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DRAFT STAFF REPORT

California Energy Resource and Reliability Outlook, 2026

Energy Assessments Division

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Dhruv Bhatnagar
Kadir Bedir
Gerry Beamis
Miguel Cerutti
Hannah Craig
Paul Deaver
Ashley Emery
Elise Ersoy
Nick Fugate
Asish Gautam
Quentin Gee
Liz Gill
Aloke Gupta
Jonathan Margoliash
Jake McDermott
C.D. McLean
Joseph Merrill
Michael Nyberg
Jason Orta
Xieng Saephan
Sean Simon
Jeremy Smith
Max Solanki
David Stout
Justin Szasz
Alyssa Tavares
Kristen Widdifield
Amanda Wong
Chie Hong Yee Yang

Kristen Widdifield
Project Manager

Elise Ersoy
Supervisor
RELIABILITY AND EMERGENCY UNIT

Liz Gill
Branch Manager
RELIABILITY ANALYSIS BRANCH

David Erne
Deputy Director
ENERGY ASSESSMENT DIVISION

Aleecia Gutierrez
Director
ENERGY ASSESSMENT DIVISION

Drew Bohan
Executive Director

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ABSTRACT

The *California Energy Resource and Reliability Outlook* is the California Energy Commission staff's comprehensive, statewide assessment of electric, fossil gas, and petroleum resource planning and reliability. The report has a focus on the summer 2026 but also considers the midterm, spanning the next five years.

The intent of this *California Energy Resource and Reliability Outlook* is to provide an overview of planning and reliability across California for the period of 2026–2045, based on available data. In contrast to the 2025 report, this report provides more comprehensive analyses of energy resource planning issues, considerations, and trends.

Keywords: Reliability, reliability planning assessment, CERRO, California ISO, CEC, CPUC, DWR, California, electricity, supply and demand, extreme event, electricity system planning, resource stack analysis, summer reliability, resource procurement

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EXECUTIVE SUMMARY

The *California Energy Resource and Reliability Outlook* is the California Energy Commission (CEC) staff's comprehensive, statewide assessment of energy resource planning and reliability across the electric system, fossil gas system, and petroleum supply. California is undergoing a significant energy transition to meet the state's 2045 carbon neutrality mandate. This transition impacts all fuel types, and the changes across these sectors are increasingly interconnected. This report seeks to use energy assessments to identify challenges, near- and long-term, and inform policy needed to reliably, affordably and equitably transition California's energy systems.

Previous editions of the California Energy Resource and Reliability Outlook have been more centrally focused on the challenge of energy sector summer reliability across a variety of scenarios. This report expands its scope to describe challenges with emerging loads, the opportunity for expanded demand flexibility, resource options for long-term electricity planning, and long-term electric reliability assessments. This report examines California's summer reliability outlook. The report also reviews fossil gas supply conditions, including projected storage capacities relative to anticipated peak summer demand. Moreover, this outlook includes an analysis of petroleum resources, market trends, and overall system risks.

A draft of this report was published on June 14, 2026. The reader should be aware that this final report is published post-summer, and no additional analyses were performed nor reported data updated.

2026 Summer Conditions

This report provides an overview of the conditions shaping the California energy landscape with a focus on the summer of 2026, offering insights into the key aspects that influence reliability. Furthermore, the report includes a broad assessment of reliability that considers Western and national trends that impact California, including the following.

- Electricity demand: California's electricity demand continues to increase and peak in the summer months. The CEC's recently adopted *Integrated Energy Policy Report* (IEPR) Forecast projects slower near-term growth in peak demand; however, higher-than-expected levels of load during 2025 are driving a slightly higher system-wide forecast for 2026 summer peaks.
- Westwide weather: Summer climate forecasting for July, August, and September predicts above normal temperatures in the entirety of the West. This prediction means widespread heat events could reduce electricity imports available to California and create challenging grid conditions. During March, conditions transitioned from La Niña to neutral and expectations favor a transition to El Niño in the summer. Transition to El Niño tends to result in moderately higher temperatures for Southern California in the summer and wetter conditions for

Southern California in the fall and winter. Neutral to very strong El Niño conditions are possible this winter.

- Westwide wildfire: California summer fire season affects California grid reliability. Fires within and outside the state can affect supply and transmission capabilities into and within California. Based on the current early forecasts, fire potential will be above normal in much of Northern California, Oregon, and Washington in June and July. The wildfire outlook only covers months with available forecasting.
- New resources: California continues to grow its electric resource portfolio. Between January 2019 and December 2025, the state added more than 30.1 gigawatts (GW) of new clean energy capacity, a notable uptick in new resource additions. These additions, critical to meeting statewide reliability needs, include about 13.8 GW of utility-scale battery storage, and more than 13.4 GW of solar photovoltaics (PV). Energy storage continues to provide critical value by charging with excess resources in midday and discharging later in the day as solar PV is declining.
- Hydroelectric capacity conditions: Hydroelectric resources provide an average of 14.6 percent of the state's electricity needs, based on data collected from 2001 through 2024, and up to 7,000 megawatts (MW) of peak capacity to support reliability. The Department of Water Resource's April 1, 2026, snow survey indicated the statewide snowpack was at 18 percent of average, compared to 90 percent last year. However, reservoir levels across the state remain above average at 116 percent as of April 1.

The summer 2026 California outlook is cautiously optimistic for electric and fossil gas reliability, but contingency resources may be needed during coinciding extreme events.

California has added nearly 30.1 gigawatts of new resources since January 2019, signaling a promising uptick in new resource additions.

Summer Reliability Outlook

California's electric system continues to indicate a cautiously optimistic reliability outlook, as new resources come online and updated forecasts refine expectations for summer 2026 and beyond.

Resource Stack Analysis

CEC staff conducted a resource stack analysis to evaluate potential contingency needs under extreme grid conditions by comparing anticipated electricity supply with projected demand in the California Independent System Operator (ISO) balancing area and statewide. California is expected to maintain positive supply margins under all analyzed system conditions. Under planning standards, the California ISO balancing area is estimated to have a surplus of 6,600 MW at peak hour 18, and even under a 2022-like extreme heat event, a surplus of 2,900 MW. However, risks exist such as up to 1,600 MW of additional known loads (loads that have the potential to come on the system during the analysis period), wildfire-related transmission losses exceeding 4,000 MW, and combined extreme heat and wildfire scenarios. These scenarios could reduce margins substantially, with the latter indicating a need for more than 1,000 MW of contingency resources.

The statewide assessment indicates total reliable statewide capacity is sufficient for average conditions.

The statewide resource stack analysis indicates that the state has a small surplus under planning standards and a potential shortfall under a 2022-equivalent extreme heat event, suggesting tighter conditions during extreme events. The statewide stack analysis relied on supply forms for POUs and may not reflect short-term contracts to fill capacity needs.

Probabilistic Assessment

This report includes a statewide probabilistic assessment for 2026 using the CEC's *2025 IEPR Update* Forecast and California ISO and POU resource portfolios through December 2025. The goal of probabilistic reliability assessments is to evaluate whether resource planning is likely to achieve the reliability standard of one day of outage per 10 years (0.1 loss of load expectation). Based on CEC's analysis, California is projected to meet the reliability standard and maintain reliable service under several resource adequacy risks, including uncertainty in resource availability, hourly demand, generator outages, imports, and resource build timeframes, during both summer and winter periods of 2026. The CEC evaluated the system across multiple *2025 IEPR Update* Forecasts including 2025 Planning, 2025 Planning with Known Loads, 2024 IEPR Planning, and 2025 Local Reliability with Known Loads. Across all forecasts, the state power system meets the reliability standard. The CEC projects a capacity surplus of 5-7 GW across the set of demand forecasts for 2026 relative to the 0.1 loss of load standard.

In addition to that short-term analysis for 2026, the CEC also conducted a mid-term assessment of system reliability in 2031 and 2036. As with the short-term analysis, this work evaluates whether California is meeting the 1-in-10-year loss of load expectation across a range of scenarios related to demand variability and import uncertainty. Unlike the short-term analysis, however, timing issues prevented an assessment of additional resources added to the system after 2028, including those driven by the CPUC's

February 2026 Procurement order. As a result, the results of the analysis for these years should be interpreted as an assessment of residual need remaining after implementation of the CPUC's prior procurement orders up through 2028.

Results indicate that with the expected resource procurements through 2028 that the California system is expected to have sufficient resources—under normal hydro and transmission conditions—to meet the 0.1 days/year loss of load expectation criterion through 2031 in the Base demand scenario. The loss of load expectation criterion is exceeded in all other demand forecast scenarios in 2031 and all scenarios in 2036, meaning additional resources would be needed for the system to be considered reliable. However, under procurement ordered by the CPUC after this analysis was conducted, namely the CPUC February 2026 procurement, the California system would meet the 0.1 LOLE reliability criterion through 2031.

Fossil Gas Plant Performance

Fossil gas plants supply a significant portion of the peaking capacity and ramping requirements of California's electric grid and are critical to system reliability. Fossil gas plants refer to natural gas fueled power plants, not gas turbines that use coal or other fossil fuels. However, fossil gas plants, like many resources, operate less efficiently (are derated) when surrounding temperatures exceed certain thresholds and can be more susceptible to mechanical failure or reduced availability when capacity is needed most. Fossil gas plants can also provide ancillary services such as voltage regulation, load following capabilities, and black start capability. Analysis in this report examines the causes of fossil gas plant derates, the frequency of derate events, and the magnitude of capacity reductions using California ISO fossil gas plant derate and outage data from 2021 through 2025.

Emerging Loads and Demand Flexibility

The *2025 IEPR* Forecast results show continued growth in California's annual statewide peak demand, from around 61 GW in 2026 to 83 GW by 2045. This report discusses the trends and emerging challenges or opportunities associated with California's growing load. These issues include Investor-Owned Utility (IOU) known loads, and growing data center loads. Some important highlights include the following.

- Load from artificial intelligence data centers could grow exponentially over the next decade, increasing to 5.7 to 8.3 times the existing load by 2040.
- The likely need for the state to develop additional near-term strategies for demand flexibility that are cost-effective and support reliability and decarbonization efforts.
- The importance of incorporating known loads into the *IEPR* Forecast to prevent misalignments between distribution planning and other system planning that adheres to the *IEPR* Forecast, notably transmission system planning.

Electric Resource Planning Issues

To meet its mandate of 100 percent clean energy by 2045 (Senate Bill 100, De León, Chapter 312, Statutes of 2018), CEC modeling finds that California must build an unprecedented 150 to 200 GW nameplate capacity of new zero-carbon resources over the next two decades to satisfy a projected 50 percent increase in demand. The CEC used capacity expansion planning to evaluate how scenarios around resource costs, technology availability, federal tax credit policy, and land use constraints affect the mix and quantity of investment required to meet California's clean energy targets. Meeting the 2035 greenhouse gas (GHG) target of 20 million metric tons by 2035 will require reducing annual gas generation by about 50 percent while load increases by 40 percent. To cover this differential, the model builds about 50 GW of zero-carbon resources between 2030 and 2035, in addition to the 50 GW of planned resources built between 2025 and 2030.

This represents about 10 GW of new generation every year through 2035. Longer-term through 2045, while results indicate that solar photovoltaic and wind remain the primary resources of this transition, the removal of federal subsidies and the diminishing capacity value of intermittent resources have intensified the need for firm clean technologies. The candidate emerging technologies available to the model are picked up under different scenarios, driven by a need for energy during the winter. This includes carbon capture and storage retrofits of existing gas plants that represent the lowest-priced firm zero-carbon technology; enhanced geothermal, which the model picks up when carbon capture and storage is not available; offshore wind that is selected under optimistic price assumptions and when other lower-priced firm technologies are not available; and long duration energy storage which is also selected under optimistic price assumptions.

Simultaneously, the CEC is investigating the indirect impacts of wildfires on power system reliability with the goal of producing a wildfire-informed resource adequacy evaluation to capture transmission and generation risks both short-term and long-term. Initial results find significant transmission de-rates aligned with times of significant wildfire activity on both Path 65 and 66 (transmission paths into and out of California from the Pacific Northwest). Transmission line ratings can vary significantly, yet the lowest line ratings are typically only seen during periods of known wildfires. The analysis shows that even small wildfires are associated with significant de-rates.

As inverter-based resources, including utility-scale and distributed solar PV, wind, and battery storage, have rapidly expanded to meet California's clean energy goals, they may also introduce new reliability challenges that differ fundamentally from those posed by conventional synchronous generators. The CEC is evaluating grid strength concerns in areas of the state where high concentrations of inverter-based resources could cause weak grid points and lead to voltage instability. Grid strength represents the ability of an electric system to maintain stable voltage or frequency despite disturbances. Next steps will focus on refining the analysis by assessing grid strength during contingency

conditions and evaluating potential solutions to improve grid strength and system reliability.

These integrated planning efforts are designed to identify infrastructure bottlenecks and ensure a reliable, decarbonized grid through 2026 and beyond. As the energy transition accelerates, CEC will continue to deepen its analytical work to anticipate emerging challenges and inform the policy and infrastructure decisions needed to keep California's grid clean and reliable.

Western Coordination

California is part of the Western Interconnection (WI), a network of transmission lines linking diverse generating resources to loads throughout the region. Twenty-four balancing authorities currently participate in the Western Energy Imbalance Market, which allows entities throughout 12 Western states to buy and sell electricity on a sub-hourly basis increasing the efficiency of the market.

The recently launched Extended Day-Ahead Market will allow more entities to participate in a 24-hour forward market for energy that the California ISO already operates in its footprint. This market may further decrease the cost of electricity generation and transmission, especially as more balancing authorities join the market. The following Balancing Authorities have announced their intention to participate in the Extended Day-Ahead Market: the Los Angeles Department of Water and Power, the Balancing Authority of Northern California, Imperial Irrigation District, Turlock Irrigation District, PacifiCorp, the Public Service Company of New Mexico, and Portland General Electric.

A key development last year was progress made on the West-Wide Governance Pathways Initiative, which would create a new regional organization with authority over the Western Energy Imbalance Market and Extended Day-Ahead Market. This potential change may allow for increased coordination across the West, if more entities participating in the Western Energy Imbalance Market volunteer to participate in the Extended Day-Ahead Market.

Eight new out-of-state 500-kilovolt transmission additions are already operating, close to operating or under construction, including TransWest Express, Greenlink, Gateway South and West, the Southwest Intertie, and SunZia. These projects will contribute substantially to reliability and resource adequacy in California by providing transfer capability for out of state energy at times needed to meet high net loads in the state. With the exception of Greenlink, which is located within Nevada, these are all interstate transmission projects. Together, resource and transmission additions, coupled with ongoing work to implement new regional electricity markets, have improved the reliability outlook for California and the ability to coordinate more broadly with the West resulting in reduced costs for ratepayers.

Gas System Reliability

While California's gas system remains winter-peaking, the summer months can present distinct challenges. Gas demand can shift quickly on hot summer days as gas-fired power generation ramps up to meet electric load. When these rapid demand increases occur, utilities may need to withdraw gas from underground storage or suspend storage injections to maintain system balance. The assessment in this report evaluates whether hot temperatures and dry hydroelectric conditions during summer could intensify the rapid demand swings enough to affect summer reliability or reduce the ability to inject gas into storage for the upcoming winter. Based on forecasted gas demand this summer and the expected availability of infrastructure (absent unforeseen events including unscheduled maintenance and unusual amounts of consecutive hot days), CEC staff expect that Pacific Gas and Electric and Southern California Gas will meet demand with no curtailments during summer 2026.

The gas system is anticipated to have sufficient capacity to meet summer demand.

Petroleum System Reliability

Because of increased fuel efficiency and adoption of zero-emission vehicles, gasoline demand in California is in decline. As this continues, in-state refineries will likely continue to transition away from producing gasoline; either permanently closing or converting to the refining of renewable feedstocks for renewable diesel or other types of bio-based fuels. For example, in 2024 Phillips 66 Rodeo ceased petroleum operations and converted the facility to produce renewable fuels. In October 2025, Phillips 66 closed its Wilmington refinery while Valero announced in April 2025 its intent to idle, restructure, or cease refining operations at their Benicia refinery by April 2026[1]. These changes are reducing the number of refineries capable of producing California reformulated blended gasoline in California. The closures have reduced the number of in-state gasoline refineries to seven and California's crude refining capacity by nearly 18 percent.

The difference between the gradual decline in gasoline demand and the large stepwise decline in gasoline supply from instate production as refineries close creates increased reliance on imports of refined fuel and the potential for supply and demand imbalances and subsequent price spikes. California's gasoline prices in 2025 were relatively stable compared to the prior three years and the state did not experience any price spikes such as those seen in 2022-2023. However, the effects of the refinery closures won't be fully felt until summer 2026 with peak demand coinciding with constrained supply from instate production, increasing reliance on imports to meet

1 "Valero Energy Corporation, Valero Announces Notice to the California Energy Commission Regarding its Benicia, California Refinery" https://investorvalero.com/news/news-details/2025/Valero-Announces-Notice-to-the-California-Energy-Commission-Regarding-its-Benicia-California-Refinery/default.aspx

demand. Marine imports tend to have higher prices compared to in-state refining, which can increase retail prices. Furthermore, the war in Iran disrupted shipping of crude oil through the Strait of Hormuz. This led to rapid crude oil price increases starting in March 2026. The conflict introduces additional uncertainty into the broader supply chain and may pose risks to California's fuel availability should global conditions further deteriorate and decrease global crude supply.

Refineries typically operate at their maximum stated capacity. The permanent or temporary reduction of refining capacity at a single refinery represents a critical reduction. A fire at PBF Energy's Martinez[2] refinery in February 2025 resulted in reduced production at the refinery for the remainder of the year, while additional incidents[3] at Valero's Benicia refinery in May 2025 and Chevron's El Segundo refinery in October 2025 further contributed to short-term volatility in weekly production. These supply constraints underscore vulnerability in California's refinery network and increased reliance on imports. The lack of pipelines bringing finished products into California limits import options to marine vessels. California experienced record high marine imports in 2025, including record high months, indicating that the state can accommodate elevated imports. However, record months do not necessarily demonstrate sustained reliability, especially during concurrent refinery outages or disruptions. Further assessment, consistent with SB 237 (Grayson, Chapter 118, Statutes of 2025), is needed to determine whether existing ports and related infrastructure can sustain or expand their current capacity and to identify steps necessary to ensure they remain adequate.

Between 2023 and 2025, California passed new legislation focused on stabilizing fuel supplies and prices and enabling increased transparency of the petroleum fuels market. This legislation will help develop and administer energy policies in the interest of the state's economy and the public's well-being and better respond to possible shortages or supply disruptions. As laid out in Vice Chair Gunda's June 2025 letter to the Governor, California must develop holistic strategies for the petroleum fuels transition and work to stabilize fuel imports, maintain in-state refining capacity for system resilience, and give the petroleum industry confidence to invest to maintain reliable and safe operations in California. Doing so will help ensure Californians have access to safe, reliable,

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2 PBF Energy Inc., "PBF Energy Provides Update on Martinez Refinery," March 6, 2025. https://investors.pbfenergy.com/news/news-details/2025/PBF-Energy-Provides-Update-on-Martinez-Refinery/default.aspx

3 Bay Area Air Quality Management District, Incident Report: Valero Refinery, Benicia, May 5, 2025. https://www.baaqmd.gov/~/media/files/compliance-and-enforcement/incident-reports/2025/valero-incident-report-050525-pdf.pdf Chevron Corporation, "Fire at Chevron El Segundo Refinery Is Now Out," October 3, 2025. https://www.chevron.com/newsroom/2025/q4/fire-at-chevron-el-segundo-refinery-is-now-out

affordable, and equitable petroleum-based transportation fuels to meet demand as the state transitions to cleaner alternatives.

Electric and Fossil Gas Conclusions

California's electric and fossil gas systems are changing quickly and are closely connected. As the state works to cut greenhouse gas emissions, more things are being powered by electricity, which is increasing demand. New loads, such as large data centers, also add uncertainty to how much electricity will be needed. At the same time, the state is using less petroleum and fossil gas, which means existing gas systems must be managed carefully to keep energy reliable. The outlook for summer 2026 is generally positive, with more clean energy and battery storage helping provide enough supply under normal and extreme heat conditions.

However, risks like wildfires, higher-than-expected demand, and multiple stress events happening at once could reduce these supply margins. During these times, the fossil gas system will continue to support electric reliability by fueling power plants that can run when solar PV and wind output are low. Looking ahead, reliability challenges will become more complex. Winter electricity demand is expected to grow faster due to electrification, while solar PV generation is lower in winter. In addition, nearby regions that California depends on for electricity imports are also expected to have higher winter demand. These trends increase the risk of winter shortages. To address this, the state will need better forecasting, robust planning tools, and continued investment in clean firm resources, grid infrastructure, and a flexible gas system. Working with other Western states through new transmission and market coordination will also be important. Overall, maintaining reliability will require careful coordination between the electric and fossil gas systems to manage risks and support a stable transition to cleaner energy.

Petroleum Conclusions

Gasoline demand in California is gradually declining due to increased fuel efficiency, the increased adoption of zero-emission vehicles, and other factors. Differences between the gradual decline in gasoline demand and large stepwise decline in supply from instate refinery closures can lead to supply and demand imbalances that must be met with imports. Recent refinery closures reduced California's crude refining capacity by nearly 18 percent, further constraining supply of the state's unique gasoline blend and increasing reliance on marine imports. California experienced record monthly high marine imports in 2025 due to unplanned outages, indicating the state can accommodate increased imports at the levels required to meet this summer's demand. However, this does not demonstrate sustained reliability of increased import capacity, particularly if the state experiences significant unplanned outages coinciding with peak summer demand. The impact of the war in Iran is expected to negatively affect global crude supply and price volatility, however as of May 2026 the situation is still rapidly developing.

CHAPTER 1: Introduction

California is in the midst of a major transformation of its energy systems. The state is a world leader on policies that shift energy resources from fossil fuels to clean energy resources to reduce the impacts of climate change. As shown in the first two months of 2026, California's largest balancing authority, the California Independent System Operator published data showing that over 85 percent of the days had some portion of the day when clean energy electric generation exceeded electricity demand.[4] This shift requires fundamental changes across all the state's energy systems. Large swaths of the economy will electrify, resulting in significant electricity load growth. At the same time, the electric grid transitions from a fossil-based system to a clean energy driven system, resulting in a need for continued deployment of resources like solar PV, wind and storage and a need to understand physical changes to grid operations. While the electricity sector grows at an unprecedented rate, the fossil gas and petroleum systems must adapt to maintain reliability and affordability to customers while demand diminishes. Increasingly, the interconnectedness of these systems must be considered, as well as how the transition can be equitable to all Californians. At the same time, California is experiencing more frequent and prolonged extreme events because of climate change that strain the state's energy systems.

California is not alone in facing these challenges as other Western states experience similar climate impacts. In an increasingly integrated Western grid, localized extreme events in one area can impact reliability across other parts of the region. While California leads in the energy transition, other states are following with similar goals, causing greater competition for clean energy resources and the equipment necessary to integrate them. These challenges have demonstrated the need to better understand energy resource availability in the near term (1-3 years), midterm (4-10 years), and long term (10+ years), as well as the reliability of the energy systems during the transition.

The *California Energy Resource and Reliability Outlook (CERRO)* is the CEC staff's comprehensive, statewide assessment of resource planning and reliability for the summer 2026 and the next five years. In 2021, the CEC's *Midterm Reliability Outlook* [5] provided an electric reliability outlook through 2026 and assessed the performance of

4 California Energy Commission. *Tracking Progress Toward 100% Clean Energy*. Available: https://www.energy.ca.gov/data-reports/clean-energy-serving-california/tracking-progress-toward-100-clean-energy.

5 Gill, Liz, Mark Kootstra, Elizabeth Huber, Brett Fooks, Chris McLean. 2021. *Midterm Reliability Analysis*. California Energy Commission. Publication Number: CEC-200-2021-009, https://www.energy.ca.gov/publications/2021/midterm-reliability-analysis.

critical resources such as battery storage and the fossil gas fleet. The *2024 CERRO* [6] provided a comprehensive picture of electricity and gas planning and reliability of all investor-owned utilities (IOUs) and some publicly owned utilities (POUs) in California through 2028, to the extent that data were available. The 2025 *CERRO*[7] expanded content by including petroleum and expanding existing electric system analyses. For the 2026 CERRO, the analyses are expanded again to provide more comprehensive insights of energy resource planning issues, considerations, and trends. The CERRO effectively serves as a vehicle to capture new analysis and data with insights into reliability and considerations for energy planning including 1) near-term reliability outlook across sectors and 2) emerging issues requiring new data or analysis.

The CEC has a longstanding mandate under the Warren-Alquist Act[8] to serve as California's primary energy policy and planning agency. By providing annual summer assessments and preparing for extreme events, the CEC staff play a critical role in reporting on electric resource adequacy (RA). This reporting ensures that adequate physical generating capacity dedicated to serving all load requirements is available to meet peak demand, planning, and operating reserves. Historically, the CEC has provided updates on these topics in the *IEPR* or through separate, topic-specific reports. The CERRO seeks to combine all relevant staff analyses related to energy system reliability into one document annually, whether part of the Warren-Alquist Act or other legislation.

The CERRO also summarizes analyses that may be provided by CEC staff in other reports in collaboration with other agencies, such as the quarterly reliability reports required by SB 846 (Dodd, Chapter 239, Statutes of 2022). This CERRO may include summaries of CEC's analyses for those reports for context, and CEC staff will include any additional analyses conducted by CEC staff that may not be in the scope of those reports but relevant to system reliability (for example, natural gas system reliability) or emerging issues.

Where legislation requires reporting on a separate timeline from the CERRO, CEC staff has included summaries of those relevant reports or status updates as part of this document. Examples of relevant other requirements include the following:

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6 Yee Yang, Chie Hong, Kristen Widdifield, Liz Gill, Hannah Craig, Angela Tanghetti, Grace Anderson, C. D. McLean, Aloke Gupta, Justin Cochran, Joseph Merrill, Lana Wong, Heidi Javanbakht, and Michael Nyberg. August 2024. *California Energy Resource and Reliability Outlook, 2024*. California Energy Commission. Publication Number: CEC-200- 2024-016, https://www.energy.ca.gov/publications/2024/california-energy-resource-and-reliability-outlook-2024.

7 Chie Hong Yee Yang, Kristen Widdifield, Liz Gill, Paul Deaver, Justin Cochran, Joseph Merrill, Ashley Emery, Matthew Cooper, Michael Nyberg, Bryan Neff, Jason Orta, Jake McDermott, and Justin Szasz. May 2025. *California Energy Resource and Reliability Outlook, 2025* California Energy Commission. Publication Number: CEC-200-2025-011, https://www.energy.ca.gov/publications/2025/california-energy-resource-and-reliability-outlook-2025.

8 California Public Resources Code, Division 15, commencing with Section 2500. (Chapter 276, Statutes of 1974)

- SB 423 (Stern, Chapter 243, Statutes of 2021) requires the CEC, in consultation with the CPUC, California ISO, and California Air Resources Board (CARB) to develop and submit assessment to the Legislature. The report shall include an analysis of emerging renewable energy and firm zero-carbon resources that support a clean, reliable, and resilient electrical grid in California. Furthermore, the assessment must identify available, commercially feasible, and near-commercially feasible emerging renewable energy and firm zero-carbon resources. Additionally, the report shall distinguish which resources can address system reliability needs and local reliability needs, with an emphasis on reducing the emissions of greenhouse gases, toxic air contaminants, and criteria air pollutants. SB 423 also requires that the assessment evaluates the potential needs for, and role of, these resources using a reasonable range of resource cost and performance assumptions, and identify barriers to the procurement of these resources and possible pathways for additional procurement. The *2025 IEPR*[9] includes an update to the final report (which was published in May 2025) and was published on June 26, 2026.
- SB 100 (De León, Chapter 312, Statutes of 2018) establishes a target for renewable and zero-carbon resources to supply 100 percent of retail sales and electricity procured to serve all state agencies by 2045. The bill also increases the state's Renewables Portfolio Standard (RPS) to 60 percent of retail sales by December 31, 2030, and requires all state agencies to incorporate these targets into their relevant planning. The 2021 SB 100 Joint Agency Report was published in September 2021.
- SB 350 (De León, Chapter 547, Statutes of 2015) requires publicly owned utilities whose average annual electrical demand between 2013 and 2015 exceeded 700 gigawatt-hours to adopt an integrated resource plan. In their integrated resource plans, filing publicly owned utilities must forecast annual electricity demand from their customers for 2019–2030. The utilities must also present a plan for electricity procurement, energy efficiency, and demand response that would meet their expected demand while—per Public Utilities Code Section 9621—meeting greenhouse gas emission reduction targets, meeting requirements to procure renewable energy, ensuring electricity reliability, and charging reasonable electricity rates. Under Public Utilities Code Section 9622, the CEC must review the integrated resource plans for consistency with the requirements of Public Utilities Code Section 9621.
- SB X1-2 (Skinner, Chapter 1, Statutes of 2023) amended the Petroleum Industry Information Reporting Act of 1980 (PIIRA), added other requirements associated

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9 Bailey, Stephanie, Jim Bartridge, Kadir Bedir, Mathew Cooper, Susan Ejlalmaneshan, Tom Flynn, Quentin Gee, et al. 2026. *Final 2025 Integrated Energy Policy Report*. California Energy Commission. Publication Number: CEC-100-2026-001-CMF. https://efiling.energy.ca.gov/GetDocument.aspx?tn=271035&DocumentContentId=108608

with the CEC's oversight of the petroleum industry, and introduced several new petroleum industry reporting requirements. The new information includes spot market transactions, firm ownership, agreements and contracts, inventory holdings by type, refinery maintenance schedules, notice of marine vessel imports, expanded refinery operator reporting, and new pipeline and port operator reporting. These expanded requirements provide new insight about petroleum markets and more immediate information on marine imports and refinery operations. The Transportation Fuels Assessment was published in 2024, with the next one due in 2027. The joint agency report with the California Department of Tax and Fee Administration was published in 2024, with the next one due in 2026.

- AB X2-1 (Hart, Chapter 1, Statutes of 2024) requires the CEC to consider the effects of refiners' inventory on the price of transportation fuels. AB X2-1 also requires a three-year assessment to evaluate California's future import needs for crude oil and petroleum, and steps that could be taken to prepare ports and marine infrastructure to transport this quantity of petroleum products.

CHAPTER 2:
2026 Summer Conditions

IEPR Forecast

California's electricity demand forecast contains multiple scenarios developed annually within each IEPR proceeding. A baseline scenario extends existing trends into the future ("business-as-usual"). Managed scenarios are created by adding "additional achievable" load modifiers onto the baseline to account for the potential impacts of policies and programs which—while reasonably likely to occur—have substantial uncertainty surrounding their implementation. These additional achievable load modifiers can be arranged in various combinations, but the primary managed scenario used by utilities, the California ISO, and other state agencies for system-wide studies is the Planning Forecast.[10]

Relative to the *2024 IEPR*, the newly adopted *2025 IEPR* Planning Forecast generally projects lower growth for both electricity sales and peak demand. This is due to several factors including lower expected population and economic growth, higher electricity rates, increased energy efficiency, and deferred adoption of both transportation and building electrification measures. For peak demand, lower near-term growth is offset by a weather normal[11] estimate of 2025 peak load that is higher than previously forecast, particularly for the Pacific Gas and Electric (PG&E) Transmission Access Charge (TAC) area. This higher starting point means that *2025 IEPR* Planning Forecast of annual system peak for 2026 is slightly higher than previously forecast, both statewide and for the California ISO system.

Electricity demand typically peaks in the summer months of July, August, or early September. The coincident peak[12] forecasts for the summer months of 2026 for the entire California ISO territory, composed primarily of the PG&E, Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) TAC areas, are shown in Figure 1. Note that the annual system peak[13] for the California ISO territory of more than 46,800 MW is forecast to occur in September, but the July and August peaks have a

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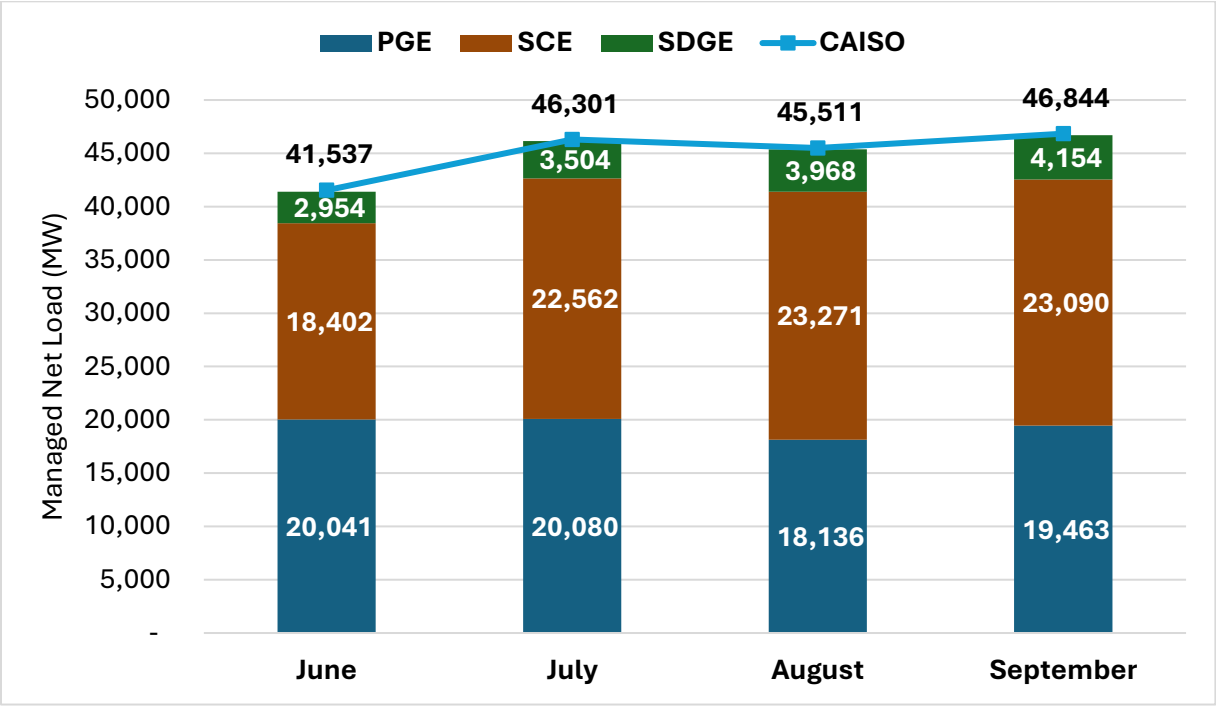
10 The single forecast set agreement between the CEC, CPUC and California ISO documents which components of the IEPR Forecast will be used in specific studies conducted by each organization.
11 Because electricity demand is highly sensitive to temperature, staff use observed loads and temperatures from the most recent summer to estimate what peak demand would have been under typical weather conditions. This weather-normal estimate is used as a starting point for the IEPR peak forecast.
12 *Coincident peaks* are the amount of demand that the individual TAC areas contribute at the time of the overall California ISO system peak. *Noncoincident peaks* are the maximum peaks of each individual TAC areas, which do not necessarily occur at the same time.
13 The annual system peak is the point of highest demand experienced by the entire California ISO transmission system for a given year.

comparable magnitude. The annual system peak could be reasonably expected to occur in any of these months.

Figure 1: California ISO Coincident Monthly Peaks for Summer 2026



Source: CEC *2025 IEPR* Planning Forecast
Note: SCE includes pumping load from the Metropolitan Water District (MWD) of Southern California. The California ISO total also includes a small amount of load from the Valley Electric Association (VEA).

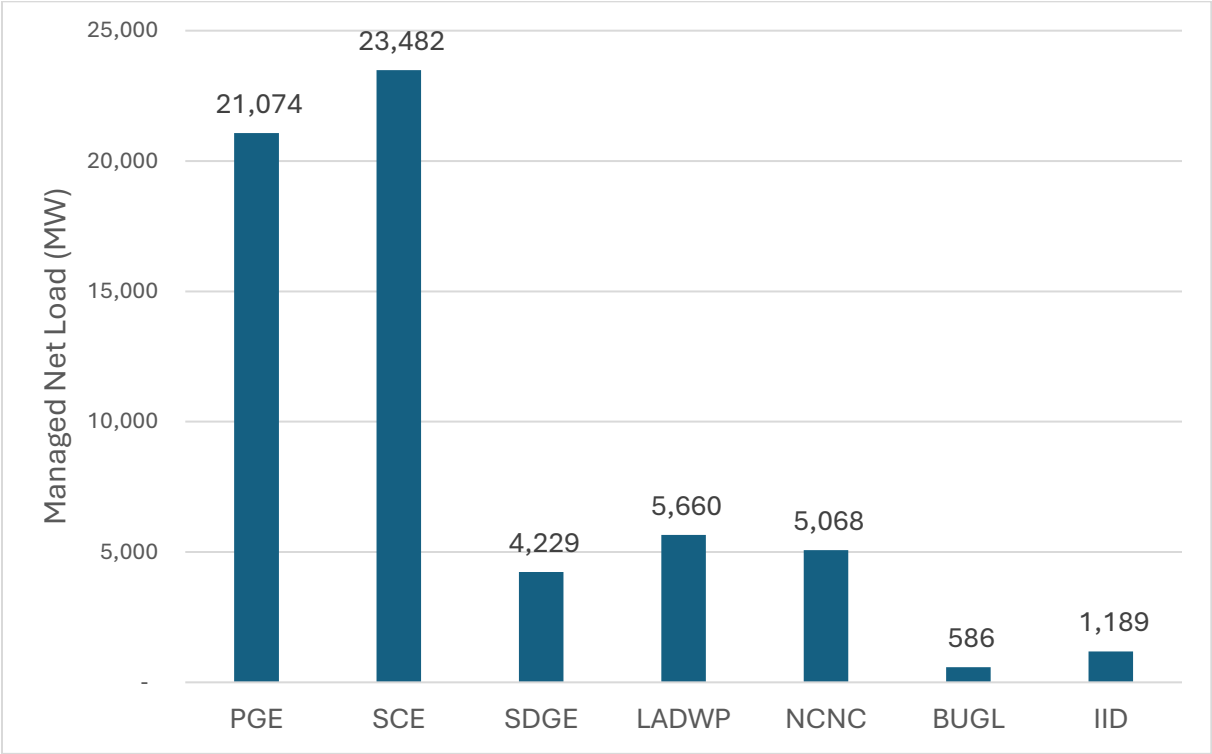
For the first time, as part of the *2025 IEPR*, staff considered utility known loads data when developing the electricity demand forecast.[14] Preliminary findings indicate that known loads have the potential to add up to 1,500 MW of load growth to the California ISO system peak in 2026. Due to significant uncertainty around the timing and magnitude of these loads being added this year and their potential for overlap with other categories of load growth already considered within the managed scenarios, these impacts were not included in the *2025 IEPR* Planning Forecast, but are included in the reliability analysis in this report to understand the impact if those loads do materialize.

Figure 2 shows the annual noncoincident system peaks from the *2025 IEPR* Planning Forecast for the IOU TAC areas within the California ISO control area, and the four other main planning areas within California. The IOU TAC area noncoincident peaks sum to nearly 48,800 MW, just over 2,000 MW higher than the sum of their peaks

14 Known loads are energization requests made to investor-owned utilities at the distribution system level. The utilities submit this data to the CPUC as part of their distribution system planning and the data are shared with CEC forecasters.

coincident with the California ISO system peak. In addition, the non-California ISO peaks sum to 12,500 MW, for a statewide noncoincident total of nearly 61,300 MW.

