Ava Community Energy

Electric Load Forecasting Across California Regulatory Agencies and Independent System Operator

Claire Huang, Regulatory Analyst II
Michael Quiroz, Senior Regulatory & Data Analyst
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Contents

Purpose

This narrative document is intended to accompany a flowchart produced by Ava similarly titled "Electric Load Forecasting Across California Regulatory Agencies and Independent System Operator," providing a more detailed explanation of the data sources and processes illustrated in the flowchart, with narrative section numbers corresponding to the numbered sections of the flowchart.

Executive Summary

The California Energy Commission ("CEC"), California Public Utilities Commission ("CPUC"), and California Independent System Operator ("CAISO") work together to forecast the state's energy demand and capacity needs through interrelated regulatory processes, including:

- CEC's Integrated Energy Policy Report ("IEPR")
- CAISO's Flexible and Local Capacity Needs Assessments
- CPUC's Resource Adequacy ("RA") Program
- CPUC Integrated Resource Plan ("IRP") Program

The load forecasts developed and refined through these processes ultimately inform load-serving entity ("LSE") procurement obligations. As such, it is important to understand the mechanisms by which agencies anticipate load growth and the opportunities for non-agency stakeholders to provide input. This report provides a detailed narrative of each of the four above forecasting processes, intended to supplement the accompanying flowchart.

As part of the annual IEPR, the CEC develops and updates the California Energy Demand Forecast, which informs energy planning across the state, including the CPUC's IRP, RA, and distribution planning and the CAISO's transmission planning. The California Energy Demand Forecast looks at least 15 years into the future, taking into account a range of factors including economic and demographic projects, utility rates, energy technology costs, energy efficiency, building and transportation electrification, weather and climate trends, behind-the-meter distributed generation, utility energization applications, and data center load growth. The CEC produces several forecasts, reflecting more or less conservative assumptions affecting energy demand and peak load and different time granularity (annual and hourly). At the end of an IEPR cycle, the CEC adopts a singular set of forecasts to be used for transmission and generation resource planning processes, including the CAISO's Local and Flexible Capacity Needs Assessments and the CPUC's RA and IRP modeling and procurement processes.

In the annual Local Capacity Needs Assessment, the CAISO annual studies the minimum local resource capacity required in each transmission-constrained local reliability area to meet established reliability criteria based on anticipated load growth in the most recent IEPR. Similarly, in annual Flexible Capacity Needs Assessment, CAISO studies the flexible capacity needed on the ISO system for the following three years, guiding flexible resource adequacy procurement for each year.

The results of CAISO's local and flexible studies inform LSE local and flexible resource adequacy procurement obligations, ultimately set by the CPUC. System resource adequacy obligations are set via a standardized annual process in which LSEs provide load forecasts to the CPUC and CEC, who then compare LSE forecasts against adopted IEPR forecasts and make various adjustments.

Across all stages of the IRP process, the CPUC generally relies on the most recently available IEPR planning forecast, or whichever forecast the CEC and CPUC have jointly agreed to use for the applicable planning cycle. This IEPR forecast serves as a consistent foundation for both IRP modeling and IRP procurement orders.

1. CEC Integrated Energy Policy Report

The California Energy Commission ("CEC") develops the Integrated Energy Policy Report ("IEPR") Energy Demand Forecast. The IEPR forecast is updated annually, with a limited update of only the model components in even-numbered years and a full update of the electricity demand forecast, including updated load-serving entity ("LSE") electricity demand forecasts and resource plans, in odd-numbered years.

1a. IEPR Inputs

The IEPR Energy Demand Forecast is comprised of the following components:

- Baseline forecast (annual energy, annual peak demand, and hourly load), encompassing:
    - Economic, demographic, and fuel price scenarios
    - Weather and climate trends
    - Historical and projected rates
    - Committed savings
    - Historical and projected energy demand
    - LSE demand forecasts
- Load modifiers:
    - Distributed generation
    - Additional achievable energy efficiency ("AAEE"): integrate policies or market transformations beyond existing trends and policies
    - Additional achievable fuel substitution ("AAFS")
    - Additional achievable transportation electrification ("AATE")
    - Data centers
- Energization application impacts (known loads)

Baseline Forecast

The baseline forecast is comprised of the following factors:

- Economic and Demographic Drivers and Price Scenarios:
    - Economic and demographic drivers, including gross state product, per capita personal income, manufacturing output, commercial employment, population, and number of households
    - Transportation fuel price scenario(s) for gasoline, diesel, E-85, electricity, hydrogen, natural gas, propane, jet fuel
- Rates: Historical and projected gas and electricity rates, by sector
- Committed Savings: Energy savings from existing energy programs and codes and standards
- Historical and Projected Weather: Historical temperatures for distinct geographic zones, and projected temperatures derived from downscaled climate models.

- 1-in-X Peak Weather Event Variant: Peak demand under temperature conditions that have a 20, 10, and 5 percent chance of being met or exceeded (1-in-5, 1-in-10, 1-in-20, respectively).
- Historical and Projected Energy Demand: Historical energy demand using sales data from CEC's Quarterly Fuel and Energy Report ("QFER") data. Estimates of historical distributed generation are added to historical sales to estimate historical consumption. CEC sector and transportation models use economic, demographic and programmatic data to project energy demand. LSE demand forms (see LSE Electricity Demand Forms section below for details) inform historical estimates and the allocation of projected energy demand across LSEs.

Load Modifiers

The CEC then identifies several factors that modify the baseline forecast. These include behind-the-meter ("BTM") distributed generation, Additional Achievable scenarios, data center scenarios, and impacts of utility energization applications (known loads).

