DOCKETED	
Docket Number:	26-IEPR-03
Project Title:	Electricity and Gas Demand Forecast
TN #:	272792
Document Title:	CALCCA COMMENTS ON THE IEPR COMMISSIONER WORKSHOP ON ENERGY DEMAND FORECAST INPUTS AND ASSUMPTIONS
Description:	CALCCA COMMENTS ON THE IEPR COMMISSIONER WORKSHOP ON ENERGY DEMAND FORECAST INPUTS AND ASSUMPTIONS
Filer:	Shawn-Dai Linderman
Organization:	CALIFORNIA COMMUNITY CHOICE ASSOCIATION
Submitter Role:	Intervenor
Submission Date:	9/15/2026 2:26:47 PM
Docketed Date:	9/15/2026

STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

IN THE MATTER OF: *ELECTRICITY AND GAS DEMAND FORECAST*	DOCKET NO. 26-IEPR-03 RE: IEPR Commissioner Workshop on Energy Demand Forecast Inputs and Assumptions

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

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
Lauren Carr,
Deputy Director of Regulatory Affairs
Katy Morsony,
Director of Policy and Senior Counsel

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

September 15, 2026

TABLE OF CONTENTS

STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

IN THE MATTER OF: *ELECTRICITY AND GAS DEMAND FORECAST*	DOCKET NO. 26-IEPR-03 RE: IEPR Commissioner Workshop on Energy Demand Forecast Inputs and Assumptions

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

The California Community Choice Association[1] (CalCCA) submits these comments pursuant to the *IEPR Commissioner Workshop on Energy Demand Forecast Inputs and Assumptions*[2] (Workshop), held on August 20, 2026.

I. INTRODUCTION

The California Energy Commission's (Commission) Integrated Energy Policy Report (IEPR) Demand Forecast plays a critical role in California's energy planning and the state's efforts to maintain a reliable and affordable electricity system. The Demand Forecast informs a wide range of resource, transmission, and distribution planning processes, including the California Public Utilities Commission's (CPUC) Resource Adequacy (RA) and Integrated

---

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 *IEPR Commissioner Workshop on Energy Demand Forecast Inputs and Assumptions*, CEC Docket 26-IEPR-03, (Aug. 20, 2026), https://www.energy.ca.gov/event/workshop/2026-08/iepr-commissioner-workshop-energy-demand-forecast-inputs-and-assumptions.

Resource Planning (IRP) proceedings, the California Independent System Operator's (CAISO) Transmission Planning Process (TPP), and investor-owned utility (IOU) distribution planning processes. Given the breadth of these applications, it is essential that the Demand Forecast appropriately balances the need to plan for future demand with the uncertainty inherent in forecasting rapidly developing loads. A forecast that is too low can create reliability risks, while a forecast that is too high can drive unnecessary procurement and infrastructure investment, ultimately increasing costs for customers. Because forecast uncertainty is inherent in any long-term demand forecast, the Commission's objective should be to account for uncertainty and use the best available information so that California can plan for the resources needed to maintain reliability without driving unnecessary costs for customers.

CalCCA appreciates the Commission's continued efforts to improve the IEPR Demand Forecast and, in particular, its increased coordination with community choice aggregators (CCA) on large-load developments. The Commission should build on these efforts by expanding engagement with CCAs and other informed stakeholders to obtain the most current and complete information available regarding prospective large loads, including their likelihood, timing, and magnitude. CCAs are uniquely positioned to provide information regarding large-load developments in their communities through their relationships with local cities, counties, and prospective customers. Incorporating CCA load forecasts and other relevant information into the IEPR process will help ensure that the Demand Forecast reflects the broadest and most informed assessment of prospective large-load development.

The rapid growth and uncertainty associated with data center loads also underscores the need for a coordinated and transparent approach to allocating procurement obligations associated with these loads. The Commission should coordinate with the CPUC to develop a formal process for allocating RA obligations associated with data center load based on objective information regarding interconnection status, project milestones, expected timing, and the load-serving entity (LSE) responsible for serving the load. Such a process would help ensure that procurement obligations are allocated fairly and that LSEs are not required to procure resources for loads that may not materialize—or, conversely, that emerging loads are not overlooked in a manner that creates reliability risks. A transparent, milestone-based approach would also provide greater clarity regarding which loads are reflected in each forecast scenario and which LSEs are responsible for serving those loads.

