

Supporting Document for the 2025 IEPR Forecast

This document provides a technical description of the data center forecasting methodology used in the 2025 IEPR forecast. It is intended for utilities, planners, stakeholders, and other technical audiences seeking transparency into how the CEC translates utility-reported energization requests into forecasted maximum demand and annual electricity consumption.

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1. Introduction and Purpose

Recent increases in the demand for artificial intelligence (AI) and advanced computing have contributed to a rise in utility energization requests for data centers. As a result, data centers are a leading source of electricity demand growth in California. The methods used to forecast the magnitude and timing of that growth continue to evolve as more information becomes available.

Uncertainty remains regarding:

- The number of applications utilities will receive
- How many proposed projects will ultimately be completed
- Project development timelines
- The anticipated load for each project
- Longer-term market conditions

To address this uncertainty, the California Energy Commission (CEC) develops dedicated, project-based data center demand forecast scenarios as part of the Integrated Energy Policy Report (IEPR) process.

This document provides a technical description of the data center forecasting methodology used in the 2025 IEPR forecast¹. It is intended for utilities, planners, stakeholders, and other technical audiences seeking transparency into how the CEC translates utility-reported energization requests into forecasted maximum demand and annual electricity consumption.

As of December 2025, approximately 1,000 megawatts (MW) of existing data center peak demand operates in California. While existing demand is reflected in the final demand forecast, this paper focuses on the methodology used to estimate incremental load growth from proposed data center projects.

1 [2025 Integrated Energy Policy Report](#)

2. Scenario Design Framework

The data center forecast is incorporated into the broader California Energy Demand Forecast developed for the Integrated Energy Policy Report (IEPR). The IEPR forecast is a core component of the state's energy planning and provides statewide and regional projections of expected electricity demand to support resource adequacy, transmission planning, and procurement proceedings.

The 2025 IEPR forecast consists of a baseline demand projection combined with selected component scenarios that address areas that modify the hourly system load profile, including data centers. These components are combined into two primary forecast constructs used for electricity system planning.

The Planning Forecast is used for:

- System and Flexible Resource Adequacy
- Integrated Resource Planning
- System-level transmission planning

The Planning Forecast reflects expected demand based on the baseline projection and selected component scenarios. For data centers, the Planning Forecast reflects the mid (planning) scenario, which applies moderate confidence assumptions to signed agreements and active applications.

The Local Reliability Scenario is used for:

- Local Resource Adequacy
- California ISO local transmission planning
- Investor-owned utility distribution system planning

The Local Reliability Scenario is based on the high data center scenario. It applies higher confidence levels, meaning a higher assumed likelihood that projects at each stage of the energization application process will be completed. This results in higher projected demand growth than the Planning Forecast. Using higher load assumptions helps ensure local transmission and distribution infrastructure is sized to maintain reliability if more projects move forward.

Both scenarios rely on the same underlying utility-reported energization application data. The primary distinction is the use of different confidence assumptions to reflect different planning needs at the statewide and local levels. The following sections

describe how energization data are translated into forecasted demand under each scenario.

3. Data Inputs

Due to the scale, geographic concentration, and uncertainty of large-scale data center development, the CEC developed a dedicated, project-based forecasting approach beginning with the 2024 IEPR Update². The 2025 IEPR forecast builds upon that framework with updated utility-reported data and refined modeling assumptions.

Utility Energization Requests

The forecast approach remains project-based rather than growth-rate-based. Forecasted demand is derived from utility-reported energization requests rather than from assumed percentage growth rates applied to historical load. Each potential data center project is characterized by:

- Requested capacity (in MW)
- Expected timeline or ramping schedule (if available)
- Application status (signed agreement, active application, inquiry)

For the 2025 IEPR forecast, seven utilities provided data: Silicon Valley Power (SVP), City of Palo Alto, Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), City of Burbank, and Valley Electric Association (VEA). Table 1 summarizes the data center capacity requests by utility and project status as of December 2025.

² [2024 Integrated Energy Policy Report Update](#)

Table 1: Data Center Capacity Requests in MW by Utility and Status

| Status | Agreement | Application | Inquiry | Total |
|------------------|--------------|--------------|--------------|---------------|
| PG&E | 4,356 | 3,617 | 6,774 | 14,747 |
| SVP | 644 | 196 | 198 | 1,038 |
| Palo Alto | 14 | 0 | 55 | 69 |
| SCE | 72 | 3,174 | 1,378 | 4,623 |
| SDG&E | 0 | 0 | 100 | 100 |
| Burbank | 0 | 0 | 100 | 100 |
| VEA* | 0 | 2,600 | 0 | 2,600 |
| Total | 5,086 | 9,587 | 8,604 | 23,278 |

Source: CEC with data from the utilities as of December 2025. *The VEA data center applications are for locations in Nevada but within California ISO.