Distributed Generation

Distributed generation ("DG"), primarily BTM solar photovoltaics ("PV") and energy storage, affects electricity demand and peak demand. The distributed generation forecast is developed using interconnection data and factors influencing future adoption (payback period, which is affected by system costs, energy costs, Net Energy Metering/Net Billing Tariff, and incentives, and Title 24 Building Standards that require PV systems for all newly constructed buildings).

Additional Achievable Scenarios

The "Additional Achievable" framework is applied to energy efficiency, fuel substitution, and transportation electrification ("TE"). Additional Achievable scenarios capture incremental potential energy demand impacts beyond what is included in the baseline demand forecast, within what is reasonably expected to occur.

Additional Achievable Energy Efficiency and Additional Achievable Fuel Substitution

The Additional Achievable Energy Efficiency ("AAEE") and Additional Achievable Fuel Substitution ("AAFS") scenarios incorporate impacts from programs and incremental codes and standards, such as investor-owned utility ("IOU") and publicly-owned utility ("POU") programs, state and federal appliance standards, state and federal incentive/financing programs, Title 24 new construction standards, local government ordinances, etc.

Additional Achievable Transportation Electrification

The baseline TE forecast is developed based on continuing economic and market trends and existing policies. The Additional Achievable Transportation Electrification ("AATE") scenarios integrate policies or market transformations beyond existing trends and policies.

Data Centers

The CEC develops several scenarios of the load impacts of data center buildout in California. The CEC's current methodology is to request data center application data from utilities, then apply assumptions to account for the following factors:

- Utilization factor: Expected peak load / Requested nameplate capacity (67%, as shared by Silicon Valley Power)
- Confidence level: Probability of project completion, which varies by scenario
- Ramping: Years to reach full capacity, applied to projects without ramping information and projects with unrealistically large first year capacity

The CEC then uses existing advanced metering infrastructure data to create an hourly load factor profile.

The CEC began incorporating data centers as a load modifier in 2024 and is continuing to modify its methodology for doing so. The data center methodology changed between the 2024 and 2025 IEPR cycles as the CEC received more detailed information about data centers and refined assumptions. Under the current methodology, the CEC divides data center information into three groups, with associated confidence levels. Table 1 below shows the change in group definitions from the 2024 to 2025 IEPR.

Table 1: Change in Group Definition from 2024 to 2025 IEPR

Group	2024 IEPR	Draft 2025 IEPR
Group 1	Active applications with completed or to-be completed engineering studies	Signed agreement for electric service
Group 2	Active applications prior to initiating engineering studies	Active application for electric service
Group 3	Inquiries	Inquiries

Source: CEC (adapted from CEC slides)[1]

The CEC also adjusted the confidence levels for each group and applied the same confidence levels across all utilities.

[1] Mathew Cooper, *2025 IEPR: Preliminary Data Center Forecast*, CEC (November 13, 2025), p. 5.

Table 2 and Table 3 show the 2024 IEPR data center confidence levels by group for PG&E and SCE, respectively, while Table 4 shows the 2025 IEPR confidence levels by group, for all utilities except SVP. The data center confidence levels used in the 2025 IEPR match what was used for PG&E in 2024, except for a change in the mid case Group 2 and high case Group 1 assumptions, which are highlighted in red in Table 4.

Table 2: 2024 IEPR PG&E Data Center Confidence Levels

PG&E	Low	Mid	High
Group 1	50%	70%	70%
Group 2	-	-	50%
Group 3	-	-	10%

Source: CEC with data inputs from PG&E (adapted from CEC slides)[2]

Table 3: 2024 IEPR SCE Data Center Confidence Levels

SCE	Low	Mid	High
T&D planning	100%	100%	100%
Group 1	50%	70%	70%
Group 2	-	50%	50%
Group 3	-	-	10% – 50%, per SCE

Source: CEC with data inputs from SCE (adapted from CEC slides)[3]

Table 4: 2025 IEPR Confidence Levels

All (except SVP)	Low	Mid	High
Group 1	50%	70%	100%
Group 2	-	33%	50%
Group 3	-	-	10%

Source: CEC (adapted from CEC slides)[4]

Lastly, the CEC adjusted data center ramping assumptions, which are applied to data centers without ramping information or those with unrealistically large first year capacity, as shown in Table 5.

Table 5: Change in Ramping Assumptions from 2024 to 2025 IEPR

	2024 IEPR	Draft 2025 IEPR
Ramping	Year 0-5: 149% Year 6+: 113%	Linear ramp over 7 years

Source: CEC with data from SVP (adapted from CEC slides)[5]

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[2] *Id.*, p. 9.
[3] *Id.*
[4] *Id.*
[5] *Id.*, p. 10.

Known Loads

Known loads are energization requests to the utility at the distribution system level, submitted by the utilities to the CPUC for use in distribution system planning, as directed by the California Public Utilities Commission ("CPUC") in the High Distributed Energy Resources ("DERs") Future proceeding.[6] The CEC began evaluating known loads as an input to the IEPR in the 2025 cycle. The CEC receives project-level data from each IOU via a joint CEC-CPUC data request, including customer sector, energization date, capacity, and load profiles. The CEC then applies a cancellation rate, utilization rate, and ramp rate to the known loads data, and any load that is incremental to each sector's load growth forecast is added to the IEPR forecast. The 2025 IEPR included known loads in the Local Reliability Scenario but not the Planning Scenario. These scenarios are discussed below in Section 1c. IEPR Outputs.