Figure 2: Noncoincident Annual Peaks for 2026



Source: CEC *2025 IEPR* Planning Forecast

Summer Climate Outlook

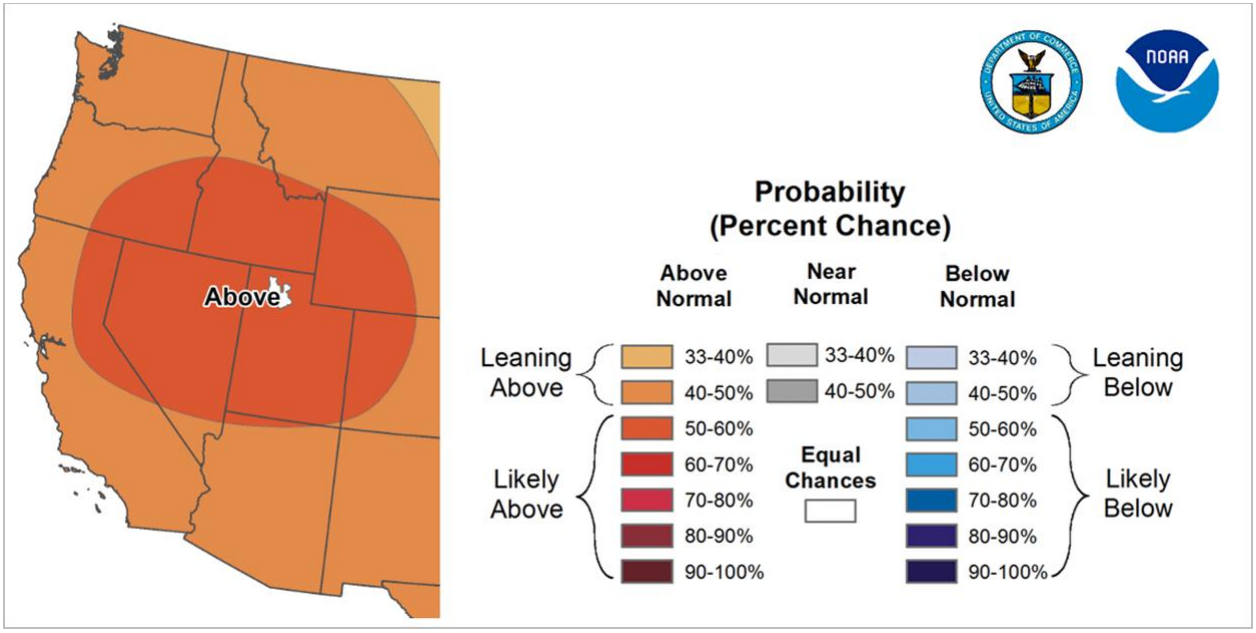
California peak electrical loads are driven by high temperatures and air-conditioning usage in populated areas. Widespread heat events affecting multiple population centers present the greatest risks to the electricity system. The 2026 summer temperature outlook suggests a high likelihood of above-normal temperatures throughout the West in the peak months of July, August, and September. A coinciding event of high temperatures in California and other parts of the WI is a particularly bad weather scenario as availability of imports decreases when power is needed most.

El Niño and La Niña conditions are the two phases of the El Niño Southern Oscillation (ENSO), representing patterns of warmer-than-average and cooler-than-average sea surface temperatures in the tropical Pacific Ocean, respectively. The ENSO tends to have a small impact on Northern California and a larger impact on Southern California. La Niña conditions tend to promote warmer and drier weather in Southern California because of positioning of the jet stream steering storms away from the region. El Niño tends to promote wetter falls and winters in Southern California, while tending to promote mildly warmer temperatures compared to ENSO neutral conditions.

During late 2024, ENSO conditions transitioned from ENSO-neutral to La Niña, which has persisted through early 2026 before transitioning back to ENSO-neutral in March. A transition to neutral conditions may mean relatively cooler and wetter weather in the southern half of California compared to La Niña conditions, but neutral conditions also make the climate less predictable. During May through July, El Niño conditions are expected with 61 percent chance to return and persist through at least the end of 2026. A transition to El Niño means greater chance for a wetter fall and winter, with limited impact during summer. The possible outcomes range from ENSO-neutral to a very strong El Niño this winter.[15]

The Climate Prediction Center (CPC) expects above-normal temperatures throughout the Western U.S. for July, August, and September. The outlook means a higher chance for Westwide heat events corresponding with extreme temperatures in California, creating more challenging grid conditions for the California balancing authorities, which typically rely on imports in the peak hours. Figure 3 shows the CPC Seasonal Temperature Outlook for July–September 2026.

Figure 3: Seasonal Temperature Outlook for July–September



Source: CPC Seasonal Temperature Outlook for July–September 2026, valid March 19, 2026

After widespread rains in October, November and December 2025, California was entirely drought free in January for the first time in 25 years.[16] Southern California in

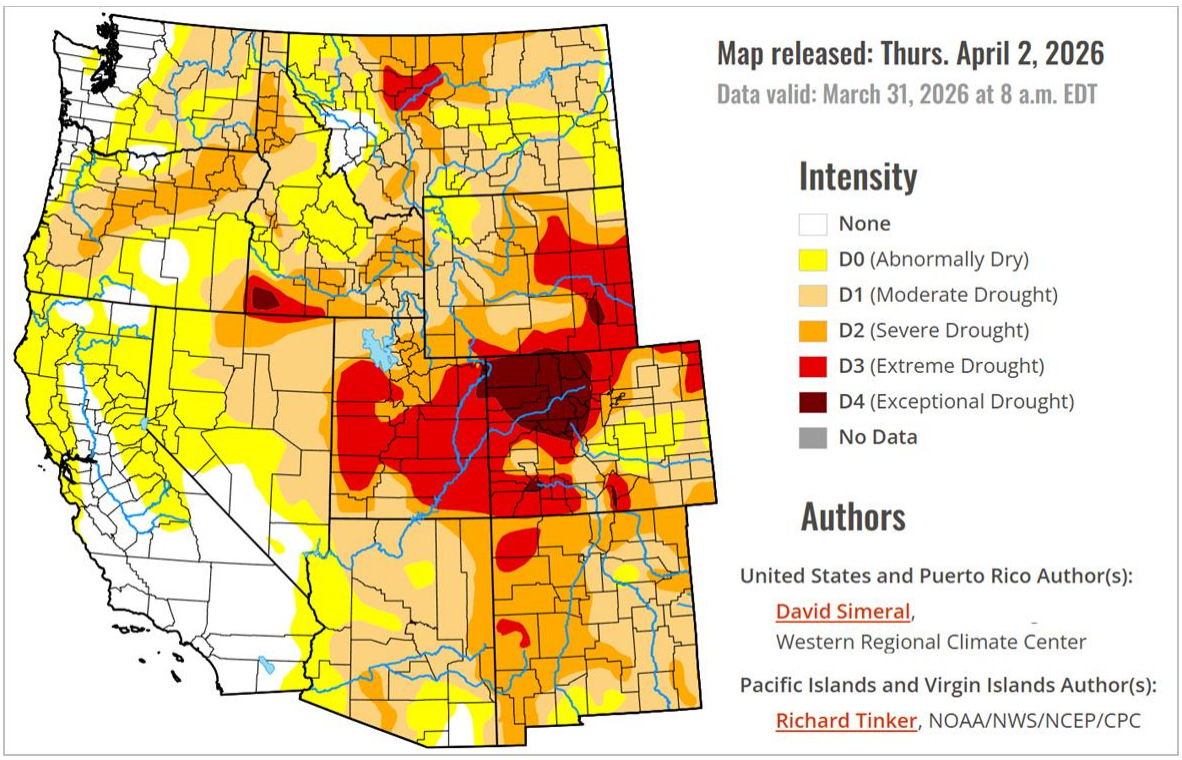
15 Climate Prediction Center staff. April 9, 2026. Climate Prediction Center: ENSO Diagnostic Discussion. National Oceanic and Atmospheric Administration, National Centers for Environmental Protection, National Weather Service, cpc.ncep.noaa.gov. https://www.cpc.ncep.noaa.gov/products/analysis_monitoring/enso_advisory/ensodisc.shtml

16 U.S. Drought Monitor. 2026. *Drought Conditions - March 31, 2026.* National Drought Mitigation Center, https://droughtmonitor.unl.edu/data/png/20260331/20260331_west_trd.png

particular experienced significant rainfall in late 2025. By the start of April 2026, abnormally dry (pre-drought) conditions are back in many areas of Northern California and pockets of Southern California.

Drought is still occurring in significant portions of the other states in the West, and is expected to persist with below normal precipitation expected in parts of Washington, Oregon, Idaho and Montana.[17] As of December 31, 2025, much of British Columbia is also experiencing abnormally dry or moderate drought conditions with pockets of severe drought.[18] The drought in the Pacific Northwest is a concern as much of the region's capacity is derived from hydroelectric resources. Figure 4 shows the current United States (U.S.) Drought Monitor conditions for the Western states. Figure 5 shows the CPC Seasonal Precipitation Outlook for July–September 2026.

Figure 4: Drought Conditions for the Western United States

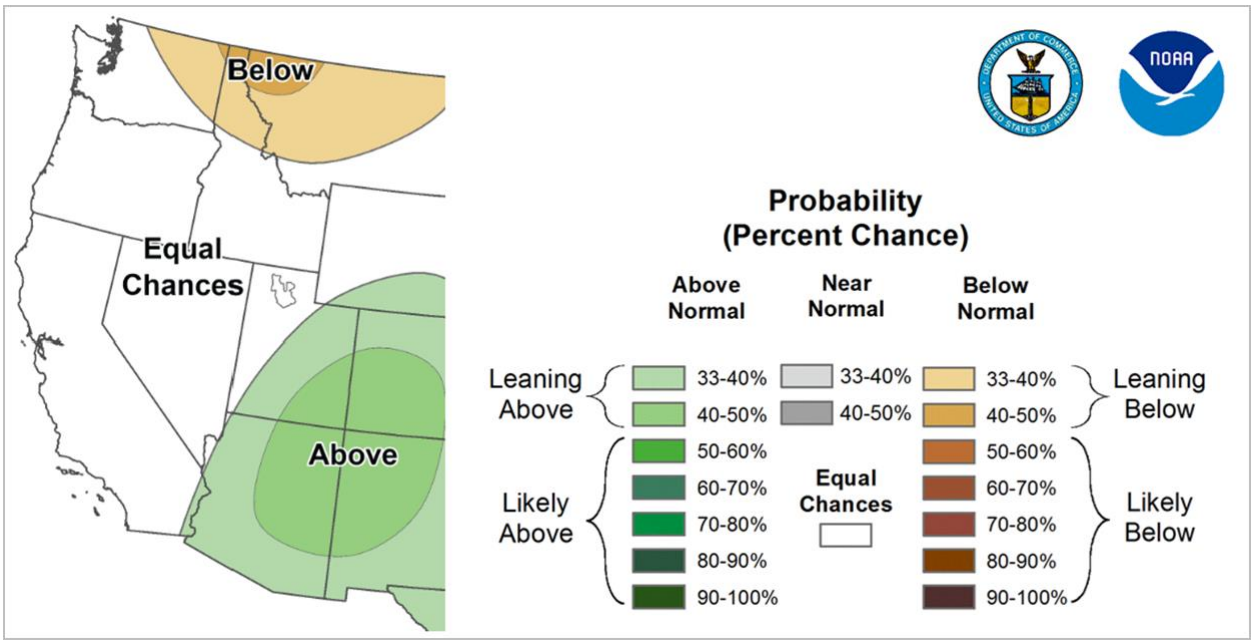


Source: U.S Drought Monitor, valid March 31, 2026

17 Climate Prediction Center staff. 2026. *Seasonal Precipitation Outlook for July - September - March 19, 2026.* Climate Prediction Center, https://www.cpc.ncep.noaa.gov/products/predictions/long_range/lead05/off05_prcp.gif

18 Agriculture and Agri-Food Canada staff. December 2025. *Current Drought Conditions*. Agriculture and Agri-Food Canada, https://agriculture.canada.ca/en/agricultural-production/weather/canadian-drought-monitor/current-drought-conditions

Figure 5: Seasonal Precipitation Outlook for July–September



Source: CPC Seasonal Precipitation Outlook for July–September 2026, valid March 19, 2026

Wildfire Risk

Wildfire and risk of wildfire can disrupt energy systems directly and indirectly. Heat and smoke can directly damage equipment or disrupt electricity flows. For example, water or other particles in smoke can directly cause electricity flowing on powerlines to arc, presenting a dangerous situation around the lines and potentially causing electrical disturbances in the network. This hazard also presents an indirect risk to the availability of power as firefighting crews may request such powerlines be proactively shut off for firefighter safety, impacting the ability to deliver generation to load or making the system more susceptible to disturbances. Because electricity equipment can cause ignitions, utilities may also proactively shut off certain power lines for safety during elevated wildfire conditions, a policy known as Public Safety Power Shutoffs.

The Wildfire Forecast & Threat Intelligence Integration Center (WFTIIC) serves as California's central organizing hub for wildfire forecasting, weather information, threat intelligence gathering, analysis, and dissemination, including a monthly four-month outlook.[19] The current WFTIIC four-month outlook forecasts above normal conditions for wildfires in most of Northern California in June and July.[20] WFTIIC outlooks for later months are not available at the time of this writing. Significant wildfire potential is

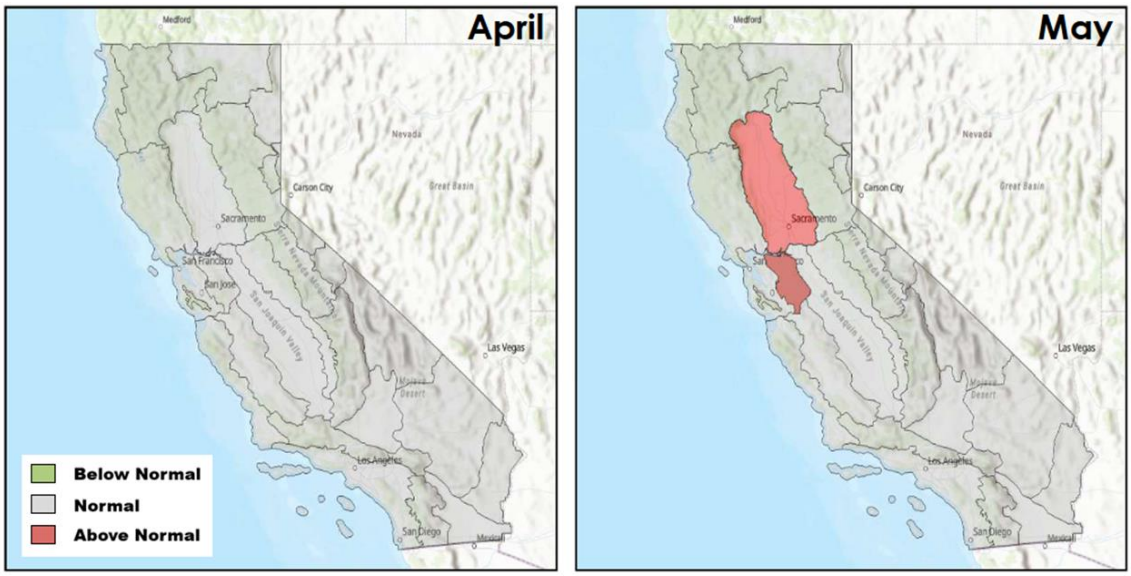
19 Wildfire Forecast and Threat Intelligence Integration Center staff. N.d. *Wildfire Forecast and Threat Intelligence Integration Center*. Wildfire Forecast and Threat Intelligence Integration Center, https://hub.wftiic.ca.gov/
20 Wildfire Forecast and Threat Intelligence Integration Center staff. N.d. WFTIIC Four Month Outlook. https://www.wftiic.ca.gov/long-term/

relative to the month and location and many areas are prone to wildfires in the summer and fall, so destructive wildfires can still occur even in normal or below normal conditions.

The California-Oregon Intertie and the Pacific DC Intertie, two critical north-to-south import paths into California, providing up to 4,800 MW of import capacity and up to 3,200 MW of import capacity, respectively, traverses areas in Oregon and Nevada prone to wildfires.[21] Current forecasts predict normal fire conditions in California and the Pacific Northwest in April. Starting in May, forecasts predict growing areas of above normal fire conditions in Northern California with much of Northern California, Oregon and Washington in above normal conditions in June and July. Forecasts through May for British Columbia indicate normal fire conditions. Forecasts beyond July for the Western states and British Columbia, respectively, are not available yet. Normal conditions during fire season include significant potential for major wildfires, particularly in Oregon.[22] shows the outlook for June–July.

Figure 6 shows the WFTIIC Significant Fire Potential Outlook for California in April–May 2026. Figure 7 shows the outlook for June–July.

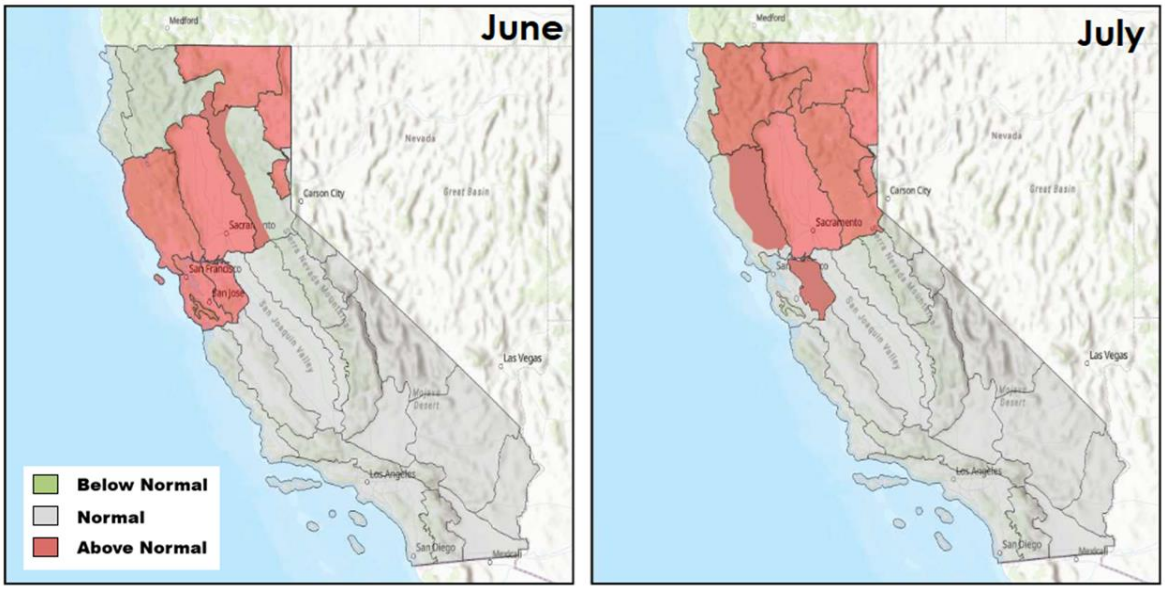
Figure 6: Significant Fire Potential Outlook for April – May 2026



21 WECC Studies Subcommittee staff. 2024. *2024 Path Rating Catalog — Public Version*. WECC, https://www.wecc.org/sites/default/files/documents/meeting/2024/2024%20Path%20Rating%20Catalog%20Public_v2.pdf

22 National Interagency Coordination Center staff. N.d. *National Significant Wildland Fire Potential Outlook*. United States Department of the Interior, https://www.nifc.gov/nicc/predictive-services/outlooks

Figure 7: Significant Fire Potential Outlook for June–July 2026



Source: WFTIIC Significant Fire Potential Outlook, valid April 2, 2026

Hydrologic Conditions

Early-season storms briefly improved snow conditions in late 2025 and early 2026, but dry weather and record hot March temperatures have reversed those gains. The Department of Water Resources (DWR) found no measurable snowpack during its critical April 1 survey. Statewide, the April 1 snowpack was 18 percent of average for this date.[23] Despite the weakened snowpack outlook, reservoir storage conditions remain strong in California, Oregon and Washington. Major reservoirs statewide are approximately 116 percent of average, and most major reservoirs in California, Oregon, and Washington have reached, almost reached, or exceeded seasonal average water levels.[24] While the Sierra snowpack typically supplies about 30 percent of the state's water needs, the current reservoir levels suggest California hydroelectric resources will likely be available throughout the peak summer months. However, current water level observations indicate potential limitations on the availability of water this year for hydroelectric generation in the Western Interconnection (WI) and consequently for imports into California.

23 Jason Ince. Record Hot, Dry March Wipes Out California Snowpack, Leaving No Measurable Snow for April Survey. https://water.ca.gov/News/News-Releases/2026/Apr-2026/Record-Hot-Dry-March-Wipes-Out-California-Snowpack-Leaving-No-Measurable-Snow-for-April-Survey
24 U.S. Bureau of Reclamation. Current Major Reclamation Reservoir Storage as of April 1, 2026. https://data.usbr.gov/rise/rise-resviz/usbrTeacups20260401.pdf

New California Resources

In 2026, the California ISO is set to bring online a range of new energy resources to enhance grid reliability and support the state's clean energy goals. These additions include new solar PV, wind, and battery storage capacity. As California continues to adapt to increasing electricity demand and climate related challenges, these new resources will play a critical role in maintaining system reliability and meeting long term energy goals.

Table 1 shows the cumulative expected new resources by month. By June 30, 2026, over 5,600 MW of new capacity is expected to come online. Solar and battery storage represents the largest share of expected new resources, accounting for 84 percent of total capacity expected by June. Separate from Table 1, Sunzia Wind, a 3,600 MW wind resource connecting to the CAISO from New Mexico using the Subscriber Participating Transmission Owner model, is expected to be online before the start of summer.

Table 1: California ISO Queue Cumulative Expected Resources (in MW) as of April 20, 2026

Resource Type	Jan	Feb	Mar	Apr	May	Jun
Battery	92	92	348	1,369	2,103	2,936
Geothermal	0	0	0	0	0	0
Hydro	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0
Other	0	0	0	0	0	0
Solar	3	8	173	755	1,139	1,849
Wind	0	0	300	650	879	903
Total Expected	**95**	**100**	**821**	**2,774**	**4,121**	**5,688**

Source: California ISO New Resource Interconnection

Energy Storage

Energy storage continues to provide critical value by reducing curtailments, capturing generation during off-peak times, and discharging later in the day as solar energy declines with the setting sun and loads reach their diurnal peak. The rapid expansion of energy storage across the residential, commercial, and utility-scale sectors in California has provided grid stabilization, peak-shaving, and time-shifting capabilities. California has now gone three years in a row without calling a Flex Alert for voluntary conservation—a testament to building the state's strong battery storage fleet.[25]

25 California Energy Commission. 2025. *California's Battery Storage Fleet Continues Record Growth, Strengthening Grid Reliability*. California Energy Commission, https://www.energy.ca.gov/news/2025-11/californias-battery-storage-fleet-continues-record-growth-strengthening-grid.

As of July 2025, California has almost 17,000 MW of battery energy storage deployed across more than 284,000 installations. Utility-scale installations make up 13,880 MW, or 82 percent, of the total capacity from some 248 facilities. Residential and commercial installations make up 3,062 MW, or 18 percent, of the total capacity from more than 284,000 behind-the-meter installations. Of these BTM installations, residential homes account for more than 2,200 MW and are a significant resource in aggregate that help reduce demand during high-use periods, providing new ways to keep the grid balanced in real time. Finally, there is an additional 1,550 MW of utility-scale storage capacity actively serving California from 13 facilities located in Arizona and Nevada. These grid-level systems are dispatched directly by California utilities operating in the California ISO balancing area.

Battery storage is the fastest growing resource type in the California ISO balancing area. As of January 1, 2025, utility-scale battery storage makes up nearly 14 percent of the California ISO's nameplate capacity.[26] Based on the California ISO interconnection queue, approximately 2,100 MW of utility scale battery storage is expected to come online by December 31, 2026, across 40 sites. The largest additions will occur in Kern, Riverside, and San Diego counties. Beyond the assigned resources, there is an additional 6,000 MW of energy storage in the queue for deployment through 2029, more than half planned for Southern California, specifically Los Angeles, Orange, Riverside, and Ventura Counties.

A comprehensive interactive Tableau dashboard[27] tracks all three sectors of battery energy storage and includes filters for utility, county, and ZIP code. Until recently, the dashboard was updated semiannually to correspond with the cadence of CEC statewide data collection. However, because California ISO data updates are more frequent, the dashboard will receive interim monthly updates reflecting new CAISO territory storage beginning September 2026. Dashboard data for the remainder of the state will continue to be updated semiannually, with the next update planned for October 2026.

Resource Adequacy

Tight resource adequacy (RA) supply conditions—which California experienced in 2020 and 2022s—reflect the interaction of higher forecasted system loads, challenges with the unprecedented ramp up of resource development, and higher planning reserve margins (PRMs). Regional supply constraints across the West have also limited the availability of imports for contracting to fill the supply gap in these situations.

During the 2023 compliance year, CPUC-jurisdictional load-serving entities (LSEs) met their system, local, and flexible RA obligations. Total committed RA capacity ranged

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26 California ISO. May 29, 2025, *2024 Special Report on Battery Storage*. California ISO, https://www.caiso.com/documents/2024-special-report-on-battery-storage-may-29-2025.pdf
27 California Energy Commission. "California Energy Storage System Survey" https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/california-energy-storage-system-survey

from about 32,500 MW in spring to roughly 50,000 MW in September. Actual California ISO peak demand in 2023 was lower than in 2022, but RA obligations increased due to higher load forecasts and a higher PRM requirement. Most capacity was procured from in-state physical resources, supplemented by imports, demand response, and centrally procured resources.

Tight supply conditions were reflected in RA prices[28]. Table 2 shows system RA prices increased by at least $3/kilowatt (kW)-month in 2024, especially in summer months, with system and local RA prices far above levels seen in 2020. Price increases were driven by higher procurement volumes, reduced qualifying capacity from wind and solar PV during critical hours, and a limited supply of available resources as some units retired or faced operational limits. Flexible RA prices also increased, reflecting the value of dispatchable and ramping capability.

Table 2: RA System Capacity Prices 2020-2025

	2020	2021	2022	2023	2024	2025
Contracted Capacity (MW)	165,422	182,029	99,685	136,431	216,309	200,937
Weighted Average Price ($/kW-month)	$4.97	$6.50	$7.67	$11.10	$14.51	$11.87
Average Price ($/kW-month)	$5.95	$6.93	$8.31	$11.78	$17.31	$14.60
85% of MW at or below ($/kW-month)	$7.60	$9.00	$10.75	$20.00	$30.00	$25.00
Source: 2020-2025 price data submitted by LSEs						

Source: CPUC 2020, 2021, 2022, 2023 RA Reports

Recent Developments in California Resource Adequacy

Building on the 2023 RA compliance year, the CPUC has adopted a series of major program changes through successive decisions in the RA rulemaking (R.23-10-011) that materially reshape how reliability is procured in California. In mid-2024, track 1[29] of the proceeding finalized the transition to the Slice-of-Day (SOD) framework beginning with

28 Draghi, Zoe, Allyson DiLorenzo, Elijah Cohen, Lily Chow, Jaime Rose Gannon, and Nathan Barcic. August 2025. *2023 Resource Adequacy Report*. California Public Utilities Commission. Available: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2023-resource-adequacy-reportv2.pdf

29 CPUC decision D.24-06-004 resolves issues scoped in Track 1 of the of the Resource Adequacy Proceeding, Rulemaking R.23-10-011. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M534/K619/534619523.PDF

the 2025 compliance year. Under SOD, LSEs must procure capacity to cover every hour of the day rather than only the single system peak hour, emphasizing potential reliability risks during evening and non-peak hours. The Decision set a 17 percent PRM under SOD. The SOD framework is increasingly important to support reliability as solar PV market penetration continues to increase rapidly. Under an effective load carrying capability (ELCC) RA framework, solar PV contribution at peak is captured as a single capacity value while SOD expands capacity contributions to representative 24 one-hour slices for the month. Greater granularity allows for a more accurate reflection of each resource's hourly reliability contribution, better alignment with evolving net-load shapes, and improved valuation of technologies that provide capacity outside the traditional peak window.

Subsequent Track 2 decisions in late 2024 shifted the focus from near-term procurement targets to analytical foundations for future reliability standards. These changes are intended to improve the technical basis for reserve margin setting under the SOD framework.

Track 3, decided in 2025, further tightened reliability requirements and clarified longer-term expectations. The CPUC increased the PRM to 18 percent for the 2026–2027 compliance years under SOD and layered on an additional "effective PRM" procurement target, requiring IOUs to procure an extra 1,260 to 2,300 MW of reliability resources, based on the estimated CPUC jurisdictional load share of the 2026 California ISO coincident peak demand forecast for summer months. The CPUC deferred more structural reforms, such as unforced capacity accreditation and hourly obligation trading[30], for further study in a successor RA proceeding. These changes directly respond to the tightening supply conditions, rising RA costs, and compliance challenges documented in the 2023 RA Report, by introducing RA program reforms aim at aligning capacity requirements more closely with hourly reliability risk, and reducing inefficiencies in the RA market.

30 CalCCA's Hourly load obligation trading proposal may need further studies. However, CalCCA states this market mechanism "will promote affordability without compromising reliability". https://cal-cca.org/wp-content/uploads/2025/01/Proposals-on-Track-3-of-OIR-to-Oversee-the-RA-Program-01-17-25.pdf

CHAPTER 3:
Summer 2026 Electric Reliability Analysis

This chapter presents the 2026 Loss of Load Expectation (LOLE) assessment and resource stack analysis to evaluate near-term electric system reliability. The CEC uses two methods that provide valuable, but different, perspectives on the reliability outlook, a LOLE analysis[31], and a resource stack analysis. The resource stack analysis is used to evaluate scenarios to determine the potential need for contingency resources under a variety of conditions. The LOLE determines whether a forecasted resource build is projected to have a maximum of 1 day with loss of load in 10 years using a probabilistic analysis. This analysis is widely considered the industry standard for RA planning and is used for near-term to long-term planning.[32] RA analyses allow resource planners and policy makers to determine whether enough resources are being planned for or procured. A resource stack analysis can capture specific circumstances that may not be under the control of resource planners and policy makers and not easily incorporated into LOLE models, such as extreme weather events and resource delays, to guide contingency planning and is best used for near-term planning.

CEC staff's analysis of 2026 summer conditions includes:

- **Probabilistic LOLE Assessment:** The probabilistic LOLE assessment finds that California meets the 0.1 days per year, or 1 day in 10 years, reliability criterion in 2026 across multiple scenarios, including stress cases with known loads and reduced imports. The analysis estimates a statewide surplus of approximately 7 to 8 GW to the 1-in-10 reliability standard, under the base scenario. While near-term reliability conditions are strong in all but the most extraordinary circumstances, load growth, electrification, transmission constraints, and climate-related risks underscore the need for continued monitoring and forward planning.
- **Resource stack analysis:** The resource stack analysis for 2026 finds that the system maintains positive summer margins across all evaluated scenarios. However, margins narrow when known loads are incorporated and under extreme heat events comparable to 2022. Potential delays in new resource development and wildfire-related transmission outages remain key risks that could materially reduce available capacity during stressed conditions.

31 In this report, LOLE analysis is also referred to as the RA analysis.

32 RA analyses allow resource planners and policy makers to determine whether enough resources are being planned for or procured

Loss of Load Expectation Analysis

Each year the CEC performs a probabilistic reliability assessment of electric system operations for the state of California, historically focused on summer months but now extending into winter periods. These reliability assessments are published in yearly CERRO reports, and are intended to support state system operators, regulatory agencies, electric industry participants, and other stakeholders in planning and preparing for electric system operations throughout the year, especially during challenging summer grid conditions across the Western Electricity Coordinating Council (WECC) and high summer loads.

For this *2026 CERRO*, staff performed a probabilistic assessment of the reliability outlook for the entirety of 2026. This analysis seeks to determine if California is meeting the reliability criterion of 1 day in 10-year LOLE, or 0.1 days/year LOLE, under a variety of scenarios related to import uncertainty and demand variability.[33] Several RA risks are evaluated in this analysis, combining uncertainty in resource availability, hourly demand, unexpected generator outages, lower-than-expected imports, and delays in resource builds.

This analysis evaluated the system across multiple *2025 IEPR Update* Forecasts including 2025 Planning, 2025 Planning with Known Loads, and 2025 Local Reliability with Known Loads to account for demand forecast uncertainty. In addition, the 2024 *IEPR* Planning Forecast is also included in this analysis. Further the LOLE analysis leverages the resource portfolio of the CEC Stack Analysis for California ISO net qualifying capacity (NQC) resources, and the Quarterly Fuels and Energy Report (QFER) for California ISO and POU energy-only resources through 2025. This presents a better representation of the existing system and permits more direct comparison to other state reliability analyses. Diablo Canyon Power Plant (DCPP) maintains the retirement dates of October 31, 2029 (Unit 1) and October 31, 2030 (Unit 2). Finally, imports into California as a whole, are limited to 12,450 MW in all hours of the day, subject to monthly energy limits. The California ISO import constraint is set at 11,655 MW, which is the California ISO Maximum Import Capability (MIC) in non-peak hours. Imports for morning and evening peak hours across the year are restricted to 5,500 MW to represent the potential for heightened energy needs in neighboring regions or other transmission constraints.

Approach: Model Development and Key Assumptions

See Appendix C for a detailed discussion of CEC's RA model.

Scenarios

The study conducts reliability assessments on the following scenarios intended to evaluate a range of demand projections and import availability.

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33 Loss of Load Expectation (LOLE) is a probabilistic reliability metric that measures the expected number of days per year when available generation capacity is insufficient to meet demand.

1. **Base Case, 2025 IEPR Planning Forecast:** Base planning case without known loads from the 2025 IEPR Forecast. This represents the standard system resource adequacy forecast.
2. **2025 IEPR Planning Forecast with Known Loads:** Includes known loads. For 2026, known loads add about 3 percent at system annual coincident peak.
3. **2024 IEPR Planning Forecast:** Uses the prior year's IEPR planning forecast as a sensitivity. Starting in 2027, the 2024 IEPR Forecast has a higher peak load than the 2025 IEPR Planning Forecast, increasing to 6 percent higher at system annual coincident peak by 2035.
4. **2025 IEPR Local Reliability Forecast with Known Loads:** The 2025 IEPR Local Reliability forecast has significantly higher demand due to lower expected energy efficiency and behind the meter solar PV and storage resources, and higher expected fuel switching, transportation electrification, and data center development as compared to the planning forecast. The local reliability forecast is used for Transmission Local Studies. For 2026, this forecast adds about 4 percent at system annual coincident peak.

Notable Updates from Previous CEC Reliability Reports

While the overall model is consistent with previous analysis conducted by the CEC, there are notable updates that have been made over the past several months. The list below provides an overview of the major changes implemented in the model.

- **Demand Update**: The CEC adopted a 2025 *IEPR* Forecast, which lowered forecasted peak loads and classified known loads as a distinct load modifier from the original forecast. The net peaks decreased relative to the previous 2024 *IEPR* Forecast for the Planning forecast.
- **California ISO import constraint**: The maximum import constraint was used for evening (hours 16-22) peaks across the summer in previous analyses. This constraint was added to all months in this analysis for both morning and evening peak periods. The *2025 CERRO* analysis found that California faces increased risk during the winter in the mid-term horizon (i.e., through 2035) and the likelihood for tightening supplies in winter months across the West.[34] This import assumption will be explored more in future reports as electrification continues and additional system information outside of California becomes available.
- **Stochastic loads**: The CEC developed underlying stochastic load profiles aligned with historical weather patterns. These profiles ensure the simulated electricity

34 Yee Yang, Chie Hong, Kristen Widdifield, Liz Gill, Jake McDermott, Justin Cochran, Joseph Merrill, Bryan Neff, Jason Orta, Matthew Cooper, Paul Deaver, Ashley Emery, Justin Szasz, and Michael Nyberg. July 2025. *California Energy Resource and Reliability Outlook, 2025*. California Energy Commission. Publication Number: CEC-200-2025-011. https://efiling.energy.ca.gov/GetDocument.aspx?tn=264559.

demand follows similar chronological weather patterns as the simulated solar PV and wind profiles. The utility-scale solar PV, distributed solar PV, and land-based wind profiles are based on historical weather years.

Factors Differentiating CEC LOLE Analyses to other State Reliability Analyses

The CEC, California ISO, and CPUC conduct other reliability analyses to evaluate reliability for the coming summer. The LOLE and Resource Stack Analysis in this report differ from the other analyses by focusing on the entirety of California rather than just the California ISO territory. The analyses also, as discussed above, considers resources not necessarily on the CPUC NQC list as potential contributors to reliability during the year. This is intended to capture resources that do not have or do not yet have NQC designations but may still contribute to reliability with their potential availability. This approach is not intended to opine on the potential of these specific resources to contribute to reliability, rather to represent an overall picture of system operating resources and an alternative viewpoint to other reliability analyses.

2026 LOLE RA Scenario Results and Discussion

California's power system risk has historically been defined by periods of high temperatures and low hydro availability. Near-term RA risks[35] are relatively limited due to significant additions of solar PV and batteries to the resource portfolio. The RA model results project that California will have surplus resources, meeting the 0.1 days/year LOLE reliability criterion, in 2026 across both the summer and the winter under normal hydro and transmission conditions. The resulting RA metrics are provided in Table 3 below for the scenarios under evaluation.

Table 3: 2026 Statewide Reliability Assessment Results Across Scenarios

Scenarios	Units	LOLE (days/year)	Effective surplus or deficit[36]
Base Scenario, 2025 IEPR Planning	LOLE (days/year)	0	7-8 GW Surplus
2025 IEPR Planning with Known Loads	LOLE (days/year)	0	
2024 IEPR Planning	LOLE (days/year)	0	
2025 IEPR Local Reliability with Known Loads	LOLE (days/year)	0	6-7 GW Surplus

Source: CEC staff

35 California has a reliability criterion of a 1 day in 10 year LOLE, or 0.1 days per year LOLE.

36 The Base Scenario and 2025 IEPR Local Reliability with known loads represents the boundaries of the effective surplus or deficit, given low and high load, respectively.

These results are largely consistent with the 2025 *CERRO*. Although the 2025 *IEPR* Forecasted peak demand is lower than the 2024 *IEPR* Forecast, the demand for both is closely aligned in the year 2026. However, the reliability outlook has improved due to significant additions of solar PV and storage in recent years. These results indicate that the probability of resource shortfalls is zero in the very near-term. Even considering factors that this analysis does not include, resource shortfalls are likely to be very low in the near-term. Additional sensitivities were evaluated to test system reliability, including the addition of known loads and extending import limits throughout the year. Furthermore, widespread Western drought and/or wildfires could also challenge reliability but were not explicitly considered in this analysis.

Overall, system reliability is expected to continue to improve in the near term compared to prior assessments. This is due to (1) significant new resource additions (in particular, utility-scale solar PV and batteries), (2) new energy efficiency and demand response programs, and (3) a modest reduction in forecasted loads relative to the *2025 CERRO.*

Surplus Calculations

To provide additional context, the CEC quantified the amount of surplus capacity on the system while maintaining the LOLE reliability criterion. This capacity surplus is calculated by adding firm load, applied as a constant capacity (MW) addition in all hours, until a 0.1 days/year LOLE is reached. Firm load is allocated to each region based on the region's contribution to forecasted coincident peak statewide load (e.g., 82 percent to California ISO). To calculate the effective capacity deficit, perfect generation is applied instead of firm load, until 0.1 days/year LOLE is reached.[37]

This analysis finds a statewide surplus of 7-8 GW in 2026 under the Base Scenario. If known loads materialize in 2026 the surplus would likely drop by about 1,500 MW to 5.5-6.5 GW. Without additional procurements this surplus is expected to diminish in future years. However, on February 26, 2026, CPUC voted on and approved a decision to order 6 GW of NQC by 2032.[38]

The surplus calculation assumes normal hydro conditions and transmission capability. This high level of reliability in 2026 is a result of significant additions of solar PV and storage and the availability of DCPP through 2030. For each gigawatt of firm load and perfect generation added, only 82 percent is added into California ISO regions; the other 18 percent is distributed to Los Angeles Department of Water and Power, Balancing Area of Northern California (BANC), Turlock Irrigation District (TID), and Imperial Irrigation District (IID) commensurate with each region's contribution to forecasted coincident peak statewide load. Applying this factor to the 7-8 GW statewide

37 Perfect generation represents a power plant operating at its nameplate capacity in all hours of the year and is a proxy to estimate capacity needs.
38 See CPUC Rulemaking 25-06-019.