Of the total 23,278 MW of requested capacity reported by utilities in December 2025:

- 5,086 MW have signed service agreements (Group 1),
- 9,587 MW are active applications (Group 2), and
- 8,604 MW are pre-application inquiries (Group 3).

This capacity reflects requested service capacity rather than expected maximum operating demand. Applications and inquiries represent more than 75 percent of the total requested capacity. This makes probabilistic and operating assumptions necessary when translating requests into forecasted demand. These assumptions are described in Section 4.

Project Groupings

For the 2025 IEPR forecast, the CEC standardized data collection across utilities and categorized projects into three consistent groups based on application status. These groupings form the basis for applying confidence levels in the forecast.

- Group 1 – Signed Agreement: Projects with a signed agreement for electric service with the local utility. These projects have completed an engineering study, which provides information on required grid upgrades and associated timelines.
- Group 2 – Active Application: Projects with an active application for electric service but no signed agreement.

- Group 3 – Inquiry: Projects that have submitted an inquiry for electric service but have not filed a formal application.

This standardized grouping refines the 2024 IEPR approach. In 2024, Group 1 included projects with completed or pending engineering studies, even if a service agreement had not yet been executed. In 2025, Group 1 is limited to projects with signed agreements, reflecting a more advanced stage of development and supporting higher confidence levels.

4. Forecast Assumptions

Industry experts and utilities serving data centers provided input to the CEC in developing key forecast assumptions. The data center forecast applies three primary adjustments to requested capacity:

1. Utilization factors
2. Confidence levels
3. Ramping schedules

Utilization Factor

A 67 percent utilization factor is applied to requested capacity in both the Planning Forecast and the Local Reliability Scenario. The utilization factor translates requested service capacity into expected maximum operating demand based on observed operations and utility input. This value is based on input from Silicon Valley Power (SVP), which has extensive experience serving large data center customers. Among SVP's existing data centers, observed peak demand relative to requested service capacity has ranged below this level, with 67 percent representing the upper end of observed utilization. Staff selected this value to reflect the upper range of expected operating demand.

The 67 percent factor reflects utilization patterns of currently operating data centers. Future facilities, including those constructed primarily for artificial intelligence workloads, may exhibit different operating characteristics. Staff will continue to evaluate utilization assumptions as additional operating data become available.

Confidence Levels

Because not all proposed projects ultimately proceed to construction and energization, staff applied confidence levels to each project group to estimate the portion of requested capacity expected to materialize. These confidence levels were informed by utility input on historical completion rates, application attrition, potential duplication of requests, and the possibility that some facilities may rely partially on on-site generation. Projects with signed agreements were assigned the highest confidence, while inquiries were treated as an indicator of longer-term growth rather than near-term demand.

Ramping Schedules

A linear ramp rate over 7 years is applied when project-specific schedules are unavailable or inconsistent with the project's application status. Projects without signed agreements were assumed to not begin service for 3-5 years, reflecting the time

required to progress through permitting, construction, and supporting infrastructure development. For example, some Group 2 projects reported service start dates in 2025, which was unlikely without a signed agreement. In these cases, staff adjusted the start date to 2028 to reflect a more realistic development timeline. This refines the 2024 IEPR methodology, which did not consider whether the service start dates were realistic. Also, the 2025 linear ramp approach results in a more gradual progression to full load compared to the 2024 method.

Table 2 summarizes the key assumptions incorporated into the data center demand forecast. These assumptions will be revisited and refined in future IEPR forecasts as additional utility data and operational experience become available.

Table 2: Summary of Data Center Forecast Assumptions

| Assumption Category | Planning Forecast | Local Reliability Scenario | Notes |
|--|--------------------------|---|---|
| Utilization Factor | 67% | 67% | Based on discussions with utilities and observed operations |
| Ramp to full load | Ramp over 7 years | Utility-provided schedule where available | Linear ramp where schedules unavailable |
| Confidence level: Group 1 (Signed Agreement) | 70% | 100% | Highest likelihood of completion |
| Confidence level: Group 2 (Active Application) | 33% | 50% | Moderate confidence in completion; accounts for attrition |
| Confidence level: Group 3 (Inquiry) | 0% | 10% | Low likelihood of completion; useful for long-term planning |

Source: CEC staff based on discussions with utilities

One exception to application of confidence levels is for projects in SVP, which has a long history of serving data center customers. SVP maintains a consistently active energization queue due to the concentration of large technology firms within its service territory. Based on discussions with SVP, when projects withdraw or fail to advance,

new projects typically enter the queue in short order. Given this sustained demand pattern, the forecast assigns a 100 percent confidence level to SVP-reported capacity across project statuses. This treatment reflects an expectation that aggregate data center demand within SVP's service territory will materialize over time, even if specific projects change.

5. Development of Hourly Load Profiles and Peak Contribution

To estimate how data centers affect hourly load and system peak, the 2025 IEPR forecast used hourly load factor profiles developed from interval meter data. These profiles translate projected maximum demand into hourly demand and allow staff to estimate data centers' contribution to the California Independent System Operator (CAISO) system peak hour.