LSE Electricity Demand Forms

LSEs whose annual peak demand in the last two years exceeded 200 megawatts are required to file demand forms with the CEC, which inform the statewide demand forecast. The forms include historical and forecasted retail electricity sales, coincident peak demand, demand modifier impacts (from DERs, load modifying demand response, TE, etc.), budget appropriations, and revenue requirements allocation.

Timing: LSE electricity demand forms are typically due in June and July of the full IEPR years.

- LSE demand forms are used for data validation and comparison with the historical consumption reported by distribution utilities in the QFER 1306a (Utility Distribution Companies Electricity Sales/Deliveries Reports).
- Revenue requirements submitted in the LSE demand forms inform the CEC's retail electricity rate forecast.
- Load modifier and programmatic activity data submitted in LSE demand forms inform LSE-specific load modifiers in the IEPR forecast and help the CEC track load flexibility activities.

LSE Electricity Resource (Supply) Plans

LSEs are required to file electricity resource plans, including capacity/energy procurement requirements and supply and contracted resource information. Transmission owners are also required to file project details for transmission projects they own.

Timing: LSE electricity resource plans are typically due in November. The electricity resource plans submitted to the CEC under the 2025 IEPR will be used for analysis in the 2026 IEPR, a change from previous reporting cycles, where supply forms were submitted during the IEPR year.

[6] Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps (Decision ["D."] 24-10-030), Rulemaking ("R.") 21-06-017 (October 23, 2024).

1b. IEPR Stakeholder Process

IEPR workshops and Demand Analysis Working Group ("DAWG") meetings are held from approximately mid-IEPR year to the beginning of the following year to discuss and solicit feedback on model inputs and present forecast results. The forecast is finalized and presented for adoption by the CEC in January of the following year. The following details the cadence and topic of IEPR workshops and DAWG meetings held during the development of the 2024 IEPR Update and the 2025 IEPR, to illustrate the breadth of material covered during the IEPR stakeholder process.

2024 IEPR Update

- May 16, 2024 – IEPR workshop to discuss data centers, electrification in the agricultural sector, manufacturing, and hydrogen production
- July 30, 2024 – IEPR workshop to discuss updates to the forecast method with an emphasis on the use of climate scenario data
- August 21, 2024 – DAWG meeting to present updated economic and demographic inputs to the forecast and seek feedback on proposed updates for the BTM distributed generation, AAEE, and AAFS forecast components
- October 2, 2024 – IEPR workshop covering how the forecast feeds into other electricity system planning processes
- October 21, 2024 – DAWG meeting on energy demand forecast draft results for BTM PV and storage, AATE, AAEE, AAFS, and data centers
- November 7, 2024 – IEPR workshop to discuss results for the electricity demand forecast load modifiers
- November 21, 2024 – DAWG meeting to discuss energy demand forecast draft results
- December 12, 2024 – IEPR workshop to review draft results for the electricity demand forecast
- December 23, 2024 – DAWG meeting to discuss revised data center and BTM PV and storage results
- January 24, 2025 – IEPR workshop on regional electricity markets and coordination
- June 5, 2025 – IEPR workshop on updated impact study of the benefits of day-ahead markets

2025 IEPR

- May 5, 2025 – IEPR workshop on forms and instructions to collect electricity resource plan data from LSEs
- June 6, 2025 – IEPR workshop on gas price outlook, to vet assumptions, discuss price results, and seek feedback
- July 16, 2025 – DAWG meeting to discuss updates to economic and demographic inputs and methodology for forecasting data centers
- August 6, 2025 – IEPR workshop to review energy demand forecast inputs and assumptions

- August 18, 2025 – DAWG meeting to discuss load modifier (BTM PV and storage, AATE, AAEE, AAFS) inputs and methodology
- October 30, 2025 – DAWG meeting to discuss load modifier draft results
- December 17, 2025 – IEPR workshop on energy demand forecast results
- January 5, 2026 – DAWG meeting to discuss revised energy demand forecast results
- February 6, 2026 – DAWG meeting to discuss LSE/BAA tables and kick off 2027 Residential Appliance Saturation Study

1c. IEPR Outputs

The CEC produces multiple scenarios of each load modifier, then selects and applies load modifier scenarios to the baseline forecast to obtain the final IEPR Energy Demand Forecast. The CEC typically creates two forecast scenarios: the Planning Forecast and the Local Reliability Forecast. Each of these forecast scenarios includes an annual energy demand forecast, hourly load forecast, and peak load forecast (on annual, monthly, annual peak day, and monthly peak day bases).

Table 6 describes the number of scenarios produced for each forecast component. The Additional Achievable scenarios are ordered from most conservative to most optimistic. Table 7 shows the load modifier scenarios selected for the Planning and Local Reliability Forecasts.

Table 6: Forecast Component Scenarios

Forecast Component	2024 IEPR Update	2025 IEPR
Economic, demographic, and price scenarios	Baseline	Baseline
BTM Distributed Generation	3 scenarios (Low, Mid, High)	4 scenarios (Low, Mid, Mid plus Investment Tax Credit, High)
Data Centers	3 scenarios (Low, Mid, High)	3 scenarios (Low, Mid, High)
Known Loads	N/A	1 scenario, Include/Exclude
AAEE	6 scenarios (1–6)	6 scenarios (1–6)
AAFS	6 scenarios (1–6)	6 scenarios (1–6)
AATE	1 scenario	4 scenarios (1–4)
1-in-X peak event weather variant	1-in-2, 1-in-5, 1-in-10, 1-in-20	1-in-2, 1-in-5, 1-in-10, 1-in-20

Table 7: Load Modifier Scenarios Selected for Planning and Local Reliability Forecasts