Finally, the Commission should continue excluding "known loads" from the Planning Scenario and other procurement scenarios until there is sufficient confidence in their likelihood, magnitude, and timing and that they are not already reflected elsewhere in the forecast. The Commission took a well-informed and measured approach in the 2025 IEPR,[3] where after thorough discussion with stakeholders, the Commission decided to exclude known loads from the Planning Scenario and the Local Reliability Scenario used for setting local RA requirements. Significant observed delays in known loads coming online over the past year have further validated the Commission's decision. Until a sufficiently robust process is in place to establish when known loads will materialize, at what magnitude, and without duplication elsewhere in the forecast, continuing to exclude these loads from scenarios that drive procurement obligations will ensure that customers are not subject to unnecessary costs.

[3] *Final 2025 Integrated Energy Policy Report*, CEC-100-2026-001 (July 2026), https://efiling.energy.ca.gov/GetDocument.aspx?tn=271454&DocumentContentId=108996.

In summary, the Commission should:

- Continue and expand efforts to solicit information on prospective large loads from all informed stakeholders, including CCAs, and use that information to assess the likelihood, timing, and magnitude of such loads before incorporating them into the Demand Forecast;
- Coordinate with the CPUC to establish a formal process for allocating RA obligations associated with data center load based on objective information such as interconnection status, project milestones, expected commercial operation, and the LSE responsible for serving the load; and
- Continue to exclude known loads from Demand Forecast scenarios used to establish LSE procurement obligations, including the Planning Scenario, until there is sufficient confidence regarding their likelihood, magnitude, and timing and adequate assurance that they are not already accounted for elsewhere in the forecast.

These recommendations build on the Commission's ongoing efforts to improve the IEPR Demand Forecast and will support a forecasting process that is responsive to California's economic development while sufficiently rigorous and credible to support long-term resource planning. By incorporating the best available information while accounting for uncertainty, the Commission can help California plan for the resources it needs to maintain reliability without imposing unnecessary procurement and infrastructure costs on customers.

II. THE COMMISSION SHOULD CONTINUE AND EXPAND EFFORTS TO SOLICIT LARGE LOAD INFORMATION FROM CCAS TO INFORM THE LIKELIHOOD, MAGNITUDE, AND TIMING OF LARGE LOADS BEFORE INCLUDING THEM IN THE DEMAND FORECAST

During the August 12, 2026, Demand Analysis Working Group (DAWG) meeting, Commission staff stated one of its objectives of the 2026 IEPR Update[4] is to "increase engagement with utilities and CCAs."[5] CalCCA strongly supports this objective and appreciates the Commission's increased coordination with CCAs on large load issues in this cycle. The

---

[4] *2026 Integrated Energy Policy Report Update*, https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2026-integrated-energy-policy-report.

[5] *Data Center Data Collection and Forecasting*, Demand Analysis Working Group (Aug. 12, 2026) (DAWG Presentation), at 13, https://www.energy.ca.gov/sites/default/files/2026-08/Data_Center_Data_Collection_and_Forecasting_ada.pdf.

Commission should build on these efforts by engaging all CCAs with prospective large loads in their service territories and using the information they provide to validate the status, timing, and likelihood of those loads. Broadening this engagement would give the Commission access to additional, on-the-ground information that can help it develop a Demand Forecast that is both responsive to emerging load and sufficiently grounded in the likelihood that such load will materialize.