Following adoption of the forecast, staff developed an additional mathematical load profile model that provides a smooth representation of hourly data center load patterns. This model does not change the adopted projections of maximum demand or annual electricity use. Instead, it provides an alternative way to represent hourly load shapes and supports transparency in the forecasting process.

Adopted Approach in the 2025 IEPR Forecast

CEC staff analyzed multi-year interval meter data from a sample of existing data centers to develop representative hourly load profiles. Hourly load was normalized to each facility's observed annual maximum demand to derive hourly load factors. These load factors were aggregated across facilities to produce representative weekday, weekend, and seasonal load shapes. The data show that data centers:

- Operate at high and sustained load factors throughout the day
- Have little variation between daytime and nighttime hours
- Show modest seasonal differences between summer and winter months
- Run consistently across most hours of the year

Across the sampled facilities, average hourly load factors ranged from approximately 85 to 90 percent of observed annual maximum demand.

The representative hourly profiles were applied to forecasted maximum demand (after utilization, confidence, and ramping adjustments) to produce an hourly load forecast. This enables estimation of data centers' coincident contribution to the CAISO system peak hour identified in the IEPR demand forecast.

Because data centers typically operate continuously and have relatively flat load profiles, their annual maximum demand is not necessarily coincident with the CAISO system peak hour. Coincident peak contribution is calculated by applying the load factor for the system peak hour to projected maximum demand.

The interval meter analysis was not used to derive the 67 percent utilization factor. Requested service capacity is not captured in interval meter datasets, so the relationship between requested capacity and observed maximum demand is informed by utility-reported experience and discussions with utilities serving data centers. Interval meter data are used solely to develop representative hourly load shapes relative to observed maximum demand.

Existing data centers provide the best available proxy for hourly load shapes. However, future facilities may operate differently as computing technologies and cooling strategies evolve.

Supplemental Harmonic Load Profile Model

Following adoption of the 2025 IEPR forecast, staff developed a supplemental mathematical load profile model that represents hourly load using smooth seasonal and daily patterns. The harmonic (Fourier-type) model represents load factor as a combination of seasonal and hourly sinusoidal components that fluctuate around an annual mean load factor. The model also allows the magnitude of hourly variation to change seasonally.

For each hour h within the annual sequence of month-hour observations t , load factor is modeled as:

$$LF_{t,h} = \mu + \alpha \sin(\theta_t) + \beta \sin(\varphi_h)(1 + \gamma \sin(\theta_t))$$

Where:

- $LF_{t,h}$ = modeled load factor
- μ = mean annual load factor
- θ_t = seasonal phase angle
- φ_h = hourly phase angle
- α = seasonal amplitude coefficient
- β = hourly amplitude coefficient
- γ = seasonal adjustment to hourly variation

The seasonal phase angle is defined across a sequence of 288 month-hour observations (12 months \times 24 hours) representing the typical hourly load profile for the year. Separate parameter sets were estimated for weekday and weekend load profiles.

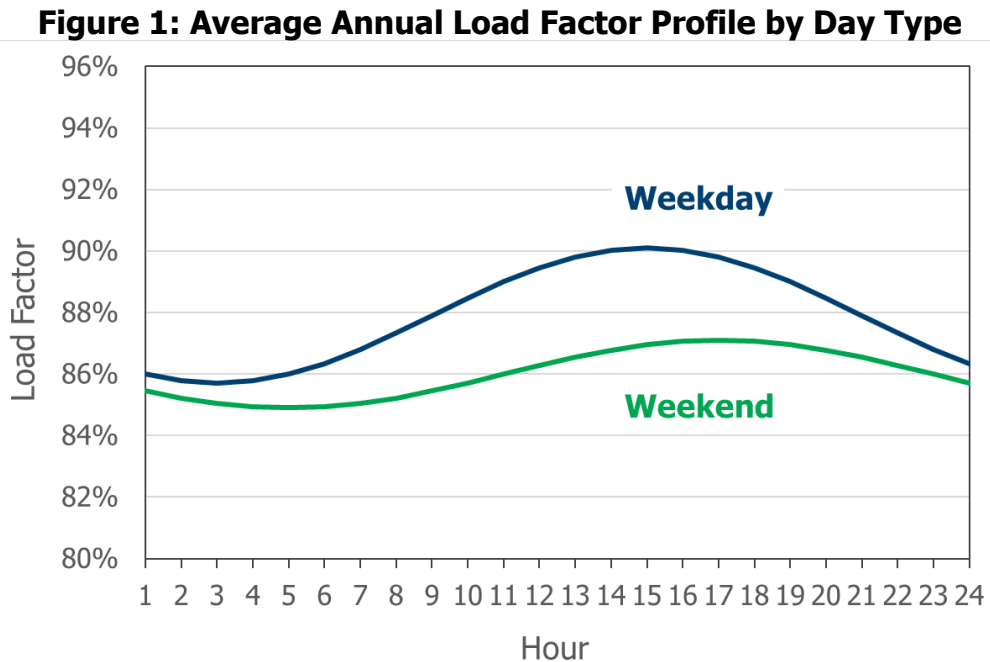
Model parameters were calibrated by minimizing root mean square error (RMSE) relative to observed hourly load data from both the CEC's interval meter sample and a PG&E dataset of nearly 100 data centers spanning 2020-2024.