	2024 IEPR Update		2025 IEPR	
	Planning Forecast	Local Reliability Forecast	Planning Forecast	Local Reliability Forecast
BTM Distributed Generation	Mid	Low	Mid	Low
Data Centers	Mid	High	Mid	High
Known Loads	N/A	N/A	Excluded	Depends on use case
AAEE	Scenario 3	Scenario 2	Scenario 3	Scenario 2
AAFS	Scenario 3	Scenario 4	Scenario 2	Scenario 3
AATE	Scenario 3	Scenario 3	Scenario 2	Scenario 3

The forecast scenarios, in various formats, are used in major forecasting processes and studies in California conducted by the CPUC and California Independent System Operator ("CAISO"). The joint agencies (CEC and CPUC) and CAISO agree upon a set of forecast elements to be used in the CAISO's Transmission Planning Process ("TPP") and the CPUC's Integrated Resource Planning ("IRP"), resource adequacy ("RA"), and other planning processes. The joint agencies and CAISO typically use the same forecast (Planning vs. Local Reliability) for each use case year-to-year (e.g., CPUC IRP and RA typically use the Planning Forecast, while CAISO Local Capacity Studies typically uses the Local Reliability Forecast), although the constituent forecast component scenarios vary from year to year (as illustrated in Table 7). However, the joint agencies and CAISO make a decision for each IEPR and may decide to use different forecasts in future IEPRs.

Table 8 describes the IEPR forecasts used in the subsequent CAISO and CPUC forecast processes shown in the flowchart. Table 9 describes the IEPR forecasts used in forecasting processes not shown in the flowchart that also use IEPR as an input. The tables also specify the time and geographic granularity of the forecasts used, where applicable. For Table 8 and Table 9, all forecasts are assumed to be outputs of the IEPR year in the column name unless otherwise specified.[7][8]

[7] *Single Forecast Set Agreement*, 25-IEPR-03 (January 23, 2026).
[8] *Final 2024 Integrated Energy Policy Report Update*, 24-IEPR-01 (October 9, 2025), pp. 48–52.

Table 8: IEPR Forecasts Used for Flowchart Forecast Processes

Process	2024 IEPR Update	2025 IEPR
CAISO Local Capacity Technical Studies	Local Reliability Forecast, annual energy and annual peak demand 1-in-10 peak event weather conditions	Local Reliability Forecast, annual energy and annual peak demand 1-in-10 peak event weather conditions No known loads
CAISO Flexible Capacity Studies for RA	Planning Forecast, hourly loads by CAISO transmission access charge ("TAC") area 1-in-2 peak event weather conditions	Planning Forecast, hourly loads by CAISO TAC area 1-in-2 peak event weather conditions
CAISO Maximum Import Capacity Allocation for CPUC's System RA Requirements for LSEs	Planning Forecast, monthly peak demand derived from managed sales hourly loads	Planning Forecast, monthly peak demand and hourly loads for monthly system peak-day demand, derived from managed sales hourly loads Data center loads and BTM DG impacts by CAISO area 1-in-2 peak event weather conditions
CPUC RA LSE System Requirements	Planning Forecast, hourly loads for monthly system peak-day demand, derived from managed sales hourly loads Data center loads and BTM DG impacts by CAISO area 1-in-2 peak event weather conditions	Planning Forecast, hourly loads for monthly system peak-day demand, derived from managed sales hourly loads Data center loads and BTM DG impacts by CAISO area 1-in-2 peak event weather conditions
CPUC IRP Modeling (Preferred System Plan)	Planning Forecast, annual energy and annual peak demand 1-in-2 peak event weather conditions	2024 Planning Forecast, annual energy and annual peak demand 1-in-2 peak event weather conditions from the 2024 IEPR

Table 9: IEPR Forecasts used for Other Forecasting Processes (not in Flowchart)

Process	2024 IEPR Update	2025 IEPR
CAISO TPP Economic Studies	Planning Forecast, annual energy and annual peak demand 1-in-2 peak event weather conditions	2024 Planning Forecast, annual energy and annual peak demand 1-in-2 peak event weather conditions from the 2024 IEPR
CAISO TPP Policy Studies and Bulk System Studies	Planning Forecast, annual energy, annual peak demand, and hourly loads 1-in-5 peak event weather conditions Staff allocations of AAEE, AAFS, and AATE to load buses	2024 Planning Forecast, annual energy, annual peak demand, and hourly loads 1-in-5 peak event weather conditions from the 2024 IEPR Staff allocations of 2024 IEPR data centers, AAEE, AAFS, and AATE to load buses
CAISO TPP Local Area Reliability Studies	Local Reliability Forecast, annual energy and annual peak demand 1-in-10 peak event weather conditions Staff allocations of AAEE, AAFS, and AATE to load buses	Local Reliability Scenario, annual energy and annual peak demand 1-in-10 peak event weather conditions Known loads included Staff allocations of known loads, data centers, AAEE, AAFS, and AATE to load buses
CPUC IOU Distribution Planning	Hourly demand and hourly loads from data center, BTM DG, AAEE, AAFS, and AATE scenarios IOUs will meet and confer to establish which IEPR datasets to use	Hourly demand and hourly loads from data center, BTM DG, AAEE, AAFS, and AATE scenarios IOUs will meet and confer to establish which IEPR datasets to use IOUs already use their own known loads data for distribution planning and will begin using pending loads data pursuant to CPUC Resolutions E-5413 and E-5414

LSE/BAA Tables

The IEPR Energy Demand Forecast is allocated to LSEs and Balancing Areas using QFER 1306b (LSE Electricity Consumption Reports, by sector and forecast zone), escalated at the CEC's forecast sector/zone growth rate. LSE Demand Forms are used for comparison and adjustment for expansion plans or other LSE-specific information.