CCAs, utilities, large customers, and other informed stakeholders may have different—and independently valuable—information regarding the status, timing, and likelihood of a prospective large-load project. Obtaining and reconciling information from these stakeholders is therefore important to developing the most informed forecast possible. As explained by San José Clean Energy (SJCE) during the Workshop, local and state forecasts of large loads "vary widely," and SJCE reports significant differences in Commission, CPUC, and CCA forecasts for the same territory.[6] For example, SJCE states that, for 2028, the 2025 IEPR forecasts a **40 percent** increase in SJCE's load, the CPUC's 2026 IRP forecasts a **100 percent** increase in SJCE's load, and SJCE's internal forecast shows a **10 percent** increase in SJCE's load.[7] The magnitude of these differences illustrate the importance of drawing on all available sources of information when evaluating rapidly developing loads.

The Commission can reduce the risk of forecasting prospective load that ultimately does not materialize by leveraging the information available to CCAs and other stakeholders to validate large-load projects before incorporating them into the Demand Forecast. CCAs are particularly well positioned to provide this information because of their direct relationships with

---

[6] *Forecasting Perspectives from San José Clean Energy* (Aug. 20, 2026) (SJCE Presentation), at 6, https://efiling.energy.ca.gov/GetDocument.aspx?tn=272027&DocumentContentId=109700.

[7] *Ibid.*

customers and their ongoing engagement with the cities and counties in their service territories. These relationships can provide CCAs with current, community-level information regarding large-load development, including project status, permitting, development timelines, and other indicators of whether and when a project is likely to come online. The Commission should leverage this local knowledge as an important complement to utility and customer information when assessing the likelihood, timing, and magnitude of prospective large loads.

The value of this stakeholder engagement is particularly important in light of Federal Energy Regulatory Commission's (FERC) concerns "that there may be speculative transmission service requests by Eligible Customers on behalf of large loads that could result in cost shifting among transmission customers."[8] FERC's concern highlights the broader consequences of incorporating speculative load into forecasts that inform downstream planning and procurement. If prospective load is incorporated into the IEPR Demand Forecast without sufficient evidence that it will materialize, the resulting procurement and infrastructure decisions could cause existing customers to bear costs associated with load that ultimately does not develop. As stated by SJCE during the Workshop, "procurement orders stemming from large amounts of 'phantom' load could cause increased rates, price volatility, distorted investment signals, and more."[9] A transparent and collaborative forecast development process can mitigate this risk by allowing CCAs and other informed stakeholders to identify changes in project status, delays, or other information that may warrant adjusting the treatment of prospective loads.

The Commission should therefore ensure that its engagement extends to all CCAs with prospective large loads forecasted in their service territories. Commission staff stated during the

[8] *Cal. Independent Sys. Operator Corp.*, 195 FERC ¶ 61,214 (2026), FERC Docket EL26-71-000 (FERC Order), at 50, para. 78, https://www.ferc.gov/media/e-10-el26-71-000.

[9] SJCE Presentation, at 6.

Workshop that it plans to send data center project data requests to a subset of LSEs, including Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company, and Southern California Edison Company, several municipal utilities, and SJCE.[10] While SJCE is particularly affected by forecasted data center development, other CCAs are also affected to varying degrees. Engaging all affected CCAs would provide the Commission with a more complete picture of prospective large-load development across the state and create an opportunity to validate project information using the local knowledge available to each CCA.

To facilitate this broader engagement, after receiving data request responses from the initial group of LSEs, the Commission should conduct a second round of data requests to any CCA implicated by a project identified by an IOU. This will allow the Commission to verify that the CCA and IOU information aligns before including a project in the forecast. If successive rounds of data requests are not feasible, the Commission should issue data requests to all LSEs so that the Commission has a complete data set.

III. A FORMAL PROCESS IS NECESSARY FOR ALLOCATING RA OBLIGATIONS FOR DATA CENTER LOAD BASED ON ACTUAL INTERCONNECTION INFORMATION, PROJECT MILESTONES, AND THE LSE SERVING THE LOAD

The unique characteristics of data center development warrant a distinct process for allocating associated RA obligations to LSEs. The process should allocate RA obligations only when there is sufficient certainty that a data center will come online, based on objective project milestones, and should assign those obligations to the LSE that will actually serve the load. This approach would reduce the risk of both over-procurement, which can impose unnecessary costs on customers, and under-procurement, which can create reliability risks. It also ensures that only the LSE that will serve a load bears the compliance costs associated with that load.

