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PG&E Comments RE CEC 2025Â IEPR Workshop on Demand Forecast DraftÂ Results

Additional submitted attachment is included below.

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California Energy Commission
Docket Number 25-IEPR-03
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RE: CEC IEPR Commissioner Workshop on Energy Demand Forecast Results

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to comment on the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) Commissioner Workshop on Energy Demand Forecast Results held on December 17, 2025. PG&E appreciates the CEC's thoughtful consideration of stakeholders' feedback throughout the IEPR processes, as well as the CEC's responsiveness to incorporating rapidly changing data, particularly for the Known Loads and data center forecasts. PG&E looks forward to seeing the revised results at the upcoming Demand Analysis Working Group (DAWG) meeting on January 5, 2026.

Below, PG&E offers comments on the topics of Known Loads, Additional Achievable Transportation Electrification and Fuel Substitution, data center forecasting, and load flexibility.

The Known Loads modifier should be included in the Local Reliability Forecast but not in the Planning Forecast.

PG&E appreciates the CEC's substantial new efforts this year to model Known Loads in light of the high degree of uncertainty as the best way to incorporate such an impactful and important forecast component. PG&E supports including the Known Loads modifier in the Local Reliability forecast to support Transmission and Distribution use cases; however, it is premature to include the Known Loads modifier in the Planning Forecast. PG&E supports further discussions and collaboration with the CEC and stakeholders in future IEPR cycles about the best approaches for representing expected system-level impacts from projects represented in the Known Loads project lists but has significant concerns with its inclusion, as currently modeled, in the Planning Forecast.

Including the entire portion of Known Loads in the Planning Forecast, as contemplated by the CEC, would likely result in an excessively high peak demand forecast (approximately a 12 percent increase for 2027, which is just one year away). Because the Planning Forecast is used for resource adequacy (RA) and integrated resource planning (IRP) purposes in the near-term, including the entire portion of the Known Loads modifier could significantly and unnecessarily increase near-term costs, further hurting affordability at a time when PG&E and all other stakeholders, including the state, are focused on improving affordability. For example, using the CPUC's market price benchmark for RA, inclusion of the

Known Loads modifier in 2026 and 2027 could result in $465 million to $565 million of additional unnecessary procurement costs for all load serving entities.[1]

A forecast change of this magnitude requires careful deliberation and review with stakeholders to ensure that timing and magnitude of the forecasted load is reasonable for an expected use case like the Planning Forecast. Known Loads applications in the forecast are primarily used for local capacity needs and facility sizing. PG&E's Known Load shapes are designed to predict the peak demand risk for a certain facility on any given day. Shapes that have the same or similar peak demand every day do not properly reflect asset utilization. PG&E Known Loads shapes are not used to estimate a customer's energy usage. Shapes that are designed for facility sizing tend to have higher utilization factors and naturally overestimate energy requirements. The Known Loads peak demands and PG&E's distribution load shapes are not designed for forecasting RA or IRP needs and, consequently, would not be a good fit for the Planning Forecast. Moreover, the CEC's existing econometric model likely captures some level of the Known Loads in its system-level sales and peak load forecast. That is, the CEC's econometric model already accounts for a portion of the Known Loads expected to come to fruition in the near-term for planning purposes. Including the Known Loads in the Planning Forecast is not recommended by PG&E for the 2025 IEPR cycle.

By contrast, PG&E supports the CEC's proposal to include Known Loads in the Local Reliability Forecast baseline and to create a Known Loads load bus modifier. Including the Known Loads modifier is important to support the Local Reliability Forecast's use cases of transmission and distribution planning. More specifically, its inclusion enables the IEPR forecast to reflect the impact that Known Loads will likely have on the transmission and distribution systems—i.e., how much load growth there will be and how it is expected to be distributed across the local areas. PG&E notes that, wherever Known Loads are included in the IEPR forecast, it is critical for the Known Loads to be assigned to their respective local region to appropriately reflect regionally-specific load growth rather than uniformly spread across the PG&E service area as baseline system growth.

PG&E has specific recommendations for including the Known Loads in the Local Reliability Scenario.

PG&E supports the creation of a Known Loads modifier for Residential (RES), Commercial (COM), Industrial (IND), and Agricultural (AGR) loads. It should not be added to the Planning Forecast. It should be added to the Local Reliability forecast in years where the baseline is less than the known loads and should provide spatially specific placement of the known loads. Current allocation methods are sufficient when the Known Loads are less than the baseline. In future cycles, PG&E seeks to produce its own disaggregation and load bus modifiers to be used in the base Transportation Electrification forecast.

