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STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

IN THE MATTER OF: *2024 Integrated Energy Policy Report Update (2024 IEPR Update)*	DOCKET NO. 24-IEPR-03 RE: Draft Load Modifier Electricity Demand Forecast Results

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE IEPR COMMISSIONER WORKSHOP ON DRAFT LOAD MODIFIER ELECTRICITY DEMAND FORECAST RESULTS

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The California Community Choice Association[1] (CalCCA) submits these comments pursuant to the *Notice of IEPR Commissioner Workshop on Draft Load Modifier Electricity Demand Forecast Results,* dated October 21, 2024. The Integrated Energy Policy Report (IEPR) Commissioner Workshop on Draft Load Modifier Electricity Demand Forecast Results (Workshop) was held on November 7, 2024.

I. INTRODUCTION

CalCCA appreciates the opportunity to provide comments on the Workshop. The California Energy Commission (Commission) staff provided draft forecasted annual electricity impacts for behind-the-meter (BTM) distributed generation and storage, additional achievable energy efficiency, additional achievable fuel substitution (AAFS), transportation electrification,

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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, 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.

and data centers. Commission staff also presented draft hourly profiles for each of these load modifiers that will be incorporated into the overall draft electricity demand forecast.

Ensuring reasonableness and year-over-year consistency of the IEPR demand forecast is crucial to minimizing financial risks for all load-serving entities (LSE), including community choice aggregators (CCA), from over- or under-procurement of resource adequacy (RA). Load modifier assumptions play a key role in determining RA obligations. The results presented by Commission staff can be especially impactful given the forecasts of significant building and transportation electrification and data center development, and substantially lower adoption of distributed generation.

To improve the accuracy and prevent the detrimental impacts of large year-to-year swings in the IEPR forecasts, CalCCA recommends that the Commission:

- Consider the impacts of large reductions in the distributed generation load modifier forecast on year-over-year RA requirements;
- Modify forecast inputs for the AAFS Scenarios to better reflect forecast uncertainty;
- Incorporate load flexibility impacts in the load modifier forecast assumptions; and
- Modify data center scenarios to improve forecast accuracy given project uncertainty assumptions.

II. THE IMPACTS OF LARGE REDUCTIONS IN THE DISTRIBUTED GENERATION LOAD MODIFIER FORECAST ON YEAR-OVER-YEAR RA REQUIREMENTS SHOULD BE CONSIDERED

Consistency in year-over-year load forecasting should be an objective for the IEPR load forecast, especially given the impact of large swings on RA requirements. While the Commission should continue to improve upon past forecasts, it should also consider the impacts of significant year-over-year changes in forecast assumptions on future RA obligations. The Commission's 2024 IEPR distributed generation load modifier forecast includes a large decrease in the BTM solar forecast from the 2023 IEPR, which is of concern given the significant year-over-year decrease may contribute to volatility in RA requirements.

Slide 10 of the Workshop's Hourly BTM Distributed Generation Forecast Results presentation shows a nearly one gigawatt (GW) reduction in the forecasted average hourly solar capacity in hour 13 for September 2024, with additional reductions in hours 9 through 16.[2] While hour 13 typically has sufficient capacity to meet RA requirements under the current mechanism, the California Public Utilities Commission's (CPUC) new Slice-of-Day mechanism requires capacity in all hours. If an LSE uses battery storage to meet an RA obligation, it must also have sufficient excess capacity in non-discharge hours to charge the battery, accounting for round-trip efficiency losses. The reduction in the BTM solar forecast will increase the load for those same hours. The result will be an increased RA obligation for LSEs for those hours, leaving less capacity to charge storage needed for compliance in later hours.

The impact of a one GW reduction from one year to the next is notable and can have significant impacts on RA requirements. Such an abrupt, unanticipated change can make meeting RA requirements difficult for LSEs, particularly in an environment with limited capacity resources. The Commission should consider whether its "bottom-up" approach used for the IEPR forecast, which may require greater accuracy of more elements than a "top-down" forecast, is the best approach to inform near term RA obligations. For example, a top-down forecast of load served by distributed generation for the next three forecast years may better inform RA needs. This top-down approach can consider grid-based generation, including BTM resources, as serving load. By using fewer inputs, this "top-down" approach may improve forecast accuracy

[2] Workshop Presentation – *Hourly Behind-The-Meter Distributed Generation Forecast Results* (Nov. 7, 2024), slide 10: https://efiling.energy.ca.gov/GetDocument.aspx?tn=259936&DocumentContentId=96139.

and reduce year-over-year volatility. Eliminating abrupt changes in demand forecasts may also better inform decisions about retaining resources while considering new resources anticipated in the Integrated Resource Plans.

III. THE FORECAST INPUTS FOR THE ADDITIONAL ACHIEVABLE FUEL SUBSTITUTION SCENARIOS SHOULD BE MODIFIED TO BETTER REFLECT FORECAST UNCERTAINTY

The Commission should modify the AAFS scenario inputs to reflect forecast uncertainty. The AAFS scenarios assume California homes and businesses will switch from gas to electric appliances, leading to the additional electricity demand of 30 to 40 terawatt-hours per year by 2040. Meeting this new load may require long lead-time grid investments in transmission and generation infrastructure. However, the degree to which this new load materializes is uncertain. As recognized by Commission staff, customer demand associated with switching from gas to electric appliances depends on the timing of regional regulations restricting the sale of gas appliances, the rate of compliance with the regulations, and the rate of appliance replacement.[3] The Commission should also recognize the potential impact of customer preferences for different appliance options. Grid planners should understand this uncertainty when considering the long lead-time investments.