---

[10] DAWG Presentation, at 12.

As discussed in Section II, increased transparency and information sharing among the Commission, CCAs, IOUs, and data center customers is essential to assessing the likelihood and timing of data center development. This information can be particularly valuable for longer-term planning, such as transmission planning, where the specific LSE serving a future data center may not yet be known and where forecast scenarios and confidence levels can appropriately capture uncertainty in system-level load growth. RA allocation presents a different challenge because it requires assigning a specific procurement obligation to a specific LSE in the near- to mid-term. For this purpose, relying solely on forecasted load or confidence factors is insufficient. A formal, milestone-based process is needed to determine when a data center is sufficiently certain to warrant an RA obligation, and which LSE should receive that obligation.

For this reason, CalCCA filed a proposal in the CPUC's Rulemaking (R.) 25-10-003 for the unique treatment of data center loads in the RA allocation process.[11] CalCCA's proposal would preserve the collaborative roles of the Commission and CPUC: the Commission would continue to forecast peak demand, including the portion attributable to data centers, while the CPUC would make LSE-specific adjustments for purposes of allocating RA obligations. Rather than incorporating uncertain data center load into the existing process for allocating obligations across LSEs using confidence factors, the proposal would establish a separate process that treats new data center load based on its actual development status. Specifically, the process should: (1) treat data center load separately from other forecasted load for purposes of allocating RA obligations, using actual project and interconnection information rather than relying solely on forecasted load and confidence factors; and (2) assign an RA obligation to the LSE serving a data

---

[11] *See California Community Choice Association's Track 1 Proposals*, R.25-10-003 (Jan. 23, 2026) at 3-7, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M596/K418/596418487.PDF; and *California Community Choice Association's Comments On Track 1 Proposals*, R.25-10-003 (Mar. 6, 2026) at 3-8, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M601/K795/601795601.PDF.

center only after the project reaches defined milestones demonstrating a sufficient level of certainty that the load will materialize. Relevant milestones could include selection of an LSE or generation provider, execution of an interconnection agreement, commencement of construction, or other objective indicators of project advancement.

This approach would better align RA obligations with the actual development of data center projects and protect existing customers from bearing procurement costs for load that may be delayed, reduced, or ultimately not materialize. It would also reduce the risk that LSEs are assigned obligations based on assumptions about projects that remain speculative. Treating data centers individually for purposes of RA allocation allows the CPUC to account for the unique uncertainty associated with each project while ensuring that obligations are ultimately assigned to the LSE responsible for serving the load.

This proposal also avoids the need to assume which LSE will serve a prospective data center. CCAs are default providers,[12] and they are willing and able to serve data center loads in their service areas; some already do. However, the customer ultimately determines its generation service provider. A CCA's status as the default provider does not mean that every data center will elect to take CCA service. The appropriate LSE should instead be identified based on the customer's actual service choice once that information is sufficiently certain.

---

[12] California Public Utilities Code section 366.2(b), the statute enabling CCAs, requires any potential public agency seeking to operate a CCA to "offer the opportunity to purchase electricity to all residential customers within its jurisdiction." The statute does not explicitly require a CCA to offer non-residential service, but it does require that the CCA offer to its customers "universal access" and "equitable treatment of all classes of customers." While under the strict statutory language, a new CCA forming could have the opportunity to only serve residential customers, to the extent that a CCA offers non-residential service, the CCA is required to offer its customers universal access and equitable treatment. Currently, all operating CCAs offer non-residential service, and therefore will be the default provider to all new large loads interconnecting in their territory. Once the CCA offers service, it is bound to serve customers in its service territory subject to each customer's choice to opt out. Section 366.2(c)(2) directs that "[i]f no negative declaration is made by a customer, that customer shall be served through the community choice aggregation program."