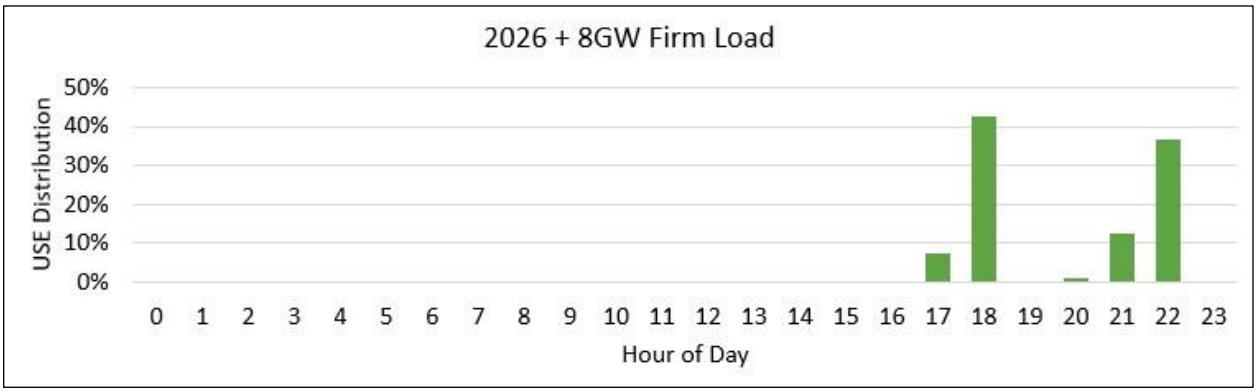
surplus, the surplus for California ISO is about 5-6 GW, which is close to the 2020 equivalent event surplus projected in the Resource Stack Analysis.

Characterizing System Risk

To further characterize system risk, the 2026 scenarios were calibrated to meet approximately 0.1 days/year LOLE utilizing the firm load or perfect generation approach described in the previous section. Note that all events occur within the California ISO, which is subject to the California ISO maximum import constraint. This analysis provides directional insights on the size, frequency, duration, and timing of reliability risk. While each scenario is calibrated to roughly 0.1 days/year, the underlying nature of the reliability risk shifts across the study horizon as the resource mix and load profiles evolve.

Figure 8 shows how unserved energy on days that have it is distributed throughout the day for calibrated study year 2026.[39] This analysis indicates reliability risks in early and late evening in 2026.

Figure 8: Unserved Energy Distribution throughout the Day for 2026 (% Unserved Energy)



Source: CEC staff

It should be noted that these results are provided for a system that was brought to the 0.1 days/year LOLE criterion by adding a constant firm load applied equally to all hours. For that reason, the demand profile is not necessarily representative of current or future demand, and the perfect generation does not necessarily represent how an installed generator would operate, particularly if a renewable or storage resource. While this is standard practice in reliability modeling, actual risk periods may be different as load grows, variable energy resources and storage are added and resources retire.

39 Unserved Energy is the total amount of customer electricity demand that cannot be met by the power system over a specific period. It serves as a key measure of the magnitude and impact of power shortfalls.

Resource Stack Analysis

The section provides a high-level overview of the resource stack analysis, as described in previously published SB 846 *Joint Agency Reliability Planning Assessment* quarterly reports.[40] This approach is a deterministic, scenario-based analysis spanning near-term horizons, with a focus on the peak summer months of July to September. The analysis compares anticipated supply against projected demand, incorporating PRMs that represent various levels of system stress.

California ISO Area: Updated Resource Stack Analysis Results for Summer 2026

This Resource Stack Analysis continues to focus on hour 18 of September, a period of high demand coupled with lower supply, making it the most critical time for evaluating potential shortfalls. Below are some key definitions to contextualize the analysis.

- Existing Resources: Existing resources refer to the amount of firm or dispatchable energy capacity currently available on the grid, excluding intermittent resources such as solar PV and wind generation. The analysis in this report uses data available through January 12, 2026.
- RA Imports: RA imports are electricity supplies from out-of-state generators contracted to provide firm capacity to California.

Expected New Resources

New resources refer to the sum of expected new in-state generation capacity projected to come online by June 30, 2026, adjusted for hourly generation profiles for resources such as solar PV, wind, and batteries. This analysis continues to apply a conservative approach to counting new resources. Given the uncertainty associated with new project development, only resources that show clear progress toward commercial operation are included. These include resources in testing or partially online status, active projects with assigned qualifying capacity, and resources that have begun operating but are not yet reflected in resource adequacy accounting. This analysis uses data from the California ISO's interconnection queue as of January 27, 2026.

Forecasted Demand

The Resource Stack Analysis in this report uses two demand projections to assess the potential impacts of additional demand on system reliability. The demand value is based on the newly adopted 2025*IEPR* Forecast, which developed a baseline forecast without

40 California Energy Commission Energy Assessments Division staff. 2025. *Summer Reliability*. California Energy Commission, https://www.energy.ca.gov/data-reports/california-energy-planning-library/reliability/summer-reliability.

the known loads dataset and a second projection incorporating the known loads dataset.[41]

For the baseline analysis, the updated projected peak demand for hour 18 of September 2026 is 46,546 MW. With the known loads dataset incorporated into the analysis, the system is projected to have over 1,300 MW of additional electricity demand in September, bringing the projected demand to 47,909 MW. If this additional demand materializes, it would reduce available supply margins across all scenarios as shown in Table 4.

Stack Analysis Results

The planning standard stack analysis in this report shows a positive supply margin for summer 2026 of 6,635 MW under current planning standard conditions, 4,540 MW for a 2020 equivalent event, and 2,911 MW for a 2022 equivalent event.

Table 4: Summer Resource Stack Analysis Results for September 2026 – Hour 18

	2026 Projection (MW)
Supply	
Existing Resources	50,988
Solar	1,766
Wind	1,307
RA Imports	5,807
Demand Response	794
Expected New Resources	897
Total (MW)	**61,559**
Demand	
Sept. Peak Demand	**46,546**
Surplus/Shortfalls	
Planning Standard	6,635
2020 Equivalent Event	4,540
2022 Equivalent Event	2,911

Source: CEC staff with California ISO data

41 California Energy Commission. 2025. *2025 Integrated Energy Policy Report*. California Energy Commission, https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2025-integrated-energy-policy-report-0

Stack Analysis Results with Known Loads

Table 5 shows the impact of known loads on system reliability across different scenarios. If these known loads materialize as expected, the available supply margin would decrease from 6,635 MW to 5,437 MW under planning standard conditions, from 4,540 MW to 3,281 MW under a 2020 equivalent extreme heat event, and from 2,911 MW to 1,604 MW under extreme heat equivalent to the 2022 event.

Table 5: Impact of Known Loads on Reliability

Scenario	Baseline Demand (MW)	Known Loads (MW)	Demand with Known Loads (MW)	Supply Margin with Known Loads (MW)	Changes in Supply Margin (MW)
Planning Standard	54,924	▲1,609	56,533	5,437	▼1,198
2020 Equivalent Event	57,019	▲1,670	58,689	3,281	▼1,259
2022 Equivalent Event	58,648	▲1,718	60,366	1,604	▼1,307

Source: CEC staff

Risk Scenarios

The current analysis shows that the grid will have enough power to meet demand this summer under the evaluated scenarios. However, several factors could reduce the available supply margin. This section examines two key risks: delays in new supply resources coming online and wildfires affecting transmission lines.

The stack analysis includes 897 MW of new resources expected to be available by summer 2026. These projects are currently being tested or are close to completion. However, new projects can be delayed due to equipment shortages, permitting issues, or interconnection problems.

Table 6 shows the impact of project delays under a 2022 equivalent heat event. If 40 percent of new projects are delayed, the system would lose up to 359 MW of new resource capacity. However, the system has sufficient existing supply to absorb the impact of delayed new resources. Even if all currently forecasted new resources are delayed, the grid would still maintain positive supply margins under this extreme heat scenario, assuming no other coincident events.

Table 6: Impact of New Project Delays – 2022 Equivalent Heat Event

Delay Scenario	Expected New Resources (MW)	Delayed Capacity Difference (MW)	Supply Margin Result (MW)
No Delays	897	0	2,911
20% of New Projects Delayed	897	▼179	2,732
40% of New Projects Delayed	897	▼359	2,552

Source: CEC staff

Wildfire remains a major source of uncertainty, with the potential to reduce available capacity primarily through impacts on major transmission lines. For example, the 2021 Bootleg Fire caused the loss of 4,000 MW of import capability on the California-Oregon Intertie (COI). Modeling results from a similar transmission outage scenario show that under typical conditions, the system would remain reliable. However, if a wildfire related outage were to occur during extreme heat, California could face reliability challenges. Table 7 shows the combined impact of potential wildfires and extreme heat conditions. If a transmission outage (similar to that of the Bootleg Fire) coincides with a 2022 equivalent heat event, the analysis indicates a potential contingency need exceeding 1,000 MW.

Table 7: Impact of Wildfire Transmission Outages on Reliability

System Condition	Current Forecasted Surplus/Shortfall (MW)	Loss of Transmission (MW)	Supply Margin Result (MW)
Planning Standard	6,635	▼4,000	2,635
2020 Equivalent Event	4,540	▼4,000	540
2022 Equivalent Event	2,911	▼4,000	**-1,089**

Source: CEC staff

Statewide Resource Stack Analysis

This section expands the Resource Stack Analysis to include supply and demand from all LSEs and POUs statewide. This analysis used data collected through the 2025 supply forms[42] to evaluate the amount of reliable capacity and net qualifying capacity (NQC) against average and extreme conditions, equivalent to 2020 and 2022 extreme heat

42 California Energy Commission staff. N.d. 2025.*California Energy Commission: Docket Log: 25-IEPR-02*. California Energy Commission, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=25-IEPR-02.

events, as defined in Table 8. For the planning standard conditions, a PRM is applied to each LSE's and POU's reported peak demand in the submitted supply forms.

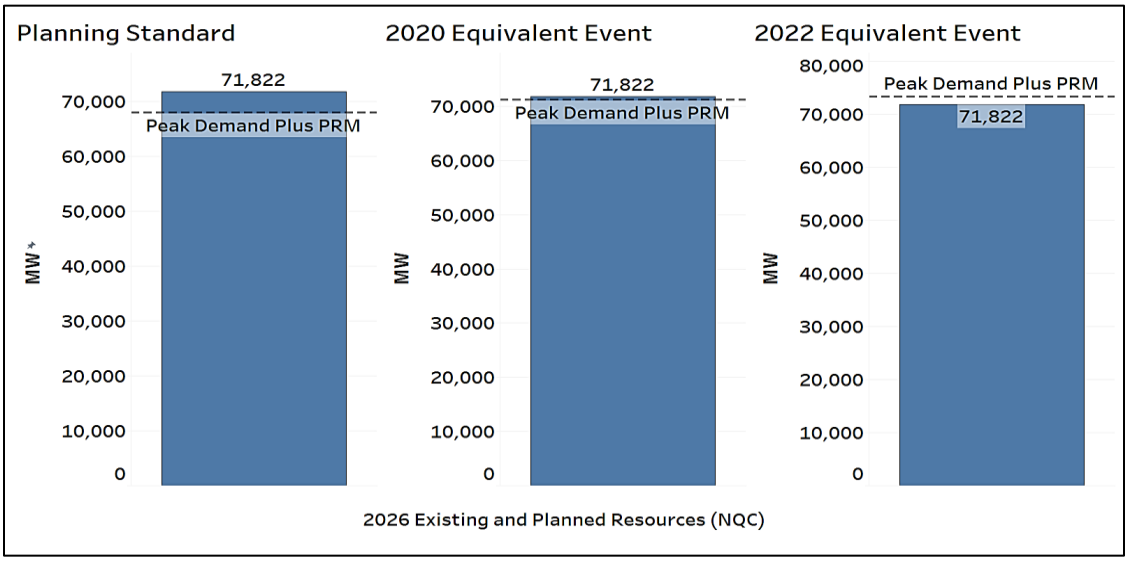
In 2026, the total reliable capacity reported in the supply forms is 71,800 MW, which includes existing and planned supply capacity. In comparing the resource requirements and total reliable capacity, Figure 9 shows a 3,800 MW surplus margin under planning standard conditions, at least a 500 MW surplus margin in a 2020 equivalent heat event and a 1,500 MW capacity deficit in a 2022 equivalent heat event. These results indicate potential tight conditions under heat events equivalent to a 2022 heat event. It is important to note supply forms typically include capacity contracted at the time of submission and LSEs, if short on capacity, continue to procure short-term capacity and spot market purchases throughout the year. In 2024, LSEs collectively procured over 5,800 MWs of short-term capacity and spot market purchases to meet peak demand.

Table 8: System Planning Reserve Margin Assumptions

Condition Relative to 1-in-2 Forecast	Operating Reserves	Outages	Demand Variability	Coincidental Fire Risk	Notes
Average Conditions: Current RA Planning Standard for CPUC LSEs– 18%	6%	5%	7%	4,000 MW	PRM for CPUC LSEs updated to 18% starting in 2026 Statewide PRM weighted average is 17.04%
2020 Equivalent Event: Additional capacity needed to ride-through heat event like 2020	6%	7.5%	9%	4,000 MW	9% higher demand over median forecast value, and 2.5% higher levels of outages
2022 Equivalent Event: Additional capacity needed to ride-through heat event like 2022	6%	7.5%	12.5%	4,000 MW	12.5% higher demand over median, and 2.5% higher levels of outages

Source: CEC staff

Figure 9: 2026 Statewide Reliable Capacity at Peak Demand



Source: CEC staff with supply forms

While the Resource Stack Analysis provides insights on projected system conditions, the actual conditions that materialize in real time may differ from projections in this analysis. Furthermore, the expected new resources available by the start of each summer month may also differ due to factors such as delays, construction, weather, permitting, and extended outages.

Contingency Resources

The state and the California ISO continue to track contingency resources, which are resources outside of the resources considered in the stack analysis and provide support during extreme events. The updated contingency list for 2026 is shown in Table 9. Contingency resources may provide up to 4,500 MW during extreme events and may be called upon to cover contingency needs identified in real time grid operations.

Table 9: Contingency Resources for Summer 2026

Type	Contingency Resource	Available MW July	Available MW August	Available MW September
SRR, SPAP[43]	DWR Electricity Supply Strategic Reliability Reserve Program and State Power Augmentation Program[44]	3,079	3,079	3,079
SRR	Demand Side Grid Support (DSGS) [45]	325	325	325
SRR	Distributed Electricity Backup Assets (DEBA) [46]	0	0	0
CPUC	Ratepayer Programs (Emergency Load Reduction Program, Smart Thermostats, etc.)	200	200	200
CPUC	Imports Beyond Stack	0	0	0
CPUC	Capacity at Co-gen or Gas Units Above Resource Adequacy	599	599	499
Non-Program	Balancing Authority Emergency Transfers	300	300	300
Non-Program	Thermal Resources Beyond Limits: Gen Limits Needing 202c [47]	25	25	25
N/A	**Total**	4,528	4,528	4,428

Source: CEC staff with California ISO, DWR, and CPUC data

43 Strategic Reliability Reserve and State Power Augmentation Program, MW amounts reflect expected maximum capability

44 The Time Schedule Order (TSO) associated with Alamitos Generating Stations' National Pollutant Discharge Elimination System (NPDES) permit expired on December 31, 2025. As such, maximum generation from Alamitos Generating Station may be reduced to meet the requirements of the NPDES permit such as high outfall water temperature restrictions, especially between May and October 2026.

45 DSG capacity values are preliminary estimates based on budget assumptions and expected participation; actual capacity may vary due to uncertainties in enrollment and performance. Approximately 186 MW are anticipated to come online in 2027.

46 Seven projects, totaling approximately 186 MW, are anticipated to come online in 2027.

47 Federal Power Act (FPA) section 202(c) (authorizes the Department of Energy to temporarily waive federal, state, or local environmental regulations during emergency conditions to maintain electric reliability).

Conclusions

The study did not evaluate all potential risks to reliability, and work is underway to evaluate risks associated with wildfire and the broad deployment of inverter-based resources, described in CHAPTER 5: Electric Resource Planning Issues. Further work is planned to evaluate the impacts of transmission outages, and reduced availability of new resources or imports, among others. Alternative load scenarios are also not evaluated, such as increased or different electric vehicle charging patterns or weather dependent electrification that may further drive summer or winter reliability risks, though CEC may study these issues in future analyses.

While the results from all scenarios indicate that California is expected to meet its RA targets for 2026, local generation or transmission outages during periods of particularly high demand, coupled with limited imports, could still lead to tight conditions.

The probabilistic assessment concludes that California's existing resources, along with those expected to come online by 2025, will be sufficient to meet the 0.1 LOLE reliability standard and maintain reliable service under demanding conditions including peak demand, resource constraints, and import constraints, during summer and winter of 2026.

CHAPTER 4: Emerging Loads and Demand Flexibility

The CEC 2025 IEPR Forecast contains baseline forecasts and several scenarios for forecast components that are more uncertain. For electricity system planning, sets of the baseline forecasts, known loads, data centers, and other load modifying components are combined into a planning forecast and a local reliability scenario. The CEC, CPUC, and California ISO agree to use specific combinations of this forecast set for planning and procurement. The planning forecast is used for resource adequacy, integrated resource planning, and system-level transmission planning. The local reliability scenario is used for planning activities with more granular geography, such as the California ISOs transmission planning process local area reliability studies and distribution planning process.

The CEC 2025 IEPR Planning Forecast provides estimates for California's future noncoincidental peak electricity demand in seven planning areas. The *2025 IEPR* shows that the annual peak demand in California will increase from around 61 GW in 2026 to 83 GW by 2045. About 80 percent of the load during peak demand in 2026 occurs in the California ISO territory.

Chapter 2 discusses the trends and emerging challenges or opportunities associated with California's growing load. These issues include IOU known loads and data center. These issues include improving the IEPR load forecast with IOU known loads and, data center loads, hydrogen, agricultural sector electrification, and demand flexibility as a resource. The known loads dataset are customer applications to connect new loads onto the utility distribution system and are integral to the IOUs distribution planning process. Examples of known loads projects include new tract homes, commercial office buildings, electric vehicle (EV) charging stations, and industrial facilities.

Improving Load Forecast with Known Loads

In the distribution planning process, IOUs identify grid updates needed to accommodate utility customer applications to add new load which is reflected in the known loads application data. Due to the various types of loads and the load amount requested by customers to be added to the distribution system, utilities have relied on the known loads dataset to inform distribution planning.

CPUC launched the High distributed energy resources (DER) proceeding in 2021 to promote proactive distribution planning and to solve challenges with delays in energizing new construction buildings. In the CPUC's High DER proceeding, the utilities expressed concern that the IEPR demand forecast showed less load growth in the near-

term than their known loads data indicated. CPUC Decision D.24-10-030[48] under the High DER proceeding required IOUs to share known load data with the CEC as of 2025. CPUC Decision D.24-10-030 also allows the IOUs to exceed the IEPR Forecast where known loads show more load growth than was included in the IEPR Forecast. This change leads to misalignment between distribution planning and other system planning processes that adhere to the IEPR Forecast, notably transmission system planning. As a first step towards resolving this misalignment, CEC staff began examining the impacts of the known loads data to inform near-term load growth for the *IEPR* Forecast.

Projects tracked in the known loads dataset have gone through review by utility distribution planning staff and are considered to have a high degree of certainty that projects will start construction and eventually be energized. However, some projects may be cancelled for a variety of reasons, such as difficulty obtaining funding, factors related to the broader economy, or other reasons. Approximately 23 percent of projects tracked in the known loads dataset are for EV charging stations.

However, adding known loads to the planning forecast risks overestimating demand given uncertainty in project completion, energization timelines, actual load as a percentage of requested capacity, and interaction with other components of the overall demand forecast. For these reasons, the impacts of known loads are included only in the Local Reliability scenario that is used by the California ISO for transmission local studies, to help align distribution and local transmission planning. For additional discussion on this topic, refer to the section on "Uncertainty and Limitations" below. As part of the 2026 *IEPR* cycle, CEC staff will undertake additional analysis of the known loads data to better understand trends in the known loads data.

Known Loads Forecast Methodology

Utility Data Collection

CEC staff, working collaboratively with the CPUC, issued data requests to IOUs to collect project-level data contained in the known loads dataset. CEC staff also collected load profile assumptions and collected meter IDs for completed projects to facilitate analysis of interval meter data. The known loads dataset, along with the associated load profiles and meter data, informed CEC staff analysis of near-term load growth. In addition, staff from IOUs also provided input to CEC staff on assumptions regarding project completion date, load ramping, and utilization rates.

48 California Public Utilities Commission. October 17, 2024. *Decision 24-10-030: Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps*. Rulemaking 21-06-017. Available: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M544/K154/544154869.PDF

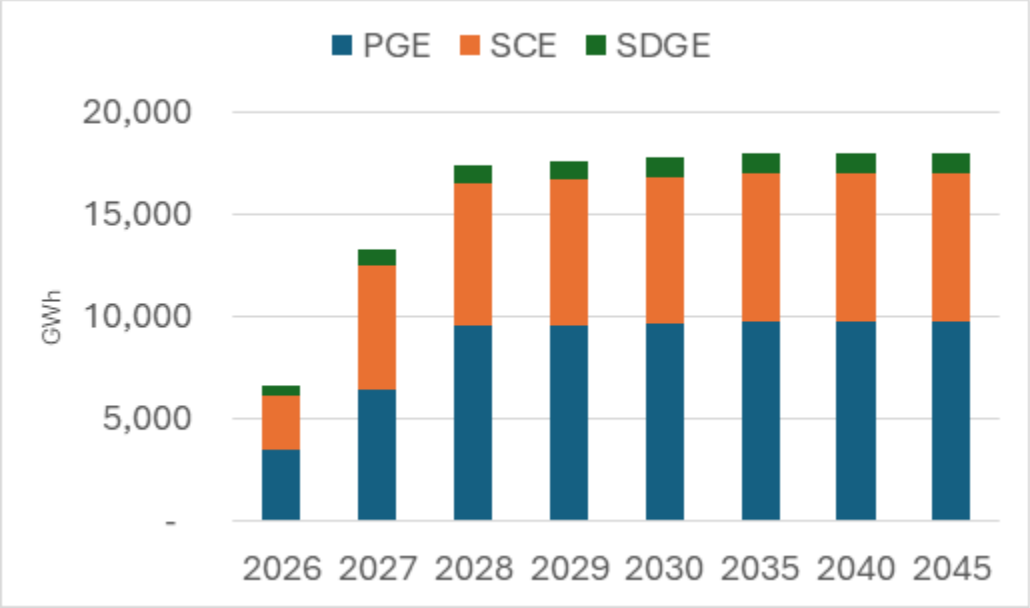
Conversion of Capacity Requests to Load

CEC staff took several steps to translate capacity requested to load. First, CEC staff aggregated project level capacity in the known loads dataset by CEC demand forecast zone, sector, and the year and month of the requested energization date. Second, based on this grouping, the aggregated capacity was adjusted for project cancellation rate, based on historical project cancellation rates, utilization rate, and extended over the forecast period. Finally, load profiles were applied to estimate the corresponding annual load impacts. The estimated annual load impact was then compared to the CEC's baseline sector sales forecast, and only the incremental portion exceeding the CEC's baseline sector sales forecast was counted as load impacts attributable to known loads. While this helps avoid double-counting, CEC staff notes that this approach provides an estimate of the impacts of known loads that may be high due to interactive effects with other forecast load modifiers, which were not assessed for the 2025 *IEPR* Forecast due to a lack of information. For example, the known loads dataset does not include information about building electrification or on-site generation resources therefore CEC staff were not able to make adjustments. Staff will work with the IOUs throughout 2026 to develop a methodology to account for load modifiers embedded in the known load data.

Known Loads Forecast Results

CEC staff estimated that known loads could increase annual electricity sales and contribute to additional peak load as shown in Figure 10 based on updated data provided in December 2025 by utilities. These impacts are incremental to load growth captured in the baseline forecast, based on economic and demographic data.

Figure 10: Known Loads Annual Electricity Sales Impacts by Year and Utility



Source: CEC staff

Uncertainty and Limitations

Forecasting impacts of known loads can be challenging for several reasons:

- Limited Historical Data: Historical data on key metrics needed to estimate impacts are unavailable. Additionally, while IOUs routinely add new customer loads due to expansion plans or to construct new buildings, the volume of requests over the last several years is unprecedented.
- Energization Timelines: There is uncertainty with how many projects will finish construction and the timing of completed project energization.
- Load Ramping: The pace of how quickly the new load will ramp to its maximum load after the project is energized is another uncertainty in the forecast. If the completed projects ramp faster than assumed, this will lead to higher annual sales and a higher contribution to system peak while a slower ramping schedule will lead to lower sales and a lower contribution to system peak.
- Utilization Factor: There is uncertainty regarding the percentage of requested capacity that will be used by the customer. CEC staff will continue to analyze meter data for completed projects to develop assumptions for utilization factors.
- Interaction with Other Forecast Components: The known load data do not include information about whether the requested capacity accounts for self-generation; whether the non-transportation loads include electric vehicle charging stations; or whether the project is all electric. As such these impacts may not be properly accounted for and may result in load estimates that are too high. CEC staff will investigate this further for the 2026 IEPR Forecast.

Because of these uncertainties, the impacts of known loads are only considered as part of the local reliability scenario used by the California ISO for local transmission studies. This will allow the California ISO to identify any potential impacts to the local transmission network and plan for upgrades if necessary. Including the impact of known loads in the planning scenario would increase resource adequacy requirements and integrated resource planning procurement targets. Therefore, to minimize impacts to rates, the joint agencies decided not to include known loads in the planning scenario and allow CEC staff more time to collaborate with stakeholders to better understand the impact of known loads before considering them in other electricity system planning processes.

Future Improvements and Ongoing Work

As part of the *2026 IEPR* forecast cycle, CEC staff will explore new tools and methodologies that can bridge the gap between the *IEPR* Forecast used for transmission planning and the IOUs' distribution planning forecasts. This is an active area of research. CEC staff will continue to collaborate with other energy planning agencies and will present options in future Demand Analysis Working Group meetings and IEPR workshops.

Data Center Load Growth

Large-scale data centers represent a significant and rapidly growing source of electricity demand in California. Recent growth in the demand for artificial intelligence (AI) has led to an increase in utility energization requests for data centers, particularly within the California ISO balancing authority area. Electrical demand from individual data centers commonly ranges from 10 to 100 MW but can exceed this for AI-focused data centers or when multiple facilities are located at a single site. Given the magnitude and geographic concentration of these loads, the CEC developed a dedicated data center demand forecast to support near- and mid-term reliability, resource adequacy, resource planning, and transmission planning.

Beginning with the *2024 IEPR Update,*[49] the CEC incorporated data centers as a distinct component of the statewide electricity demand forecast. For the *2025 IEPR* Forecast,[50] staff refined and expanded this approach, incorporating updated utility data, revised assumptions, and additional analysis of data center load profiles and other factors impacting growth uncertainty. This section describes the data center forecasting methodology, summarizes forecast results, discusses key sources of uncertainty, and outlines areas for future improvement.

Data Center Forecast Methodology

The CEC's data center demand forecast is based on a bottom-up assessment of utility interconnection requests combined with operational assumptions derived from observed data center performance. This approach reflects the limited availability of historical load data for AI data centers and relies primarily on information utilities receive directly from prospective customers.

Utility Data Collection

CEC staff requested project-level information from IOUs and select POUs with known or anticipated data center development. Utilities provided data on:

- Requested electrical capacity (MW)
- Application or agreement status
- Anticipated interconnection timing or ramp schedule, where available
- Location

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49 Stephanie Bailey, Mathew Cooper, Quentin Gee, Heidi Javanbakht, Jake McDermott, Danielle Mullany. 2024. 2024 Integrated Energy Policy Report Update. California Energy Commission. Publication Number: CEC-100-2024-001. https://www.energy.ca.gov/publications/2024/2024-integrated-energy-policy-report-update

50 California Energy Commission. 2025. *2025 Integrated Energy Policy Report*. California Energy Commission. 2025. https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2025-integrated-energy-policy-report.

For the *2025 IEPR*, staff received data from PG&E, SCE, SDG&E, Silicon Valley Power, the City of Palo Alto, the City of Burbank, and Valley Electric Association. Staff also consulted with other utilities, including Los Angeles Department of Water and Power (LADWP) and Sacramento Municipal Utility District (SMUD), to confirm whether data center growth was expected in their service territories.

Project Grouping and Confidence Levels

Each data center project was assigned to one of three groups based on its application status:

- Signed Agreements: 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.
- Active Applications: Projects with an active application for electric service but no signed agreement.
- Inquiries: Projects that have submitted an inquiry for electric service but have not filed a formal application.

Because not all proposed projects ultimately proceed to construction and utility service, staff applied confidence levels to each group to estimate the portion of requested capacity expected to materialize. Confidence levels were informed by discussions with utilities regarding historical completion rates, application attrition, the likelihood of duplicate or speculative requests, and the likelihood that a data center will primarily use on-site generation and only rely on the grid for backup power. 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. The confidence levels applied to each project group for the Planning Forecast and Local Reliability Scenario are summarized in Table 10. The confidence levels in this study represent the likelihood of data center projects will materialize. For example, a 33 percent confidence level assumes roughly one third of the data center projects on utility interconnection queues will be built. Separate confidence levels were developed for the 2025 IEPR Planning Forecast and Local Reliability Scenario to reflect different assumptions about project completion for statewide and local planning, with higher assumptions applied for local reliability.

Conversion of Capacity Requests to Demand

To translate requested energization capacity into expected maximum electricity demand, staff applied the following assumptions:

- Utilization Factor: A 67 percent utilization factor was applied to reflect the expected maximum operating load relative to requested capacity. This value is based on observed operation of existing data centers, including data provided by Silicon Valley Power.

- Ramping Assumptions: Data center loads were assumed to ramp gradually rather than reaching full utilization immediately upon energization. For the Planning Forecast, staff applied a linear ramp over seven years based on discussions with Silicon Valley Power and other utilities. For the Local Reliability Scenario, staff applied project-specific ramp schedules provided by the utilities, or the same linear ramp when project-specific schedules were not available.
- Timing Constraints: Projects without signed agreements or active applications were assumed to not begin service for 3-5 years, reflecting the time required to progress through permitting, construction, and supporting infrastructure development.

Summary of Forecast Assumptions

To ensure transparency and consistency across utilities and planning applications, CEC staff applied a common set of assumptions to translate data center energization requests into expected electricity demand. These assumptions are based on observed data center operations, discussions with utilities, and differences in certainty across stages of the interconnection process. Table 10 summarizes the key assumptions incorporated into the data center demand forecast. These assumptions will be revisited and refined for future *IEPR* Forecasts as additional data become available.

Table 10: Summary of Data Center Forecast Assumptions

Assumption Category	Value	Notes
Utilization Factor	67%	Based on discussions with utilities and observed operations
Ramp to full load	Planning: Ramp over 7 years Local Reliability: Schedule provided by utility	Linear ramp where schedules unavailable
Confidence level: Signed agreements	Planning: 70% Local Reliability: 100%	Higher confidence plus more conservative local planning
Confidence level: Active applications	Planning: 33% Local Reliability: 50%	Account for attrition and potential duplication
Confidence level: Inquiries	Planning: 0% Local Reliability: 10%	Speculative, but useful for proactive long-term planning

Source: CEC staff based on discussions with utilities

Hourly Load Profiles

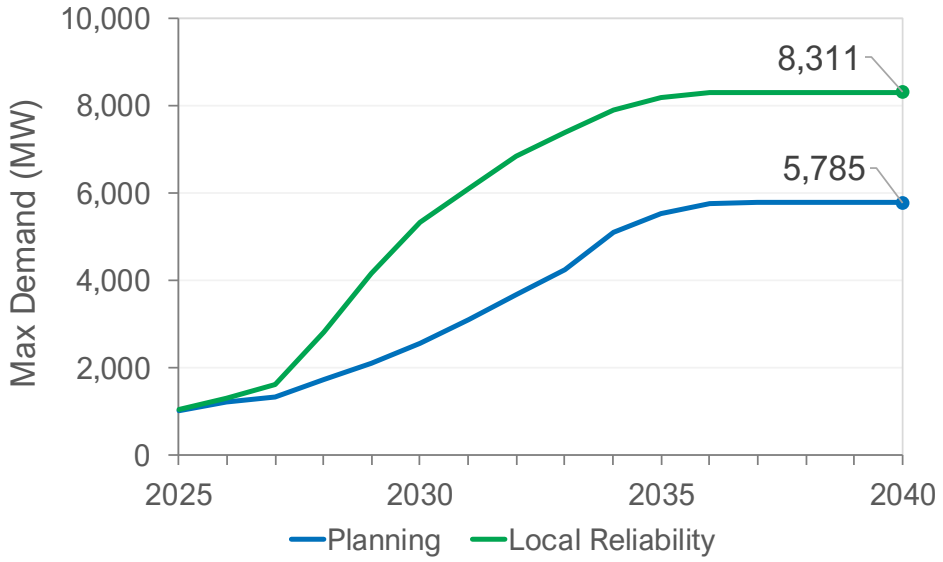
CEC staff analyzed interval meter data from a sample of existing data centers to develop an hourly load profile. These profiles were used to translate the total forecasted maximum demand, discounted by the previously mentioned assumptions, into hourly demand and to estimate data center demand's contribution to the system peak. While existing data centers provide the best available proxy for typical hourly load shapes, staff recognize that future facilities may operate differently as business applications, computing technologies, and cooling strategies evolve.

Data Center Forecast Results

Based on utility data as of December 2025 and the assumptions described above, the CEC estimates that data center electricity demand will increase over the next decade and contribute additional peak load to the California electricity system.

Figure 11 presents the statewide total maximum demand from data centers, including approximately 930 MW of existing data center load, under both the Planning Forecast and Local Reliability Scenario. Under the Planning Forecast, which reflects expected demand based primarily on signed interconnection agreements and a portion of active applications, total data center peak demand grows to approximately 5,800 MW by 2040. Under the Local Reliability Scenario, which assumes a higher likelihood for pending data center projects to be realized, total peak demand reaches approximately 8,300 MW by 2040. This scenario is generated to support proactive infrastructure planning.

Figure 11: Statewide Data Center Maximum Demand Forecast, including Existing Load



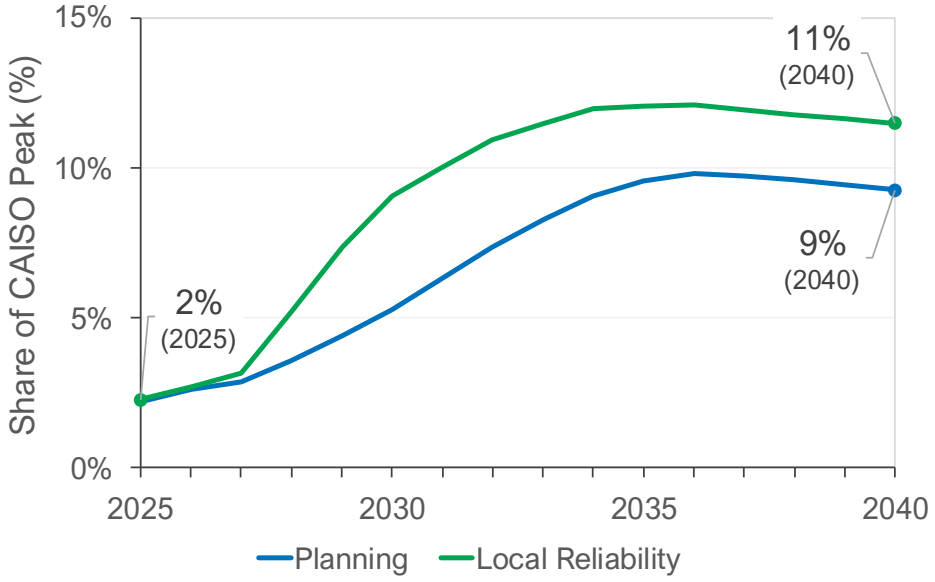
Source: CEC staff based on utility data as of December 2025

In both scenarios, data center demand increases rapidly through the late 2020s and early 2030s before leveling off in the mid-2030s. This plateau reflects the decision to base the forecast on projects in utility energization queues, rather than assumed future growth. As a result, forecast growth is concentrated in years where utilities have greater visibility into project timelines and energization status.

Although utilities reported more than 23,000 MW of total requested capacity across all application stages, a significant share of this capacity consists of early-stage inquiries that are not assumed to materialize in the Planning Forecast. As a result, projected demand growth is considerably lower than total requested capacity. The difference between the Planning Forecast and the Local Reliability Scenario illustrates the uncertainty inherent in forecasting these new large loads.

As shown in Figure 12, the data center share of California ISO peak demand increases substantially over the study horizon, reaching roughly 9 percent under the Planning Forecast and 11 percent under the Local Reliability Scenario by 2040. This figure illustrates the increasing contribution of data centers to California ISO peak demand, although these loads are not expected to represent a majority of total statewide electricity demand.

Figure 12: Data Center Share of California ISO Peak Demand



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

Uncertainty and Limitations

Forecasting data center demand presents several challenges distinct from traditional economic sectors:

- Limited Historical Data: Unlike residential or other commercial sectors, data centers, especially those performing AI-centric workloads, lack a long historical record of load growth and operational behavior.
- Dynamic Energization Queues: Utility application queues change frequently, and the forecast reflects a snapshot in time.
- Project Attrition and Duplication: Developers may submit multiple applications across utilities or withdraw projects as market conditions change.
- Operational Uncertainty: Future data centers may employ different computing densities, cooling technologies, or onsite generation strategies than existing facilities.
- Long-Term Growth Beyond Known Projects: The forecast does not assume additional speculative applications beyond those currently reported, which may understate longer-term growth.

To address these uncertainties, the CEC produces multiple forecast scenarios and coordinates closely with electric utilities, the CPUC, and the California ISO to ensure planning processes remain adaptive.

Data Center Load Flexibility

As described above, data centers represent a significant and growing portion of the electricity demand forecast. Particularly as the state already anticipates record build rates to achieve the state's SB 100 and carbon neutrality policies, flexible operation of data centers may present an opportunity to reduce the impact of new large loads.

Data center loads consist of critical IT equipment (servers, storage, networking) and essential infrastructure, primarily cooling systems, power distribution, and lighting. Self-reports suggest an average of 64 percent of power went to IT equipment across the largest U.S. data centers in 2024 (with newer and larger data centers being more efficient), while the remainder supports cooling (chillers, fans) and power delivery.[51] AI data centers differ from regular data centers by requiring up to 11 times higher power density per rack, advanced liquid cooling, and high-speed networking to handle immense AI training workloads[52].

Currently, data center load in California is broadly inflexible outside of emergency conditions. Data center operators have historically operated cloud computing as a load

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51 Donnellan, Douglas, Andy Lawrence, Daniel Bzio, Peter Judge, John O'Brien, Jacqueline Davis, Max Smolaks, Jabari Williams-George, and Rose Weinschenk. 2024. *Review of Uptime Institute Global Data Center Survey 2024*. Uptime Intelligence. https://datacenter.uptimeinstitute.com/rs/711-RIA-145/images/2024.GlobalDataCenterSurvey.Report.pdf?version=0.

52 EdgeCore Digital Infrastructure. 2025. *What Does an AI Data Center Look Like? Inside Modern AI Facilities*. EdgeCore, https://edgecore.com/a-look-inside-the-ai-data-center/#:~:text=AI%20data%20centers%20can%20support%20workloads%20and,machines%20with%20about%2040%2D110%20kW%20per%20rack.

which does not flex in response to grid conditions. More recently, there have been extensive discussions about the possibility for data centers to provide flexibility to the grid. However, contracts where data centers provide such flexibility to grid operators are currently quite rare (with none currently existing in California), and to our knowledge there is no publicly released information quantifying the grid impacts of those contracts. While data center operators acknowledge much more potential for flexibility from AI-training data centers as opposed to other types of data centers, California currently does not host a significant quantity of AI-training data centers.

Minimal data center loads in California currently participate in demand response programs. CEC staff identified less than 10 MW participating in demand response programs, less than 1 percent of the total data center load. Data centers can provide support under emergency conditions utilizing diesel backup generators when air permits are waived, such as during the 2022 extreme heat event. This flexibility is facilitated through the Demand Side Grid Support (DSGS) program's option 1 with total of 12 MW to 183 MW of enrolled capacity in 2025. However, the DSGS program option 1 participation pathway is suspended for the 2026 program season due to budget constraints.

The federal government has ordered the use of diesel gas generators for grid support in-lieu of power outages.[53] This approach provides for emergency grid support from data centers but also increases emissions of greenhouse gases and pollutants to communities local to data centers.

There is ongoing interest in data centers with on-site non-emergency generation or storage to enable flexibility, but such installations do not currently exist in California. A Microsoft data center is under construction in San Jose with 100 MW of on-site natural gas generators backed with a renewable natural gas power purchase agreement.[54] Microsoft signaled that, once it is operational, this data center may participate in PG&E emergency demand response programs.[55] To date, no other California data center projects with large, on-site, non-diesel generation or storage has been reported to CEC.