The outputs are IEPR Forms 1.1c (Electricity Deliveries to End Users by Agency) and 1.5a, 1.5b, 1.5c, 1.5d, and 1.5e (Balancing Area tables). This is the starting point for IRP demand forecasts, described in the PG&E and SCE serve as the central procurement entities for local RA under the CPUC's central procurement framework and are responsible for procuring RA capacity on behalf of all CPUC-jurisdictional load-serving entities within their service territories.

Beginning with the 2023 RA compliance year, the CPUC adopted a hybrid central procurement framework for local RA requirements within the distribution service areas of PG&E and SCE. Under this framework, LSEs in these territories no longer receive individual local RA allocations. Instead, PG&E and SCE, operating as local RA CPEs, procure the total local capacity requirement on behalf of all benefiting LSEs in the service area.

The adopted structure is "hybrid" in that it centralizes responsibility for meeting the Local Capacity Requirement while preserving LSE flexibility. If an LSE has procured a resource that meets a local RA need, it may: (1) show the resource to reduce the CPE's overall local procurement obligation while retaining the resource for its own system and flexible RA compliance; (2) bid the resource into the CPE's competitive solicitation; or (3) elect not to show or bid the resource and instead use it solely for its own system and flexible RA requirements. An LSE that elects to show a resource may do so in advance of the solicitation or as part of its bid, including indicating that the resource will remain available for local reliability even if not selected. This structure allows locally deliverable resources to reduce the aggregate procurement need and potentially lower total costs.

The CPE is required to conduct a competitive, all-source solicitation for local RA procurement. Eligible bidders include existing local resources without contracts, new resources capable of timely online dates, and LSE- or third-party-contracted local resources. RA attributes remain bundled, and LSEs receive credits for any system or flexible capacity procured through the local RA or backstop processes based on coincident peak load shares, consistent with Cost Allocation Mechanism ("CAM") treatment. Existing CAM resources and IOU local DR resources reduce the total local capacity the CPE must procure.

The framework maintains a functional distinction between local and system/flexible obligations. Local RA ensures reliability within transmission-constrained areas and is procured centrally in PG&E and SCE territories. System and flexible RA obligations remain the responsibility of individual LSEs. If an LSE-procured local resource is not selected in the CPE solicitation, the resource may still count toward the LSE's system or flexible RA requirements, provided it is otherwise eligible. This design centralizes local reliability procurement while avoiding unnecessary duplication and preserving LSE autonomy over broader portfolio compliance.

3b. System Resource Adequacy Requirements

System RA obligations are set via a standardized annual process (summarized in Table 10 below) that involves LSEs, the CPUC, and the CEC. This process is formalized each year in the Resource Adequacy Slice of Day Guide, typically released in September prior to the compliance year.

Table 10: Annual Process for Determining System RA Obligations

Date	Process
March	LSEs submit historical hourly peak load data for the preceding year
April	LSEs submit *initial* YA monthly energy and hourly peak day forecasts for the coming compliance year

May	LSEs submit *revised* YA monthly energy and hourly peak day forecasts for the coming compliance year
July	LSEs receive draft 2026 YA RA obligations. To produce draft obligations, the CEC adjusts LSE forecasts such that aggregate peak-day demand within each TAC area is within 1% of the adopted IEPR planning scenario forecast. Draft obligations also include deductions of CPE procurement (both local RA and CAM) from system obligations.
Aug.	LSEs submit *final* YA monthly energy and hourly peak day forecasts for the coming compliance year. Per D.19-06,026, load migration is the only allowable reason for differences between the initial and final YA forecasts.
Sept.	LSEs receive final 2026 RA obligations based on: Updates to CEC load forecasts from LSE revisions or small true-up due to changes from other LSEs Increases/decreases to IOU CPE capacity Additional CPE resources increase CPE allocation to LSEs, further reducing system allocations. Local RA procurement can change substantially or not at all; however, CAM procurement typically does not change significantly unless there is an outage.
Oct.	LSEs submit YA compliance filing; must demonstrate procurement of 90% of system RA obligation for the five summer months of the coming compliance year.
Feb. (of the next year)	LSEs submit revised forecast to cover load migration update for June to December load migration. LSE load is otherwise locked in for January–May and June–December timeframes.

4. CPUC Integrated Resource Planning Modeling Cycle section below, as well as for CAISO transmission planning studies.

2. CAISO Capacity Needs Assessments

Local Capacity Needs Assessment

CAISO performs annual study processes to identify the minimum local resource capacity required in each local reliability area to meet established reliability criteria.

Local reliability areas are geographies which, due to transmission constraints, the CAISO determines that some amount of electricity must be generated within the area itself to maintain reliability. There are currently ten local reliability areas defined by CAISO.[9]

As an input to local capacity needs assessments, CAISO typically uses the most recent IEPR Local Reliability Scenario 1-in-10 year summer peak load forecast. Additionally, the CAISO obtains input from stakeholders on the criteria, methodology and assumptions used as inputs into the studies, as well as feedback on the study results.

CAISO submits draft and finalized study results to the CPUC in each RA proceeding. The CPUC then allocates the minimum required local resource capacity by TAC area to the central

[9] California State Geoportal, Local Reliability Areas (Jan 24, 2022)

procurement entities ("CPEs") (for Pacific Gas & Electric ["PG&E"] and Southern California Edison ["SCE"] areas) or each LSE (for the San Diego Gas & Electric ["SDG&E"] area). CPEs and LSEs then submit resource adequacy plans to show that they have procured the necessary capacity.