The harmonic model closely matches the aggregated interval meter profiles while smoothing short-term variability caused by weather and other factors. For example, in the adopted 2025 profile, September shows slightly lower load than adjacent months due to local weather patterns in the underlying sample data. The harmonic model smooths these differences to represent typical seasonal conditions rather than a specific year.

Both weekday and weekend models peak during the late summer and early fall months, consistent with observed seasonal patterns. In the model, weekday load peaks around hour ending 15 (2-3 p.m.) and weekend demand peaks around hour ending 17 (4-5 p.m.), consistent with observations in the interval meter data.

This supplemental model does not change adopted projections of annual maximum demand, annual electricity consumption, or scenario assumptions adopted in the 2025 IEPR forecast. It provides an additional analytical tool for representing hourly load patterns and supporting future modeling work.

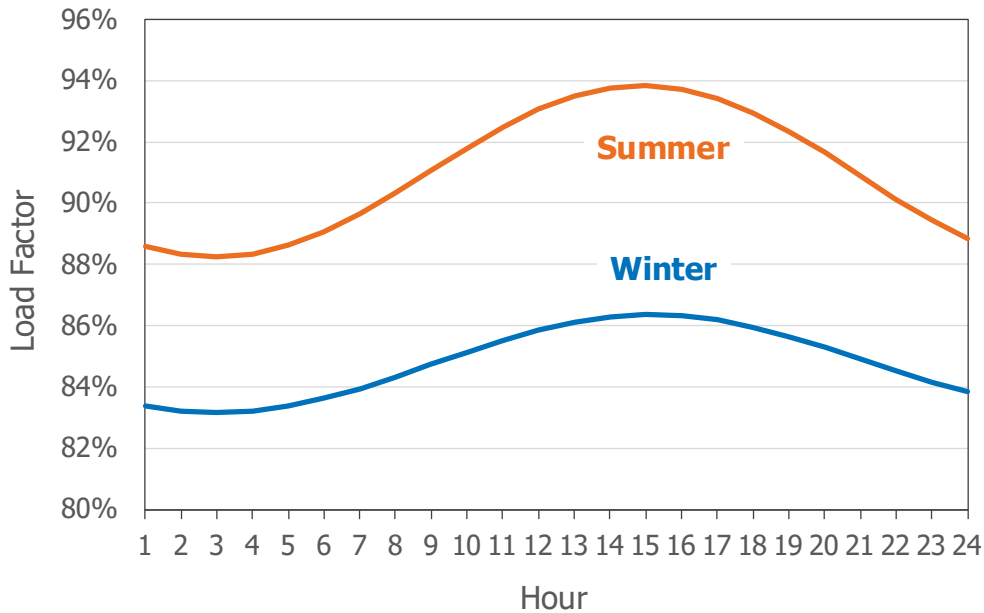
Figure 1 shows the typical weekday and weekend hourly load factors generated using the harmonic model.



Source: CEC Staff

Figure 2 compares representative summer (August through October) and winter (February through April) weekday load factor profiles.

Figure 2: Average Weekday Load Factor Profile by Season



Source: CEC staff

Evolution from the 2024 IEPR Forecast Approach

The 2024 IEPR Update estimated hourly data center load using representative profiles that were differentiated by day type (weekday and weekend). Those profiles were developed using available interval meter data from a sample of data centers.

For the 2025 IEPR forecast, staff expanded both the dataset and the level of detail in the profiles. The 2025 adopted approach uses:

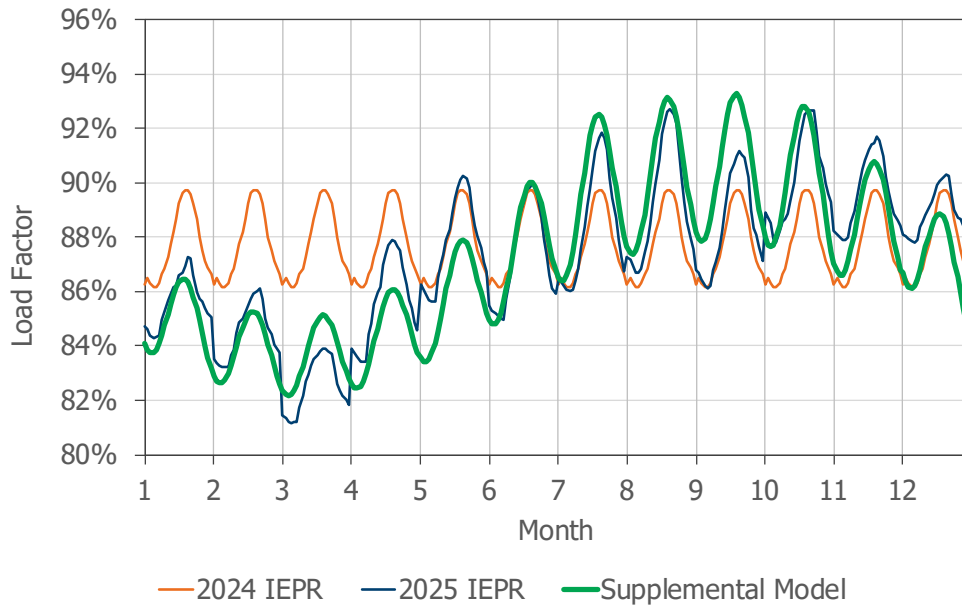
- An expanded interval meter dataset covering additional service territories
- One additional year of observed data
- Hourly load profiles differentiated by day type and month

Adding the monthly component to the representative hourly profile improves estimates of seasonal variation and coincident contribution to system peak.

In addition to the adopted method, staff developed a supplemental harmonic model that provides a smooth mathematical representation of data center load patterns while remaining consistent with observed interval meter data.

Figure 3 compares the average hourly load factor profiles for each month. Hours are displayed in sequence and vertical gridlines mark the transition between months.

Figure 3: Evolution of Average Hourly Load Factor by Month-Hour



Source: CEC staff

All three approaches show the same general pattern of high, steady load with little variation across hours. The refinements in 2025 increase seasonal detail and improve estimates of coincidental contribution to system peak. Staff will continue to update and refine the hourly load analysis as additional data become available through future IEPR cycles.

6. Results

The modeling framework converts the 23,278 MW of utility-reported energization requests into expected demand growth by applying three assumptions:

1. Utilization factors convert requested capacity to expected maximum operating demand.
2. Confidence levels estimate the likelihood that projects at each status are expected to materialize.
3. Ramping assumptions determine the timeline for when the facility reaches full electrical demand.

Portfolio-Level Application of Utilization and Confidence

To illustrate how utilization and confidence levels are applied, consider the 9,587 MW of requested capacity at the active application stage (Group 2).

Under the Planning Forecast:

- Applying the 67 percent utilization factor results in $9,587 \text{ MW} \times 67\% = 6,423 \text{ MW}$ of expected maximum demand if constructed.
- Applying the 33 percent confidence level results in $6,423 \text{ MW} \times 33\% = 2,120 \text{ MW}$ expected realized demand.

Under the Local Reliability Scenario:

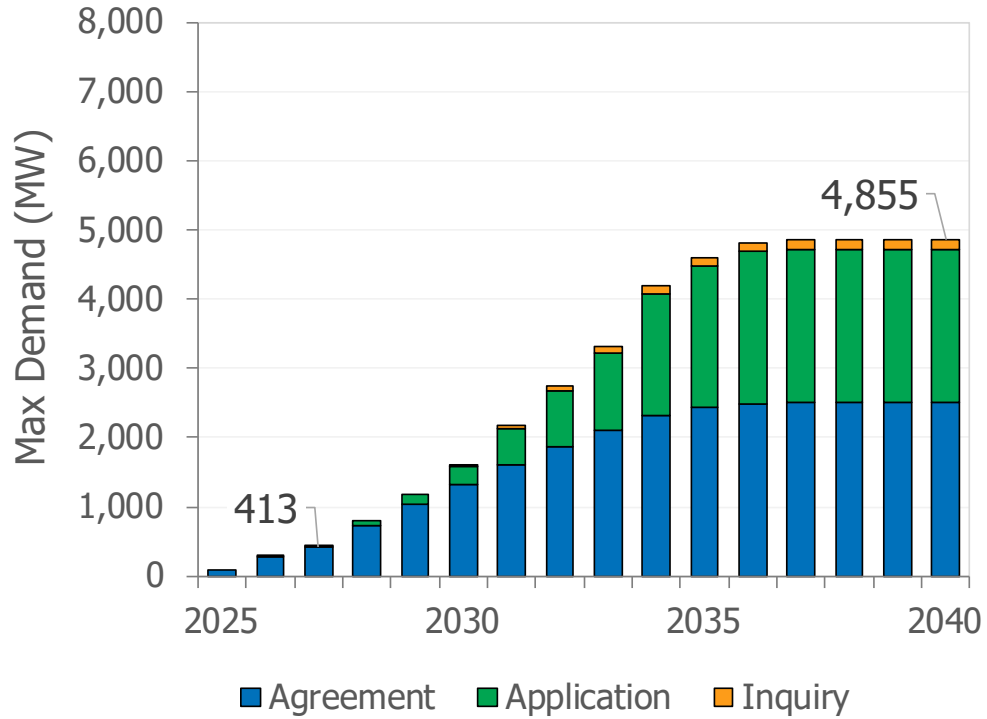
- Applying the 67 percent utilization factor results in $9,587 \text{ MW} \times 67\% = 6,423 \text{ MW}$ of expected maximum demand if constructed.
- Applying the 50 percent confidence level results in $6,423 \text{ MW} \times 50\% = 3,212 \text{ MW}$ expected realized demand.