Some utilities are piloting flexible service connection agreements for distribution-connected customers. For instance, in early 2024, PG&E started its FlexConnect pilot for large loads, primarily for commercial EV charging stations and data centers.[56] However,

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53 Wright, Chris, ed. 2026. *Order No. 202-26-01 Review of Leveraging Backup Generation Facilities during Energy Emergencies*. Department of Energy United States of America. https://www.energy.gov/documents/order-no-202-26-01-ercot.
54 Team, Local Community. 2025. *Alviso Datacenter Construction Update - Microsoft Local*. Microsoft Local. https://local.microsoft.com/blog/alviso-datacenter-construction-update/.
55 San Jose Data Center Final Environmental Impact Review – Part 1, pg. 3-17 (57) https://efiling.energy.ca.gov/GetDocument.aspx?tn=241977-1&DocumentContentId=75659
56 PG&E Corporation. 2025. *New PG&E Service Offering Makes It Easier and Faster to Connect EV Chargers, EV Fleets and Big Batteries to the Grid*. Pgecorp.com. https://investor.pgecorp.com/news-events/press-releases/press-release-details/2025/New-PGE-Service-Offering-Makes-It-Easier-and-Faster-to-Connect-EV-Chargers-EV-Fleets-and-Big-Batteries-to-the-Grid/default.aspx.

as of April 2025, no data centers were participating in PG&E's Flex Connect pilot. Google touts the flexibility of its data centers to reduce grid strain and emissions but has not contracted to provide that flexibility to California utilities.

There are some policies outside of California that require data centers to ease grid reliability concerns via some combination of on-site generation and participating in demand response programs. In Ireland, new data centers are required to bring dispatchable, market-integrated, on-site generation matching their maximum capacity, though they can offset some of that on-site requirement by purchasing capacity from off-site renewable generation.[57] This eliminates the data center's impact on the grid while on-site generation is being dispatched. Texas Senate Bill 6 (Phil King and Charles Schwertner, Statues of 2025)[58] gives the Electric Reliability Council of Texas (ERCOT) the authority to, in an emergency, dispatch backup generating resources at data centers or curtail those data centers, before instituting blackouts for the full system.

There are also examples of upcoming data center operators and developers voluntarily coordinating with their utilities to bring demand response or on-site generation capacity to the grid. In May 2025, data center developer Verrus in coordination with the National Lab of the Rockies, demonstrated demand response capabilities of 70 MW of on-site batteries.[59] They plan to bring this capability to new, commercial data centers by the end of 2026, though no other details have been provided. Aligned, a data center developer, is planning to bring 31 MW/62 megawatt-hour (MWh) of batteries alongside a data center in the Pacific Northwest to reduce the time it would take to interconnect the facility.[60] Google has contracted with Indiana Michigan Power and the Tennessee Valley Authority to provide them with demand flexibility from its data centers,[61] though no details of what that entails have been made public.

Future Improvements and Ongoing Work

The CEC will continue refining its data center demand forecast as additional data becomes available. Planned improvements include the following.

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57 Commission for Regulation of Utilities. 2025. Executive Summary and Section 3.5.3. *Large Energy Users Connection Policy*. n.d. https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/CRU2025236_Large_Energy_User_connection_policy_decision_paper.pdf
58 Texas State Legislature. TX SB6. https://legiscan.com/TX/bill/SB6/2025
59 Giacobone, Bianca. 2025. *Verrus Successfully Demos Its Flexible Data Center Technology*. Latitude Media. https://www.latitudemedia.com/news/verrus-successfully-demos-its-flexible-data-center-technology/.
60 Calibrant. 2025. *Aligned and Calibrant to Deploy First-of-Its-Kind On-Site Battery Storage Project to Unlock Utility Power for Data Centers,* Calibrantenergy.com. https://www.calibrantenergy.com/resources/aligned-and-calibrant-to-deploy-first-of-its-kind-on-site-battery-storage-project.
61 Terrell, Michael. 2025. *How We're Making Data Centers More Flexible to Benefit Power Grids*. Google, https://blog.google/innovation-and-ai/infrastructure-and-cloud/global-network/how-were-making-data-centers-more-flexible-to-benefit-power-grids/.

- Incorporating additional years of observed data center load to refine utilization, ramping assumptions, and load profiles
- Improving differentiation among data center types and sizes, and their associated operating characteristics
- Updating confidence levels as more projects progress through the energization process
- Continuing coordination with utilities to obtain more frequent and standardized updates
- Exploring approaches to inform longer-term data center growth beyond the visibility provided by current utility energization queues

As data center development accelerates, proactive forecasting and close interagency coordination will remain essential to maintaining electric system reliability while supporting California's economic and technological growth.

CHAPTER 5:
Electric Resource Planning Issues

California's electric system is undergoing a fundamental transformation. The state's clean energy laws and climate commitments require a near-complete transition away from fossil fuels by 2045, while simultaneously managing rapid load growth driven by electrification of transportation, buildings, and industry, and increasingly, large-scale data center development. Meeting these objectives requires not only sustained investment in new generation and storage resources, both on the supply and demand side, as well as transmission and distribution, but a clear-eyed understanding of the uncertainties and risks that could shape how that transition unfolds.

This chapter presents the CEC's electric resource planning analysis, with the overarching goal of understanding how different assumptions around resource costs and availability, demand and load forecasts, policy and tax incentives, land use constraints, and other key uncertainties impact California's electric system development through 2045. Rather than identifying a single preferred trajectory, this work is meant to illuminate the range of plausible outcomes, highlighting where planning decisions are robust across scenarios and where they are sensitive to assumptions that remain unresolved.

The chapter starts with long-term capacity expansion modeling to evaluate how scenarios around resource costs, technology availability, federal tax credit policy, and land use constraints affect the mix and quantity of investment required to meet California's clean energy targets over the next two decades. This analysis establishes the broader resource buildout context within which the nearer-term reliability questions that follow can be understood: the types and volumes of resources that long-term modeling identifies as necessary through 2045 are the same resources whose pace of development and cost trajectories create procurement uncertainty in the mid-term.

Building on that foundation, the chapter then presents a probabilistic resource adequacy assessment of California's electric system in 2031 and 2036. Using stochastic modeling against existing resource builds and ordered procurement, this analysis asks a more immediate question: given what has already been procured, how does uncertainty in future demand translate into reliability risk—and how much additional procurement might be needed? Where the capacity expansion analysis looks across the full arc of the energy transition, the resource adequacy analysis focuses on the near-term consequences of uncertainty in demand forecasting and supply procurement, underscoring why the load growth assumptions embedded in long-run planning deserve ongoing scrutiny.

The final two sections zoom in on system characteristics that the buildout envisioned in both prior analyses will increasingly stress. The first examines how wildfire risk affects

grid operations, with a focus on transmission flows under wildfire conditions, a constraint that shapes not just operations, but the value and siting of new resources. The second explores grid strength concerns arising from the rapid growth of inverter-based resources, as the system shifts away from the synchronous generation that has historically provided essential reliability services. Together, these analyses are a reminder that the scale of resource development identified in long-term planning and reliability work cannot be evaluated in isolation: the grid must also be able to physically accommodate and operate these resources reliably. Both efforts are at an early stage, and this chapter documents initial findings as part of a longer-term analytical effort.

Resource Availability and California's Future Electric System: Technology Feasibility, Cost Trajectories, and Wind and Land Use

In this assessment, the CEC uses capacity expansion modeling to evaluate sensitivities around resource costs and emerging resource availability on California's future electric system. California has aggressive emissions goals and targets for the economy as a whole and they translate to aggressive electric sector emissions targets. Meeting these mandates and other interim targets requires aggressive electric system investments to replace polluting resources and meet rapidly growing demand.

This report explores pathways to meeting these targets, specifically focusing on future energy resource needs. By evaluating diverse scenarios, this work helps policymakers, stakeholders, and the public understand necessary investments and technology tradeoffs while maintaining grid reliability. Unlike formal planning processes, this report is intended to inform policy, research, technology development, and long-term strategy rather than direct procurement mandates.

Approach

The CERRO Scenarios are intended to explore a range of sensitivities surrounding the availability and cost-effectiveness of various technologies. The scenarios have been split into three categories, Feasibility Scenarios centered around future resource or technology availability, Cost Reduction Scenarios focused on energy resource technology costs, and Wind and Land Use Scenarios evaluating variability in resource potential.

<u>Feasibility Scenarios</u>

- **Base:** This scenario is allowed to build all emerging resources at their default prices and reflects tax credit policy as of 2025, which repeals tax credits for

wind and solar PV.[62] Investment tax credits for other renewable resources are phased out by 2035.

- **No Carbon Capture Storage (CCS)**: Removes the availability of CCS retrofits from the portfolio. There are significant questions around the costs, commercial viability, and operational readiness of retrofitting a significant quantity of the existing fleet of gas plants with CCS technology.[63] This scenario looks at the potential impact on the resource build of removing this firm zero-carbon technology from the portfolio completely.
- **No Emerging Resources:** This scenario removes the availability of CCS, EGS, OSW, and LDES from the resource portfolio. This is intended to compare other scenarios to the feasibility of meeting clean energy targets without emerging technologies, and the associated costs.

Cost Reduction Scenarios

- **Tax Credits Extension:** This scenario maintains the tax credit regime from the Inflation Reduction Act, including production tax credits for onshore wind and solar PV and investment tax credits for other renewable resources and storage extended through 2045. This scenario is intended as a comparison point to see how tax credits affect resource portfolios.
- **Low-Cost LDES**: This scenario achieves the cost reductions projected by the LDES Storage Council[64], to explore the usage patterns of LDES and its impact
- on the resource build.
- **No CCS – Low-Cost OSW:** This scenario uses the low price of OSW from the National Lab of the Rockies (NRL) Annual Technology Baseline (ATB) to determine the impact of OSW on the base portfolio, rather than the moderate ATB costs used in other scenarios. This scenario also removes CCS as an option because the assumed costs for CCS are comparatively low and difficult for other emerging resources to compete with if CCS is adopted at scale.

Wind and Land Use Scenarios

- **No Emerging – High Wind Potential**: This scenario adds as a candidate resource 35 GW of low-capacity factor in-state wind, where the wind resource is considered insufficient to justify development under today's planning

62 Emerging resources are defined as carbon capture and storage (CCS), enhanced geothermal systems (EGS), off-shore wind (OSW), and long-duration energy storage (LDES.

63 Gidden, Matthew J., Siddharth Joshi, John J. Armitage, et al. "A Prudent Planetary Limit for Geologic Carbon Storage." Nature 645, no. 8079 (2025): 124–32. https://doi.org/10.1038/s41586-025-09423-y.

64 LDES Council and McKinsey & Company. 2021. *Net-zero power: Long duration energy storage for a renewable grid.* LDES Council. https://www.mckinsey.com/capabilities/sustainability/our-insights/net-zero-power-long-duration-energy-storage-for-a-renewable-grid.

regime, but could be economical in the future.[65] This scenario illustrates the benefit of resource diversity even in the scenario where emerging resources are not available for widescale deployment by 2045.

- **No Emerging** – **Terrestrial Climate Resilience (TCR) Land Use Screen**: This scenario uses the TCR Land Use Screen,[66] which sets aside more land for conservation purposes and consequently reduces the resource potentials for wind and solar PV.

Modeling Stages

Capacity expansion models optimize for the least-cost resource build across a future horizon. This is a computationally intensive process that requires simplifying the future time horizon into representative days or hours to complete in reasonable computation time. It is best practice to verify portfolio results through production cost models to ensure portfolios meet reliability and clean energy targets. As opposed to sampling, a production cost model simulates every day in a year consecutively. The CERRO modeling approach used three models to build and validate resource portfolios.

The PLEXOS LT™ capacity expansion model builds a resource portfolio for California that satisfies all modeling constraints in the simplified horizon.

The PLEXOS™ production cost model runs the resource portfolio in an hourly model to ensure it meets SB 100 and GHG targets and that the resource build is sufficient to meet electricity demand in all hours.

The PLEXOS™ stochastic reliability simulation runs the resource portfolio through multiple weather years and generator outage possibilities to ensure it meets reliability targets.

See Appendix C: for additional details about CEC's long-term planning framework.

Modeling Inputs and Assumptions

Reliability and State Clean Energy Goals

The resource portfolios must meet the following clean energy and reliability targets in all scenarios:

- **SB 100/SB 1020:** Specified percentage of retail sales[67] must be from renewable and zero-carbon resources by 2030, 2035, 2040, 2045. 100 percent must be renewable and zero-carbon by 2045.

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65 Modeling the expected generation profiles of marginal wind resource areas is challenging and somewhat speculative as there are no nearby wind facilities for comparison. Therefore this resource is not allowed as a candidate in all scenarios.
66 CEC. "Land Use Screens."

67 Retail sales do not include transmission, distribution, or storage losses or behind-the-meter resources.

- **GHG Target:** 85 percent statewide anthropogenic GHG emissions reduction and carbon neutrality by 2045 as mandated by AB 1279. The 2045 electric sector GHG emissions are limited to those from CA 2022 Scoping Plan[68]: 6.9 MMT CO_2e.
- **Reliability Targets:** The model must meet a 17 percent statewide PRM in the capacity expansion model, less than a 0.1 LOLE target in the reliability model and show no unserved load in the dispatch model.

Base System

Existing resources for California are based on the QFER capacity data. Resources planned by utilities through 2030 are included in the model as part of the base system. Planned resources for CPUC-jurisdictional entities are based on the 2023 Preferred System Plan (PSP) Reference scenario, adopted in February 2023. Planned resources for POUs are based on supply form filings through 2030. Between the PSP and POU plans, the model assumes California's solar PV, wind, and battery capacity will double between 2025 and 2030, with about 50 GWs of resources coming online.

Table 11: California Existing and Planned Resource Build

Resource	Existing (2024)	Planned (2025-2030)
Geothermal	2,743	1,765
Solar	21,050	20,934
Wind	6,286	7,063
Gas	33,965	2,900[69]
Out of State (OOS) Wind	2,418	5,300
Lithium Batteries	12,500	13,228
Hydro	14,074	477
Other[70]	2,747	1,794

Source: CEC staff

All three models – capacity expansion, production cost, and reliability – represent California zonally, with the rest of WECC represented only as available imports. The capacity expansion model can build dedicated wind facilities[71], whose power is imported

68 California Air Resources Board. 2022. *Final 2022 Scoping Report*. https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents
69 Planned gas additions include retrofitting the Intermountain Power Plan from coal to gas and replacing once-through-cooling facilities with new units.
70 Other includes Demand Response, Biofuel, and thermal resources that rely on fossil fuels other than natural gas (fuel oil, coal, etc). Most of the planned new additions are Demand Response resources.
71 Other renewable resources are not modeled as dedicated resources as California has sufficient in-state solar potential, and most out of state geothermal potential is already assumed to be built out as planned resources for California or for other BAs within WECC by 2030.

GHG-free. Unspecified imports have a GHG emissions factor of 0.21 MT/MWh,[72] based on CARB estimates of WECC-wide system average emissions impact. The capacity expansion and reliability models are limited to 7.5 GW of total statewide imports during peak summer and winter periods, and 5.5 GW into the California ISO. All three models are limited to 12,450 MW of imports statewide in all other hours of the year.

Candidate Resources

In the capacity expansion model, resources are selected to meet the reliability and GHG constraints at least cost. The following resources were eligible to be built in the model for California:

- In-state renewable resources (solar PV, solar thermal, biomass, conventional and enhanced geothermal, onshore wind, and offshore wind)
- Out-of-state wind and enhanced geothermal, subject to new transmission limits
- Storage resources (four-hour and eight-hour lithium-ion batteries, twelve-hour flow batteries, twenty-four-hour metal-air batteries)
- Retrofits of existing gas plants to 95 percent CCS[73]

The graph below shows the build costs for storage and generators, including the impact of the investment tax credits, which phase out for geothermal, biomass, and storage resources between 2033 and 2035. Unless noted otherwise, all resource costs were sourced from the 2024 NLR ATB.[74] LDES costs were sourced from the Pacific Northwest National Laboratory National Storage database. The database contains costs for 2023 and 2030; costs were extended to 2045 by extrapolating the decrease between 2023 and 2030 linearly. Costs for CCS Retrofits include an approximate cost for building carbon dioxide (CO_2) storage facilities and local pipelines to CO_2 storage based on EPRI's analysis with Carbon Solutions.[75] California has significant geological resources for CO_2 storage. The cost of building and maintaining CO_2 storage is about 10 percent of the cost of a CCS retrofit of an existing gas generator.

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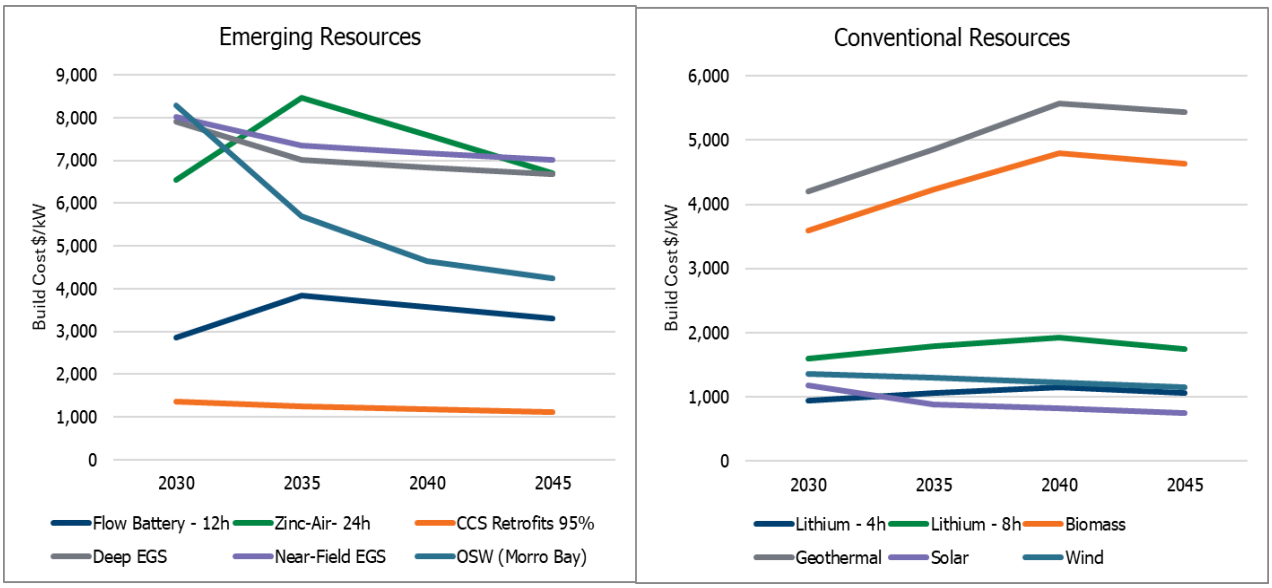
72 California Air Resources Board, "GHG Emissions Inventory (GHG EI) 2000-2021," 2023. [Online]. Available: https://ww2.arb.ca.gov/ghg-inventory-data

73 Generation from CCS Retrofit plants is counted towards SB100 compliance on a ratio basis, i.e., 95 percent of generation counts towards SB100. This is consistent with the approach in the 2025 SB100 Report. Note that the 2025 SB100 Report process is not a venue for determining compliance.

74 National Renewable Energy Laboratory. "Electricity Annual Technology Baseline (ATB) Data Download." https://atb.nrel.gov/electricity/2024/data.

75 Electric Power Research Institute. June 30, 2023. *Geospatial Modeling of Geologic Carbon Dioxide Storage Potential*. Low-Carbon Resources Initiative. EPRI Product ID: 3002027776. Available: https://www.epri.com/research/products/000000003002027776

Figure 13: Storage and Generator Build Costs



Recent Changes in Tax Credits

Recent federal legislation has changed the structure and duration of renewable energy tax credits, affecting project timelines, financing, and investment decisions. The IRA of 2022 extended and expanded federal incentives by replacing technology-specific credits with technology-neutral production (Section 45Y) and investment (Section 48E) tax credits. These credits apply to qualifying zero-emission electricity generation and energy storage projects and are available through the mid-2030s, subject to labor, apprenticeship, and domestic content requirements. The IRA also introduced credit transferability and elective payment options, which reduced financing constraints and broadened participation by allowing developers to monetize credits without relying solely on tax equity investors.

One Big Beautiful Bill Act, signed into law on July 4, 2025, modified this framework by accelerating phase-out timelines for certain clean energy tax credits and adding eligibility restrictions for certain technologies. Solar and wind projects are now subject to earlier construction start and placed-in-service deadlines, with most new facilities required to begin construction by 2026 or be operational by 2027 to qualify for full credits. The legislation also introduced Foreign Entity of Concern restrictions that limit eligibility based on ownership, financing, and supply chain relationships. These changes increase scheduling and compliance risk for developers, raise financing costs for projects that cannot meet revised requirements, and reduce long-term certainty relative to the IRA baseline. As a result, renewable project development may shift toward technologies with longer credit availability or face slower deployment where incentives are reduced or time-limited.

Source: CEC staff

The table below summarizes the maximum new build (incremental to PSP and POU planned resources) for 2045 for candidate resources with build restrictions. Solar and land-based wind values were developed based on the CEC's Land Use Screens as a starting point,[76] which identify areas feasible for new resource build. Within these feasible areas, resource classes are created based on long-run average wind speed or direct normal irradiation and are combined with coarse resolution hourly profiles from the European Centre for Medium-Range Weather Forecasts. These raw resource quality profiles are converted to capacity factors based on power curves for each technology. For offshore wind resources in California, the resource potential was developed based on wind speed data, existing California state offshore lease areas (Bureau of Ocean Energy Management) and additional areas identified during the AB 525 process.[77] EGS potentials are aligned with the CPUC draft input and assumptions, based on NRL estimates of temperatures at 3km depth.[78] Note that this technology is not considered fully mature and this potential could be an overestimate of the actual commercial potential for EGS.

New gas facilities with CCS technology are not a candidate resource in this analysis, but the model can retrofit existing combined cycle plants with CCS. Retrofit viability depends on several factors, including access to CO2 storage geology, proximity to pipeline or other transport infrastructure, plant configuration, and site conditions. To simplify the analysis given limited data, only existing combined cycle plants larger than 150 MW are eligible on the assumption that smaller plants may lack adequate onsite space, siting conditions, and access to favorable storage geology.

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76 CEC. "*Land Use Screens*." https://www.energy.ca.gov/data-reports/california-energy-planning-library/land-use-screens.
77 CEC. "*AB 525 Reports: Offshore Renewable Energy*." https://www.energy.ca.gov/data-reports/reports/ab-525-reports-offshore-renewable-energy
78 California Public Utilities Commission, Energy Division. February 2025. *Draft 2025 Inputs and Assumptions: 2024–2026 Integrated Resource Planning*. California Public Utilities Commission. Available: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/draft-2025-inputs-and-assumptions-document.pdf

Table 12: Resource Potential by Resource Type in GW

Resource	Core Land Use Screen	TCR Land Use Screen[79]
Solar	791	410
In-State Wind[80]	14	11
Incremental Low-Capacity Factor Wind[81]	35	N/A
Offshore Wind	29	29
Conventional Geothermal	1.2	1.2
Enhanced Geothermal	29	29
Biomass	1.4	1.4
CCS Retrofits	18	18

Source: CEC Staff

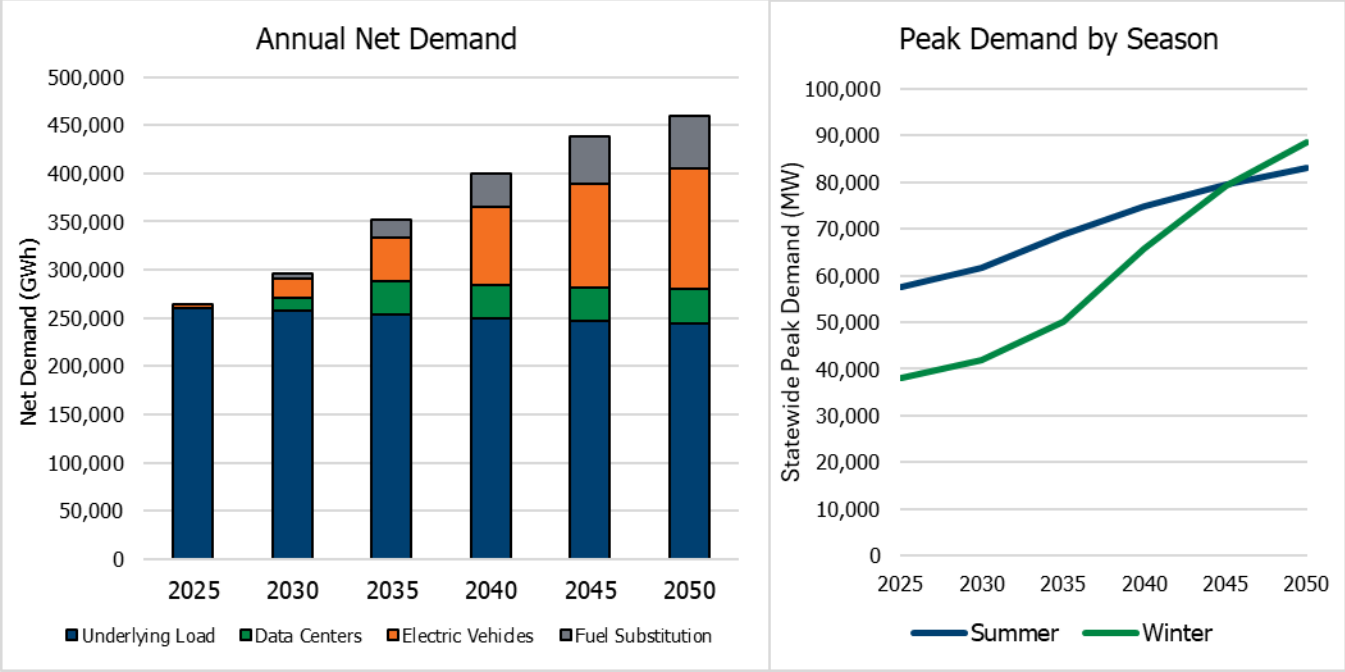
Demand

All scenarios use the 2025 IEPR Planning Forecast. This vintage of the demand forecast features significant growth in electric vehicles, data centers, and fuel substitution, all of which increase load outside the traditional summer peak hours. Winter peaks reach parity with summer peaks by 2045. Because traditional renewables like solar PV and wind will generate less in winter, this makes the winter period the most challenging for a capacity expansion model to meet load without relying on traditional gas generators. The flatter load shape also reduces the utility of storage, as it must be relied on for much longer periods of time than the traditional peak period of the day.

The graph below shows annual modeled demand[82] on the left and the summer/winter peaks on the right. The Underlying Load bar in the left graph includes the impacts of all modifiers other than EVs, data centers, and fuel substitution, to highlight the relative impact of the three major sources of additional demand.[83]

79 Only used in the No Emerging Resources – TCR Land Use Screen Scenario
80 Significant portions of Arizona and Nevada are considered electrically connected to the CAISO and therefore eligible for "in-state" development. 9 GW of the wind in the default scenario is located in Arizona and Nevada. All of the Incremental Low-Capacity Factor Wind is inside the state of California.
81 Included in the model only in the No Emerging Resources – High Wind Potential Scenario.
82 Modeled demand incorporates the effect of BTM resources (included as the blue Underlying Load bar) and line losses (adds about 8% to total demand compared to consumption).
83 The other modifiers include energy efficiency, behind the meter solar and storage, pumping load, climate change impacts, and other adjustments. Of these, behind the meter solar and energy efficiency are by far the largest and reduce load.

Figure 14: Annual and Peak Demands for 2025 IEPR Demand Forecast



Modeling Results

All scenarios select a significant amount of solar PV and storage between 2030 and 2045, with solar PV being the largest source of generation in California by 2035. However, the removal of federal subsidies for wind and solar PV, combined with the increase in large flat loads, increase the level of firm zero-carbon resources compared to past exercises like the 2025 SB 100 Report modeling.[84] The following results present the resource build, costs, generation, and information on the seasonal patterns driving the model towards firm zero-carbon resources, for 2035 and 2045. Note that all costs presented are modeled costs and do not holistically capture electricity system costs. Modeled costs represent the annualized cost of building new and planned resources, maintaining all resources, and operating generating resources. Costs are intended to be directional and illustrate the relative impacts of changes to scenarios.

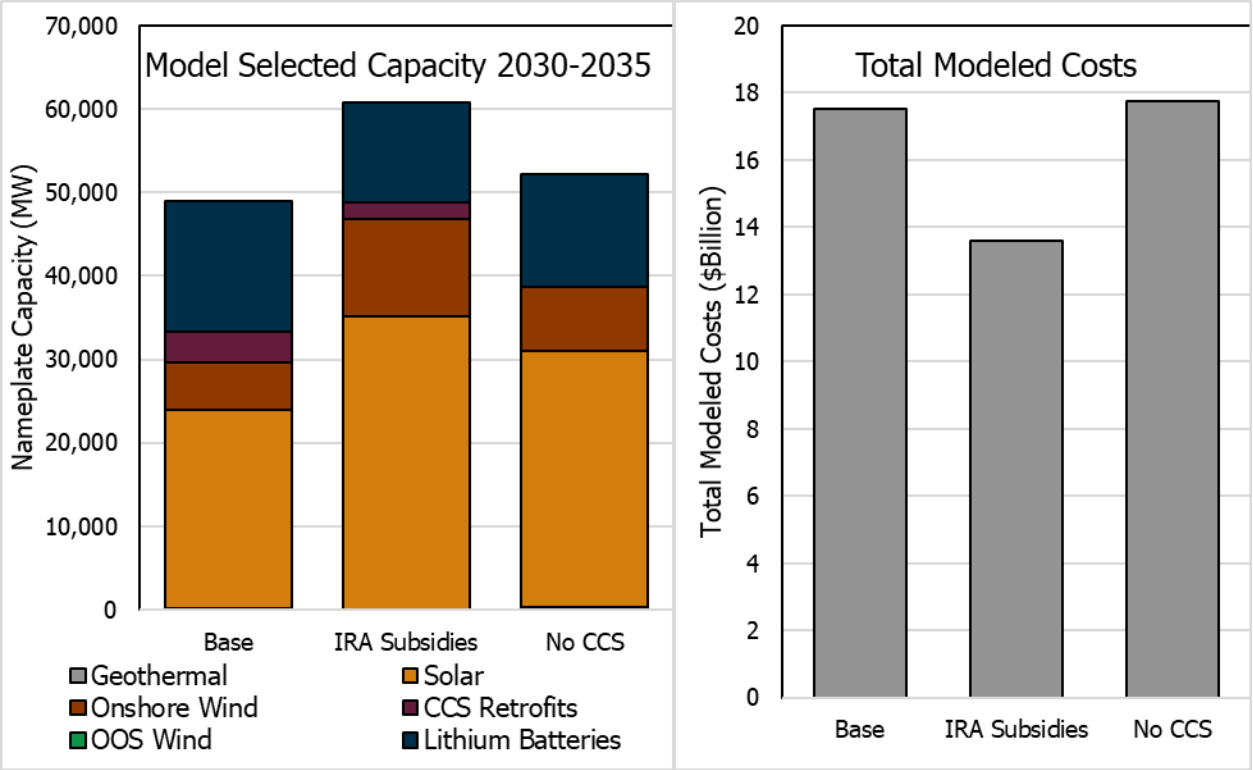
2035 Resource Build and Costs

Meeting the 2035 GHG target of 20 MMT CO_2e by 2035 will require reducing annual gas generation by about 50 percent while load increases by 40 percent. About 50 GW of zero-carbon resources are built between 2030 and 2035, in addition to the 50 GW of planned resources built between 2025 and 2030. This represents about 10 GW of new

84 Hybrid Workshop on 2025 SB 100 Joint Agency Report Draft Results available at: https://www.energy.ca.gov/event/workshop/2026-02/hybrid-workshop-2025-sb-100-joint-agency-report-draft-results

generation every year through 2035. All scenarios well exceed reliability and SB100 compliance metrics, suggesting GHG reductions will be the primary driver of new resource builds through 2035. Scenarios generally build similar resource portfolios through 2035, with the only emerging resource picked up by the model before 2040 being CCS retrofits of existing natural gas facilities. The graphs in Figure 15 below show the resource build and modeled costs for the Base, IRA Subsidies, and No CCS Scenarios. These scenarios were chosen to display as they have the most significant divergences.

Figure 15: Modeled Capacity and Costs in 2035 for Select Scenarios



Source: CEC Staff

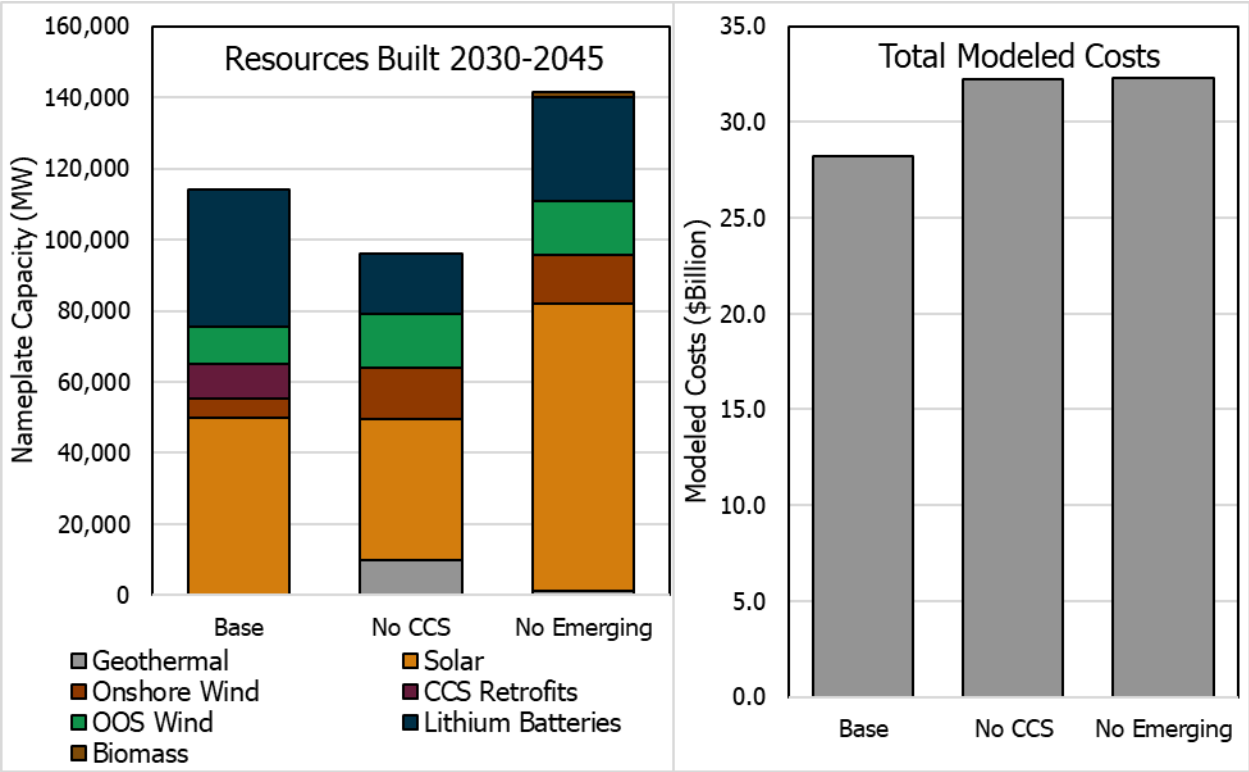
See additional details about 2035 resource buildout in Appendix C: Resource Availability and California's Future Electric System: Technology Feasibility, Cost Trajectories, and Wind and Land Use.

Feasibility Scenarios

Resource Buildout and Modeled Costs

The graphs in Figure 16 below show the resources and the total modeled costs needed to meet load in 2045 while reaching a 6.9 MMT CO_2e target in 2045. All three scenarios demonstrate the need for resource diversity, and in particular clean firm technologies, as all three scenarios build a significant amount of whichever clean firm technologies are available, even at relatively high costs per MWh.

Figure 16: Model Capacity and Annual Costs for Feasibility Scenarios



Source: CEC Staff

The Base scenario, which has all candidate resources available in the model, retrofits about 10 GW of existing natural gas plants with CCS technology. This represents about half of the existing combined cycle fleet, which would require significant investment in carbon storage across the state. Carbon capture is a relatively mature technology with a low cost in the NLR ATB, although long-term storage costs are not well explored. The 2022 CARB Scoping Plan from which the 6.9 MMT CO_2e target is derived achieves this target with a similarly significant investment in retrofitting existing gas plants with CCS, alongside CCS projects in other industries across the state. The feasibility of this scenario depends upon both the development of long-term carbon storage across the state, and existing plants having sufficient room and technological compatibility with CCS technology. The cost-competitiveness of CCS retrofits also depends on the price of natural gas. The 2026 CERRO report assumes that gas prices[85] in 2045 will be similar to prices today; however, this may not be true depending on many external variables, including the impact of deep decarbonization on California's gas infrastructure.

Given the uncertainty around feasibility of CCS Retrofits in the state, the CEC also explored a No CCS option. Without the option of low-cost CCS, the model turns to the deployment of about 10 GW of EGS, which can provide firm, clean power at any time of

85 Natural gas prices are based on EIA's Annual Outlook.

day. EGS costs in 2045 are close to $7,000 per kW, compared to $800 per kW for solar PV and $1,100 per kW for battery storage. The model selects EGS at ten times as much per kW and three times as much per kilowatt-hour (kWh) because the energy is available even in low-renewable periods when no other clean energy is available. However, there are uncertainties in these costs as this is a technology that has not yet been deployed at scale. The total modeled costs in 2045 are about 15 percent higher than in the base scenario.

The No Emerging Resources scenario does not have access to EGS, CCS, OSW, or LDES to provide a bookend illustrating the scale of resources needed if no emerging resources are available at scale. The only clean firm resources available to the model are a small amount of conventional geothermal and biomass, which do not get picked up in the Base scenario but do in the No CCS scenario. This scenario must build an additional 40 GW of solar PV and 15 GW of storage to meet the same GHG target as the No CCS scenario. The total costs, however, are less than 1 percent higher than those in the No CCS scenario. This scenario illustrates that it is technically feasible to meet the 6.9 MMT CO_2e target without emerging resources, but requires significantly higher deployment of solar PV and storage, and whatever other resources (wind, geothermal, biomass, and OOS resources) can be deployed. The No Emerging Resources builds about 200 GW of new solar PV, storage, and wind between planned and modeled resources, which is a pace of about 10 GW/year.