Currently, the close correspondence of the load forecast between the different scenarios of fuel switching, particularly AAFS 3 and AAFS 4,[4] suggests a higher degree of confidence than is warranted. Grid planners in the California Independent System Operator Corporation use the forecast from the Planning Scenario (AAFS 3) in bulk system reliability evaluation and economic assessments, and the Local Reliability Scenario (AAFS 4) in local reliability evaluations. AAFS 4

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[3] *See* Workshop Presentation - *Additional Achievable Fuel Substitution (AAFS) Draft Results* (Nov. 7, 2024): https://efiling.energy.ca.gov/GetDocument.aspx?tn=259931&DocumentContentId=96134.

[4] *Id.*, slide 4.

represents the potential for increased electric demand to stress the electric system. Contrary to that expectation, the Commission's current AAFS 3 and 4 forecasts lead to nearly equivalent electric loads, with the AAFS 3 forecast exceeding the AAFS 4 forecast after 2033.

The Commission should consider its AAFS assumptions in the context of regional regulations, appliance replacement rates, and customer preferences between alternative technology choices. Where these rates are uncertain due to a lack of empirical data or challenges with measurement, the Commission should note that uncertainty through different assumptions across the appliance fuel-switching scenarios.

IV. LOAD FLEXIBILITY IMPACTS SHOULD BE INCORPORATED IN THE LOAD MODIFIERS FORECAST ASSUMPTIONS

The Commission should incorporate load flexibility impacts in the load modifier forecasts rather than performing this step separately. Increased electric demand from customers' adoption of electric appliances and electric vehicles brings new opportunities for customers to choose how to operate those technologies. Factors including time-varying electricity rates and customer behaviors will likely influence customers' decisions. The hourly profiles for the load modifiers should therefore account for these economic and behavioral factors.

During the Q&A after the presentation on hourly demand shapes for the AAFS scenarios, Commission staff stated that the hourly shapes do not consider load flexibility.[5] The potential for significant increases in new electric loads may change customers' ability to adjust electricity consumption in response to grid needs, thereby greatly increasing load flexibility relative to historically observed amounts. The development of hourly shapes for the load modifier forecasts should account for existing and future load flexibility levels to reflect this customer behavior, resulting in a more reasonable forecast result.

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5 *Id.*, slides 27-29.

V. DATA CENTER SCENARIOS SHOULD BE MODIFIED TO IMPROVE FORECAST ACCURACY AND ENSURE CONSISTENCY IN PROJECT UNCERTAINTY ASSUMPTIONS

Assumptions for the data center Scenario 1 Planning Scenario and Scenario 3 Local Reliability Scenario[6] should be modified to improve confidence in forecast results and to better inform grid planning for data center development. Forecasting data center demand is challenging due to these facilities' size, rapid construction timeline, and project uncertainty. Under-forecasting load growth could exacerbate energization delays while over-forecasting will result in costly and unnecessary grid investments. Striking the right balance of minimizing ratepayer costs while ensuring the timely energization of data centers requires close coordination with the CPUC, utilities, and communities where these facilities will be located. This effort should include developing and harmonizing a process for determining project uncertainty across utilities.

Scenario 1 should include both projects with existing applications and those with pending applications that can reasonably be expected to come online within four years. This approach is consistent with the CPUC's recent Decision to adopt improvements to the investor-owned utilities' (IOU) distribution planning processes.[7] The Decision allows IOUs to use bottom-up, known loads for near-term (one to two years) distribution planning. It also creates a pending loads category that includes less certain loads, informing mid-term (two to four years) distribution planning. Known loads include projects with submitted or approved energization applications that are more certain than pending loads. The Decision also requires IOUs to implement a scenario planning framework for long-term (5 to 15 years) distribution planning.

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6 Workshop Presentation – *Data Center Forecasts* (Nov. 7, 2024), slide 7: https://efiling.energy.ca.gov/GetDocument.aspx?tn=259935&DocumentContentId=96138.

7 D.24-10-030, *Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps,* R.21-06-017 (Oct. 23, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M544/K154/544154869.PDF.

Scenario 3, currently under development, should use more aggressive load growth assumptions and include locational information where possible. Project completion confidence assumptions should be less conservative than those used in the Scenario 1, and a higher growth rate should be used. The forecast should be disaggregated to the busbar level to reflect the potential clustering of data centers in certain areas. The goal of Scenario 3 should be to allow utilities to plan for large-scale data center development and minimize potential energization delays.

The Commission should work with the CPUC and utilities to refine and harmonize methods for determining project development certainty assumptions to minimize year-over-year demand forecast volatility. A more rigorous method should be developed for all utilities rather than relying on a purely subjective assessment of a project's uncertainty. While a certain level of subjectivity is expected, the goal should be to ensure consistency within and among utilities' planning processes.

VI. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the comments herein.

Respectfully submitted,

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November 21, 2024