Confidence levels are applied to the portfolio of projects within each status category. The weighting reflects an expectation that only a portion of projects within each category will ultimately proceed to energization. Similar calculations are applied to Group 1 and Group 3 projects, resulting in total expected maximum demand under each scenario.

Incremental Demand Growth by Scenario

Figure 4 shows incremental projected demand from new data center projects under the Planning Forecast, reaching approximately 4,855 MW by 2040.

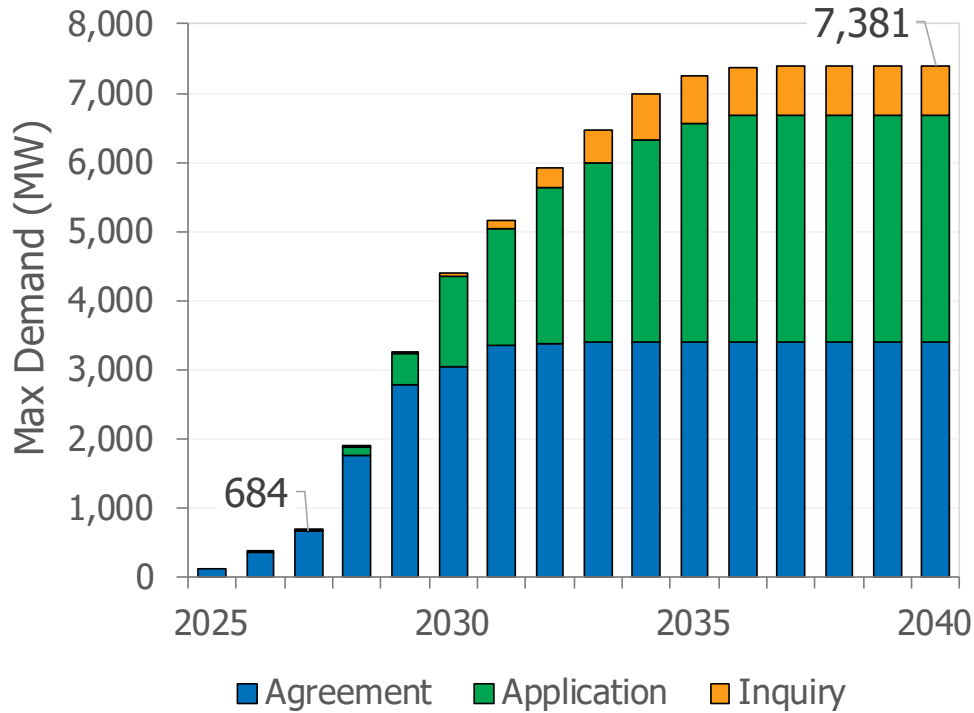
Figure 4: 2025 IEPR Demand Growth by Project Status (Planning Forecast)



Source: CEC Staff

Figure 5 shows projected demand growth under the Local Reliability Scenario, reaching approximately 7,381 MW by 2040. The Local Reliability Scenario reflects higher confidence assumptions and therefore results in greater projected growth.

Figure 5: 2025 IEPR Demand Growth by Project Status (Local Reliability Scenario)



Source: CEC Staff

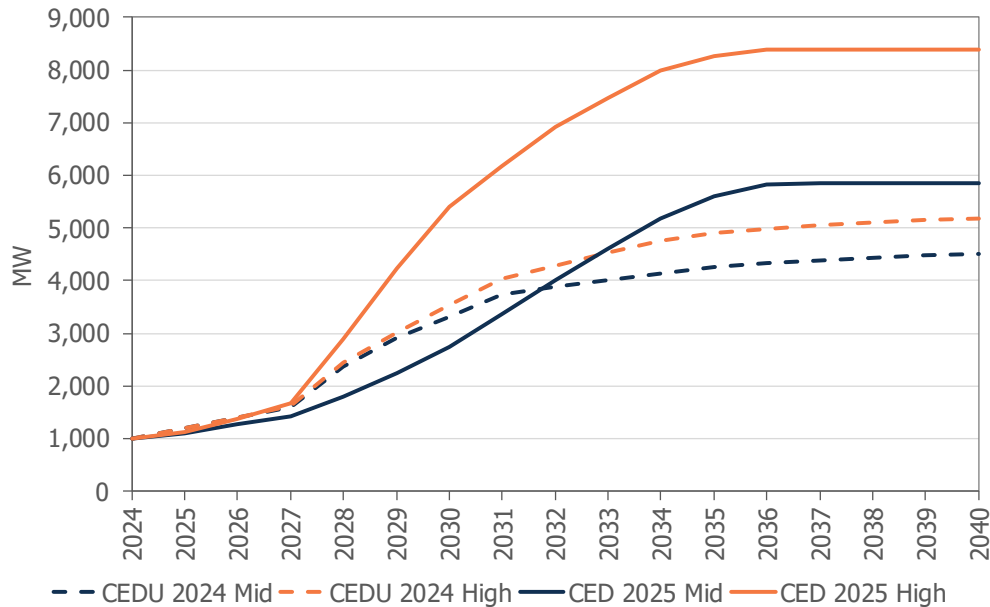
These values represent incremental growth beyond approximately 1,000 MW of existing data center load. Total projected maximum demand equals existing load plus incremental growth.