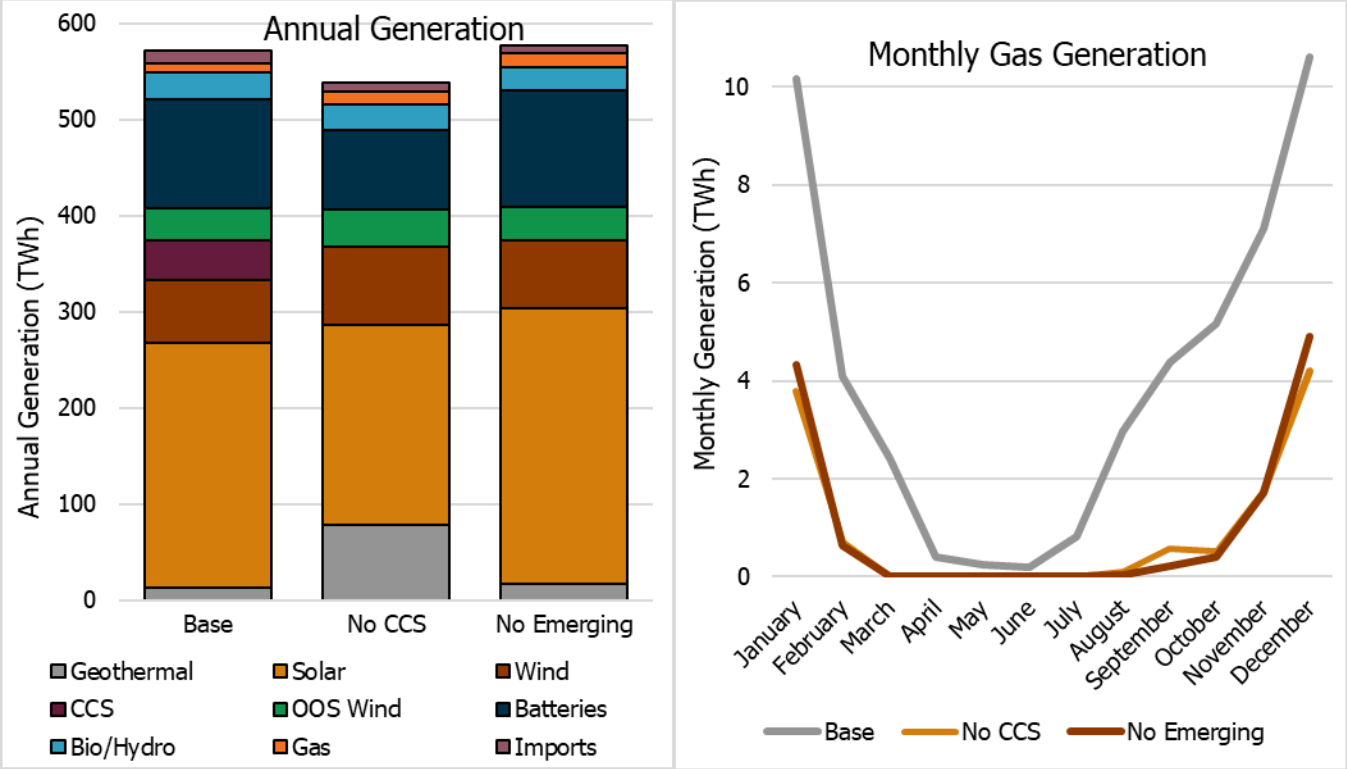
Annual and Monthly Gas Generation

The chart on the left in Figure 17 shows the total annual generation in 2045. Solar PV is the primary source of generation in all three scenarios. CCS retrofits and geothermal provide significant generation when included, making up about 11 percent of generation in the Base scenario and 15 percent of generation in the No CCS scenario. Fossil gas from unretrofitted plants provides less than 3 percent of total generation in all scenarios, compared to 34 percent of generation today. It is not feasible to meet the 6.9 MMT CO_2e GHG target with more than about 12 TWh of unretrofitted gas generation per year, compared to about 90 TWh per year today, and all scenarios show similar amounts of unretrofitted gas generation.

The graph on the right in Figure 17 shows the monthly generation from gas resources, both retrofitted and unretrofitted, across the three scenarios. Gas generation is highest in January and December across all three scenarios. Winter days are short and many days experience significant cloud cover during which there is little solar, so it is most cost-effective to save GHGs for these low-solar days. Under current modeling assumptions the system can operate without gas resources operating in most hours of the year by 2045. If gas generation is needed for operational reasons in other hours of the year, these scenarios would be significantly more expensive, requiring significantly more sources, as more gas generation in spring and summer would mean less gas generation in winter, and the cost of an additional GHG-free GWh in winter is much more expensive.

In the Base scenario, by contrast, significant generation from gas resources occurs throughout the year, mostly from facilities retrofitted with CCS.

Figure 17: Annual Generation and Monthly Gas Generation for Feasibility Scenarios



Source: CEC Staff

For a discussion on the resource adequacy of the set of Feasibility Scenarios, see Appendix C: .

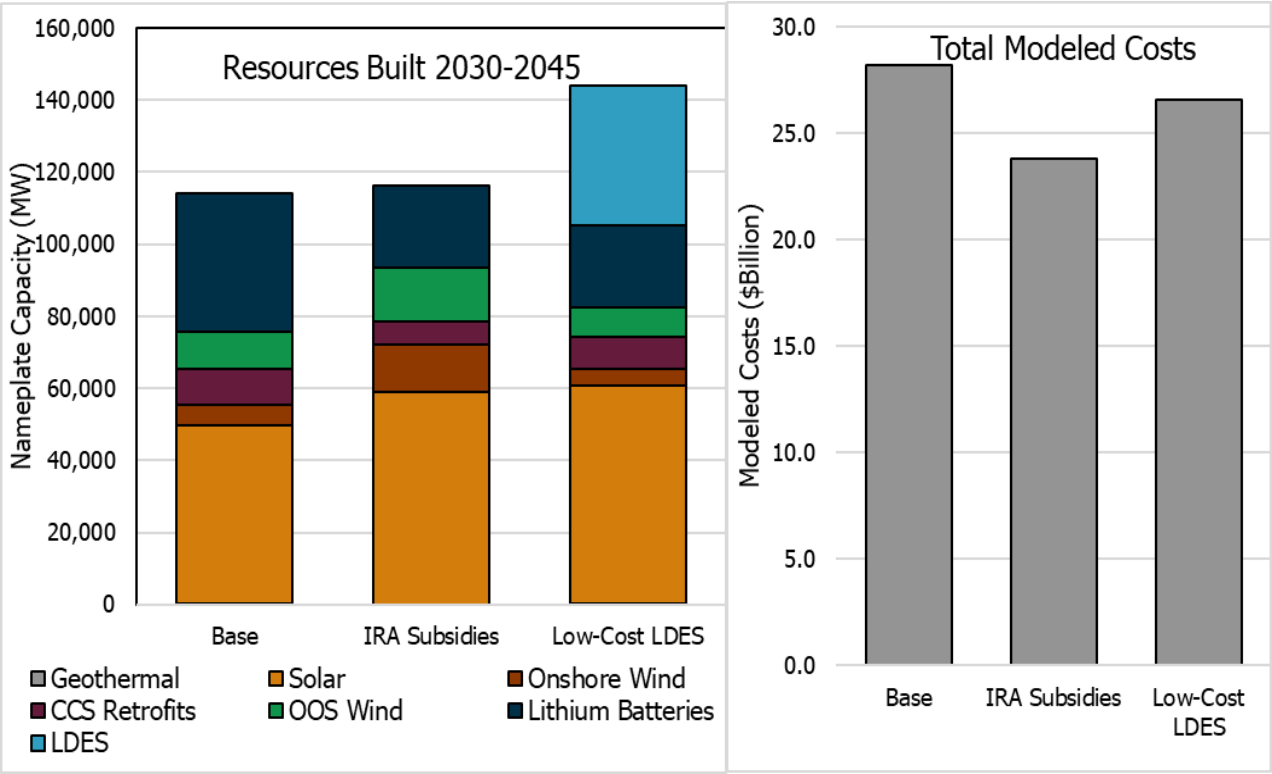
Cost Reduction Scenarios

Resource Buildout and Modeled Costs

The figures below show the resources built between 2030 and 2045 for IRA Subsidies and Low-Cost LDES scenarios and the associated costs.

The IRA Subsidies scenario retains the full production and investment tax credit for renewable and storage sources going out to 2050, to provide a comparison to the Base scenario demonstrating the effect of repealing these subsidies on the resource build and associated costs. The IRA Subsidies scenario builds 20 GWs more wind and solar PV and half as much CCS as the base scenario, with portfolio costs that are 20 percent lower. The repeal of these subsidies will significantly affect the overall costs of power generation, and the economics of intermittent renewables.

Figure 18: Model Capacity and Annual Costs for Price Reduction Scenarios



Source: CEC Staff

The Low-Cost LDES scenario can build 12-hour LDES for about $800/kW and 25-hour storage for about $1,100/kW, compared to about $1,100/kW for 4-hour lithium-ion batteries. Under base assumptions 12-hour batteries are $3,300/kW and 24-hour batteries are $6,500, which means they have no cost advantage relative to lithium batteries. Only the 12-hour batteries are built by the model in this scenario, but they are built in significant quantities. Lowering the cost of storage leads to 10 GW of additional solar PV built compared to the Base scenario. This scenario still builds a significant amount of CCS, 9 GW compared to 10 GW for the Base scenario, as it still relies heavily on its firm low-carbon generation in winter. The overall costs are about 5 percent lower than in the Base scenario.

LDES Performance on Summer and Winter Days

In a solar PV-heavy system like California's, medium-duration batteries (8–12 hours) tend to outperform longer-duration alternatives with low round-trip efficiencies, particularly in winter months when limited solar PV hours constrain charging capacity more than energy storage capacity. As a result, low-cost long-duration storage scenarios still rely heavily on CCS retrofits to meet GHG targets in winter, even as longer-duration batteries reduce gas burn in summer and fall.

See Appendix C: for detailed generation mix profiles and supporting analysis.

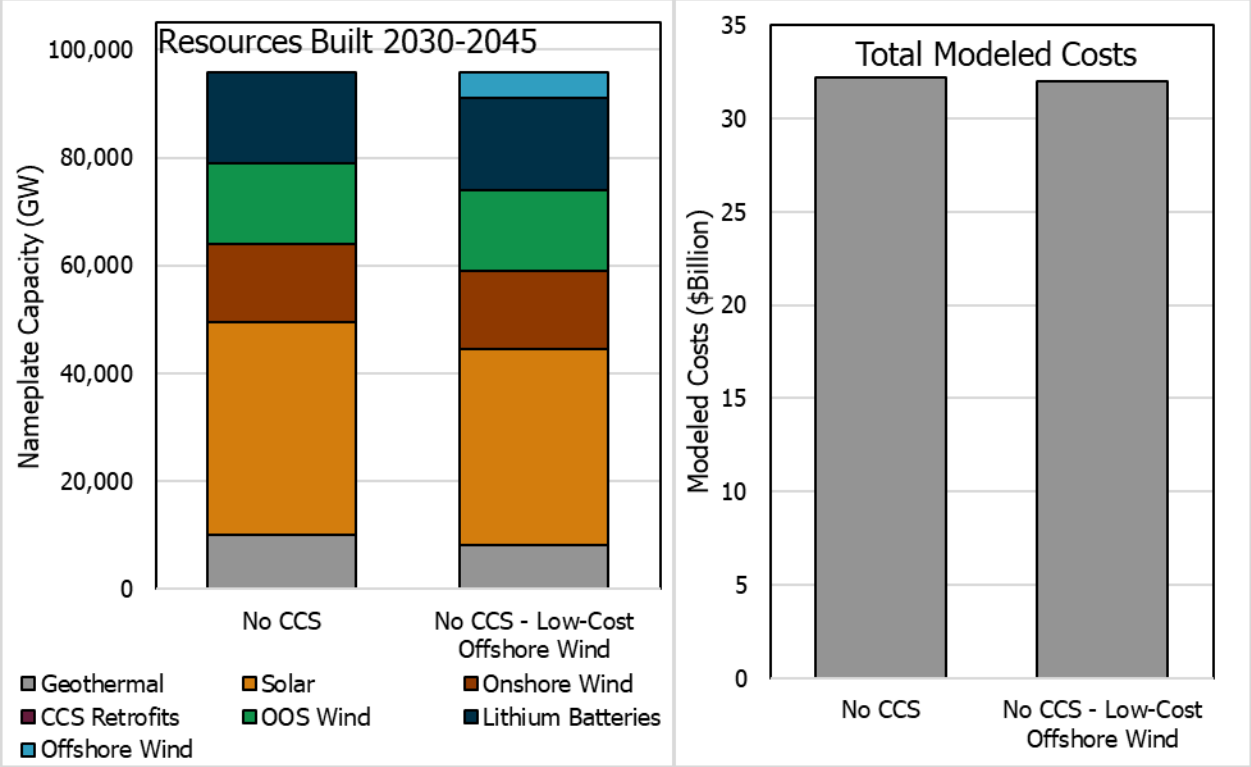
Offshore Wind Resource Buildout and Modeled Costs

The No CCS – Low-Cost Offshore Wind scenario uses the NLR ATB Advanced cost scenario for offshore wind. The Advanced cost scenarios in NRL ATB assume higher deployment[86] and higher learning rates for technologies. In this scenario, offshore wind reaches a cost of about $3,678/kW in 2045, compared to $1,200/kW for CCS and $1,100/kW for onshore wind. If CCS is available to the model, OSW must reach a significantly lower price to be picked up economically, so this scenario was tested assuming largescale CCS deployment is not feasible.

The graph below shows the resource build for the Low-Cost OSW scenario compared to the No CCS scenario, and the associated modeled costs. All 4.8 GW of the first tranche of the Morro Bay offshore wind is selected, which has lower transmission costs than the resources in the northern portion of the state, despite its slightly lower capacity factor.[87] Five GW of OSW displaces about 2 GW of EGS and 3 GW of solar PV from the resource portfolio. Total resource build and costs are only slightly lower, meaning OSW would have to achieve even further cost declines to significantly reduce overall portfolio costs. Generally, this suggests that OSW could be cost-competitive in California if OSW reaches the cost projections in the Advanced scenario and other firm resources with more competitive costs are not available.

86 For offshore wind specifically, the Advanced scenario assumes about 30 GW of both floating and fixed deployment across the United States and the Moderate scenario assumes 20 GW.
87 The capacity factor for Morro Bay is 44% compared to 51% in Humboldt. The transmission cost adder is negligible for Morro Bay and about $1,300/kW for Humboldt.

Figure 19: Model Capacity and Costs for Low-Cost Offshore Wind Scenario



Source: CEC Staff

Wind and Land Use Scenarios

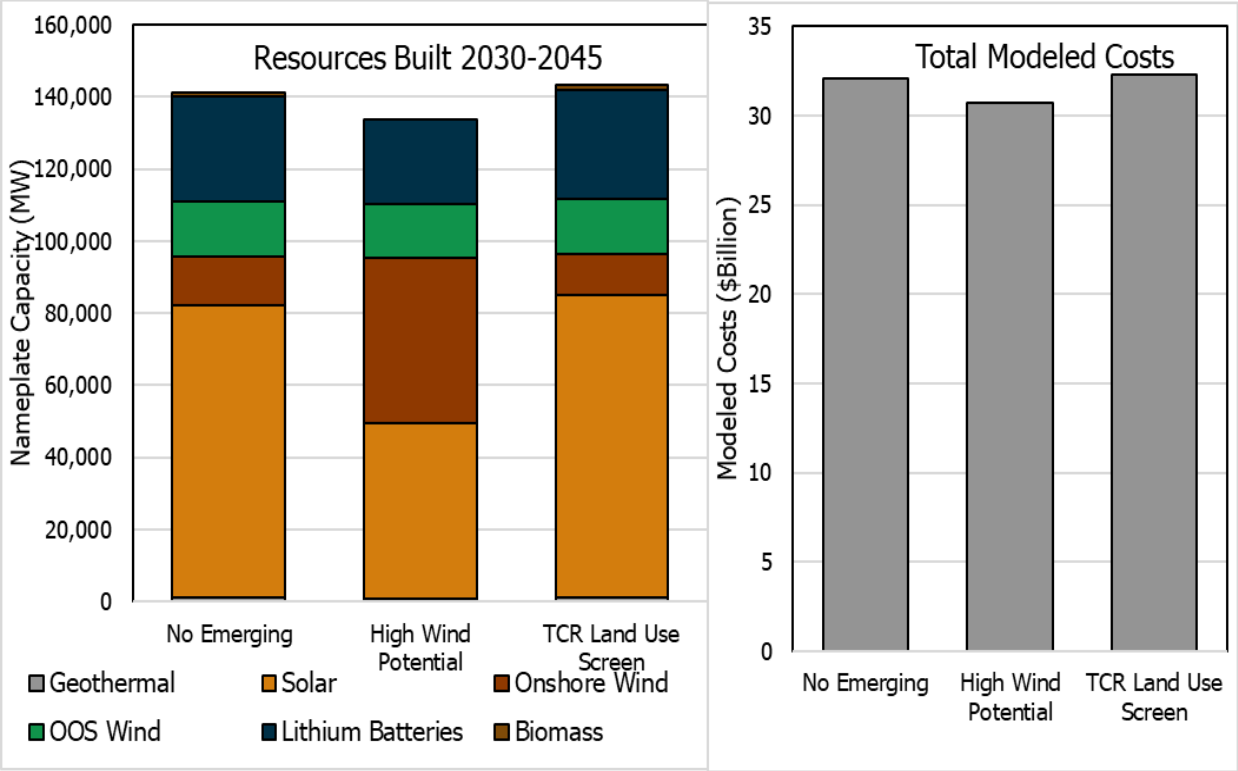
Resource Buildout and Modeled Costs

The last group of scenarios examines how changes in wind potential affect the resource build and costs in the No Emerging Resources scenario, where firm zero-carbon resources are largely unavailable. The High Wind Potential scenario allows for up to 35 GW of low-capacity factor wind to be added in marginal wind resource areas. Even though this wind generates much less energy per MW than solar PV, a significant amount is economically selected when emerging resources are not available, and wind additions actually outpace solar PV additions between 2030 and 2045. This scenario is also able to reduce total modeled costs by about 6 percent. Resource diversity reduces generation costs, even if the available resource is not particularly firm or high-quality. If other emerging resources are unable to make up a significant portion of the generation mix, increasing California's access to onshore wind via technology improvements and increased deployment in marginal areas may be a feasible way to decrease overall portfolio costs.

The other scenario uses the TCR Land Use screen, which prioritizes more land for conservation than the Core Land Use Screen used in other scenarios, and has the effect of reducing total land available for development by about 40 percent. Because the resource potential for solar PV in California is so large, this does not significantly impact

the modeling results for solar PV, and the model builds slightly more solar PV in this scenario than in the No Emerging Resources scenario. The amount of wind built is reduced from about 13 GW to 11 GW, which raises costs by about 1 percent. The overall results suggest that there is significantly more renewable resource potential than is strictly necessary to meet GHG targets. However, there are many factors that inhibit resource development beyond those considered in the CEC Land Use Screen, and it could be still be challenging to meet the 50-100 GW of new solar PV needed to meet GHG targets with a significant reduction in available land potential from land set aside for conservation.

Figure 20: Model Capacity and Costs for Wind Potential Scenarios



Source: CEC Staff

On low-solar days, the model's reliance on gas backup is highly sensitive to the availability of complementary zero-carbon resources: without wind, geothermal, or CCS, a single cloudy day can consume nearly 3 percent of the annual GHG budget, whereas high wind availability substantially displaces gas burn and reduces overall resource needs. See Appendix C: for further details.

Conclusions

Meeting California's SB 100 and GHG goals will require between 150 to 200 GW of new zero-carbon resources over the next twenty years, a significant buildout that will require record-breaking amounts of new resources every year to achieve. All scenarios evaluated build at least 100 GW of new solar PV, storage, and wind in the next 10 years

to meet the interim target of 20 MMT CO_2e emissions by 2035 while also serving new demand.

The removal of the IRA subsidies raises the cost of building and operating a decarbonized grid by 15-30 percent over the next 10 years. While solar PV, wind and storage will still be the foundation of the new resource build, firm zero-carbon resources are relatively more attractive in this new policy environment. This raises the importance of developing emerging zero-carbon firm technologies to meet the need for power during winter by 2045.

All of the studied emerging technologies are picked up under different conditions, driven by a need for energy during the winter:

- CCS retrofits of existing gas plants are the lowest-priced firm zero-carbon technology and are picked up in every scenario where they are allowed, though the true costs and performance of this emerging resource are still unknown, particularly with respect to the storage of carbon.
- EGS is picked up when CCS is not available, even with minimal price reductions from the present day.
- OSW is picked up under more optimistic price assumptions assuming high deployment that spreads infrastructure costs over a larger cost base, when other lower-priced firm technologies are not available.
- LDES is picked up under optimistic price assumptions that assume a 60 percent cost reduction.
- Expanding onshore wind to marginal areas could also be an option to provide resource diversity if other emerging technologies are not available.

Modeling results are only as robust as the assumptions that underlie them, and uncertainty around technology costs and availability, demand trajectories, including the pace of electrification and data center load growth, and the evolving policy environment will continue to shape outcomes in ways that are difficult to anticipate. The CEC will revisit these questions in future work to explore these uncertainties, and will work to incorporate additional dimensions not yet fully reflected in the current analysis: climate change impacts on resource availability including hydropower, wildfire effects on the transmission system, a more complete representation of transmission needs and constraints, and grid strength considerations that will increasingly bear on the feasibility of the resource buildouts the models identify. Greater coordination with parallel analyses by other California state agencies, and clearer documentation of where assumptions diverge and why, will also be a priority as this analytical effort continues.

Publicly Owned Utilities' Integrated Resource Plans

While CEC modeling develops a portfolio with statewide planning considerations, local utility modeling must consider local goals, transmission and distribution system limitations and details, and more granular changes to electricity consumption.

In the 2024 POU IRP cycle, public utilities focused their investments in renewable generation and zero carbon technologies. Between 2024 and 2030, the 16 filing utilities included the net addition of 204 MW of biofuels, 631 MW of geothermal, 69 MW of hydrogen, 672 MW of solar, 331 MW of solar plus storage, 91 MW of wind, and 3270 MW of battery energy storage. These values are measured as the peak dependable capacity of each resource -- the nameplate capacity of variable generation resources may be substantially larger. The POUs maintain existing zero-carbon technologies, such as hydroelectric and nuclear generation, but their capacity does not increase in MW. Most natural gas resources are also maintained, predominantly to meet peak reliability requirements.

Most of the filing POUs used a 15 percent planning reserve margin in their IRPs. However, some Southern California utilities face transmission constraints, which led them to use a loss of load expectation study to determine their planning reserve requirements. Due to their unique system constraints, reserve amounts for these utilities can exceed 40 percent of their forecasted peak demand.

As the POUs make their transition to clean energy, they have encountered similar barriers to their goals as IOUs. Many are in urban and suburban areas with little territory to site solar resources, while wind and geothermal resources are location dependent. As a result, POUs must rely on developments outside of their service territories and have transmission available to bring that energy to their customers. New transmission lines have long lead times of a decade or more and are costly. In addition, new wind and geothermal development is not is not on pace to meet prospective demand. Emerging technologies that could avoid the need for new transmission, such as small modular nuclear, are not yet a viable alternative to more traditional zero-carbon technologies. The variable nature of wind and solar also means that the POUs are relying on energy storage, primarily in the form of lithium-ion batteries, to make this energy available when it is needed. This challenge is highlighted as gas resources are retired, particularly during lower solar output months in winter.

In the last IRP cycle, the filing POUs demonstrated their ability to reliably meet their energy and capacity requirements in 2030 while meeting state policy goals. However, challenges remain to meeting future clean energy targets in 2040 and 2045.

Reliability of California's Future Electric System

The long-term planning analysis in the prior section considers questions around the long-run resource buildout California will need to meet its clean energy goals through 2045. Translating that long-run vision into near-term procurement decisions requires a different analytical lens, one focused on whether resources already planned or procured are sufficient to maintain reliability, and how sensitive that answer is to uncertainty in how demand evolves. That is the purpose of the mid-term probabilistic reliability assessment presented here.

Each year, the CEC conducts probabilistic reliability assessments of California's electric system operations, published as part of the CERRO report series. These assessments are intended to support state system operators, regulatory agencies, electric industry participants, and other stakeholders in planning and preparing for electric system operations in the near term. In addition to that annual short-term analysis, provided in CHAPTER 3: Summer 2026 Electric Reliability Analysis, the 2026 CERRO includes a mid-term assessment of system reliability in 2031 and 2036, years that sit squarely within the resource buildout horizon examined in the long-term planning analysis.

As with the short-term analysis, this work evaluates whether California is meeting the reliability criterion of 1-in-10-year LOLE, or 0.1 days/year, across a range of scenarios related to demand variability and import uncertainty. Unlike the short-term analysis, however, it also assesses whether existing and ordered procurement is sufficient to meet that criterion in future years, and by how much. This analysis estimates the timing and amount of additional capacity that may be needed beyond current procurement under various demand scenarios, providing insight into how changes in core demand assumptions impact future procurement needs. Note, however, that the analysis does not capture resources added after 2028, including procurement driven by the CPUC's February 2026 order; results for post-2028 years should therefore be interpreted as residual need remaining after implementation of the CPUC's prior procurement orders up through 2028.

Compared to similar analyses by other California agencies, this assessment covers the entirety of the state, including both California ISO and POUs, and applies different assumptions on resource availability to help define the boundaries of future resource needs. These methodological choices are intentional: by stress-testing the system across a wider range of demand and availability conditions, the CEC aims to provide a wider picture of the reliability risks associated with the current resource mix and ordered procurements.

Approach: Model Framework and Key Assumptions

Scenarios

The CEC conducted a reliability assessment on the following scenarios intended to represent a range of demand uncertainties for 2031 and 2036:

1. **Base Case, 2025 IEPR Planning Forecast:** Base planning case without known loads from the 2025 *IEPR* Forecast. This represents the standard system resource adequacy forecast.
2. **2025 IEPR Planning Forecast with Known Loads:** Includes known loads, as discussed in CHAPTER 3:
   Summer 2026 Electric Reliability Analysis. For 2026, known loads add about 3 percent at system annual coincident peak, for 2031 about 7 percent and for 2036 about 6 percent.
3. **2024 IEPR Planning Forecast:** Uses the prior year's IEPR planning forecast as a sensitivity.
4. **2025 IEPR Local Reliability Forecast with Known Loads:** The 2025 IEPR Local Reliability forecast has significantly higher demand due to lower expected energy efficiency and behind the meter solar PV and storage resources, and higher expected fuel switching, transportation electrification, and data center development as compared to the planning forecast. The local reliability forecast is used for Transmission Local Studies. For 2026, this forecast adds about 4 percent at system annual coincident peak and about 17 percent for both 2031 and 2036.

Modeling Inputs and Assumptions

See Appendix C: for a detailed discussion of CEC's Resource Adequacy model.

2031 & 2036 Demand

All regions in California are forecast to be summer peaking but winter peaks are projected to increase more quickly over the next decade due to electrification measures. Decreased solar PV generation during winter months, increased solar deployment, and a shift toward winter peaking in neighboring regions that California relies on for imports (e.g. the Pacific Northwest) point toward winter emerging as a period of heightened resource adequacy risk. Decreased solar PV generation during winter months, coupled with increasing deployment of solar PV to meet clean energy targets, and shifts to winter peaking in neighboring regions, which California relies on for imports, like the Pacific Northwest, points to winter becoming a season of increasing resource adequacy risk even if California remains a summer-peaking system.

Model Resources and Resource Additions for 2031 and 2036

Resource additions for California ISO regions beyond 2026 were based on the CPUC procurement orders for years 2026–2028.[88] Table 13 indicates the total installed

88 CPUC Order D.23-02-040 (MTR) requires LSEs to procure 2,000 MW in 2026 and an additional 2,000 MW in 2027. D.21-06-035 (MTR) orders 11,500 MW to be procured from 2023 to 2028 with 2,000 MW to occur specifically in the year 2028.

capacity of resources across California for 2025, with years 2026–2028 containing additions from the CPUC procurement orders.

The projected retirements utilized in this analysis align with retirements identified in Form Energy Information Administration (EIA) 860[89] or otherwise announced. This analysis includes DCPP as available through 2030, but not in 2031 and 2036.

Table 13: Total Installed Capacity of Resources across California 2025-2028

	2025 Baseline	2026 Additions	2027 Additions	2028 Additions
Peak Load[90]	57,560	58,807	59,423	60,532
Natural Gas	34,191	-	-	-
Utility Scale PV	26,206	2,700	2,700	2,700
Distributed PV	17,677	-	-	-
Batteries	13,462	2,364	2,430	-
Pumped Storage Hydro & Long Duration Storage	4,380	-	-	1,110
Hydro	9,693	-	-	-
Land Based Wind	7,337	-	-	-
Offshore Wind	-	-	-	-
Geothermal	3,180	-	-	-
Demand Response	2,760	-	-	-
Nuclear	2,393	-	-	-
Other	453	-	-	-
Total Incremental Additions	0	5,064	5,130	3,180
Total Resources	121,732	126,796	131,926	135,736

Source: CEC

While the overall model is consistent with previous analysis conducted by the CEC, there are notable updates that have been made.

In prior reliability analyses, the CEC used the CPUC 2023 PSP to represent resource buildout in future years, including the immediate summer. However, actual buildout may not necessarily have matched actual installed capacity as the PSP is a planning study. In this analysis, the CEC is instead leveraging the resource portfolio of the CEC Stack Analysis for California ISO NQC resources, and the QFER for energy-only[91] California ISO and POU resources through 2025. This presents a better representation of the existing system and permits more direct comparison to other state reliability

89 EIA-860 is a survey form containing generator-level specific information about existing and planned generators with 1 megawatt or greater of combined nameplate capacity.
90 Total California coincident 1-in-2 net electricity peak demand in megawatts.
91 Those resources delivering energy but not on the NQC list.

analyses. For future years, again with the intention of representing actual procurement rather than planning, CEC has included the CPUC Mid-Term Procurement orders for 2026-2028 that require CPUC jurisdictional utilities to procure resources rather than relying on the PSP.[92] For years beyond 2028, the analysis add no new resources; it identifies capacity deficits, if any, relative to the 1 in 10 or 0.1 LOLE standard.

In February 2026, the CPUC ordered an additional 6,000 MW NQC procurement by 2032. This analysis does not include this most recent procurement order.[93] Accordingly, results for post-2028 years should therefore be interpreted as residual need remaining after implementation of the CPUC's prior procurement orders up through 2028.

Results and Discussion

Scenario Results

Results shown in Table 14 indicate that expected resource procurements should sufficiently meet the 0.1 days/year LOLE criterion through 2031 under normal hydro and transmission conditions in the Base demand scenario. However, the LOLE criterion is exceeded in all other demand forecast scenarios, meaning additional resources would be needed for those scenarios to be considered reliable. Additionally, without additional procurement, the California system will not meet the 0.1 LOLE reliability criterion in 2036 in any of the demand forecast scenarios. These findings rely on resources ordered to be procured through 2028 and do not include CPUC's February 2026 procurement of resources through 2032.

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92 See California Public Utilities Commission. *Decision Requiring Procurement to Address Mid-Term Reliability (2023–2026).* Decision 21-06-035. Rulemaking 20-05-003. June 24, 2021. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF.
California Public Utilities Commission. *Decision Ordering Supplemental Mid-Term Reliability Procurement (2026–2027) and Transmitting Electric Resource Portfolios to California Independent System Operator for 2023–2024 Transmission Planning Process*. Decision 23-02-040. Rulemaking 20-05-003. February 2023. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M502/K956/502956567.PDF.
93 The February 2026 decision requires CPUC-jurisdictional load-serving entities to procure 6,000 MW NQC of new, non-GHG-emitting resources in three equal tranches of 2,000 MW NQC due by June 2030, June 2031, and June 2032 respectively. At least one-quarter of each LSE's total obligation must come from long-duration storage (8 hours or greater) or clean firm resources.
See California Public Utilities Commission, *Decision Requiring Procurement to Address Near-Term Reliability (2030–2032) and Transmitting Electric Resource Portfolios to California Independent System Operator for 2025–2026 Transmission Planning Process,* Decision [26-XX-XXX], Rulemaking 20-05-003 (February 26, 2026), https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track.

Table 14: LOLE Results Across Scenarios

LOLE Scenarios	2026	2031	2036
Base Scenario, 2025 IEPR Planning	0	0.005	1.64
2025 IEPR Planning with Known Loads	0	0.15	9.89
2024 IEPR Planning	0	0.38	>10
2025 IEPR Local Reliability with Known Loads	0	0.64	>10

Source: CEC Staff

Table 15: Effective Surplus or Deficit Capacity (GW) Results Across Scenarios

LOLE Scenarios	2026	2031	2036
Base Scenario, 2025 IEPR Planning	7-8 Surplus	3-4 Surplus	6-7 Deficit
2025 IEPR Local Reliability with Known Loads	6-7 Surplus	4-5 Deficit	>10 Deficit

Source: CEC staff

The 2031 Base Scenario results in a 3-4 GW surplus, meeting the 0.1 days/year LOLE criterion. However, the other scenarios—which include the previous demand forecast or known load and/or higher levels of building and transportation electrification—do not meet the criterion in 2031, with an LOLE range of 0.15 for 2025 IEPR Planning with Known Loads to 0.64 for the 2025 IEPR Local Reliability with Known Loads scenarios. LOLE ranges in 2036 from 1.64 days/year for the Base Scenario to greater than 10 days/year for the 2024 IEPR Planning scenario, indicating significant additional procurement over the next decade beyond that modeled through 2028 may be needed.

As noted previously, the CPUC mid-term reliability (MTR) procurement orders included in this analysis extend to 2028 with the demand forecast scenarios forecasting significant load growth in both summer and winter seasons. In February 2026, the CPUC ordered an additional 6,000 MW NQC of procurement by June 2032, which would likely fill the deficits in 2031 sensitivities. This procurement is of similar magnitude to the 6–7 GW statewide deficit identified for the 2036 base-case. The order was built on LOLE analysis using the 2024 *IEPR* Planning Forecast.[94]

These findings emphasize the need for continued resource development in the state and to regularly evaluate whether procurement will be sufficient as demand forecasts

94 *Ibid.*

are updated through the *IEPR*. The findings also emphasize the importance of considering uncertainty in the demand forecast, as evidenced by the wide range of LOLE across the demand sensitivities.

These results indicate that the probability of resource shortfalls is low in the near term, provided that there are normal hydro and transmission conditions and California LSEs continue to meet the CPUC procurement orders. However, California could face a variety of additional challenges that could lead to resource adequacy deficits. Staff evaluated additional sensitivities to test system reliability including modifying California ISO's import ability during periods of high system stress in future years. Widespread Western drought or wildfires or both could also pose a resource adequacy risk and are being considered for future analysis.

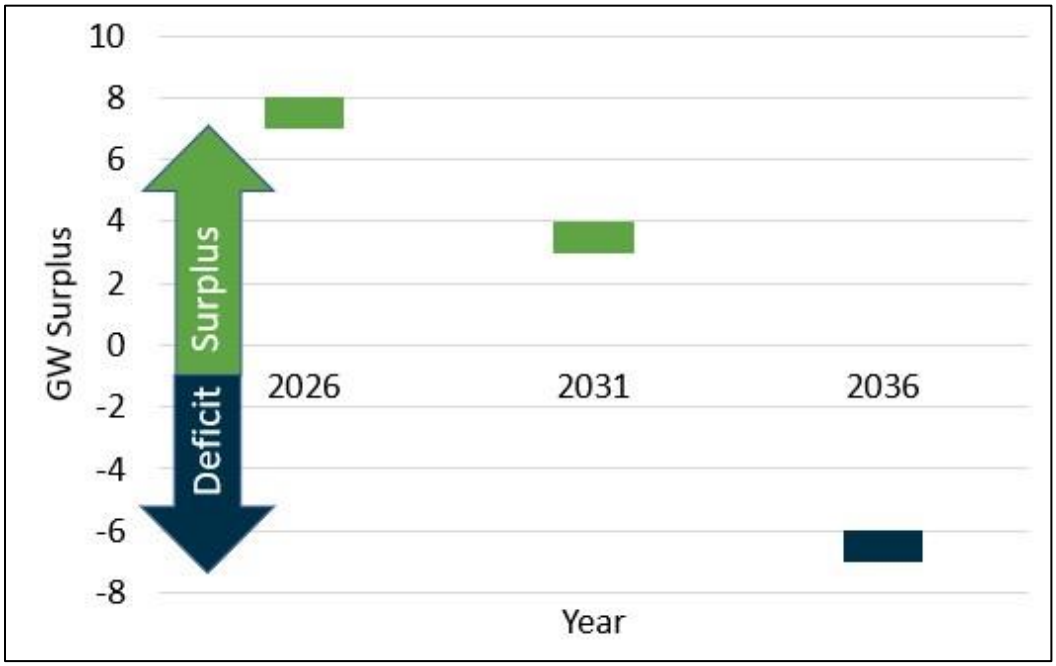
Surplus and Deficit Calculations

To provide additional information, the CEC quantified the amount of surplus or deficit capacity to achieve the 0.1 days/year LOLE reliability criterion for each study year. This effective capacity surplus or deficit is calculated by adding firm load or perfect generators, applied as a constant MW addition in all hours, until 0.1 days/year LOLE is reached. Firm load or perfect generation is allocated to each region based on the region's contribution to forecasted coincident peak statewide load.

The results of this analysis are presented in Figure 21 below. This analysis indicates that California's statewide surplus is expected to diminish across the study horizon, from 7-8 GW in 2026, to 3-4 GW in 2031, and ultimately a deficit of 6-7 GW is expected in 2036. For 2026, the surplus takes into account the stack analysis resources in addition to POU resources. For 2031 and 2036, the analysis includes resources procured under the CPUC MTR orders through 2028 but assumes no resource additions beyond that. In addition, all surpluses assume normal hydro conditions and transmission capability, including the California ISO Total Import Constraint is at 11,655 MW in hours except for peak morning and peak evening hours across the year. Those imports are restricted to 5,500 MW. Again, this level of near-term reliability is driven by resource additions from the MTR procurements for reliability needs, a reduced near-term load forecast relative to the previous (2024) *IEPR Forecast, and the retention of* DCPP *through 2030.*

It is important to note that surplus capacity and deficit are determined by adding fixed load or generation across the state, of which about 80 percent applies to the California ISO BA. Accordingly, surplus in the California ISO BA-only would be expected to be about 80 percent of the full-state value.

Figure 21: Base Scenario Surplus/Deficit Capacity



Source: CEC staff

Capturing Indirect Wildfire Risks in Power System Assessments

The resource adequacy analysis earlier in this chapter evaluates reliability risk under a range of demand and procurement scenarios, but those scenarios assume the transmission system performs as planned. In practice, there are many factors that can alter planned transmission operations. Wildfires, for example, can constrain or deenergize transmission paths at precisely the moments when the grid is under the greatest stress, compressing the margins that reliability planning depends on. Understanding how wildfire risk interacts with system reliability is therefore not a separate concern from resource adequacy, rather it is a condition that could shape how much resource adequacy margin California needs.

California's power system faces wildfire risk through both direct and indirect pathways. Direct risks include electric facilities igniting a fire, or transmission towers and other infrastructure being damaged or destroyed by fire. Indirect effects are subtler but potentially just as consequential for reliability: smoke reduces solar PV generation output, and wildfires near transmission corridors can trigger de-energization of key paths, limiting imports into California or restricting power transfers among major in-state corridors. Transmission operators use de-energization to protect equipment from heat and fault-induced damage, reduce smoke-induced arc risk, eliminate additional ignition risks from energized lines, and ensure the safety of firefighters and crews operating in the area. As the state's resource mix shifts toward more geographically

dispersed renewable generation, the buildout envisioned in the long-term capacity expansion analysis, the transmission system's exposure to these indirect effects grows alongside it.

The CEC and Telos Energy are investigating these indirect wildfire impacts on power system reliability, with the goal of producing a wildfire-informed resource adequacy evaluation that captures both transmission and generation risks. This evaluation will feed directly into the CEC's resource adequacy and capacity expansion models, and more broadly support system planning and operational efforts across the state. The work is ongoing and intended to be completed before the end of 2026; the study team has and will continue to engage with stakeholders to refine analytical approaches and inform results.

Approach

To better understand the impact of wildfires on RA and system reliability, the team built on work conducted by the Northwest Power Conservation Council,[95] which primarily focused on impacts to transmission and smoke impacts on solar PV generation. The study has thus far completed initial research on the impacts to transmission and solar PV generation. The focus of the transmission assessment is a better representation in economic and RA models of transmission derates and outages that could be attributed to wildfire risk and public safety power shutoff events, which would decrease the total transfer capability into California or within California. The solar PV analysis similarly looks to validate that the solar PV availability embedded across multiple weather years appropriately derates regional solar PV output when there is significant wildfire smoke.

Transmission Line Ratings Affected by Nearby Wildfires

Historical line ratings of key import transmission paths from Oregon into California were compared against historical wildfire data to quantify the transmission risk imposed by large and small-scale wildfires.[96] The two transmission paths studied were the AC intertie between Oregon and Northern California (Path 66) and the DC intertie between Oregon and Los Angeles (Path 65).

