improve the transparency of its IEPR system demand forecast?
- How can a reasonably accurate forecast of new large loads be developed to inform both the overall forecast and the allocation of the demand forecast to individual LSEs?

[12] *Resource Adequacy 2026 Year-Ahead Load Forecast Process*, Lynn Marshall (July 30, 2025): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/cec-presentation---ra-2026-sod-forecasts-073025.pptx.

- How should the IEPR demand forecast for new loads be allocated among LSEs, including IOUs, CCAs, and ESPs?

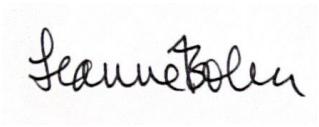
- How should individual LSE proposed adjustments to their allocations flow back to inform the overall system forecast?

Initial focus should be placed on the new Large Load forecast to ensure a more reliable incorporation in the pending IEPR.

VII. 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,



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