The Known Loads should be incorporated in the Local Reliability scenario as follows: PG&E provides a file of all known loads with designation of load category and load type. Distributed Energy Resource (DER) loads (Transportation Electrification, Fuel Substitution, etc.) should be reconciled with DER load modifiers to avoid duplication. The CEC should assess the extent to which these Known Loads are

[1] PG&E estimated the additional procurement costs by determining the difference in monthly peak loads between the Planning Forecast scenarios with and without the Known Loads modifier and adjusted the difference to reflect the CPUC's current RA program planning reserve margin of 18 percent. Then, PG&E applied the CPUC's current RA market price benchmark of $11.53/kW-month (2026) to each month's adjusted difference for 2026 and 2027 to determine the estimated additional procurement costs.

embedded in existing IEPR categories vs. incremental. RES, COM, and IND known loads should be included in UNADJUSTED_CONSUMPTION and AGR loads should be included in PUMPING. Losses should be added as these are behind-the-meter loads. A discount factor should be applied to account for cancellation and peak load diversity. Year-to-year smoothing should be applied to account for customer energization ramp rates and deferral.

The CEC should create a spatially specific Known Load modifier file with magnitudes and shapes for each Transmission Planning (TP) bus. The Investor-Owned Utilities (IOUs) can review and validate these during the January-February comment period. After magnitudes are confirmed in this period, they should be fixed in the Transmission forecasts used for studies.

The Local Reliability Scenario forecast should start by computing TP bus level forecasts, including Known Loads at specific locations. The system level Local Reliability forecast should be the simultaneous addition of TP bus level forecasts. Building the forecast from the bottom up ensures that the load bus modifiers, net system energy and MW forecast, and IEPR hourly files are aligned with each other.

PG&E supports adopting Scenario 2 for both the Additional Achievable Transportation Electrification (AATE) and the Additional Achievable Fuel Substitution (AAFS) forecasts in the 2025 IEPR Planning Forecast for both electric and gas demand forecasting.

Scenario two for the AATE forecast reflects current policy uncertainty and recent market signals, including weaker near-term electric vehicle (EV) sales, tariff headwinds, and the revocation of the federal EV tax credit. As Commissioner Andrew McCallister acknowledged during the previous IEPR Commissioner Workshop, AATE Scenario 3 in the 2025 IEPR shows limited differentiation from last year's forecast, which supports selecting AATE Scenario 2 for the Planning Forecast, given policy and market changes over the past year that signal slower EV adoption than previously forecasted. Similarly, for fuel substitution AAFS Scenario 2 better aligns with 1) trends in electric appliance adoption, thus avoiding overstating conversion rates (as highlighted by the recent California Heat Pump Partnership (CAHPP) blueprint report[2]), and 2) recent policy changes, such as changes to zero emissions appliance standards from both the California Air Resources Board and Bay Area Air District.

For future IEPR cycles, PG&E recommends the CEC replace data center Group 3 inquiries with a long-term growth factor.

Starting with the 2026 IEPR cycle, PG&E recommends that the CEC utilize a long-term growth factor approach in the data center forecast of the Local Reliability Scenario to represent uncertainty around data center growth beyond the mid-2030s, rather than tracking individual project inquiries submitted to utilities. Maintaining an up-to-date inquiry list is resource-intensive and offers limited value, given how frequently customers submit and withdraw inquiries. Using a long-term growth adder, defined either as a compound annual growth rate or a fixed incremental capacity value, is a more efficient approach to quantifying potential future growth. This method has precedent among other utilities, including Duke Energy (Carolinas), as highlighted in the Energy System Integration Group's Forecasting for Large Loads report.[3]

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[2] California Heat Pump Partnership. 2025. California Heat Pump Partnership Blueprint: Scaling California's Heat Pump Market: The Path to Six Million.

[3] Energy Systems Integration Group 2025 Forecasting for Large Loads: Current Practices and

PG&E supports continued discussions about the role of load flexibility in future IEPR forecasts.

In the December 17 IEPR Commissioner Workshop, the topic of load management was discussed during the Q&A session of the 2025 California Energy Demand Annual Consumption and Sales Forecasts presentation. PG&E acknowledges that load flexibility is evolving and is not a component of the IEPR forecast yet, but we support continued discussion about the role of load flexibility in the forecast. Load flexibility that results in a reliable and firm load shift or shed provides predictable, technology-driven flexibility. Such flexibility can help balance reliability, resiliency, and affordability as we plan for California's energy future.

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PG&E appreciates the opportunity to respond to this workshop and looks forward to continuing to collaborate with the CEC. Please reach out to me if you have any questions.

Sincerely,

Josh Harmon
State Agency Relations

Recommendations. A report by the Large Loads Task Force. https://www.esig.energy/large-loadstask-force/forecasting/.