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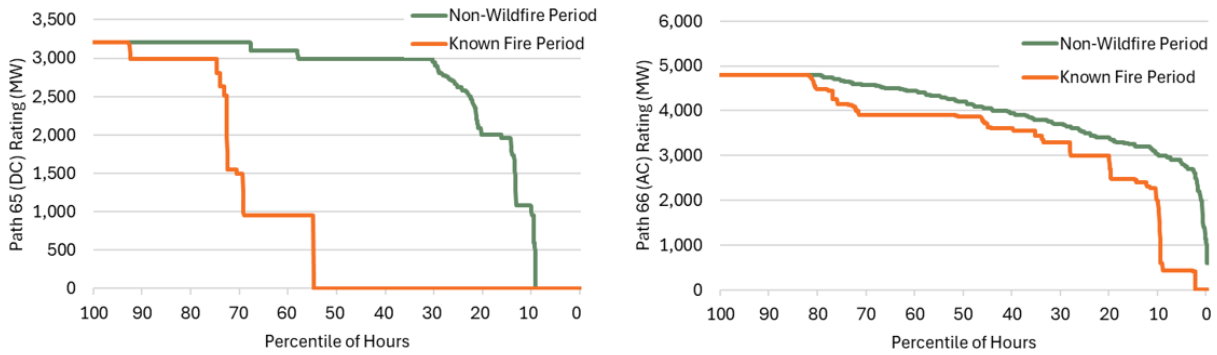
95 Cai, Mengmeng, Chin-An Lin, Vikram Ravi, Yimin Zhang, Cheng-Hsuan Lu, and Manajit Sengupta (National Renewable Energy Laboratory). June 2023. *Final Technical Report: Impact of Wildfires on Solar Generation, Reserves, and Energy Prices.* National Renewable Energy Laboratory. NREL/TP-5D00-86640. Available: https://docs.nrel.gov/docs/fy23osti/86640.pdf

96 Bonneville Power Administration. OPI Interties and Flowgates: Paths. Available: https://transmission.bpa.gov/business/operations/paths/; and California Department of Forestry and Fire Protection. Fire Perimeters. Available: https://www.fire.ca.gov/what-we-do/fire-resource-assessment-program/fire-perimeters.

The analysis finds significant transmission de-rates aligned with times of significant wildfire activity on both Path 65 and 66. Figure 22 below shows historical line ratings on Paths 65 and 66, both during periods of wildfires[97] (orange) and non-wildfires (green).

Figure 22: Path Ratings for Path 65 and Path 66 during Known Wildfire



Source: Telos Energy

Note that actual line flows on these paths could be lower for any number of reasons, including the lack of economic trades among the regions.

In both conditions, transmission line ratings can vary significantly, yet the lowest line ratings are typically only seen during periods of known wildfires. While there are still questions with respect to how operators evaluate fire risk and set these ratings, these periods of known fires often overlap with periods of high load, and the correlated risk should be considered in resource adequacy evaluations.

The analysis shows that even small fires are associated with significant de-rates[98]. However, this analysis is complicated by the fact that many factors beyond wildfires influence key transmission path ratings, including operational constraints, maintenance, and other grid conditions. These additional sources of unavailability should also be considered in reliability assessments, rather than evaluating only perfect or wildfire situations.

Statewide Solar Generation Minimally Affected by Wildfire Smoke

While academic research has identified roughly 7–10 percent reductions in solar PV generation at individual plants during periods of significant wildfire smoke, statewide

97 Wildfire periods were defined as any days when a fire was active in the CAL FIRE data set that intersected with the DC tie. The dataset includes all hours between 2005 and September 2025.
98 For example, both the Johnson Fire in August 2020 and the Hurst fire in January 2025, each under 1,000 acres in total size, were associated with a temporary de-energization of the DC tie connecting Oregon to Los Angeles, even if only for part of a day.

analysis tells a different story.[99] An assessment of California ISO resource availability and particulate matter data from 2015 to 2021, including a regression model using 9 years of hourly environmental variables, found that particulate matter has minimal explanatory power over solar PV generation when aggregated to the California ISO system level, with shortwave radiation far outweighing smoke effects.[100] In several major wildfire events, such as the August Complex and Dolan wildfires in 2020, solar PV generation exceeded historical weekly averages, suggesting that the localized impacts documented in the literature do not translate meaningfully to system-wide availability.

Next Steps: Towards Wildfire-Informed Resource Adequacy

Given the findings to date, the CEC plans to further evaluate wildfire impact on power transfers across the transmission system through 2026. As a first step, the team will translate research data that has identified the probability that a wildfire removes any individual line from service[101] into wildfire-informed transfer capabilities. When any one line is removed from service, the bulk power system can continue to deliver power to customers, but it may not be able to transfer as much power across regions and various interfaces. As transmission lines are removed from service due to correlated events (wildfires), the ability of the system to safely move power across regions is diminished due to voltage and system security limitations. Reducing the capability of the transmission system to move power may require the system to: operate local units at increased system cost, operate at lower safety margins which increases the risk of loss of load if additional contingencies were to occur, or even shed load.

The next step in this effort is to identify system capabilities across a range of wildfire-compromised scenarios. With transfer limits defined between zones and the seasonal probabilities of such scenarios, staff will work to incorporate those constraints into a wildfire-informed resource adequacy evaluation that focuses on a few weeks of high-stress grid conditions to improve understanding of the key drivers of broader wildfire risks by the end of 2026. Longer-term, this analysis can inform the CEC's approach to RA generally while also informing statewide wildfire risk management priorities by identifying key corridors for RA that are potentially at risk of wildfire.

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99 A study conducted by Sandia National Laboratories saw a 6.7% decrease in solar production due to additional particulate matter from wildfire smoke. A study conducted by NREL and SUNY Albany measured an 10% average reduction in California solar availability during months with significant wildfire activity when compared to a baseline availability seen in 2019.

100 The explanatory weather data includes temperature (F), wind speed (m/s), shortwave and longwave radiation (W/m2). Shortwave radiation represents direct solar radiation, while longwave represents radiation emitted by the lower atmosphere. Particulate matter data was calculated as an capacity-weighted average value across monitors in California located nearby solar generation sites and sourced from https://aqs.epa.gov/aqsweb/airdata/download_files.html. *Also see* https://www.caiso.com/library/production-curtailments-data.

101 Datta, Sohom, Chalishazar, Vishvas H., Ahmad, Tawsif, et al. "Western Interconnect Transmission Line Wildfire Risk." Pacific Northwest National Laboratory. (2026). https://doi.org/10.11578/3018229. https://doi.org/10.11578/3018229.

Analysis of Grid Strength and its Potential Impacts to the Grid in California

The long-term planning analysis earlier in this chapter projects a California grid running predominantly on solar PV, wind, and battery storage by 2045. The resource adequacy and wildfire analyses then examine whether that grid can maintain reliability under demand uncertainty and transmission stress. But there is a more fundamental question underlying these analyses: as the grid's physical character changes, as the synchronous generators that have long anchored system stability are displaced by inverter-based resources, will the grid itself remain stable and controllable? That is the question this section explores.

California's power system is undergoing rapid change. Draft modeling results from the 2025 Joint Agency SB 100 Report process indicate that the grid will need to run for extended periods almost exclusively on inverter-based resources (IBRs), namely solar PV, wind, and battery storage, to achieve the state's greenhouse gas targets. Under these operating conditions, California may increasingly experience weak grid conditions, as the large synchronous generators (i.e., gas and nuclear plants) that have historically anchored system strength are displaced by IBRs that interact with the grid very differently. Weak grids create new risks for system stability that must be actively managed.

Conventional synchronous generators, such as natural gas plants and large hydro facilities, have long been the backbone of grid stability, providing inherent physical properties like inertia, voltage regulation, and fault current that help the grid automatically resist and recover from disturbances. IBRs, by contrast, interface with the grid through power electronics rather than rotating machinery, meaning they do not naturally provide these same stabilizing responses unless explicitly programmed to do so, introducing new dynamics that require updated planning frameworks and grid management approaches. The terms "weak grid" and "system strength" refer broadly to the ability of a power system to dynamically maintain voltage control across a variety of conditions and disturbances. Resources on the grid interact on very fast, often sub-second timescales to maintain voltage and reliability. If the grid becomes excessively weak, it can struggle to recover from disturbances—or begin to oscillate—even in response to routine events like line maintenance. System strength is not uniform across the grid; pockets of weakness and weak points of interconnection (POIs) can develop within an otherwise functional system and identifying them in advance is essential for proactive planning.

The ERCOT[102] and other system operators around the world have been grappling with this challenge for over a decade, often responding by limiting power transfers and

102 Rehman, Ehsan Ur, and John Schmall (Electric Reliability Council of Texas). June 2020. *2020 West Texas Export Stability Assessment*. Electric Reliability Council of Texas. Version 1.0. Available: https://www.ercot.com/files/docs/2020/11/27/2020_West_Texas_Export_report_final.pdf

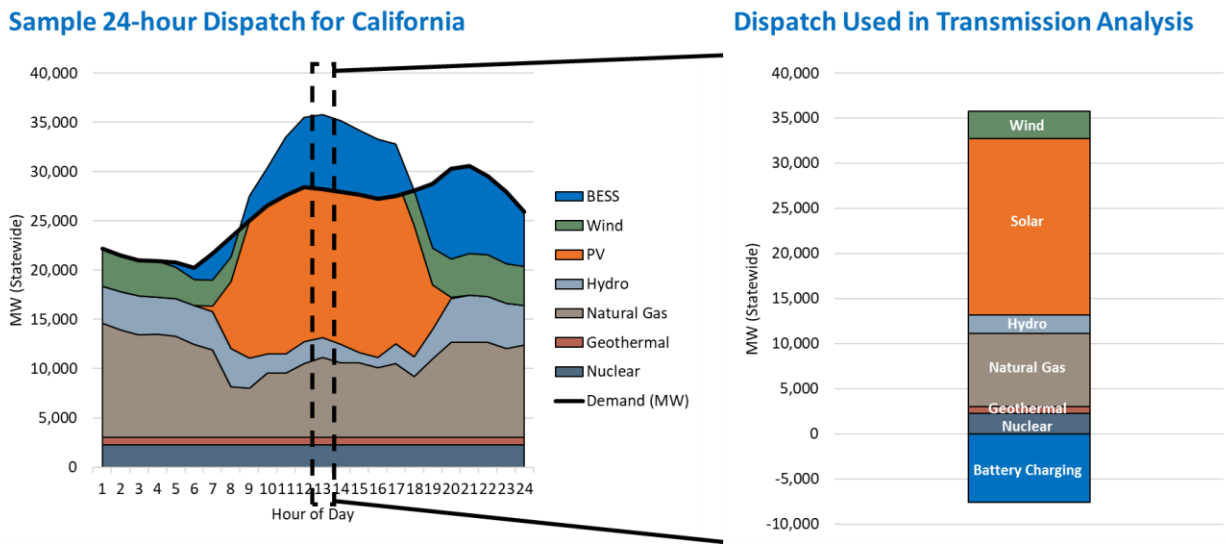
curtailing renewable output, with resulting cost and emissions penalties. Closer to home, National Energy Reliability Corporation (NERC)[103] and WECC[104] Disturbance Reports have documented widespread reductions in California's solar PV output during periods of high IBR generation over the past 10 years, a pattern indicative of weakening grid conditions already emerging on the system.

The CEC and its contractor Telos Energy are investigating potential weak points in the California power system to evaluate grid strength in the near and medium term. As with the wildfire work, findings from this analysis will feed into the CEC's broader resource adequacy and resource planning analysis work, informing not just resource selection, but operational decisions such as dispatch limitations or constraints on interregional power transfers within the models. This is ongoing work intended to be completed before the end of 2026, and the study team will continue to engage with grid operators and utilities to refine analytical approaches and inform results.

Initial Approach

The 2026 Spring Light-Load Power Flow Case from WECC was used to assess potential near-term grid strength challenges, given the rapid pace of large solar PV and battery installations in the last few years.[105] A real-time resource mix for a spring day in April 2025, shown in Figure 23 below, was used as a basis for dispatch.

Figure 23: Spring Day Resource Mix used in Transmission Analysis

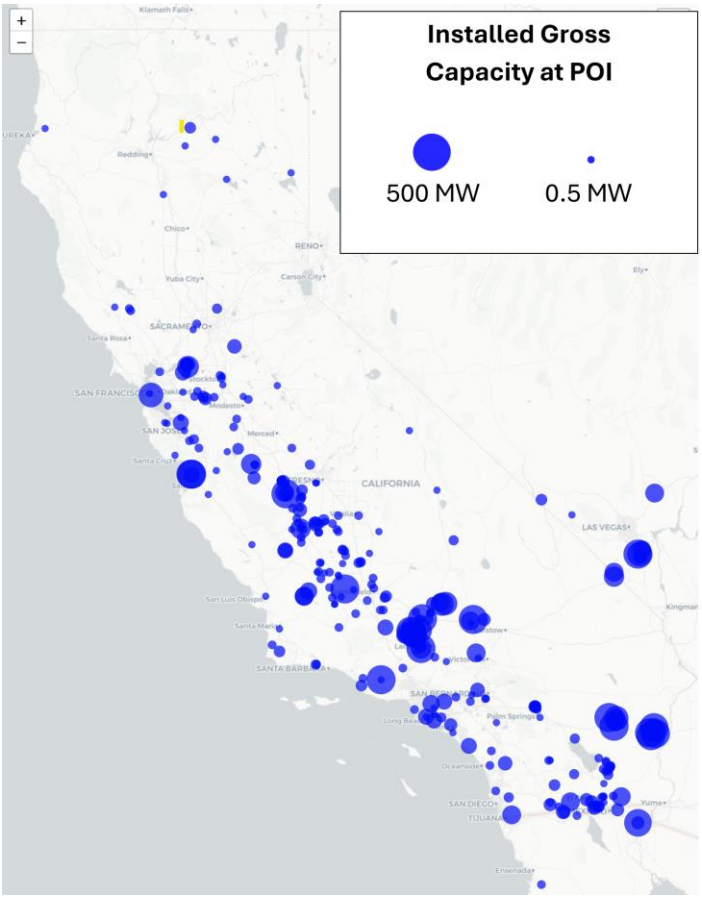


Source: Telos Energy

103 Multiple Solar PV Disturbances in CAISO
104 Inverter-Based Resource Disturbances in the Western Interconnection
105 WECC Base Case webpage

The map in Figure 24 depicts the location and size of IBRs including solar PV, wind, and batteries, that are modeled in the near-term study case. Installed gross nameplate capacity connected at a single node is used to help highlight the size and concentration of IBRs across California.

Figure 24: IBR Installations in California



Source: Telos Energy

Industry has developed several different ways to quantify grid strength, each with advantages and limitations.[106] Short-circuit ratio (SCR) has typically been the most used metric, but it can often produce overly optimistic results as it does not consider surrounding IBRs. A variant of SCR, the Equivalent Short Circuit Ratio (EqSCR) is preferred because it considers IBRs near the POIs under consideration. EqSCR is further enhanced by considering the behaviors of different types of IBRs, such as grid-following

106 B. Badrzadeh, Z. Emin (eds.), Power System Dynamic Modelling and Analysis in Evolving Networks, CIGRE Green Books, https://doi.org/10.1007/978-3-031-47821-5_5

(GFL) versus grid-forming (GFM) inverters, when used in conjunction with the Dynamic Impedance Method (DZM).[107]

The distinction between GFL and GFM inverter technology is an important one, as GFM is significantly more capable of supporting system strength than GFL. The EqSCR with DZM metric was used for this analysis to accurately depict California's grid strength considering the IBRs interconnected to the system. California does not generally employ GFM technology today, so for initial analysis, all IBRs are assumed to be GFL.

Next Steps

Next steps will focus on assessing grid strength during contingency conditions and evaluating potential solutions to improve grid strength and system reliability. Potential solutions could include operational rules, such as transfer constraints and generation curtailment, and physical mitigations, such as application of GFM inverters and synchronous condensers. Key trade-offs exist between these approaches. Operational rules, while effective for stability, often force the curtailment of clean energy in favor of fossil-fueled generation, thereby increasing system costs and hindering GHG reduction efforts. Infrastructure solutions, despite higher upfront capital costs, enable the grid to integrate renewable resources more effectively, supporting long-term decarbonization and lowering future operational costs.

Further, the study team will work to reflect the broader economic, affordability, and resource adequacy impacts of weak grid risks, particularly given how such risks can influence transfer limits and govern system resource decisions and dispatch. By looking towards a long-term planning horizon, the analysis will identify constraints that may arise as the grid evolves that could hinder progress towards the state's GHG targets. These could include constraints on resource retirements or new resource investment, such as in local capacity areas, transmission needs, operating constraints, amongst others. Overall, this assessment will help define near-term planning actions needed to eliminate bottlenecks and support California's transition to a decarbonized energy future.

Future Work

While this analysis evaluates long-term planning, resource adequacy risk, wildfire risks and weak grid considerations, it is not exhaustive in its consideration of all power system risks faced in the state. The CEC intends to continue evaluating the current and future power system to better understand and measure potential resource adequacy risk in the state. Future work is intended to improve system modeling and help guide policy decisions related to resource procurement, retirements, demand-side

107 Richwine, M., Miller, N., et al, Power System Stability Analysis & Planning Using Impedance-Based Methods. 22nd Wind & Solar Integration Workshop, Copenhagen, Denmark, 28 September 2023

management programs, and interregional coordination. Potential topics to be addressed in future work are discussed below.

Emerging Winter Reliability Risks for California

California's energy system is on a trajectory of significant transformation. While this analysis captured some components of winter risk, additional improvements can be made. By 2045, California's primary reliability risk period remains to be summer although the winter season also shows increasing reliability risk due to the resource mix and widespread heat pump adoption and electrification. Furthermore, other regions in WECC—even those in warmer climates—are on a similar trajectory due to changes in resource mixes and electrification patterns.

As mentioned in this report, the transition to dual summer and winter risk changes fundamental assumptions buried across models and necessitates reconsideration of the suitability of historical data to represent future constraints. Import availability and limits, hydro availability, and demand response programs are all traditionally oriented around summer periods. As reliability risk changes to a dual season risk, models and system operations will need to continue to evolve.

Addressing Fuel Supply Disruptions

Fuel supply disruptions pose a compounding risk to California's winter reliability, particularly as natural gas continues to support resource adequacy and winter reliability risks increase. Disruptions to gas pipelines or storage facilities during extremely cold events can curtail the availability of critical dispatchable generation. Incorporating fuel supply risk scenarios into planning models will help stakeholders better understand the potential magnitude of this threat and identify mitigation strategies. These strategies include diversifying winter energy sources and enhancing grid flexibility to respond to unanticipated resource shortfalls.

The Role of Load Flexibility

Demand response and load flexibility programs within this study are oriented around summer peak periods, but future programs could meet grid needs as they shift. Future analysis could examine the role of load flexibility beyond traditional peak shavings to evaluate load modification strategies that respond to renewable generation availability, such as load reduction during extended cloudy periods or seasonal load shifting. As the power system grows to include new end uses, such as EVs, heat pumps, and increasing amounts of data centers, resource adequacy methods could illuminate the forms of future load flexibility that could be most beneficial under different system conditions and weather patterns.

Expanding Beyond Resource Adequacy Assessments

Resource adequacy is just one component of bulk electric power system risk. Operational constraints like forecast uncertainty and weak grid concerns may not be sufficiently captured in traditional zonal resource adequacy assessments. Emerging

study approaches that capture operational constraints and forecast uncertainty on battery performance reveal that a reliable system with perfect renewable and load forecasting may experience reliability challenges when forecast uncertainty is introduced. Similarly, AC power flow constraints may inform resource adequacy analysis dispatch conditions, particularly as generation and load change location throughout the network.

CHAPTER 6: Maintaining Reliability Through Extreme Events

As described in Chapters 3 and 5, reliability planning standards only account for the risks captured in models that set those standards. The risks captured by these models reflect historical demand and outage data. These standards do not capture risks such as climate-driven extreme heat events outside the historical data and wildfire impacting major transmission lines, potentially creating vulnerabilities to grid reliability. Contingency resources can provide a means to support grid reliability without creating additional pressures on electricity rates.

In June 2022, following the 2020 extreme heatwave that led to rotating outages and State of Emergency Proclamation due to grid conditions in 2021, Assembly Bill (AB) 205 (Committee on Budget, Chapter 61, Statutes of 2022), created three programs as part of a new Strategic Reliability Reserve (SRR). The SRR expands the resources capable of managing or reducing net-peak demand during extreme events and acts as an insurance policy for grid reliability. These programs include the DSGS Program and the Distributed Electricity Backup Assets (DEBA) Program, which are administered by the CEC, and the Electricity Supply Strategic Reliability Reserve Program (ESSRRP), administered by DWR.

- The DSGS Program incentivizes dispatchable customer load reduction and back-up generation resources that serve as on-call emergency supply and load reduction for the state's electrical grid during extreme events. As of October 30, 2025, estimated capacity enrolled in DSGS was more than 1,145 MW, as reported by DSGS providers.
- The DEBA Program incentivizes the construction of cleaner and more efficient distributed energy assets that serve as on-call emergency supply and load reduction. As of December 1, 2025, the CEC has approved seven grant agreements totaling more than 185 MW of new incremental capacity.
- The ESSRRP provides additional generation capacity to support grid reliability during extreme events. In 2025, investments for this program focused on 3,079 MW of emergency and temporary natural gas resources and contracts for extreme events, including the extension of operating life for existing generating facilities that were planned for retirement. These resources are only called upon

to support gid operations in anticipation of or during extreme events and no longer provide power to the market on a consistent basis.[108]

Demand Side Grid Support Program

When the DSGS Program launched in summer 2022, the program offered one participation option, Option 1 Emergency Dispatch, under which 44 individual participants provided over 3,100 MWh of incremental load reduction during the September 2022 heat event, helping to avert rotating outages. Since then, the DSGS Program has expanded, and is designed to provide incremental clean resources in support of the SRR without interfering with resource adequacy and to test new concepts that may help scale demand flexibility.

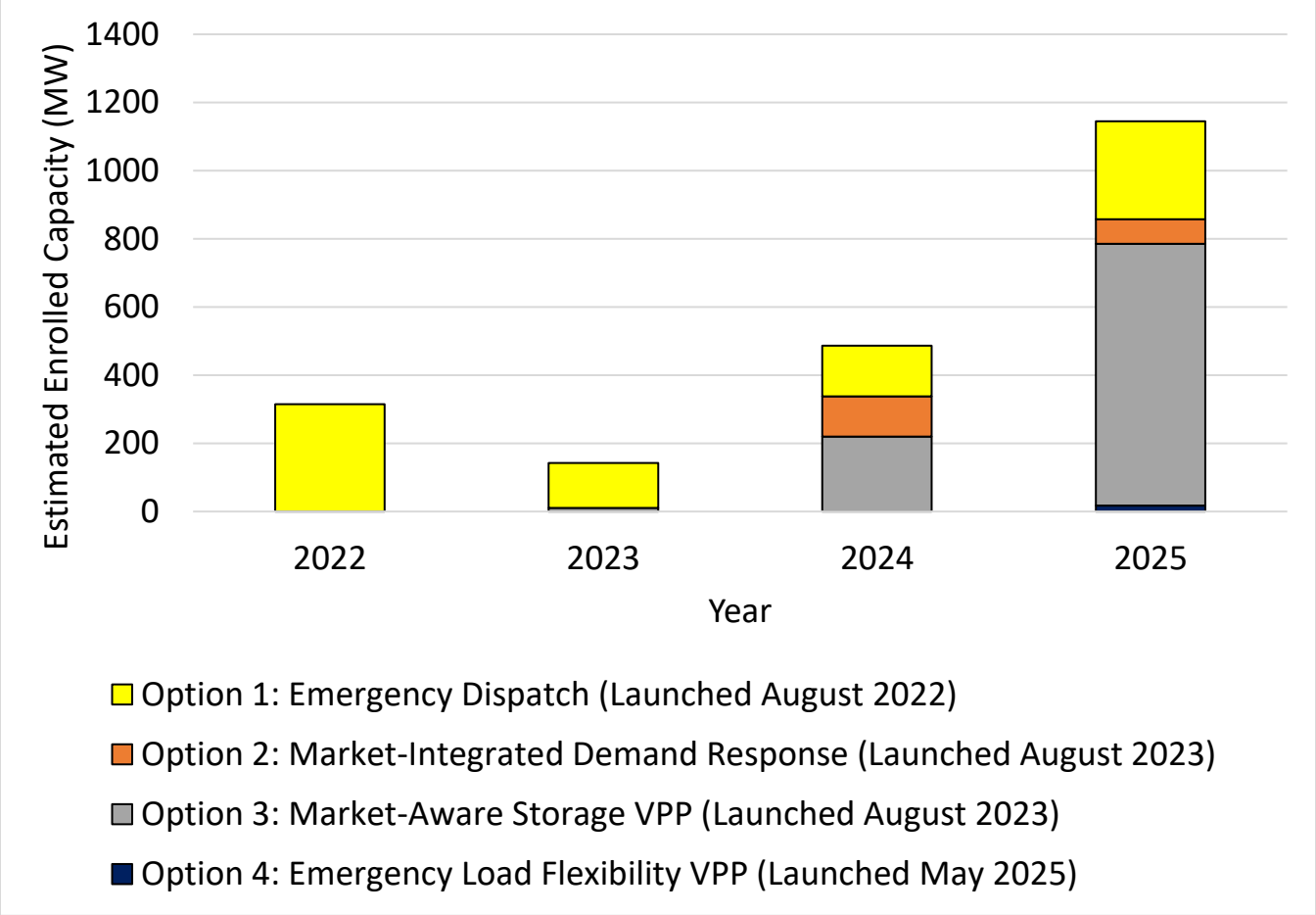
The DSGS Program now has four participation options. The estimated enrolled capacity for each option, based on DSGS provider estimates, is shown in Figure 25.

- **Option 1: Emergency Dispatch** offers performance-based energy and standby payments to nonresidential customers who reduce net load during Program events triggered by energy emergency alerts (EEA) issued by a California balancing authority. Eligible technologies include combustion resources, subject to emergency proclamation, and clean, non-combustion resources.
- **Option 2: Market-Integrated Demand Response Incremental Capacity Pilot** offers a performance-based capacity payment for demonstrated capacity achieved by participating proxy demand resources that is incremental to existing resource adequacy commitments when dispatched by the California ISO.
- **Option 3: Market-Aware Storage Virtual Power Plant (VPP) Pilot** offers a performance-based capacity payment for behind-the-meter storage VPPs based on demonstrated capacity achieved during a program event, and an energy payment for energy delivered in response to day-of EEAs. Program events are triggered when day-ahead California ISO wholesale energy market prices exceed a specified price threshold (or an alternative trigger for other balancing authorities), by required test events, or by EEAs.[109]
- **Option 4: Emergency Load Flexibility VPP Pilot** offers performance-based capacity compensation for load reduction capacity delivered during a program event relative to a capacity level pre-committed by aggregators operating dispatchable VPPs composed of: aggregated smart thermostat-controlled heating, ventilation, and air conditioning (HVAC) systems; electric water heaters; electric vehicle supply equipment; stationary batteries; and residential "smart

108 Mindy Graybill, October 8, 2025, Department of Water Resources: Electricity Supply Strategic Reliability Reserve Program Update. Item 05, California Energy Commission Business Meeting. https://www.energy.ca.gov/filebrowser/download/8707?fid=8707.
109 The VPP capacity is not bid into the California ISO energy market

electrical panels." Program events are triggered based on EEAs issued by a California balancing authority, or required test events.

Figure 25: DSGS Estimated Enrolled Capacity (MW) for 2022 through October 2025



Source: CEC

The DSGS Program season runs from May through October. Compensation for participation is paid after the CEC has validated performance during the program season. The 2025 Program season ended with over 448,000 participants enrolled. Table 16, below, provides a summary of the DSGS Program activity for the 2025 Program season.

Table 16: 2025 DSGS Program Activity

	Option #1 Emergency Dispatch	Option #2 Market-Integrated Demand Response	Option #3 Market-Aware Storage VPP	Option #4 Emergency Load Flexibility VPP	Total
Enrolled Providers	5	3	16	2	23[110]
Enrolled Participants	48	256,414	124,771	67,167	448,400
Estimated Capacity Enrolled[111]	288 MW	72 MW	768 MW	17 MW	1145 MW
CEC Ex-Ante Estimate	N/A[112]	7.2 MW	373.0 MW	First Season	N/A
Program Events	No EEA events	TBD	No price-triggered or EEA events; monthly test events	No EEA events; test events July 11 and September 16	Not Applicable
Preliminary Ex-Post Delivered	N/A (no program events)	TBD (pending California ISO settlement data)	484.4 MW	18.8 MW (September)	TBD

Source: CEC

Distributed Electricity Backup Assets Program

The DEBA program has two distinct funding categories:

- **Bulk Grid Assets** includes efficiency upgrades, maintenance, and capacity additions to existing power generators. Eligible bulk grid projects must increase the nameplate capacity of an existing power generator or the power output of an existing facility that is interconnected in California to the bulk transmission grid.

110 Some providers offer more than one participation option.
111 Capacity is estimated based on provider and participant estimates.
112 Insufficient historical data to estimate.

- **Distributed Resources** includes new zero-emission technologies at existing or new facilities in California that are directly connected to a California utility's distribution grid and can provide on-call incremental net load reduction during grid emergency.

The DEBA Guidelines serve as a broad program framework, but individual grant funding opportunities (GFOs) will include specific parameters, such as which projects are eligible for funding and what technical scoring criteria will be used to evaluate grant applications.

The DEBA Program began accepting applications for the Bulk Grid Asset Enhancements for Grid Reliability GFO (Bulk Grid GFO) in December 2023 and released the Notice of Proposed Awards in April 2024. Through December 2025, the CEC has approved seven grants totaling more than 185 MW from the DEBA Bulk Grid GFO. Each grant is required to:

- Make the DEBA-funded capacity available during extreme events for a term of 5 years from the commercial online date of the upgraded generators.
- Make the DEBA-funded capacity available on a day-ahead and real-time basis to the host balancing authority for economic and exceptional dispatch, consistent with the applicable requirements and operational capabilities of the upgraded generators.
- Begin operations by or before June 30, 2027.

CEC staff released a draft solicitation concept (draft concept) to the public in February 2024 to solicit feedback on the proposed framework for a future GFO that would support the deployment of DER for reliability. Staff conducted a public workshop on March 5, 2024, to request stakeholder feedback on this draft concept. The release of the final DEBA DER solicitation was paused pending the DEBA Program receiving additional budget authority.

In November 2024, California voters approved Proposition 4, known as the Safe Drinking Water, Wildfire Prevention, Drought Preparedness, and Clean Air Bond of 2024 which authorized the issuance of bonds in the amount of $10 billion for projects to strengthen communities against climate change. In September 2025, the 2025-26 Budget appropriated $46.1 million for the DEBA Program to fund new clean microgrids, or new non-residential or aggregated residential distributed clean energy and storage projects. A draft solicitation is currently in development and program staff are planning for public engagement opportunities in 2026.

CHAPTER 7:
Western Interconnection and Coordination

The CEC, CPUC, California ISO, and California utilities coordinate with other entities in the WI, a synchronous system that allows 14 Western states, two Canadian provinces, and a part of Baja California, Mexico to operate their generation and transmission at the same frequency. The WI is complex, as it comprises an immense region with great diversity in geography, political boundaries, weather, generation characteristics, loads, and time zones. Mandatory reliability standards for the WI have been in place since 2005 and have proven necessary to ensure consistent regulation and compliance. This chapter provides an overview of the WI, along with major updates regarding Western electricity markets, an overview of generation capacity across the West, and current information about transmission infrastructure development.

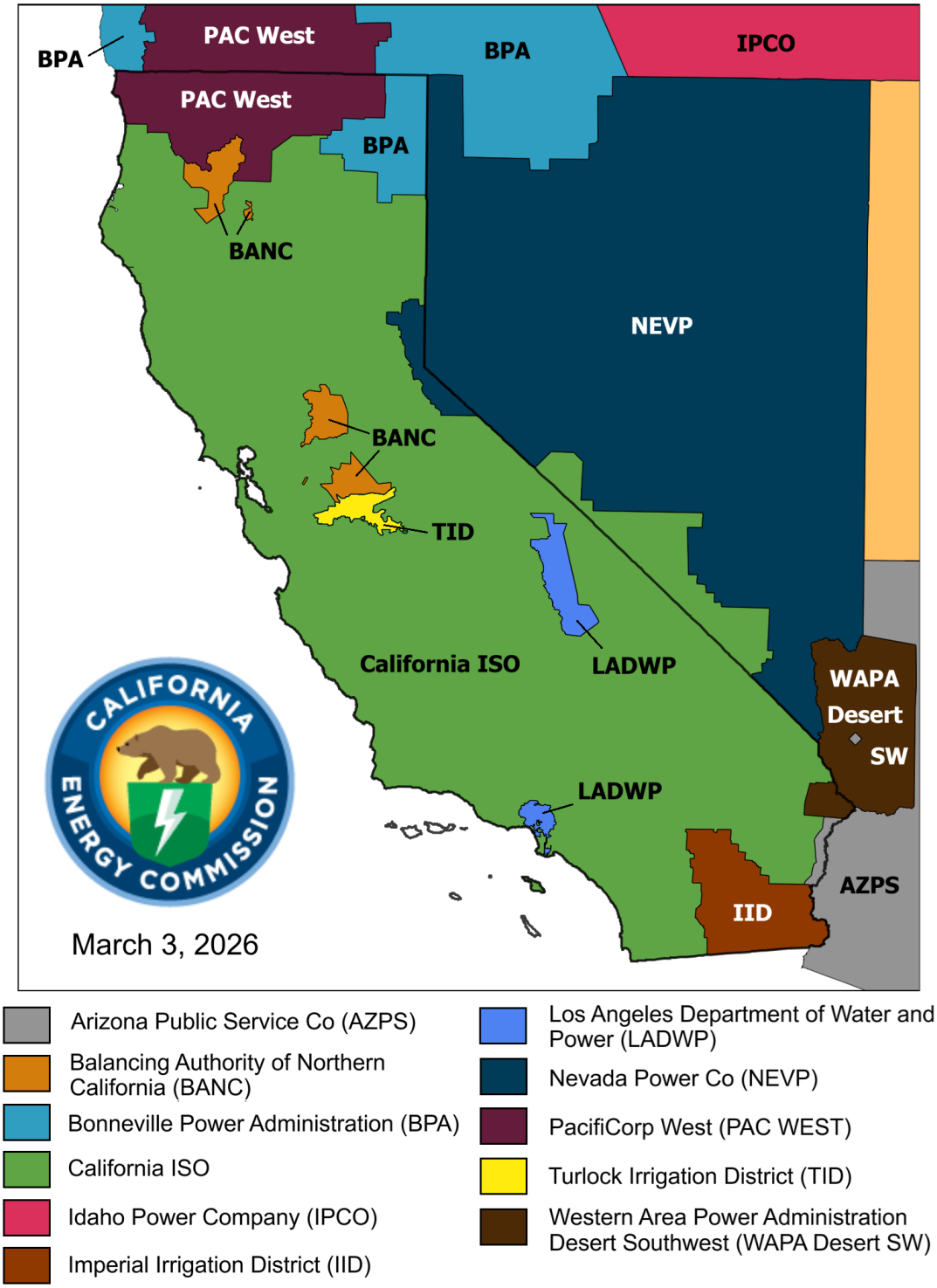
Balancing Authority Areas in California

Balancing Authorities (BAs) in California are responsible for matching electricity supply with demand in real time and manage intricate networks of power generation, transmission, and sometimes distribution. BAs are tasked with maintaining grid frequency, managing congestion, and coordinating energy transfers across interconnected systems. BAs are subject to NERC reliability standards and compliance, which are delegated to the WECC. A Balancing Authority Area (BAA) is the physical area and assets (transmission, generation, and load) that a BA oversees.

In California, the largest BAs are the California ISO and the LADWP. The California ISO is the BA responsible for managing the bulk of the state's electrical grid, overseeing transmission, dispatching power plants, and ensuring grid reliability for about 80 percent of California's electricity consumers. LADWP, on the other hand, operates as a BA for its service territory and for neighboring POUs in the Los Angeles Basin.

Figure 26 shows BAs within and near California. These BAs work collaboratively to maintain grid stability and reliability across the state.

Figure 26: Map of Balancing Authorities Within and Near California



Source: CEC

In addition to being a BA, the California ISO also operates various markets, including the WEIM, which enables participating utilities to balance supply and demand across the Western U.S. The California ISO also manages day-ahead and real-time markets,[113] simplifying the scheduling and dispatch of electricity generation to meet forecasted and real-time demand.

BAs outside the California ISO footprint provide similar functions. Some of the BAs have additional functions that concern other utilities, such as water, or responsibilities that extend beyond the borders of California. Many of these BAs coordinate their electricity operations through the WEIM which can address grid imbalances across BAAs and reduce operational costs. Through this collaborative platform, utilities share surplus energy or access additional power when needed, enhancing grid reliability and resilience.

Western Markets

In the *2022 IEPR Update*,[114] the CEC highlighted the importance of increasing integration of the Western electricity systems through implementing regional system planning and operation, with particular focus on implementing markets, encouraging transmission investment, and enhancing regional governance over energy markets. A central goal of regional integration is to bring autonomous BAs, of which there are 38 in the WI, into more efficient coordinated methods of operating the electric grid.

The WEIM was established in 2014 and is the first regional market in the Western U.S., delivering monetary benefits to California and all participants through a real-time wholesale energy trading platform that allows participants from anywhere in the WI to buy and sell power on a sub-hourly basis. This allows operators to manage and balance deviations from their forecasts while participating in a larger market with more diverse resources, thus leading to energy and cost efficiencies. Twenty-two BAs from 11 states and British Columbia voluntarily participate in this market. For the third quarter of 2025, the California ISO estimated that the combined monetary benefits (cost savings or profits for market participants from buying from/selling into other BAAs) from the WEIM were $412 million. At that time, the cumulative monetary benefits from the WEIM since the market's inception were $7.8 billion.[115] In addition to increasing cost savings and

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113 Day-ahead and real-time markets are energy markets that optimize the dispatch and cost of generation resources to create a competitive platform to drive down the cost of wholesale electricity.
114 Bailey, Stephanie, Jane Berner, David Erne, Noemí Gallardo, Quentin Gee, Akruti Gupta, Heidi Javanbakht, Hilary Poore, John Reid, and Kristen Widdifield. 2023. *Final 2022 Integrated Energy Policy Report*. California Energy Commission. Publication Number: CEC-100-2022- 001-CMF, https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2022-integrated-energy-policy-report.
115 Market Performance and Advanced Analytics. 2025. *Western Energy Imbalance Market Benefits Report: Third Quarter 2025*. California Independent System Operator. https://www.westernenergymarkets.com/documents/iso-western-energy-imbalance-market-benefits-report-q3-2025.pdf

profits for market participants, markets also enhance reliability during normal operations and during conditions where the grid is stressed.

Major steps have been taken in recent years to increase coordination of system dispatch from real-time markets to day-ahead markets, which allow grid operators to collect supply and demand bids 24 hours out from physical deliveries and optimize the system accordingly along existing transmission pathways. The California ISO launched its extended day-ahead market (EDAM) in May 2026, while the Southwest Power Pool has engaged stakeholders in developing its own version of a day-ahead market (Markets+). The Federal Energy Regulatory Commission (FERC) approved the California ISO's EDAM tariff, which was needed for EDAM to start operating as planned in 2026. FERC has also approved the Markets+ tariff, which plans to begin operations in 2027.

The Pathways Initiative and Day-Ahead Market Developments

In July 2023, regulators throughout the WI sent a letter to the leadership of the Western Interstate Energy Board (WIEB) and the Committee on Regional Electric Power Cooperation (CREPC),[116] expressing a desire for broader coordination and integration of wholesale electricity markets across the West.[117] Those actions formed the basis of the Pathways Initiative (Pathways). At its essence, Pathways would transfer governance of the WEIM and the EDAM to a new regional organization (RO), a 501(c)(3) nonprofit that mirrors other regional market institutions across the U.S., without changing the governance of any of the California ISO's other functions.

The Implementation of Pathways Phase 1, which the Pathways Launch Committee outlined in its April 10, 2024, straw proposal, is well underway. Phase 1 includes three steps; progress to date is outlined below.[118]

- On August 13, 2024, the California ISO Board of Governors and the Western Energy Markets (WEM) Governing Body voted and unanimously approved Step 1, which worked through existing law to modify the governance of the WEIM and EDAM. Prior to this step, the California ISO Board of Governors shared joint authority over WEIM and EDAM with the WEM Governing Body. Step 1 provided WEIM and EDAM governance with additional independence from the California ISO Board of Governors by vesting the WEM Governing Body with primary

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116 WIEB is a collection of 11 states and 2 Canadian provinces. Its goal is to promote cooperation throughout the region. CREPC is a joint committee of WIEB and the Western Conference of Public Service Commissioners.