Flexible Capacity Needs Assessment

CAISO performs annual study processes to identify the flexible capacity needed on the CAISO system for the following three years, guiding flexible resource adequacy procurement for each year.

Flexible capacity ensures the system can meet rapid changes in net load (i.e., ramping needs), especially from solar variability and the net load ramp (i.e., the "duck curve"). To qualify, resources must have sufficient ramping capability (be able to ramp up or down quickly) and provide continuous output over required duration.

As an input to flexible capacity needs assessments, CAISO typically uses the most recent IEPR Planning Scenario 1-in-2 hourly managed net load forecast. Additionally, CAISO gathers data from LSEs on variable energy resources under contract and stakeholder input on the criteria, methodology, and assumptions used to build the assessment.

CAISO submits study results to the CPUC in each RA proceeding. The CPUC then allocates a portion of the total flexible capacity required to each LSE. LSEs then submit resource adequacy plans to show that they have procured the necessary capacity.

Availability Assessment Hours

As part of its flexible capacity needs assessment, CAISO also identifies Availability Assessment Hours ("AAH"), the hours of the year when system need is greatest and resource availability is most valuable. The AAH are established through the same flexible capacity study process and are intended to maximize the effectiveness of the Resource Adequacy Availability Incentive Mechanism by focusing performance incentives on the most critical hours.

CAISO calculates AAH using the CEC's hourly IEPR load forecast, determining average hourly load by month for each study year (e.g., 2026–2028) and designating the top five percent of load hours within each month as AAH.

AAH are particularly important for demand response ("DR") resources, as they define the specific hours during which DR must be available and capable of responding in order to receive RA availability payments and avoid penalties.

Maximum Import Capability

Maximum import Capability ("MIC") represents the maximum simultaneous deliverability[10] of all imports used in the RA process. MIC reflects the transmission system's ability to deliver imports at the same time as internal generation under stressed system conditions. It is used only within the

[10] Deliverability refers to whether a resource's output can be reliably delivered to load over the transmission system, and is primarily used in the context of peak, stressed conditions, where transmission lines may be congested.

RA framework and does not affect real-time energy schedules, which are determined by market prices.

CAISO calculates MIC using a historically based methodology designed to reflect demonstrated system capability. CAISO identifies the two years with the highest imports among the previous five years and selects two hours in each of those years when total imports were highest while system load was at least 90% of the annual peak load. The scheduled net imports for each intertie[11] during those hours are then combined with unused Existing Transmission Contract rights and Transmission Ownership Rights[12] and averaged across the four selected hours to determine MIC values. This approach ensures that historical transmission rights and existing contractual commitments are recognized in the import capability calculation.

MIC values for each intertie are calculated annually and then allocated to LSEs through an assignment process defined in the CAISO tariff.[13] After accounting for existing transmission rights and prior RA import commitments, the remaining import capability is allocated to LSEs largely in proportion to their coincident peak load share within the CAISO balancing authority area. MIC is assigned to LSEs rather than to specific external generators, allowing each LSE to determine which external resources it will use to meet its RA obligations. To count imported capacity toward RA requirements, LSEs must hold sufficient MIC at the relevant intertie, and RA import showings must designate those imports in conjunction with a MIC allocation.

3. CPUC Resource Adequacy

The CPUC's RA program ensures sufficient capacity is under LSE contract in the near term (0–1 years) to reliably serve customer demand. There are three types of RA requirements set by the CPUC:

- System RA: The total CPUC-jurisdictional system capacity needed to meet peak demand plus a planning reserve margin. Each LSE is allocated system RA obligations per forecasted share of peak load.
- Local RA: Capacity in transmission-constrained areas where imports from the system are limited. PG&E serves as the CPE for local RA in its service territory.
- Flexible RA: Ensures the system can meet rapid changes in supply or demand, such as the net load ramp (i.e., the "duck curve"). To qualify, resources must have sufficient ramping capability (i.e., be able to rapidly change their power output upward or downward).

The forecasting and obligation-setting processes for each type of RA requirement differ, as detailed below.

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[11] An intertie is a physical connection that links two or more regional power grids, utility companies, or independent electrical systems

[12] Existing Transmission Contract rights and Transmission Ownership Rights are legacy transmission rights held by certain market participants that entitle the holder to schedule imports or exports across specific transmission paths on the CAISO-controlled grid. In the MIC calculation, any portion of these rights that is not scheduled for use ("unused") during the selected historical hours is added to the historical import schedules to reflect transmission capability that could have supported additional imports.

[13] For the full 13 step process, see Maximum Import Capability Enhancements Issue Paper (2021), pp. 2–3.

3a. Flexible and Local Resource Adequacy Requirements

Flexible Resource Adequacy

As discussed in Section 2, CAISO performs annual study processes to identify the *total* flexible capacity needed on the CAISO system for the following three years. CAISO submits study results to the CPUC who, in turn, adopts total program requirements via an annual decision in the current RA proceeding and then allocates a portion of the total flexible capacity required to each LSE.[14]

Per D.13-06-024, the CPUC adopted the following formula to calculate the system's flexibility requirement.[15]

$$\text{Flexibility Need } MTH_y = \text{Max } [(3RRHR_x)\ MTH_y] + \text{Max } (MSSC,\ 3.5\%*E(PLMTH_y)) + \varepsilon$$

Where:

- Max $[(3RRHR_x)\ MTH_y]$ = Largest three-hour continuous ramp starting in hour x for month y
- E(PL) = Expected peak load
- MTH_y= Month y
- MSSC = Most Severe Single Contingency
- ε = annually adjustable error term to account for uncertainties such as load following.