The following sections illustrate how updated data and methodological refinements affect forecast results relative to the 2024 IEPR Update.

2024 vs. 2025 Maximum Demand Forecast

Figure 5 compares projected maximum demand under the 2025 IEPR Planning Forecast (mid case) and Local Reliability Scenario (high case) with the 2024 IEPR Update.

Figure 6: Statewide Data Center Maximum Demand Forecast (MW)



Source: CEC staff based on utility data as of December 2025

Under the Planning Forecast:

- Maximum demand increases from approximately 1,000 MW in 2024 to approximately 5,800 MW by 2040.
- This is approximately 1,300 MW higher in 2040 than the 2024 IEPR Update.

Under the Local Reliability Scenario:

- Maximum demand increases to approximately 8,400 MW by 2040.
- This is approximately 3,200 MW higher in 2040 than the 2024 IEPR Update.

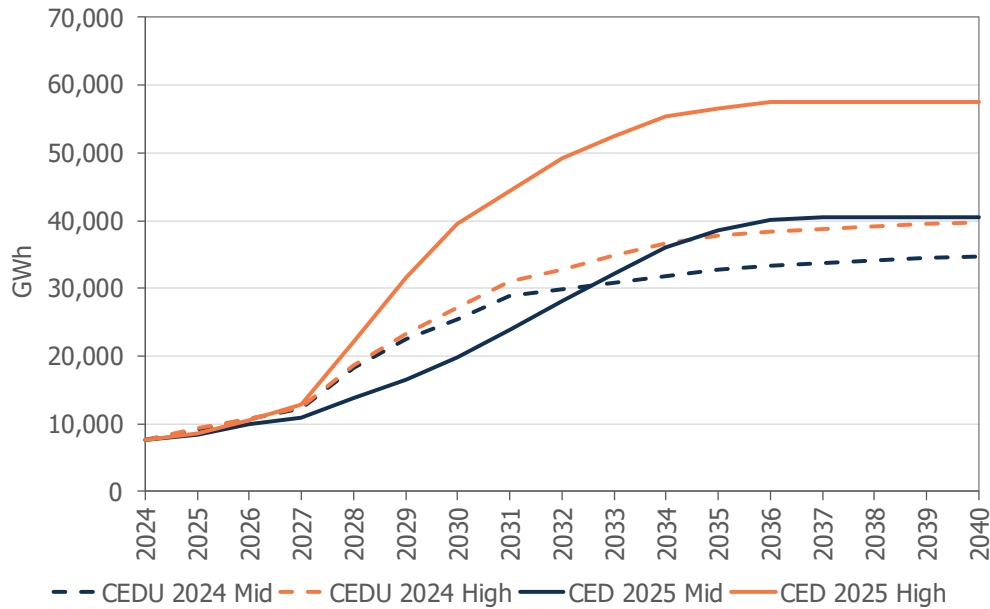
In both scenarios, most growth occurs between the late 2020s and mid-2030s. Demand levels off thereafter because the forecast is based on currently known energization requests rather than an assumed long-term growth rate.

Maximum demand results include Valley Electric Association (VEA)-served projects because these loads connect to the California ISO system and therefore contribute to ISO peak demand. Data center maximum demand represents estimated annual maximum demand and is not necessarily coincident with the ISO system peak hour.

2024 vs. 2025 Annual Consumption Forecast

Figure 6 shows projected statewide annual electricity consumption through 2040 under the Planning Forecast and Local Reliability Scenario.

Figure 7: Statewide Data Center Annual Electricity Consumption (GWh)



Source: CEC staff based on utility data as of December 2025

Under the Planning Forecast:

- Annual consumption increases to approximately 40,000 GWh by 2040.
- This is approximately 6,000 GWh higher in 2040 than the 2024 IEPR Update.

Under the Local Reliability Scenario:

- Annual consumption reaches approximately 57,000 GWh by 2040.
- This is approximately 18,000 GWh higher in 2040 than the 2024 IEPR Update.