117 Danner, David, Alice Reynolds, Ann Rendahl, Siva Gunda, Milt Doumit, Kevin Thompson, Letha Tawney, Pat O'Connell, and Mark Thompson. 2023. *State Regulators' Call for Viable Path to Electricity Market Inclusive of all Western States, With Independent Governance*, https://www.westernenergyboard.org/wp-content/uploads/Letter-to-CREPC-WIEB-Regulators-Call-for-West-Wide-Market-Solution-7-14-23-1.pdf.

118 West-Wide Governance Pathways Initiative Launch Committee. 2024. *Phase 1 Straw Proposal. West-Wide Governance Pathways Initiative*, https://www.westernenergyboard.org/wp-content/uploads/Phase-1-Straw-Proposal.pdf.

authority over tariff changes, rather than the current joint authority shared with the California ISO's Board of Governors.

- On November 22, 2024, the launch committee approved Step 2 to enable establishment of a new, independent RO with governance authority over market rules within the WEIM and EDAM. The RO will leverage existing market infrastructure to minimize costs.[119] The RO was formally incorporated on January 20, 2026, as the Regional Organization of Western Energy, Inc.
- Step 3 could continue to expand the scope of the different market functions and regional services offered by the RO beyond the current electricity market offerings. Step 3 may occur following Step 2 implementation if there is broad stakeholder interest in the RO offering additional voluntary services, such as those offered in other organized markets. The launch committee has previously noted that these services "could take many forms" and are "yet undefined."[120]

On January 24, 2025, the CEC convened a workshop on regional electricity markets and coordination to facilitate a public discussion on the potential benefits and risks of the Pathways Initiative for California.[121] The workshop sought to highlight an array of stakeholder groups and voices throughout the WI including labor, environmental organizations, publicly owned utilities, investor-owned utilities, and community choice aggregators. Regulators throughout the WI participated and shared their perspectives. The Brattle Group presented their analysis on the benefits of day-ahead markets to California, and researchers from Stanford University discussed reliability benefits of larger regional markets during a variety of grid stress events. Notably, stakeholders at the workshop appeared uniformly supportive of Pathways and highlighted the incremental and stepwise nature of the initiative. A full summary of the workshop is included in Appendix A of the *2024 IEPR Update*.[122]

On June 5, 2025, the CEC convened a follow-up workshop in which the Brattle Group provided an update to their impact study of the benefits of day-ahead markets. Their analysis finds that a large and unified Western day-ahead market could provide

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119 West-Wide Governance Pathways Initiative Launch Committee. 2024. *Step 2 Draft Proposal*. West-Wide Governance Pathways Initiative, https://www.westernenergyboard.org/wp-content/uploads/Pathways-Step-2-DRAFT-Proposal_-FINAL.pdf.
120 Ibid.
121 California Energy Commission. January 24, 2025. *IEPR Commissioner Workshop on Regional Electricity Markets and Coordination*. California Energy Commission. https://www.energy.ca.gov/event/workshop/2025-01/iepr-commissioner-workshop-regional-electricity-markets-and-coordination.
122 Bailey, Stephanie, Mathew Cooper, Quentin Gee, Heidi Javanbakht, Jake McDermott, and Danielle Mullany. 2024. Final 2024 Integrated Energy Policy Report Update. California Energy Commission. Publication Number: CEC-100-2024-001-LCF. https://efiling.energy.ca.gov/GetDocument.aspx?tn=266141.

California with about $1 billion in economic benefits each year, along with important environmental and reliability benefits.[123]

In July 2025, the Public Service Company of New Mexico committed to joining EDAM[124] which satisfied a geographic diversity requirement and allowed Step 1 of Pathways to take effect.[125] As a result of meeting these thresholds, WEIM and EDAM are now primarily governed by the Western Energy Markets (WEM) Governing Body.

As described above, Step 2 of the Pathways Initiative advances additional independent governance over electricity markets by transferring authority over the market rules (i.e., the tariff) to a newly established RO. Step 2 required a legislative change, which was achieved by AB 825 (Petrie-Norris, Chapter 116, Statutes of 2025). The legislation allows (1) the IOUs to participate in energy markets governed by an independent RO if certain requirements are met and (2) for the California ISO to operate the market governed by an independent RO. These changes could occur as early as January 1, 2028, if the California ISO confirms that the RO meets specific criteria outlined and enacts a resolution allowing the RO's rules to govern the WEIM and EDAM. Additionally, the CPUC must make a determination that these requirements and the underlying criteria are satisfied before any IOUs participate in markets governed by the RO. Finally, AB 825 adds new requirements for legislative oversight and transparency including annual testimony before the legislature and an annual report prepared by the California ISO.

Because the changes enacted under AB 825 cannot take effect until January 1, 2028, the WEIM and EDAM will continue governance under the WEM Governing Body and California ISO Board of Governors. EDAM launched in May 2026 with Pacificorp as its inaugural member. Portland General Electric is expected to join EDAM in Fall 2026, with additional BAs joining in 2027 and 2028. The CEC will continue to track and report on market development.

Transmission: Regional Projects and New Planning Initiatives

Additional transmission capability across the WI will be critical to integrating new generating resources and serving growing demand. New transmission projects being added (as outlined below) are essential to realizing the benefits of regional diversity in

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123 California Energy Commission. April 2025. *FACT SHEET Updated Day-Ahead Energy Markets Impact Study*, https://efiling.energy.ca.gov/GetDocument.aspx?tn=263571
124 California ISO. July 1, 2025. Public Service Company of New Mexico commits to join the Extended Day-Ahead Market. California ISO. https://www.caiso.com/about/news/news-releases/public-service-company-of-new-mexico-commits-to-join-the-extended-day-ahead-market.
125 California ISO. July 1, 2025. *Governance Changes from Pathways Step 1 Now Effective*, https://www.caiso.com/notices/governance-changes-from-pathways-step-1-now-effective

generating resources and loads. Additional lines also improve grid resilience during wildfires and unexpected outages across the system.

Major transmission continues to be built despite some long-running challenges with regional coordination and an absence of interconnection-wide transmission planning. Several recent projects feature designs to enable power flows across the WI from wind resources in the East to load centers in the West. Regional projects making progress towards commercial operations include the following:

- SunZia, New Mexico, and Arizona: merchant 525 kV high-voltage direct current line proposing to use the novel California ISO subscriber participating transmission owner model (2026).
- Boardman to Hemingway, Idaho, and Oregon: 500 kV line in joint development by Idaho Power and PacifiCorp (2026).
- Greenlink North and Greenlink West, Nevada: 525 kV lines developed by NV Energy (2026).
- Southwest Intertie Project (SWIP) — SWIP-North, Idaho to Nevada: merchant 500 kV line (2027).
- TransWest Express, Wyoming to Nevada: merchant 500 kV and 320 kV lines proposing to use the novel California ISO subscriber participating transmission owner model (2027).

Infrastructure cost considerations have historically been a challenging aspect of the development of regional transmission. The CREPC Transmission Collaborative (CREPC TC) has facilitated engagement from Western states to better understand the challenge. The CREPC TC contracted with a consultant to develop an interregional transmission cost allocation framework that might support, and even promote, multistate transmission projects in the WI. A policy brief[126] and technical report[127] on the framework were published in July 2025 and could support transmission cost assessments in future planning initiatives.

WECC-wide Transmission Assessments

A broad initiative led by the Western Power Pool, known as WestTEC, has been established to assess WECC-wide transmission needs, recognizing that the status quo

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126 Western Interstate Energy Board. 2025. State Exploration of Western Transmission Cost Allocation Frameworks: Policy Brief on Behalf of CREPC. *Committee on Regional Power Cooperation*. https://www.westernenergyboard.org/wp-content/uploads/CREPC-TC-Cost-Allocation-Frameworks-Policy-Brief-FINAL.pdf.

127 Energy Strategies. 2025. State Exploration of Western Transmission Cost Allocation Frameworks: Final Technical Report. *Committee on Regional Power Cooperation Transmission Collaborative*. https://www.westernenergyboard.org/wp-content/uploads/CREPC-TC-Cost-Allocation-Frameworks-Technical-Report-FINAL.pdf.

approach to planning is insufficient. A WestTEC consultant is conducting WECC-wide power flow, capacity expansion and production cost modeling, focusing on 10- and 20-year horizons. The California ISO maintains engagement in this effort, helping to ensure that accurate data and modeling are used in the study. Results of the study will highlight the most cost-effective and beneficial transmission projects that can deliver renewable and zero-carbon energy to meet SB 100 mandates and provide resilience in periods of extreme weather or wildfire-related outages. WestTEC released the 10-year horizon study in February 2026. The findings confirm that the timely completion of planned transmission projects is essential and newly identified transmission projects will need collaborative sponsorship. The 20-year horizon study is expected to be complete in late 2026.

In 2024 and 2025, FERC issued Orders 1920, 1920-A, and 1920-B. These orders focus on long-term transmission planning processes and cost allocation. Notably these orders will require the California ISO to develop long-term, 20-year forward, transmission plans at least every five years. In December 2025, the California ISO submitted a filing to comply with FERC Orders 1920, 1920-A and 1920-B. The California ISO proposes to revise the sequence of its transmission planning processes. Specifically, the California ISO proposes to issue its first long-term transmission plan in 2030 as well as a comprehensive reliability, economic, and policy transmission plan that looks forward over a 10 to 15 year horizon. Thereafter, the California ISO proposes issue a long-term transmission plan every four years, a comprehensive transmission plan every two years, and an interim reliability assessment every other year in which it does not issue a comprehensive transmission plan.

CHAPTER 8: Gas System Reliability

2026 Summer Gas Reliability Outlook

This chapter assesses the ability of PG&E and Southern California Gas (SoCalGas) to serve forecasted gas demand during the summer of 2026.[128] In addition, this chapter provides a qualitative outlook of fossil gas prices in California for the summer of 2026.

During summer, utilities perform maintenance on the gas system and inject gas into underground storage facilities to build inventory to meet winter demand. California's peak gas demand occurs in the winter because of increased use of space and water heating. As such, assessing summer seasonal gas reliability is crucial to statewide gas system planning for the summer and winter gas seasons. Based on forecasted gas demand this summer and the expected availability of infrastructure (absent unforeseen events including unscheduled maintenance and unusual amounts of consecutive hot days), CEC expects that PG&E and SoCalGas will meet demand with no curtailments during summer 2026.

For this independent assessment, the CEC developed demand scenarios and forecasts for monthly normal temperature, increased electric generation[129], and peak days of the PG&E and SoCalGas systems. An increased electric generation scenario refers to conditions in which there is significant demand for electric generation (e.g. a hot summer month where renewable resources are constrained or unavailable), increasing California's reliance on fossil gas-fired generation to meet electric demand and raising overall gas demand for power generation. CEC then prepared estimates of available gas via pipeline deliveries and storage withdrawals. These forecasts were then put into modeling tools that assess the ability of the gas systems to meet demand.

The CEC also reviewed the monthly normal temperature gas demand forecasts that PG&E and SoCalGas provided in the *2025 IEPR*.[130] In the *2025 IEPR*, both SoCalGas

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128 The summer gas season consists of the months of April through October, while the winter gas season occurs from November through March.

129 Historically, reliability analyses for gas have focused on winter reliability assessments using a "cold/dry" scenario. As the state undertakes its ambitious climate goals, CEC staff have sought to better assess gas system reliability in summer months. The "normal temperature with increased electric generation" scenario leveraged for this analysis represents a projection of maximum summer gas demand, with increased electric generation demand causing California's fossil gas fired electric power plants to be needed to meet expected demand.

130 California Energy Commission. 2025. *2025 Integrated Energy Policy Report*. California Energy Commission, https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2025-integrated-energy-policy-report.

and PG&E track historical summer days with high system demand. However, PG&E does not provide a formal summer peak-day demand forecast comparable to SoCalGas's summer peak-day framework.

While California's gas system remains winter-peaking, the summer months can present distinct challenges. On hot summer days, gas demand can fluctuate rapidly because of power plant demand. This fluctuation may require utilities to withdraw gas from underground storage facilities or to stop injections to meet demand. This assessment evaluates whether an increased electric generation scenario can exacerbate these ramps to the point that they affect summer reliability or the ability to inject gas for the coming winter.

Staff's reliability assessment evaluates the ability to meet demand using the following tools.

- Gas balance tables: Tables that compare estimated supply capacity and forecasted demand.
- Hydraulic models:[131] Computer models produced by PG&E and SoCalGas that calculate pressures and flows at various points on a gas system resulting from the simulation of operation under input conditions.
- Stochastic models: Hourly gas balance models using historical data to forecast hourly demand on a peak day. This model is available only for SoCalGas. Staff may incorporate a stochastic model to assess intraday operations for PG&E in future seasonal assessments.

PG&E System Assessment

This section summarizes the CEC staff assessment of the ability of the PG&E gas transmission to meet demand in summer 2026 and refill underground gas storage facilities to help meet demand in winter 2026–2027.

PG&E Gas Demand Forecast

Table 17 and Table 18 present CEC's findings from the monthly average demand, increased electric generation demand, and summer peak demand forecast for the PG&E system. CEC staff estimated that peak gas demand on the PG&E system for a summer day would be an estimated 3,031 million cubic feet per day (MMcfd). This amount

131 Hydraulic models use system parameters including pipeline characteristics, such as pipeline lengths and diameters, storage withdrawals, and demand scenarios to calculate system pressures and flows.

compares to a highest recorded daily summer demand on the PG&E system of 3,388 MMcfd in the last 10 years, which occurred September 9, 2021.[132]

Table 17: CEC Forecast of PG&E Monthly Demand

Demand Scenario	April 2026	May 2026	Jun 2026	Jul 2026	Aug 2026	Sep 2026	Oct 2026
Normal Temperature Demand (MMcfd)[133]	2,056	1,801	1,815	1,990	2,088	2,074	2,172
Increased Electric Generation Demand (MMcfd)[134]	2,166	1,865	2,001	2,275	2,302	2,303	2,308

Source: CEC staff

Table 18: CEC Staff Forecast - PG&E Summer Peak-Day Demand

Demand Type	Summer Peak Day (MMcfd)
Core[135]	342
Non-core — Electric Generation[136]	1,655
Non-core — Other [137]	664
Off System[138]	371
Total Demand	**3,031***

*Note: Due to rounding, some totals may not correspond with the sum of the separate figures.
Source: CEC staff

PG&E Pipeline Capacity

For the summer assessment, staff estimated available pipeline capacity and storage inventory on the PG&E system (Figure 27). The pipeline capacity estimates are used in all scenarios.

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132 PG&E staff. N.d. *Pipe Ranger Operations: Operating Data of CGT's Systems.* PG&E, https://www.pge.com/pipeline/en/operating-data.html.
133 Average daily demand by month in a normal year.
134 Average daily demand by month at the 90th percentile of demand, which equates to a 1-in-10 probability of occurrence.
135 Customers with average usage less than 20,800 therms per month. These are mainly residential and small commercial customers.
136 Power plant customers whose average usage exceeds 20,800 therms per month.
137 Commercial and industrial customers whose average usage exceeds 20,800 therms per month, not including power plants.
138 Gas deliveries to customers outside the utility's service area. For this table, this constitutes an estimate of deliveries to the SoCalGas system.

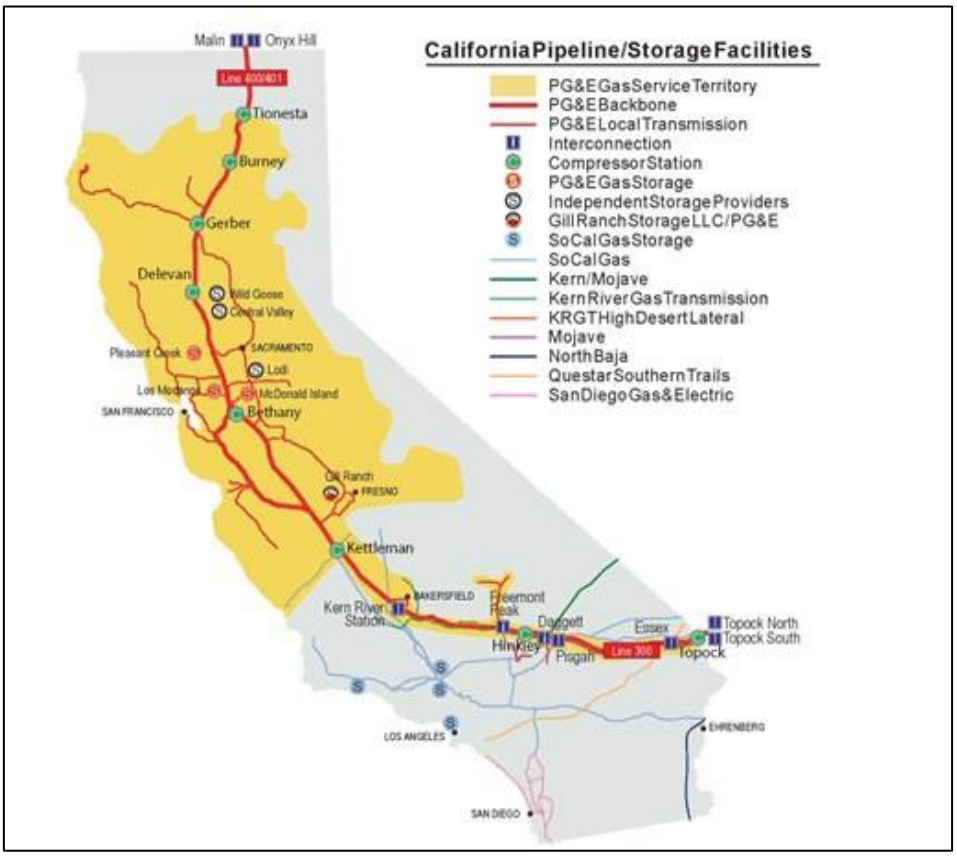
PG&E's backbone transmission system[139] and high diameter pipes run through much of the length of California (from Topock, Arizona, to Malin, Oregon). This system, which includes more than 1,700 miles of pipe, provides significant pipe inventory that PG&E can draw upon to meet demand and maintain operating pressures on the gas system. These unique characteristics enable PG&E to maintain sizable linepack (the quantity of gas stored in a pipeline) even on high-demand days, which effectively offers short-term storage.

Staff took a conservative approach in estimating pipeline capacity for summer 2026, using PG&E's Pipe Ranger data on scheduled maintenance. Monthly average capacities were generated for the Baja (southern backbone) and Redwood (northern PG&E's backbone) pipeline systems.[140] Maintenance is scheduled on both systems from April through October, including in-line inspections, working on compressor and regulator stations, and pipeline maintenance.

139 A natural gas backbone system refers to the primary network of large, high-pressure pipelines that transport natural gas from production areas to major consumption centers.

140 PG&E staff. 2026. *CGT Prospective Mainten*ance*. PG&E, https://www.pge.com/assets/pipeline/docs/operations/pipelinemaintenance/ProspectiveMaintenanceCGT.xlsx.

Figure 27: Map of the PG&E Gas Transmission System



Source: PG&E

In January 2025, PG&E announced the proposed date for retiring the Tionesta Compressor Station[141] on the Redwood system as May 7, 2025.[142] Table 19 below lists PG&E capacity assumptions that include the estimated impact from this retirement.

141 PG&E staff. 2025. *Tionesta Compressor Station Retirement on May 7, 2025*. PG&E, https://www.pge.com/pipeline/en/reference-library/news-archive/tionesta-compressor-statement-retirement-on-may-7--2025.html.

142 Compressor stations along transmission systems enable the transportation of gas over long distances and through changes in elevation. The transmission systems of PG&E and SoCalGas have numerous compressor stations that ease the delivery of gas along their systems. These compressor stations use motors (in the form of an electric motor or a gas turbine) to pressurize the gas and pump it through the system.

Table 19: PG&E Pipeline Capacity Assumptions

Supply (MMcfd)	April 2026	May 2026	Jun 2026	Jul 2026	Aug 2026	Sep 2026	Oct 2026
California Source Gas	22	22	22	22	22	22	22
Baja Path	685	748	745	791	780	400	772
Redwood Path	1,845	2,043	2,050	2,031	2,050	1,977	1,875
Sub Total Pipeline Receipts*	**2,553**	**2,813**	**2,817**	**2,844**	**2,852**	**2,399**	**2,669**

*Note: Due to rounding, some totals may not correspond with the sum of the separate figures.
Source: CEC

California Source Gas, listed in the table above, consists of fossil gas produced in the Northern Sacramento Valley and the Sacramento-San Joaquin River Delta regions. The Baja Path is connected to U.S. Southwest and Rocky Mountain pipeline systems (Transwestern and El Paso at Topock, Arizona) and Kern River at Daggett (San Bernardino County). The Redwood Path is connected to Gas Transmission Northwest (which delivers gas from Canada through the U.S. Northwest) and Ruby (which delivers gas from the Rockies) at Malin, Oregon. Staff assume these quantities of gas will be available for delivery by the upstream interstate pipelines.

Maintenance or outages on those pipelines would reduce deliveries to California and are risks outside the scope of this analysis.[143]

PG&E and Independent Storage Providers

PG&E owns and operates the Los Medanos and McDonald Island underground gas storage facilities, which have a combined maximum working gas capacity of about 51.1 billion cubic feet (Bcf). Staff assumes a working gas inventory of 40.7 Bcf on April 1, 2026.

Independent storage providers owned and operated by independent third parties—Wild Goose, Central Valley Gas Storage, Lodi, and Gill Ranch (partially owned by PG&E)—connect to PG&E backbone transmission pipelines and operate within the PG&E system.

Neither the Pipe Ranger website nor the PG&E prospective maintenance report[144] identify maintenance activities that would reduce injection or withdrawal capacities at PG&E underground gas storage facilities for the remainder of 2026. PG&E reported in

143 Events that significantly reduce deliveries to California are rare and are reflected when they are known.
144 PG&E staff. N.d. *Pipeline Maintenance*. PG&E. https://www.pge.com/pipeline/en/operating-data/current-pipeline-status/pipeline-maintenance/foghorn.html.

CPUC Application 24-07-020[145] plans for adding capacity to its storage facilities through new and replacement wells from 2024 through 2027 in compliance with California Geologic Energy Management Division safety regulations for underground gas storage facilities. For winter 2026–2027, PG&E reported plans to add 106 MMcfd in storage facility capacity by building new and replacement wells at McDonald Island, Los Medanos, and Gill Ranch.

The PG&E prospective maintenance report indicates reduced withdrawal capacities at the independently owned Wild Goose and Central Valley storage facilities in early and late April and for four days in September. PG&E does not report reduced withdrawal capacities for the Lodi and Gill Ranch facilities.

PG&E Gas Balance

Staff assessed the availability of supply for meeting demand under three cases: monthly normal temperature demand, monthly increased electric generation demand, and summer peak-day demand (see Table 20, Table 21, and Table 22).

Table 20 shows the monthly gas balance for April–October 2026 using the CEC's forecast for normal temperature demand. This analysis captures planned pipeline maintenance as reported by PG&E in January 2026 and is reflected in available pipeline capacity, where relevant.

Table 20 and Table 21 below capture pipeline and storage field planned maintenance as of January 2026 as reflected in row 2 "Available Pipeline Capacity." Staff analysis shows that pipeline capacity is sufficient to meet demand and refill storage, thereby allowing PG&E to undertake planned maintenance during the summer months without jeopardizing reliability. While some storage withdrawals are needed under the increased electric generation demand scenario in July 2026, staff analysis shows enough pipeline capacity to refill storage during the remainder of the summer. In both scenarios, storage is full by November 2026.

Staff demand forecasts for PG&E include estimates of off-system deliveries, particularly to the SoCalGas system at Kern River Station. Demand can be met under the normal temperature scenario without withdrawals from underground gas storage facilities. Should it become necessary to preserve the higher-priority deliveries to on-system customers or to preserve storage injections, PG&E can reduce or eliminate the portion of its off-system deliveries that are made on an as-available basis. For July 2026 under the hot temperature and dry hydro scenario, the CEC estimated 347 MMcfd could go off-system, of which only 80 MMcfd is contractually firm. This means 267 MMcfd is interruptible. Thus, under this scenario, PG&E could reduce off-system deliveries to 80

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145 California Public Utilities Commission. 2024. *PG&E Application of Pacific Gas and Electric Company (U 39 G) for Approval of Peak Day Supply Standard Pursuant to Decision 23-11-069*. California Public Utilities Commission, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M536/K706/536706078.PDF.

MMcfd and shift from storage withdrawals in July 2026 to storage injections if it chooses.

Table 20: PG&E Monthly Gas Balance Normal Temperature Demand

Normal Demand Scenario	April 2026	May 2026	Jun 2026	Jul 2026	Aug 2026	Sep 2026	Oct 2026
Demand (MMcfd)	2,056	1,801	1,815	1,990	2,088	2,074	2,172
Available Pipeline Capacity (MMcfd)	2,553	2,813	2,817	2,844	2,852	2,399	2,669
PG&E Average Daily Injection/Withdrawal (MMcfd)	28	83	95	24	25	27	25
PG&E End-of-Month Inventory (MMcfd)	40,680	43,768	46,955	48,701	49,746	50,956	51,098

Source: CEC staff

Table 21: PG&E Monthly Gas Balance Increased Electric Generation Demand

Increased Electric Generation	April 2026	May 2026	Jun 2026	Jul 2026	Aug 2026	Sep 2026	Oct 2026
Demand (MMcfd)	2,181	1,844	1,980	2,341	2,334	2,398	2,319
Available Pipeline Capacity (MMcfd)	2,553	2,813	2,817	2,844	2,852	2,399	2,669
PG&E Avg Daily Injection/Withdrawal (MMcfd)	28	83	95	24	25	27	25
PG&E End-of-Month Inventory (MMcfd)	40,680	43,768	46,955	48,701	49,746	50,956	51,098

Source: CEC staff

Based on staff analysis, the PG&E gas transmission system can meet demand under the normal temperature demand and increased electric generation scenarios.

PG&E Peak-Day Analysis

Table 22 presents the results of staff analysis of a summer peak day demand scenario where electric generation comprised the bulk of the gas demand. The electric generation forecast of 1,655 MMcfd accounts for a high temperature day in a dry, low-hydro year. The available pipeline capacity represents an average of the estimates for

July through September 2026 used on the normal demand and increased electric generation demand scenarios above.

To preserve higher-priority deliveries to on-system customers or preserve storage injections, PG&E can reduce or eliminate a portion of off-system deliveries.[146] Under the peak demand scenario, the CEC estimated 371 MMcfd could go off-system, of which only 80 MMcfd is contractually firm. This means 291 MMcfd is interruptible. Under this scenario, PG&E could reduce off-system deliveries to 80 MMcfd and shift from storage withdrawals to storage injections, if it chooses.

PG&E will have the working gas inventory to meet peak demand beginning summer 2026. By July 2026, CEC staff estimates that PG&E's storage inventory will range from 44 to 49 Bcf. At this level, PG&E can withdraw the projected 179 MMcfd from its underground gas storage facilities. Staff analysis indicates that the PG&E gas transmission system can meet demand on a summer peak day.

Table 22: PG&E Peak Demand Day Gas Balances

Demand Type, Available Pipeline Capacity, and Needed Withdrawal	Peak Summer Day (MMcfd)
Core Demand	342
Non-Core – Electric Generation Demand	1,655
Non-Core- Other Demand	664
Off System Demand	371
Total Demand	**3,031***
Available Pipeline Capacity	2,852
Needed Withdrawal**	**(179)**

*Note: Due to rounding, some totals may not correspond with the sum of the separate figures.
** Needed Withdrawal = Total Demand – Available Pipeline Capacity

PG&E Hydraulic Analysis

Staff used the Synergi Gas hydraulic modeling platform to assess PG&E gas system operations.[147] PG&E's hydraulic model for its Baja and Redwood transmission systems estimates system capacity using demand scenarios input by a user. The hydraulic

146 Off-system deliveries are gas sent to customers or pipelines outside of a specific utility's authorized service territory. These transactions allow utilities to move gas, often via displacement or physical flow, to external markets (e.g., in neighboring states).

147 Synergi Gas is the long-time industry standard for hydraulic modeling of large, complex gas distribution and transmission systems.

analysis also identifies any pressure violations and allows simulation testing of different operational solutions.

Staff modeled the peak demand scenario as was done for the gas balances. Staff assumed pipeline supply of 2,852 MMcfd from the gas balances and that 189 MMcfd would be available for withdrawal on a peak day in either July, August, or September 2026. In staff's hydraulic modeling, PG&E can meet summer peak-day demand.

PG&E Conclusion

In the three scenarios, staff estimates that PG&E can meet demand with available pipeline capacity combined with some storage withdrawal capacity or other measures. If necessary, PG&E could limit off-system deliveries to its firm contracted commitment of 80 MMcfd. Further, estimates show that PG&E-owned underground gas storage facilities will be at capacity under all scenarios by the end of summer 2026. Absent a multiday, hot weather event with additional infrastructure outages, the risk to gas system reliability is low.

SoCalGas System Assessment

This section outlines the CEC staff assessment of the ability of the SoCalGas transmission system to meet demand in summer 2026 and to refill underground gas storage facilities to help meet demand in winter 2026–2027.

SoCalGas Gas Demand Forecast

Table 23 and Table 24 present the CEC's findings from the monthly normal temperature demand, increased electric generation demand, and summer peak demand forecasts for the SoCalGas system. The CEC monthly average forecasts are slightly higher than SoCalGas' in the *2025 IEPR*. The *2025 IEPR* does not include a summer peak demand forecast for SoCalGas.

Table 23: CEC Forecast of SoCalGas Monthly Demand

Demand Scenario	April 2026	May 2026	June 2026	July 2026	August 2026	September 2026	October 2026
Normal Temperature Demand (MMcfd)[148]	2,206	1,734	1,706	2,212	2,360	2,021	2,158
Increased Electric Generation Demand (MMcfd)[149]	2,173	1,762	1,730	2,258	2,420	2,060	2,201

Source: CEC staff

148 Average daily demand by month in a normal year.
149 Average daily demand by month at the 90th percentile of demand, which equates to a 1-in-10 probability of occurrence.

The CEC estimates peak gas demand on the SoCalGas system for a summer day at around 3,133 MMcfd. Since 2015, the highest daily demand of 3,468 MMcfd for SoCalGas occurred August 28, 2017, because of high cooling demand resulting from high temperatures.[150]

Table 24: CEC Forecast - SoCalGas Summer Peak Day Demand

Demand Type	Summer Peak Day (MMcfd)
Core	710
Non-Core - Electric Generation	1,860
Non-Core - Other	562
Total Demand	**3,133***

*Note: Due to rounding, some totals may not correspond with the sum of the separate figures.
Source: CEC staff

SoCalGas Pipeline Capacity

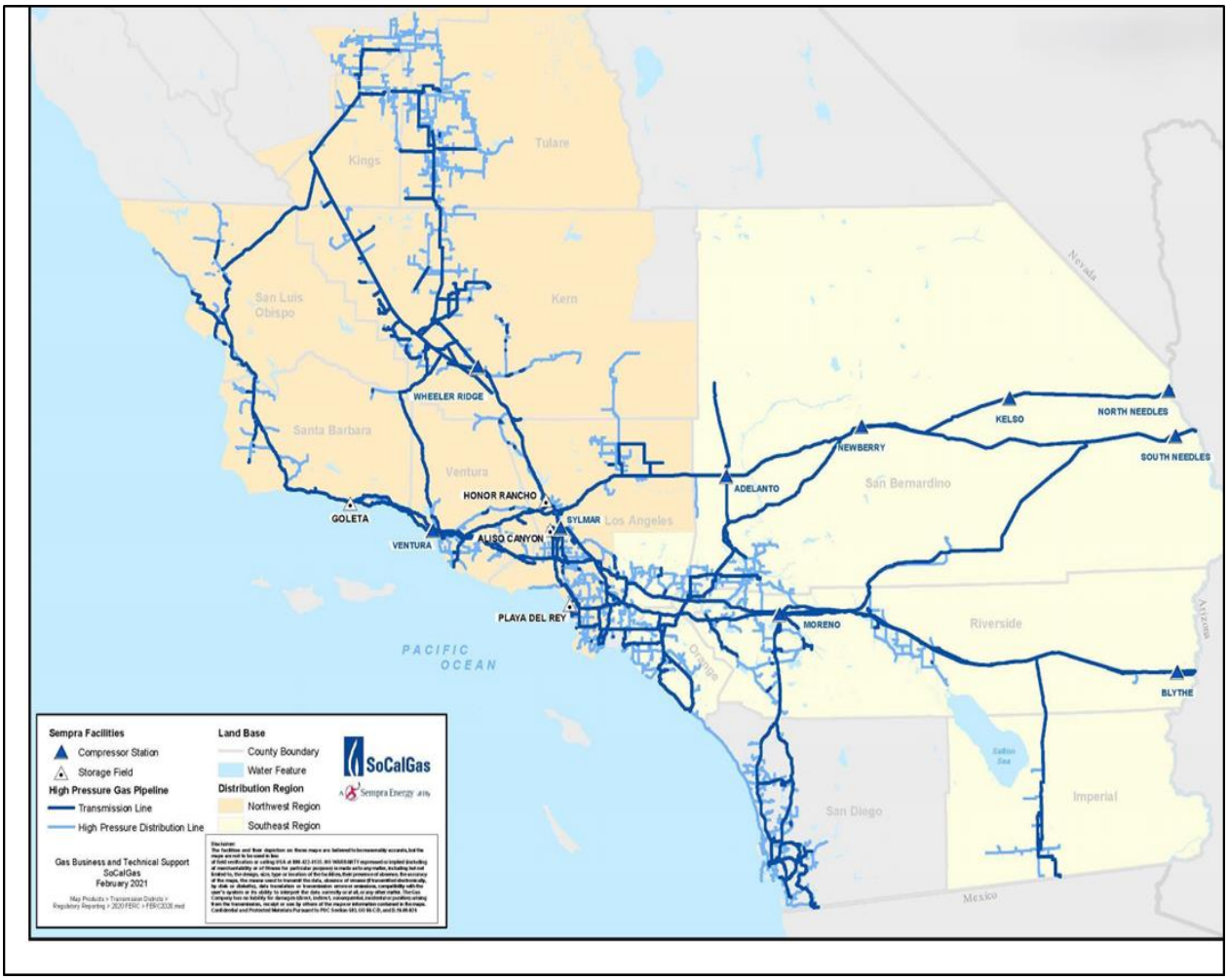
For the summer assessment, staff estimated available pipeline capacity and storage inventory on the SoCalGas system (Figure 28). The pipeline capacity estimates are used in the average, increased electric generation, and peak-day scenarios.

SoCalGas can experience challenges in managing linepack, as its gas transmission pipeline system has roughly half the linear miles of PG&E's. As such, SoCalGas system operators may have to rely more heavily on storage facilities such as Aliso Canyon, Honor Rancho, La Goleta, and Playa del Rey to restore linepack at the end of day.

SoCalGas uses transient hydraulic modeling to support transmission system analyses related to inventory management. The transient model can assess intraday changes in linepack under certain conditions. The CEC has also developed a stochastic model that estimates intraday peak-day trends for the SoCalGas system.

150 SoCalGas. 2025. *Analysis of the 2016, 2018, 2020, 2022, 2024, 2025 editions of the California Gas Report: The California Gas and Electric Utilities staff*. The California Gas and Electric Utilities, https://www.socalgas.com/regulatory/cgr.

Figure 28: Map of the SoCalGas System



Source: CEC Docket 21-IEPR-05

Staff took a conservative approach in estimating pipeline capacity for summer 2026 (Table 25). The estimates were generated by staff analyses of information posted on the SoCalGas Envoy website.[151] These estimates include capacity available to its customers for scheduling maintenance and outage events that impact the capacity. Per the SoCalGas Envoy website, scheduled maintenance projects include pipeline remediation with inline inspections,[152] and work at the Aliso Canyon and Honor Rancho storage fields.

151 SoCalGas Envoy staff. N.d. "SoCalGas Envoy" https://www.socalgasenvoy.com
152 A technique used to assess the integrity of natural gas transmission pipelines from the inside of the pipe by using of technologically advanced equipment that uses natural gas pressure to push the tool through the line without having to shut it down or interrupt service to customers.

Table 25: SoCalGas Pipeline Capacity Assumptions

Supply (MMcfd)	Apr 2026	May 2026	Jun 2026	Jul 2026	Aug 2026	Sep 2026	Oct 2026
California Line 85 Zone	40	40	40	40	40	40	40
Wheeler Ridge Zone	118	118	118	118	118	118	118
Blythe (Ehrenberg) into Southern Zone	975	946	980	980	980	860	980
Otay Mesa into Southern Zone	0	0	0	0	0	0	0
Kramer Junction into Northern Zone	700	700	700	700	700	700	700
North Needles/Topock into Northern Zone	650	650	650	882	890	890	890
Total Supply	**2,483**	**2,454**	**2,488**	**2,720**	**2,728**	**2,608**	**2,728**

Source: CEC staff estimates

SoCalGas' Northern and Southern Zones, referenced in Figure 28 above, represent portions of its system connected to different interstate pipelines. SoCalGas' Northern Zone is connected to U.S. Southwest (Transwestern, El Paso, Kern River, and Mojave) at Needles, west of Topock, Arizona. It also connects to Kern River Gas Transmission to receive Rockies gas at Kramer Junction in San Bernardino County and at Wheeler Ridge, south of Bakersfield. SoCalGas' Southern Zone receives gas primarily from the Permian basin in Texas via the El Paso Natural Gas pipeline.

In December 2025, there was a pipe rupture at Wheeler Ridge Zone,[153] which required immediate isolation of the affected segment and highlighted how unexpected infrastructure failures can quickly reduce transmission capability. SoCalGas has indicated that permanent repairs to the damaged section are expected to begin around March 2026 and could take several months to complete, which may result in a prolonged period of reduced operational redundancy on the system.

SoCalGas Storage

SoCalGas' underground gas storage facilities have a combined maximum working gas capacity of 119.5 Bcf. This capacity includes the working gas capacity at Aliso Canyon

153 SoCalGas. 2026. *Castaic Line Break Repair* SoCalGas, https://www.socalgas.com/castaic-line-break-repair.

of 68.6 Bcf, which was authorized by CPUC Decision 23-08-050. Staff assume a working gas inventory of 91.5 Bcf on the first day of summer (April 1, 2026).

SoCalGas Gas Balance

Table 26 shows the monthly gas balance for April–October 2026 using the CEC's forecast for normal temperature demand.

Table 26 and Table 27 capture pipeline and storage field planned maintenance as of February 2026 and is reflected in row 2 "Available Pipeline Capacity." Staff analysis shows that pipeline capacity is sufficient to meet demand and refill storage, thereby allowing SoCalGas to undertake planned maintenance during the summer months without jeopardizing reliability.

Since the increased electric generation scenario has only a modest increase in demand above the average demand, the scenarios demonstrate an identical storage injection pattern (row 3). In both scenarios, storage is forecast to be full by November 2026.

Based on staff's analysis, the SoCalGas transmission system can meet demand in the normal temperature and increased electric generation scenarios despite current constraints on the system.

Table 26: SoCalGas Monthly Gas Balance Normal Temperature Demand

Average Demand Scenario	Apr 2026	May 2026	Jun 2026	Jul 2026	Aug 2026	Sep 2026	Oct 2026
Demand (MMcfd)	2,206	1,733	1,707	2,212	2,361	2,022	2,159
Available Pipeline Capacity (MMcfd)	2,483	2,454	2,488	2,720	2,728	2,608	2,728
SoCalGas Average Daily Injection/Withdrawal (MMcfd)	202	188	304	203	29	136	95
SoCalGas End-of-Month Inventory (MMcfd)	91,500	101,205	112,295	119,500	108,511	119,500	119,500

Source: CEC staff forecasts and estimates.

Table 27: SoCalGas Monthly Gas Balance Increased Electric Generation Demand

Increased Electric Generation Scenario (MMcdf)	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26
Demand	2,173	1,762	1,730	2,258	2,420	2,060	2,201
Available Pipeline Capacity	2,483	2,454	2,488	2,720	2,728	2,608	2,728
SoCalGas Average Daily Injection/Withdrawal	202	188	304	203	29	136	95
SoCalGas End-of-Month Inventory	91,500	101,205	112,295	119,500	108,511	119,500	119,500

Source: CEC staff forecasts and estimates

SoCalGas Peak-Day Analysis

Table 28 presents the results of staff analysis for a summer peak-day demand scenario with electric generation comprising the bulk of the demand. The electric generation forecast of 1,860 MMcfd accounts for a high-temperature day in a dry, low-hydro year. As mentioned in the previous sections, SoCalGas is planning maintenance on its pipeline systems during the summer months.