An LSE's flexible procurement obligation is calculated as follows, consistent with how system and local RA requirements are allocated:[16]

> LSE monthly flexible capacity procurement obligation = [(LSE monthly coincident peak load)/ (CAISO monthly coincident peak load)] * Cumulative monthly flexible capacity requirement

In the October Year Ahead ("YA") filing, LSEs must demonstrate procurement of 90% of their flexible RA obligation for each month of coming compliance year. In each Month Ahead ("MA") filing, LSEs must demonstrate procurement of 100% of their monthly flexible RA obligation.

Local Resource Adequacy

As discussed in Section 2, CAISO performs annual study processes to identify the minimum local resource capacity required in each local reliability area to meet established reliability criteria. CAISO submits draft and final study results to the CPUC in each RA proceeding, who allocates the minimum required local resource capacity by TAC area to each LSE.

PG&E and SCE serve as the central procurement entities for local RA under the CPUC's central procurement framework and are responsible for procuring RA capacity on behalf of all CPUC-jurisdictional load-serving entities within their service territories.

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[14] In the current RA Proceeding (R.25-10-003), CAISO is scheduled to submit the final study to the CPUC in May 2026, and the CPUC is slated to issue a decision by July 2026 for 2027 RA compliance year obligations.
[15] California Public Utilities Commission, *2026 Resource Adequacy and Slice of Day Guide* (September 23, 2025)
[16] Id.

Beginning with the 2023 RA compliance year, the CPUC adopted a hybrid central procurement framework for local RA requirements within the distribution service areas of PG&E and SCE. Under this framework, LSEs in these territories no longer receive individual local RA allocations. Instead, PG&E and SCE, operating as local RA CPEs, procure the total local capacity requirement on behalf of all benefiting LSEs in the service area.

The adopted structure is "hybrid" in that it centralizes responsibility for meeting the Local Capacity Requirement while preserving LSE flexibility. If an LSE has procured a resource that meets a local RA need, it may: (1) show the resource to reduce the CPE's overall local procurement obligation while retaining the resource for its own system and flexible RA compliance; (2) bid the resource into the CPE's competitive solicitation; or (3) elect not to show or bid the resource and instead use it solely for its own system and flexible RA requirements. An LSE that elects to show a resource may do so in advance of the solicitation or as part of its bid, including indicating that the resource will remain available for local reliability even if not selected. This structure allows locally deliverable resources to reduce the aggregate procurement need and potentially lower total costs.

The CPE is required to conduct a competitive, all-source solicitation for local RA procurement. Eligible bidders include existing local resources without contracts, new resources capable of timely online dates, and LSE- or third-party-contracted local resources. RA attributes remain bundled, and LSEs receive credits for any system or flexible capacity procured through the local RA or backstop processes based on coincident peak load shares, consistent with Cost Allocation Mechanism ("CAM") treatment. Existing CAM resources and IOU local DR resources reduce the total local capacity the CPE must procure.

The framework maintains a functional distinction between local and system/flexible obligations. Local RA ensures reliability within transmission-constrained areas and is procured centrally in PG&E and SCE territories. System and flexible RA obligations remain the responsibility of individual LSEs. If an LSE-procured local resource is not selected in the CPE solicitation, the resource may still count toward the LSE's system or flexible RA requirements, provided it is otherwise eligible. This design centralizes local reliability procurement while avoiding unnecessary duplication and preserving LSE autonomy over broader portfolio compliance.

3b. System Resource Adequacy Requirements

System RA obligations are set via a standardized annual process (summarized in Table 10 below) that involves LSEs, the CPUC, and the CEC. This process is formalized each year in the Resource Adequacy Slice of Day Guide, typically released in September prior to the compliance year.[17]

Table 10: Annual Process for Determining System RA Obligations

Date	Process
March	LSEs submit historical hourly peak load data for the preceding year

[17] For example, see the 2026 Resource Adequacy and Slice of Day Guide, released in September 2025.

April	LSEs submit *initial* YA monthly energy and hourly peak day forecasts for the coming compliance year
May	LSEs submit *revised* YA monthly energy and hourly peak day forecasts for the coming compliance year
July	LSEs receive draft 2026 YA RA obligations. To produce draft obligations, the CEC adjusts LSE forecasts such that aggregate peak-day demand within each TAC area is within 1% of the adopted IEPR planning scenario forecast. Draft obligations also include deductions of CPE procurement (both local RA and CAM) from system obligations.
Aug.	LSEs submit *final* YA monthly energy and hourly peak day forecasts for the coming compliance year. Per D.19-06,026, load migration is the only allowable reason for differences between the initial and final YA forecasts.
Sept.	LSEs receive final 2026 RA obligations based on: Updates to CEC load forecasts from LSE revisions or small true-up due to changes from other LSEs Increases/decreases to IOU CPE capacity Additional CPE resources increase CPE allocation to LSEs, further reducing system allocations. Local RA procurement can change substantially or not at all; however, CAM procurement typically does not change significantly unless there is an outage.
Oct.	LSEs submit YA compliance filing; must demonstrate procurement of 90% of system RA obligation for the five summer months of the coming compliance year.
Feb. (of the next year)	LSEs submit revised forecast to cover load migration update for June to December load migration. LSE load is otherwise locked in for January–May and June–December timeframes.[18]

4. CPUC Integrated Resource Planning Modeling Cycle

Across all stages of the Integrated Resource Planning (IRP) process, the CPUC generally relies on the most recently available IEPR planning forecast, or whichever forecast the agencies (the CEC and CAISO) have jointly agreed to use for the applicable planning cycle. This forecast serves as a consistent foundation for filing requirements and modeling.