Most growth occurs through the mid-2030s, after which it levels off as the current queue is exhausted. Statewide annual electricity consumption excludes data center projects located outside California, specifically those in the Nevada portion of VEA’s service territory. The differences between the 2025 IEPR and 2024 IEPR Update reflect both updated utility-reported energization data and refinements to forecast assumptions.

7. Allocation of Forecasted Data Center Demand to Load-Serving Entities

After the data center demand forecast is developed, projected demand is allocated to the load-serving entities (LSEs) expected to supply electricity to each project. This step allows the forecast to be used in planning processes that rely on LSE-specific load projections.

Utilities provided project-level data that included an “Expected LSE” field identifying the generation provider expected to serve the project. For projects located in community choice aggregator (CCA) territories, the Expected LSE typically reflects the default CCA serving that location.

After applying the forecast adjustments described in earlier sections to each project, including utilization factors, confidence levels, and ramping schedules, projected demand is aggregated by year and by Expected LSE.

Because not all customers remain with their default CCA, additional adjustments are applied to account for customer choice. Some customers may opt out of CCA service and receive bundled electricity service from the investor-owned utility (IOU). To reflect this behavior, opt-out rates provided by utilities are applied to projects assigned to CCAs.

For the 2025 IEPR forecast, the following adjustments were applied:

- PG&E territory: A 5 percent opt-out rate. This was revised down from 13%, based on PG&E’s 2026 Energy Resource Recovery Account (ERRA) documentation, in response to comments from LSEs.
- SCE territory: A 30 percent opt-out rate based on preliminary analysis by Southern California Edison.
- SDG&E territory: Because specific CCAs were not yet identified for some projects, load was allocated based on the commercial sector load share.

Some projects may also be served through Direct Access, in which customers purchase electricity from an energy service provider (ESP) rather than from a CCA or the IOU. Direct Access participation in California is limited by statutory caps. Where relevant, a portion of projected load is allocated to Direct Access providers based on current participation levels and available program capacity. PG&E identified some projects that are possibly or likely to be served by ESPs. The load of possibly-ESP projects was split evenly between ESPs and the default CCA. No ESP projects were identified by SCE, but

aggregate ESP load has been more than 10% below the direct access cap, so 5% of project load was allocated to ESPs beginning in 2028.

After calculating CCA and ESP data center load, all remaining load was allocated to IOU bundled service. These adjustments are applied to the aggregated forecast totals for each LSE, rather than to individual projects. This approach reflects expected customer participation patterns while maintaining consistency with project-level forecast inputs provided by utilities.

The resulting allocations produce annual demand projections by LSE that can be used in procurement planning, resource adequacy assessments, and other electricity planning processes.

8. Ongoing Analytical Development

Data center development remains a rapidly evolving area of electricity demand. Several factors introduce uncertainty that staff will continue to monitor in future IEPR cycles.

First, California has a limited historical record of large-scale data center energization, particularly for facilities with AI-focused workloads. The confidence levels used to translate requested capacity to expected maximum load are informed by utility experience and industry input. A longer historical record will support better estimates of which projects materialize.

Second, utility energization queues are dynamic. Projects may advance, withdraw, or be replaced by new applications. The forecasting approach reflects a snapshot of reported data as of December 2025 and will be updated in future cycles as conditions change.

Third, development timelines may vary depending on permitting, construction, supply chains, and transmission availability. Because CAISO's transmission planning process looks several years ahead, it's important to include even lower-confidence projects to support proactive system planning.

Finally, future data center technologies and operating models may differ from those observed today. Advances in artificial intelligence, computing technologies, and cooling systems could affect utilization rates and hourly load patterns.

In addition, some large data centers are exploring on-site generation options. In certain regions of the country, new facilities have proposed building dedicated power plants as their primary energy source. These facilities may connect to the natural gas system and maintain a grid connection for backup service. If similar models were pursued in California, grid demand could differ from the full requested electric capacity reported in utility energization applications. Staff will continue to monitor these developments and assess how evolving energy supply strategies may affect future load forecasts.

Staff will further refine data center forecasting assumptions and modeling approaches as additional data become available through ongoing utility reporting and interval meter analysis.

9. Other Resources

The following is a list of additional resources that describe CEC's data center forecasting inputs, methodologies, and results.

- 2024 IEPR Update: <https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2024-integrated-energy-policy-report>
- 2025 IEPR Update: <https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2025-integrated-energy-policy-report>
- Demand Analysis Working Group (DAWG) meeting presentation including data center revised results: <https://www.energy.ca.gov/event/meeting/2026-01/ca-energy-demand-forecast-2025-iepr-revised-result>
- Products from the CED 2025 Forecast, including a file comparing the adopted hourly data center demand forecast to the supplemental harmonic model: <https://www.energy.ca.gov/data-reports/california-energy-planning-library/forecasts-and-system-planning/demand-side-3>