This approach would also reduce reliance on confidence factors to address data center load for RA allocation purposes. Data center development generally has an inherently binary outcome—a project either comes online, or it does not. If a data center has a defined ramping schedules under which portions of the load come online at different times, the timing and magnitude of that ramp can also be uncertain. Confidence factors may not adequately capture this project-specific uncertainty or provide a clear basis for determining when a particular portion of a data center's load should result in an RA obligation for a specific LSE. While confidence factors may be useful for longer-term forecasting and planning, a milestone-based process would provide a more transparent and administratively workable mechanism for aligning RA obligations with the actual development and ramping of individual data center projects.

If implementation of CalCCA's proposed approach is delayed, the Commission should facilitate further discussion regarding how opt-out assumptions should be developed for large loads. For example, the Commission has provided data center load by CCA in gigawatt-hour but not by number of customers. Because opt-outs are based on the number of customers rather than the amount of load, providing data center information by customer count would help LSEs and the Commission develop more informed opt-out assumptions.

IV. KNOWN LOADS SHOULD CONTINUE TO BE EXCLUDED FROM THE DEMAND FORECAST SCENARIOS USED TO DRIVE LSE PROCUREMENT OBLIGATIONS UNTIL THERE IS SUFFICIENT CONFIDENCE REGARDING THEIR LIKELIHOOD, MAGNITUDE, TIMING AND ASSURANCE THAT THEY ARE NOT ALREADY ACCOUNTED FOR ELSEWHERE IN THE FORECAST

The Commission should refrain from including known loads in the Planning Scenario, and any future scenarios used to drive resource procurement, until there is sufficient confidence regarding their likelihood, magnitude, and timing and there are assurances that these loads are not already accounted for elsewhere in the forecast. Known loads are distribution-level energization requests that the Commission first incorporated into the Demand Forecast in the

2025 IEPR. After much discussion with stakeholders, the Commission decided to exclude known loads from the Planning Scenario and developed a separate Local Reliability Scenario excluding known loads, due to concerns that known load energization dates are very uncertain and that known loads may already be accounted for in other areas of the forecast.

Commission Staff's analysis of 2025 known loads data demonstrates that the Commission took a well-informed and measured approach to known loads in the 2025 IEPR by excluding known loads from the Planning Scenario. For example, Commission staff analyzed 1,900 megawatts (MW) of known loads with requested interconnection dates in 2025 in PG&E. Of these 1,900 MW, only 70 MW were completed in 2025.[13] This energization completion rate of 2025 known loads demonstrates that the Commission took the right approach to known loads in the 2025 IEPR and avoided subjecting customers to unnecessary costs.

In fact, had the 2025 RA requirement included the additional 1,830 MW of known loads that did not come to fruition in 2025, the unnecessary RA costs would have equaled an estimated $145 million.[14] Had an LSE procured RA for this amount and the load not materialized, all of their current customers would have paid for RA that was unnecessary. To put this in perspective, the amount of unnecessary RA that would have been required would typically serve 1.8 million people but without an additional 1.8 million people to pay for it.

CalCCA continues to support this approach for the 2026 IEPR Update. The Commission's analysis of 2025 known loads demonstrates that including known loads in the forecasts used to drive LSE procurement requirements would create significant risks of stranded

13 *See Known Loads Preliminary Analysis* (Aug. 20, 2026), at 6, https://efiling.energy.ca.gov/GetDocument.aspx?tn=272023&DocumentContentId=109698.

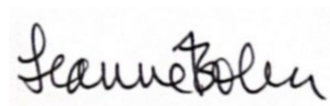
14 CalCCA used the following calculation to arrive at its estimate: the CPUC's RA market price benchmark of $11.21/kw-month multiplied by 1000 (to convert to $/MW-month), multiplied by 1,830 MW, multiplied by 118 percent (to account for the RA planning reserve margin), multiplied by six months (assumes the average of increased load spread equally over the year), equals $145 million.

costs. Until there is sufficient confidence that such loads will materialize, when they will materialize, and at what magnitude, and more clarity around how much of these loads are not already accounted for elsewhere in the forecast, the Commission should exclude known loads from the Planning Scenario, and other scenarios used to drive LSE procurement obligations.

V. CONCLUSION

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

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

September 15, 2026