4a. IRP Modeling

LSE IRP Filing Requirements

The IRP process begins with the CPUC establishing filing requirements for LSE Integrated Resource Plans ("IRPs"). LSE IRPs are filings prepared by an LSE describing how it intends to meet its forecasted customer load over the planning horizon while satisfying CPUC-established

[18] D.23-06-02, OP 22.

reliability, greenhouse gas ("GHG"), and policy requirements. LSE plans include proposed resource portfolios, supporting data templates, emissions calculations, and narrative explanations of planning assumptions and strategies.

The CPUC conducts modeling and policy analysis to determine the assumptions and constraints that LSEs must reflect in their plans. This includes use of the California Air Resources Board Scoping Plan to derive GHG emissions limits for the electricity sector, as well as CPUC determinations regarding the reliability scenarios that LSEs must plan for in their IRPs, including system adequacy and resource mix considerations.

Based on this analysis, the CPUC issues IRP filing requirements and supporting materials. These typically include, but are not limited to:

- Narrative templates requiring LSEs to describe their planning approach, assumptions, and portfolio strategy
- Resource data templates, which provide a snapshot of each LSE's contracted and planned monthly energy and capacity positions over a ten-year look-ahead period. These templates are used to verify that individual LSE portfolios meet reliability standards.
- The Clean System Power Calculator, which estimates GHG and pollutant emissions associated with each LSE's portfolio and is used to assess compliance with GHG planning benchmarks

LSE Plan Development and Review

LSEs then develop and submit their IRPs consistent with CPUC filing requirements. Each IRP includes a proposed resource portfolio, completed resource data templates, Clean System Power Calculator results, and narrative materials demonstrating how the plan aligns with state policy goals and reliability requirements.

Following submission, IRP stakeholders, including other agencies, market participants, and intervenors, review the LSE plans and submit comments. The CPUC evaluates both individual and aggregated LSE plans, assessing whether the collective statewide portfolio satisfies GHG targets, reliability standards, and cost considerations. If the CPUC identifies gaps or deficiencies in the aggregated portfolio, it may take additional actions to address those shortcomings.

Preferred System Plan Development

The CPUC then develops a Preferred System Plan ("PSP") through a series of modeling and stakeholder engagement steps. The PSP is the CPUC's preferred view of the optimal statewide resource portfolio, identifying the mix and quantity of resources it determines best meet California's reliability, cost, and greenhouse gas objectives, and serving as the primary input to CAISO's TPP. Development includes:

- Capacity expansion modeling to identify portfolios that meet policy and reliability constraints
- Production cost modeling to evaluate system operations, reliability outcomes, emissions, and costs associated with candidate portfolios
- Busbar mapping, which assigns the selected resource portfolio to specific interconnection locations on the transmission system

The CPUC releases proposed PSP and TPP portfolios through an Administrative Law Judge ruling and solicits stakeholder input via workshops and written comments. After considering stakeholder feedback, the CPUC adopts a PSP portfolio through a formal decision. The adopted PSP portfolio typically serves as the input portfolio for the CAISO's TPP,[19] following completion of CPUC busbar mapping.[20]

Procurement and Policy Implementation

Following PSP adoption, LSEs conduct procurement activities consistent with CPUC decisions and adopted portfolios. The CPUC monitors procurement progress and compliance and may issue additional procurement orders or take further policy actions if it determines that reliability, emissions, or policy objectives are not being met.

4b. IRP Procurement Obligations

When the CPUC determines that additional resource procurement is necessary to meet state reliability or policy goals, it issues a procurement order. A CPUC procurement order is a formal decision that:

- Identifies a specific incremental capacity need (typically expressed in megawatts of net qualifying capacity) over defined compliance years;
- Sets deadlines by which those capacity targets must be procured; and
- Allocates the required capacity to CPUC-jurisdictional LSEs for procurement, based on forecasted load and policy considerations.

To date, the CPUC has issued several major procurement orders in its IRP procurement track. In each of these CPUC procurement orders, the Commission has followed a two-step allocation process to distribute the identified procurement needs across LSEs:

[19] CAISO conducts an annual Transmission Planning Process to evaluate transmission system needs and identify transmission projects necessary to maintain reliability, support public policy requirements, and enable economic efficiency. The process involves technical studies performed by CAISO and includes multiple stakeholder engagement stages before CAISO publishes a draft and final transmission plan. The CAISO Board of Governors ultimately approves transmission projects recommended through the process.

[20] As part of IRP process, the CPUC conducts a "busbar mapping" exercise to translate the PSP portfolios to specific transmission network locations. Because IRP portfolios are typically specified at a zonal or regional level (e.g., by resource type and broad geographic area), the busbar mapping process assigns new generation and storage resources to specific transmission nodes or substations ("busbars") for use in CAISO transmission planning studies.

1. Initial LSE-type allocation: The total ordered capacity requirement is first allocated among LSE types (e.g., IOUs, community choice aggregators, electric service providers) based on year-ahead forecasts or obligations for system resource adequacy capacity, aggregated by LSE class.
2. Load share allocation: Within each LSE class, the capacity share is then allocated to individual LSEs based on their projected share of total load, using the most recent IEPR Form 1.1c energy forecast to reflect relative demand contributions for the compliance period.

This two-step method is intended to address the potential differential impact of varying load shapes and sizes across LSEs, ensuring that both class-level and individual obligations are tied to forecasted load responsibility.

The CPUC is also currently considering reforms under the Resource Adequacy and Clean Power Procurement Plan ("RCPPP"), which could change how load forecasting and capacity allocation are conducted, although the specific allocation methodology under RCPPP have not yet been determined.