The results of the peak-day analysis show that 580 MMcfd of storage withdrawal is needed to meet the peak-day demand. The monthly gas balance scenario in the tables above show that SoCalGas' storage inventories will be at or close to full (about 119.5 Bcfd) between July and September 2026. This amount is more than sufficient to allow the needed storage withdrawals of 580 MMcfd projected in Table 28. Based on the assumed conditions, staff finds that supply can meet peak demand, resulting in minimal risk of curtailment to the electric generators. Absent a multiday hot-weather event combined with additional infrastructure outages, the risk to reliability is low.

Based on staff's analysis, the SoCalGas transmission system can meet demand on a summer peak day.

Table 28: SoCalGas Peak-Demand Day Gas Balances

Demand, Withdrawal, and Net Demand Type, Available Pipeline Capacity, and Needed Withdrawal	Peak Summer Day (MMcfd)
Core Demand	710
Non-Core - Electric Generation (EG) Demand	1,860
Non-core - Other Demand	562
Total Demand	**3,133***
Available Pipeline Capacity**	**2,601**
Needed Withdrawal***	**(580)**

*Note: Due to rounding, some totals may not correspond with the sum of the separate figures.
** Available Pipeline Capacity is the average of the summer month's available capacity
**Note: Hourly needed withdrawal figures are displayed in Table 29, (580) does not represent a calculation in this table but rather a total peak day withdrawal.

Source: CEC staff forecasts and estimates

SoCalGas Stochastic Analysis

Staff performed an in-depth hourly stochastic gas balance analysis for the upcoming 2026 summer season, leveraging the established methodology consistent with previous reliability assessments.[154] This analysis utilizes the stochastic gas demand model that simulates demand fluctuations within a historical range derived from 15 years of granular hourly and daily gas demand data. This type of modeling is referred to as "stochastic" because the load shape is developed by randomly selecting probability distributions for each hour. For each load shape drawn, staff scales each hour to match the estimated peak-day demand.

Using this analysis, staff can gain a more detailed picture of gas demand dynamics than the conventional demand analysis.

For this iteration, the analysis is tailored to examine the hourly demand variability in the summer months along with a view of the supply side of the analysis. Staff selected hourly demand data from days recording composite temperatures above 80 degrees within the SoCalGas service area. This criterion ensures the inclusion of demand variability that aligns with peak EG demand periods in the summer. Additionally, the CEC's estimates for summer peak day demand were adopted to fit the daily aggregate

154 This analysis is further explained in Long, Joe. 2012. Winter Assessment 2022-2023 Stochastic Gas Balance Analysis. Aspen Environmental Group, https://efiling.energy.ca.gov/GetDocument.aspx?tn=247777, and in Wong, Lana, Jason Orta, and Miguel Cerrutti. 2022. *Winter 2022–2023 SoCalGas Reliability Assessment*. California Energy Commission. Publication Number: CEC-200-2022-007. https://www.energy.ca.gov/publications/2022/winter-2022-2023-southern-california-gas-company-reliability-assessment

demand projections. On the supply side, the same hourly stochastic analysis is done to capture fluctuations in receipts. Receipt supply remains relatively flat over the course of the day fluctuating by about 5 MMcfd depending on the hour.

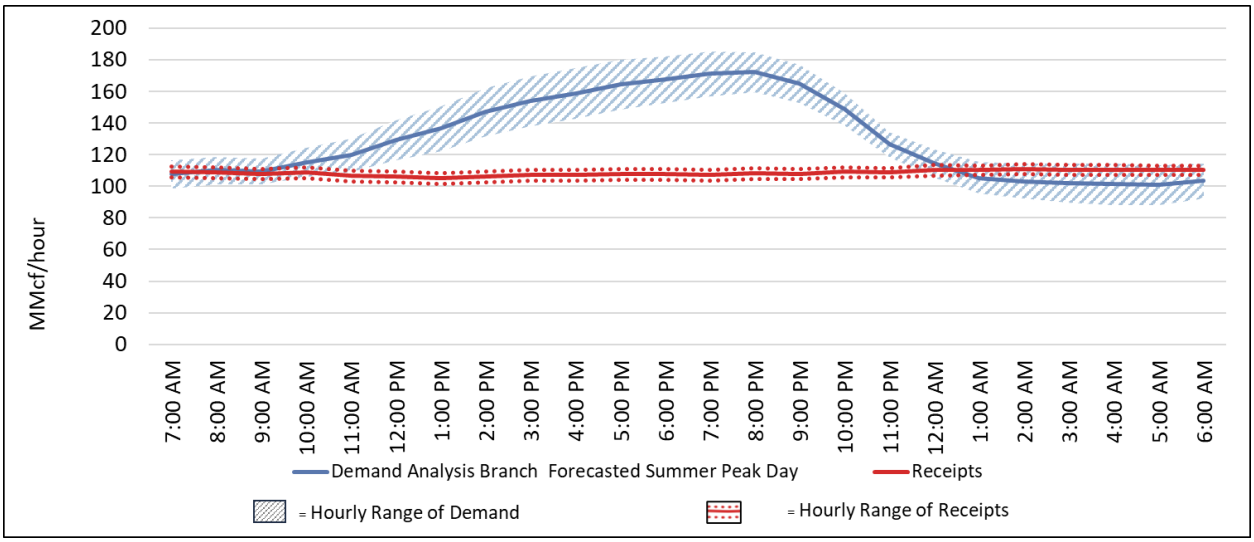
With these refined inputs, staff compared supply to demand in a gas balance for each hour of the day and the necessary gas withdrawals for each hour within the simulated peak day. Illustrated in Table 29 and Figure 29, the resulting gas balance highlights the critical midday ramping period, afternoon peak demand hours, and the corresponding withdrawal requirements. The variability band around the average load profile demonstrates hourly variations, with morning hours exhibiting greater fluctuation compared to the more stable overnight demand. Demand peaks at 172 MMcf per hour at 8 p.m. To meet demand in the afternoon and evening, the results show some withdrawals are required.

Table 29: Stochastic Hourly Gas Balance Results for SoCalGas Summer Peak Day

Units in MMcf	Simulated Summer Peak Day Hourly Gas Balance																								Total
Hour	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4	5	6	
Demand	108	110	109	115	120	129	136	147	154	159	165	167	171	172	165	149	127	114	105	103	102	101	101	103	3,133
Receipts	109	109	108	109	106	106	105	106	107	107	108	108	107	108	108	109	109	110	110	111	110	110	110	110	2601
Required Withdrawal	0	1	2	6	13	23	31	41	47	52	57	60	64	64	57	40	18	4	0	0	0	0	0	0	580
Min Curtail*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

*Note: Minimum curtailment required in each hour
Source: Aspen Environmental Group, reproduced by CEC staff

Figure 29: Summer Peak-Day Demand Hourly Load Profile by Hour



Source: Aspen Environmental Group

The results of this stochastic assessment confirm the adequacy of supply to meet demand and no risk of potential curtailments under summer peak-day conditions and corroborate the results of the hydraulic modeling and other gas balances.

SoCalGas Hydraulic Analysis

For the hydraulic modeling analysis of the SoCalGas system, staff evaluated the summer peak-day demand scenario and the load profiles prepared by the utility and submitted to the CEC in 2025. Staff used the pipeline supply of 2,601 MMcfd in the gas balances was assumed to remain constant each hour.[155] SoCalGas then used storage injections and withdrawals to meet the difference between hourly demand and flat supply flowing in from the interstate pipelines. Staff found that storage withdrawals were needed in peak hours to maintain system pressures, keeping linepack at levels allowing it to be restored overnight. Because of the need to restore linepack within the peak day, staff did not simulate any storage injections.

The hydraulic analysis confirms staff's gas balance results. Variation in hourly load profiles for electric generation can significantly impact hydraulic modeling results. The load profiles provided by the utilities in their hydraulic models assume how gas demand would be distributed for individual or groups of customers throughout the gas day. Load profiles with higher peaks can result in higher storage withdrawal totals during higher-demand hours and higher storage injection totals in lower-demand hours. In comparison, incorporating load profiles showing more constant gas demand throughout the day can lead to more consistent injection or withdrawal totals. This finding has real

155 This is the commonly accepted operating practice for gas pipelines and distribution systems and is embodied in company tariffs across the industry. It is also corroborated by the stochastic analysis.

world implications for the summer operation of the gas system. As solar PV generation is available during daylight hours, electric generation gas demand is lower in those hours.

Staff's analysis of the SoCalGas hydraulic model confirms that if expected summer pipeline conditions hold in combination with small amounts of storage withdrawals, the SoCalGas system should be able to meet summer peak-day demand.

SoCalGas Conclusion

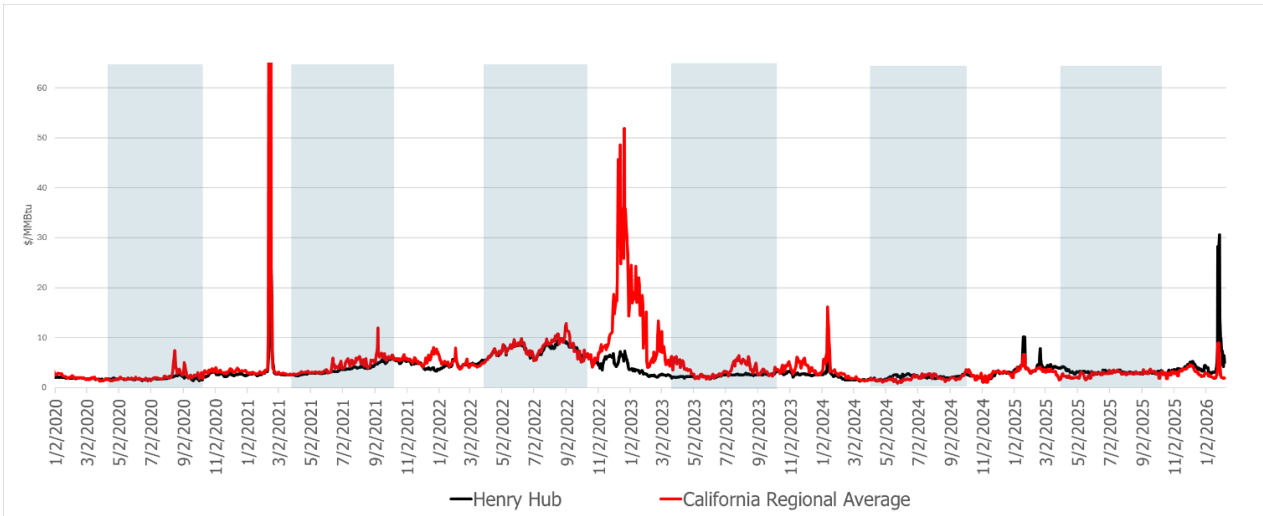
In the scenarios of normal demand day, increased electric generation day, and summer peak-day, staff estimates that SoCalGas can meet demand with available pipeline capacity combined with some storage withdrawal capacity or other measures. Furthermore, staff estimate that the SoCalGas underground gas storage facilities will be at capacity under all scenarios by the end of summer 2026. Absent a multiday, hot-weather event with additional infrastructure outages, the risk to reliability is low.

Qualitative Outlook of Fossil Gas Prices

This section provides a qualitative outlook of fossil gas prices in California for the summer of 2026. Summer prices in California in recent years have been relatively stable and track along the national benchmark, Henry Hub.[156] As shown in Figure 30, the average summer price for Henry Hub (summers 2020-2025) was $3.33/Million British thermal unit (MMBtu), while the California Regional Average price was $3.58/MMBtu. The EIAs Short-Term Energy Outlook forecasts the Henry Hub price to average around $3.50/MMBtu in 2026 compared to $3.52/MMBtu in 2025. Prices this summer look to follow this pattern if pipeline capacity and fossil gas production remain at current levels.

156 Henry Hub is the national benchmark for fossil gas prices. Futures, forwards, and basis contracts trade relative to or at Henry Hub.

Figure 30: Monthly Henry Hub and Average California Regional Prices, 2020–2026



Source: EIA, CEC staff

While summer fossil gas prices in California have been stable in recent years, unexpected events or conditions can result in price volatility. For example, during the summer of 2024,[157] the smoke from numerous wildfires in California led to decreased solar PV generation output. At the same time, the high winds that fueled the wildfires caused wind generation to decrease.

Further, wildfires caused some electric transmission lines to go offline. The decrease in renewable generation led to higher demand for fossil gas for electric generation, causing an increase in gas prices that summer.

2026 Summer Gas Reliability Assessment Conclusion

Based on forecasted gas demand this summer and the expected availability of infrastructure, and absent adverse unforeseen and unusual events, including unscheduled maintenance and consecutive hot days, staff expect PG&E and SoCalGas will meet demand with no estimated curtailments during summer 2026. Moreover, CEC staff expects that PG&E and SoCalGas will bring their underground gas storage facilities to capacity by the start of the winter 2026–2027 gas season on November 1. So long as pipeline capacity and gas production remain at current levels, staff anticipates that gas prices should remain stable this summer. Prices could become more volatile if something unusual occurs, such as an emergency that reduces supply, increases demand or both. Throughout summer 2026 and beyond, staff will continue to track the

157 Maguire, Gavin. July 31, 2024. *California Wildfires Dim Solar Generation During Power Demand Peak. Reuters*, https://www.reuters.com/markets/commodities/california-wildfires-dim-solar-generation-during-power-demand-peak-2024-07-31/.

operations of California gas utilities and trends in fossil gas prices to inform future analyses and provide support, if needed.

CHAPTER 9: Petroleum Market and Short-Term Outlook

Petroleum Reliability During Transition

Petroleum remains an important part of California's energy reliability planning as the state advances toward a cleaner transportation system. California continues to rely on petroleum fuels for a large portion of its transportation sector, but the state's petroleum system is changing. Reduced refining capacity, demand decline, and fuel imports all play a large role in balancing supply. California's fuels system is more isolated than many other regions, has no inbound pipelines for crude oil or refined products, and requires a specialized gasoline blend. As a result, the state currently depends solely on marine deliveries to supplement the declining in-state production. These dynamics make petroleum reliability both a near-term and long-term planning issue for the CEC.

Recent events, such as the closure of two in-state refineries and the Iran conflict, have underscored why this work is an important component of the California Energy Resource and Reliability Outlook. Over the last several years, California has experienced refinery conversions and closures, including the conversions of Marathon Martinez and Phillips 66 Rodeo facilities into renewable fuels processing facilities in 2023 and 2024 respectively, the closure of the Phillips 66 Wilmington refinery in 2025, and Valero's idling of refining operations at their Benicia refinery in 2026, increasing the need for imported refined products and blendstocks.

Beginning with SB 1322 (Allen, Chapter 374, Statutes of 2022) and continuing through SB X1-2 (Skinner, Chapter 1, Statutes of 2023), AB X2-1 (Hart, Chapter 1, Statutes of 2024), SB 237 (Grayson, Chapter 118, Statutes of 2025), and SB 767 (Richardson, Chapter 657, Statutes of 2025), the Legislature has significantly expanded the CEC's petroleum responsibilities over the last few years. Together, these laws moved the state from baseline petroleum reporting toward a broader framework of market monitoring, reliability analysis, and transition planning. SB 1322 required California refinery operators to submit monthly reports on the gross gasoline refining margins and related cost data. SB X1-2 expanded petroleum data collection and transparency (initially begun under the Petroleum Industry Information Reporting Act and enhanced in SB 1322), required the recurring Transportation Fuels Assessment (TFA), created the Division of Petroleum Market Oversight (DPMO), and authorized analysis and potential implementation of a maximum gross gasoline refining margin and penalty (MGGRM). AB X2-1 expanded that framework by adding authority related to refinery inventories and maintenance-related production losses as well as expanding the TFA. SB 237 further expanded the TFA and required a separate assessment evaluating strategies to support fuel reliability and affordability during the transition. SB 767 will require oil pipeline operators to report monthly pipeline flow data to the CEC, giving the commission

visibility into pipeline capacity and operations to anticipate potential supply disruptions before they hit consumers at the pump (effective March 2027).

The CEC's petroleum work now spans both short-term reliability monitoring and longer-term transition planning. The Fuels Analysis Branch within the Energy Assessments Division provides analytical and technical support, DPMO provides market oversight, and the Vice Chair's Office guides priorities, coordination, and policy direction.

In the near term, the CEC monitors refinery operations, production, inventories, imports, maintenance, and price indicators, enabled by expanded reporting requirements. The CEC provides public-facing data products such as the Weekly Fuels Watch[158] and monthly refinery margin postings[159]. The CEC's first TFA[160], published in 2024, in addition to providing a primer on petroleum refining, examined relationships between refinery outages, inventory levels, and price volatility. Since then, the CEC has continued to deepen its market analysis, improve supply monitoring, and coordinate with other state agencies and industry participants as California's petroleum system evolves.

This work also includes development of a broader reliability and transition toolkit. The objective is not to preserve the current petroleum system indefinitely, but to maintain safe, reliable, and affordable fuel availability while the state scales up cleaner alternatives and manages the decline of legacy fuel infrastructure. The CEC is evaluating refinery resupply planning for planned maintenance and turnarounds, minimum inventory requirements for greater flexibility in the system during unplanned disruptions, analysis of spot market activity, future import needs, marine infrastructure adequacy and options related to fuel specifications. The following reports examine the status of the evolving system and this transition toolkit:

- The triennial Transportation Fuels Assessment (TFA)
- The Draft Transportation Fuels Transition Plan (TFTP) which is a joint report between the California Air Resources Board (CARB) and the CEC[161]

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158 California Energy Commission. "Weekly Fuels Watch". https://www.energy.ca.gov/data-reports/reports/weekly-fuels-watch

159 California Energy Commission. "California Oil Refinery Cost Disclosure Act Monthly Report". https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/california-oil-refinery-cost-disclosure

160 Gee, Quentin, and Aria Berliner and Alexander Wong. 2024. *2024 Transportation Fuels Assessment*. California Energy Commission. Publication Number: CEC-200-2024-003-SF. https://www.energy.ca.gov/publications/2024/transportation-fuels-assessment-policy-options-reliable-supply-affordable-and

161 California Energy Commission. "SB X1-2 and AB X2-1 Implementation" https://www.energy.ca.gov/proceeding/sb-x1-2-and-ab-x2-1-implementation

- The Review of the Price of Gasoline in California and Related Impact on State Revenues which is a CEC and California Department of Tax and Fee Administration (CDTFA) annual joint report[162]
- The draft SB 237 Assessment[163]

The draft SB 237 Assessment provides an overview of a framework for managing the transition. It incorporates and examines (1) reactive stabilization for mitigating immediate disruptions, (2) systemwide reliability measures, including transparency and coordination, and (3) proactive transition governance to align petroleum system evolution with California's clean transportation goals. Moreover, the effects the transition will have on Californians are examined, particularly impacts on consumers, workers, and communities.

The above reports provide the state's current and most comprehensive view of petroleum market conditions, fuel reliability risks, and transition planning needs. This makes it clear that the CEC's role has expanded in, alongside other agencies, supporting California becoming less reliant on a petroleum-based energy ecosystem.

2026 Iran Conflict: Implications for California Petroleum Reliability

California's petroleum reliability outlook in 2026 cannot be fully understood without acknowledging the broader geopolitical environment, particularly the conflict involving Iran. As described in the Draft SB 237 Assessment, the conflict has introduced new uncertainty into global crude and refined product markets, affecting shipping routes, insurance costs, and the availability of cargoes all of which are paramount to California as the state becomes increasingly reliant on marine imports of both crude oil and finished fuels to meet demand. The conflict has contributed to tighter global refined product markets, including gasoline, diesel, and jet fuel, periodic rerouting of tankers, and higher freight rates, all of which can influence the timing and cost of deliveries to the U.S. West Coast. As of this writing, California continues to receive crude oil without interruption and in-state refiners have been able to pivot towards Latin America and Canada to offset early supply disruptions. While conditions could shift quickly, the current environment underscores the importance of maintaining clear visibility into global supply chains and ensuring strong resilience and diversification across the state's fuel system.

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162 Droboniku, Gentian and Bryan Neff. 2026. *2025 Review of the Price of Gasoline in California and Related Effect on State Revenues*. California Energy Commission and California Department of Tax and Fee Administration. Publication Number: CEC-200-2026-006. https://www.energy.ca.gov/publications/2026/joint-agency-report-2025-review-price-gasoline-california-and-related-effect

163 Keates, Theresa and Quentin Gee. 2026. *Senate Bill 237 Assessment*. California Energy Commission. Publication Number: CEC-200-2026-007-LCD. https://www.energy.ca.gov/publications/2026/senate-bill-237-assessment-supporting-transition-away-petroleum-fuels

The conflict has also highlighted the vulnerability of key maritime chokepoints and trade corridors. Disruptions in the Strait of Hormuz, Red Sea, or Suez Canal, even temporary, can ripple through global markets and affect the price and availability of cargoes destined for the U.S. West Coast. Although California does not rely heavily on Middle Eastern crude, global disruptions can shift trade flows, tighten supply in the Asia-Pacific region, and influence the availability of CARBOB and blendstocks from typical suppliers in South Korea and India. For these reasons, the CEC's petroleum reliability work increasingly incorporates geopolitical risk assessment into its near-term monitoring and mid-transition planning. The CEC tracks global crude oil and refined product prices, freight conditions, refinery outages abroad, and shifts in export policies from major suppliers. This monitoring helps the state anticipate potential impacts on California's supply chain and supports timely coordination with refiners, importers, and other state agencies to mitigate those impacts.

The Iran conflict reinforces a central theme of the state's petroleum transition planning: California must manage two realities at once. The state is committed to reducing petroleum fuel dependence over time, yet it must also ensure that the existing petroleum system remains reliable, affordable, and resilient during the transition. Global disruptions, whether geopolitical, economic, or logistical, underscore the need for a managed, data driven approach that protects consumers today while supporting the long-term shift to cleaner transportation fuels.

CHAPTER 10: Fossil Gas Plant Performance Updates

Fossil Gas Plant Performance

Fossil gas plants supply a significant portion of the peaking capacity and ramping requirements of California's electric grid and are critical to system reliability, especially between 1600 and 2100. when solar PV energy output starts declining and demand is high.[164] These resources can also provide ancillary services like voltage regulation, and load following capability and black start capability.[165]

However, these resources operate less efficiently when ambient air temperatures exceed certain thresholds and can also be susceptible to mechanical failure or reduced availability.[166] These are called derates, which is capacity that becomes unavailable for dispatch. There are two types of derates: planned derates and forced derates. Planned derates occur because of required maintenance or other operational reasons. For example, planned unit testing or an environmental limitation on the number of hours per year that the unit can run.[167] Typical notification for planned derate events provides the California ISO with at least a 7-day notice. In contrast, forced derates occur when sufficient notice cannot be given to allow the outage or unplanned event to be factored into the Day-Ahead Market or Real Time Market bidding process.[168]

CEC staff analyzed fossil gas plant performance, focusing on forced derates. Unless otherwise specified, derated capacity means forced derated capacity. Staff used data from *California ISO Prior Trade Date Reports*[169] for net-peak hours (1600 through 2159) in summer months (July-September) for the years 2021 through 2025. Staff analyzed data for the following types of plants: combined-cycle gas turbine (CCGTs), combustion turbines (CTs, or peakers), once-through cooling plants (OTCs), and simple cycles.[170] Effective as of January 2024, OTCs can only operate as part of the state's SRR within ESSRRP. OTCs are only allowed to operate for maintenance, conducting air permit

164 For this chapter, fossil gas plants will mean natural gas fueled power plants. It does not mean gas turbines that use steam, coal, or other fossil fuels as their primary fuel.
165 Voltage regulation means a gas plant absorbs or generates power to keep voltage levels within safe limits. Load following means a gas plant increasing or decreasing its output to meet sub-hourly load changes. Black start capability is the ability of a gas plant to start and energize the grid without external power; it can help recovery from a blackout.
166 California ISO Staff. February 2026, *Generation Outages Operating Procedure, page 3*. California ISO, https://www.caiso.com/Documents/3220.pdf
167 California ISO Staff. n.d. *Curtailed and Non-Operational Generators*. California ISO, https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators
168 California ISO Staff. February 2026, *Generation Outages Operating Procedure, page 3*. California ISO, https://www.caiso.com/Documents/3220.pdf
169 California ISO staff. N.d. *Curtailed and Non-Operational Generators*. California ISO, https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators
170 Definitions for these plant types can be found in the glossary appendix.

testing, and during extreme events to meet the ESSRRP requirements.[171] The OTCs operated at low hours and as such, had annual capacity factors between 5 to 10 percent, consistent with the ESSRRP's intent. Most reported capacity derates of these plants were due to plant trouble. For more information, see APPENDIX A: Fossil Gas Plant Derate Analysis.

The three most common forced derate types are ambient air temperature (ambient), plant trouble, and maintenance.[172] Ambient derates occur when high temperatures or humidity reduce the available capacity of the generator. Ambient derates are the most frequent of the three types, but plant trouble has the largest amount of derated capacity.[173] Plant trouble occurs when plant equipment fails or is in danger of imminent failure resulting in curtailment of capacity. Finally, maintenance refers to scheduled outages to maintain plant equipment as required by the manufacturers for peak performance. Maintenance can be planned or forced; this analysis considers just forced maintenance.

Fossil gas power plants, on average, lose about 5 to 13 percent of their nameplate capacity from ambient derates. CCGTs lose about 5 percent and CTs lose about 7 percent; this is approximately the same across various utility areas in California (see Table 3 in APPENDIX A: Fossil Gas Plant Derate Analysis). From 2024 to 2025, the average percentage of nameplate ambient capacity derated from fossil gas plants decrease by about one half of a percent. That is, the average ambient derate of a given plant in 2025 was slightly smaller than in 2024.

In 2025, total ambient derated capacity (adding all derates together) was 30 percent lower than what was observed in 2024, possibly due to milder temperatures. However, this drop could also be due to other factors (humidity and the frequency of plant maintenance, for example). Conversely, years 2024 and 2025 experienced more than double the total annual ambient derated capacity in 2021, 2022, and 2023.

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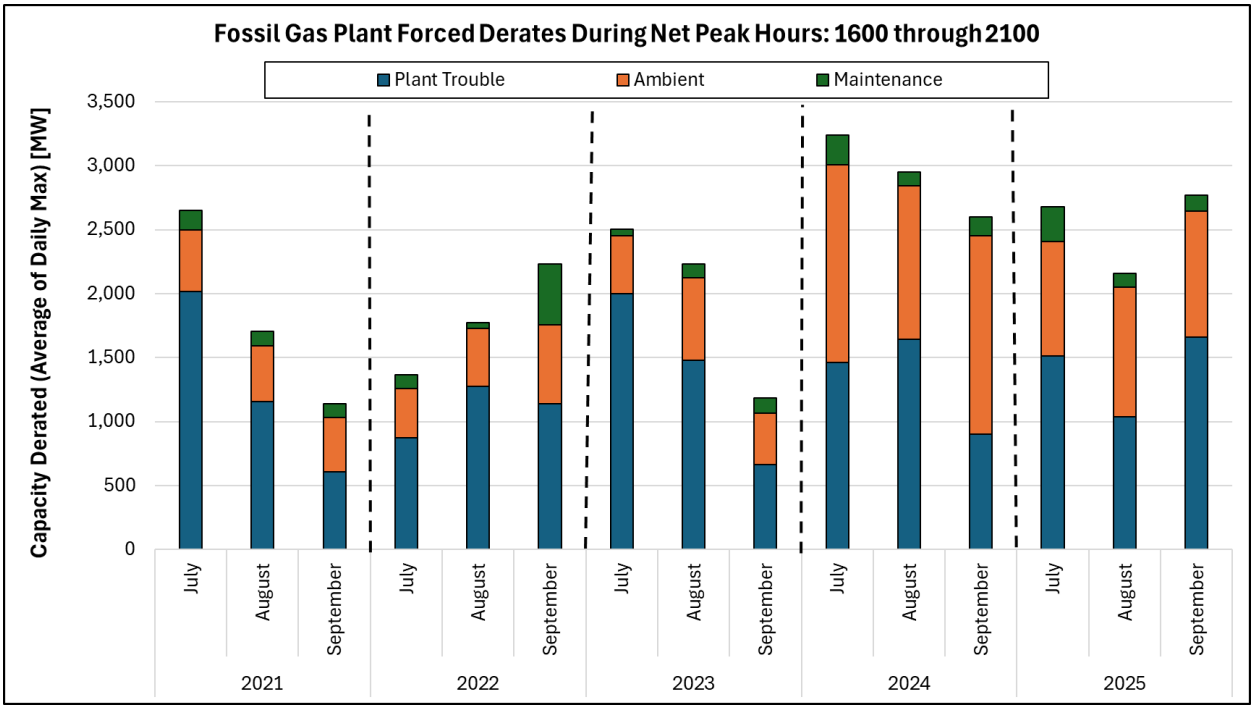
171 California State Water Resources Control Board, Division of Water Quality. January 31, 2023. *Draft Staff Report: Amendment to the Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling to Revise the Compliance Schedules for the Alamitos, Huntington Beach, Ormond Beach, and Scattergood Generating Stations and Diablo Canyon Nuclear Power Plant*. California Environmental Protection Agency. Available: https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/2023/draft-staff-report.pdf

172 Derated energy is the number of hours a derate occurred times the derated capacity amount (relative to nameplate) each hour. Derates are based on what the power plant reported to CAISO and is not necessarily related to actual dispatch. For example, a power plant may report a 200 MWh derate, but that power plant might not be called on to dispatch. Thus, that 200 MWh may not be "observable" in actual generation data.

173 See California ISO Business Practice Manual for description of outage types: Version 22.

Figure 31 shows the monthly average of daily maximum forced capacity derates for plant trouble, ambient, and maintenance events. Ambient and plant trouble derated capacity together generally make up over 80 percent of all derated capacity. Note the increase in ambient derated capacity in 2024 and 2025, compared to 2021 through 2023.

Figure 31: Fossil Gas Plant Forced Derates



Source: CEC analysis of CAISO ISO Prior Trade Date Reports, 2025: https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators.

Conclusions

Fossil gas plants can be derated (loss of some or all available capacity) for many reasons, but hot ambient air temperature, plant trouble or equipment failure, and plant maintenance derates are the most impactful. Plant trouble derates result in the most total capacity being unavailable, while ambient derates occur most often.

Total annual ambient derated capacity in 2024 and 2025 was more than double the annual amounts observed in 2021, 2022 and 2023; this is due to more fossil gas plants reporting ambient derates for more hours than previously. On average, ambient derates reduced available capacity by around five percent to seven percent consistently from 2021-2025 (months July-September 1600 through 2100).

Fossil gas plants provide grid reliability benefits like peaking capacity and ramping during net peak hours, so it is important for electric system planning to understand the availability of these plants over time. The CAISO Prior Trade Date reports provide information to quantify and describe fossil gas plants experiencing capacity derates.

These reports showed that, over the last few years, fossil gas plants experienced increased capacity derates from hot ambient air temperatures. Future analyses should continue to track ambient capacity derates as these derates could get worse from climate change.

CHAPTER 11: Conclusion

California's energy infrastructure continues to balance critical supply reliability with emerging challenges across electricity, natural gas, and petroleum sectors. The current assessment reveals a generally positive near-term energy supply outlook with notable areas of strength and potential risk.

The electricity sector demonstrates the most promising reliability outlook. With a projected surplus of up to 4,000 MW under various conditions, California's electric grid appears well-prepared to handle potential disruptions. Recent infrastructure investments, including new battery storage and solar PV capacity, have enhanced the system's supply reliability. Even under scenarios involving significant resource delays or extreme events, the grid is projected to carry enough reliable capacity to meet customer demand.

Gas reliability shows a similarly encouraging outlook. Projections for Summer 2026 and Winter 2026-27 indicate no anticipated service interruptions, with underground storage facilities expected to reach full capacity. Barring unusual market and/or emergency events, gas prices are anticipated to remain stable, depending on maintaining current production and pipeline capacities.

The petroleum sector, however, faces more complex challenges. Declining gasoline demand—driven primarily by electric vehicle adoption—is reshaping the refinery landscape. This transition introduces potential supply vulnerabilities, with increased risks of disruptions from maintenance events, accidents, or unexpected natural occurrences. Despite these challenges, California’s petroleum refining industry appears to have sufficient infrastructure to produce, procure, and store enough gasoline to meet this summer’s demand. However, this may be impacted by the war in Iran, which is expected to negatively affect global crude supply and price volatility and may impair California’s ability to import finished products.

California continues to be a leader on policies that shift energy resources away from fossil fuels, and the state is committed to rapidly building new clean energy resources. At the same time, California is experiencing more frequent and prolonged extreme weather events because of climate change that strain the state’s energy systems. The CEC will continue to develop and expand future annual iterations of the CERRO to provide comprehensive statewide assessments of energy resource planning and reliability. This may include, but is not limited to, incorporating more accurate and frequent data sets and expanding the scope of content contained in the report.

Summer 2026 Outlook Key Takeaways

- **Electric Reliability Outlook:** Based on both the resource stack and probabilistic analysis, California is expected to maintain system reliability under standard and heat events similar to 2020 and 2022. In a scenario combining a 2022 equivalent extreme heat event with wildfires that disrupt transmission lines, the analysis indicates a potential need for contingency resources exceeding 1,000 MW.
- **Gas Outlook:** Based on forecasted gas demand this summer and the expected availability of infrastructure and absent adverse unforeseen and unusual events, including unscheduled maintenance and consecutive hot days, staff expects that PG&E and SoCalGas will meet demand with no estimated curtailments during summer 2026.
- **Petroleum Outlook:** Recent refinery closures reduced California's crude refining capacity by nearly 18 percent, further constraining supply of the state's unique gasoline blend and increasing reliance on marine imports. California experienced record monthly high marine imports in 2025 due to unplanned outages, indicating the state can accommodate increased imports at the levels required to meet this summer's demand. However, this does not demonstrate sustained reliability of increased import capacity, particularly if the state experiences significant unplanned outages coinciding with peak summer demand. Furthermore, the war in Iran disrupted shipping of crude supply and caused a rapid crude oil price increases beginning in March 2026. The conflict poses risks to California's fuel availability should global conditions further deteriorate.

Emerging Issues Key Takeaways

- **Load Growth and Uncertainty:** CEC is incorporating known loads (loads based on customer applications to the distribution utility) into its demand forecast modeling to better align distribution planning and other state planning processes. At the same time, data centers driven by the AI boom are projected to add 5 to 8 GW of load growth by 2040.
- **Emerging Resources:** California's SB 100 and GHG goals require 150 to 200 GW of new zero carbon resources over the next twenty years to achieve SB 100 and GHG goals. Emerging resources are increasingly important to meet winter loads by 2045. Each emerging resource studied can be effective under different scenarios. The removal of the IRA subsidies raises the cost of building and operating a decarbonized grid by 15-30 percent over the next 10 years.
- **Long-term Electric Reliability:** Procurement as of January 2026 is sufficient to meet the reliability standard in 2031 under the 2025 *IEPR* Forecast but may not be sufficient under other demand scenarios. The CPUC's February 2026 procurement order would likely fill the modeled 2031 deficits and is of similar magnitude to the 2036 base-case deficit. Additional procurement beyond that

modeled through 2028 will likely be needed to meet reliability standards by 2036.

- **Petroleum System Transition:** Differences between the gradual decline in gasoline demand and large stepwise decline in supply from in-state refinery closures can lead to supply and demand imbalances that must be met with imports. The state must work with communities, labor, industry, and other stakeholders to manage this transition, including working with industry to manage declining in-state refining capacity and ensure that suitable infrastructure is in place to support those imports.

APPENDIX A:
Fossil Gas Plant Derate Analysis

This appendix explores how California ISO emergency event days and average summer ambient air temperatures impact ambient derates to fossil gas plants.[174]

Distribution of Fossil Gas Plant Derates

Fossil gas plants can lose their ability to generate at full rated capacity, which is called a derate. Ambient temperature, plant trouble, plant maintenance, and environmental restrictions are the three largest derate types based on event hours and potential derated energy.

- **Ambient temperature**: High temperature and high humidity can affect the efficiency or operation of the fossil gas plant resulting in a loss of available capacity.
- **Plant trouble**: Equipment fails or is in danger of imminent failure resulting in a reduction of dispatchable capacity.
- **Plant maintenance**: Required scheduled maintenance periods.
- **Environmental Restrictions**: Restrictions due to environmental regulations specific to a resource that limits the dispatchable capacity of that unit.

Table 30 shows the total summer derated energy[175] by year, for the three most common derate types, for fossil gas plants in California. The term "all fossil gas plant types" refers to CCGT, CT, and simple cycle gas turbine fossil gas plants.

174 California ISO Staff. n.d. *California ISO emergency notifications.* California ISO, https://www.caiso.com/emergency-notifications

175 Derated energy is the number of hours a derate occurred times the derated capacity amount (relative to nameplate) each hour. Derates are based on what the power plant reported to California ISO and is not necessarily related to actual dispatch. For example, a power plant may report a 200 MWh derate, but that power plant might not be called on to dispatch. Thus, that 200 MWh may not be "observable" in actual generation data.

Table 30: Fossil Gas Plant Derates by Derate Type in MWh

Year	2021	2022	2023	2024	2025
Total Derated Energy: All Fossil Gas Plant Types (MWh)					
Ambient	215,878	231,903	201,02	625,989	455,858
Plant Trouble	641,379	521,411	713,53	714,287	851,994
Plant Maintenance	75,731	112,348	32,434	96,965	98,104
Total Event Hours: All Fossil Gas Plant Types (Hours)					
Ambient	28,876	29,912	25,715	44,443	38,005
Plant Trouble	7,406	9,331	9,537	8,680	9,593
Plant Maintenance	2,253	2,369	720	1,535	1,645

Note: Plant Maintenance includes both forced and unforced maintenance events.
Each year July-September, 4:00 p.m. through 9:59 p.m.

Source: CEC analysis of CAISO ISO Prior Trade Date Reports, 2025: https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators.

Average California Temperatures: Last 5 years

Staff used data from the National Oceanic and Atmospheric Administration (NOAA) to explore how average summer temperatures have changed over time, and how that could impact ambient plant derates.[176] Table 31 shows the average summer temperature for California from 2021 through 2025. Of the five-year period, 2024 had the highest average summer temperature whereas 2023 and 2025 had the lowest. Ambient air temperature can impact the amount of fossil gas plant capacity derated, and thus not available for dispatch.[177] Table 31 shows the largest amount of ambient derates occurred in summer 2024, which had the highest average ambient temperature. The table shows that average statewide temperature does not seem indicative of derated capacity and may not be the best predictor for the whole fleet of fossil gas plants in California as temperature varies across region and hour of the day. Also, not all fossil gas plants are the same and may experience different amounts of derated capacity for the same temperature. Table 31 is meant as a high-level comparison of ambient air temperature and derated capacity of the fossil gas plant fleet.

Variable energy resources, such as solar PV, are increasing each year and can impact how and if fossil gas plants are operated. That is, fossil gas plants may turn on and off or ramp more frequently. This increased ramping can cause wear-and-tear on fossil gas plants which could

176 NOAA National Centers for Environmental information, Climate at a Glance: Statewide Time Series, published November 2025, retrieved on November 24, 2025, from https://www.ncei.noaa.gov/access/monitoring/climate-at-a-glance/statewide/time-series

177 Humidity was not included in this analysis as it impacts fossil gas plant differently depending on ambient air temperature, and the impact from humidity is relatively small compared to ambient air temperature. The Effect of ambient temperature on electric power generation in natural gas combined cycle power plant – A case study. Science Direct, November 2018. Şen, Günnur, Mustafa Nil, Hayati Mamur, Halit Doğan, Mustafa Karamolla, Mevlüt Karaçor, Fadıl Kuyucuoğlu, Nuran Yörükeren, and Mohammad Ruhul Amin Bhuiyan. 2018. *"The Effect of Ambient Temperature on Electric Power Generation in Natural Gas Combined Cycle Power Plant—A Case Study."*

cause them to be more negatively impacted by high ambient temperatures (older worn-out parts may be more susceptible to heat). On the other hand, fossil gas plants can be upgraded or have more frequent maintenance performed, to make them more resistant to ambient conditions. Lastly, regular wear-and-tear can cause gas plants to operate less efficiently and become less resilient to heat over time.

Table 31: California Average Summer Temperatures and Derates

Temperature Rank	Year	Average Temperature (Degree F)	Ambient Derated Energy (MWh)
1	2024	76.7°F	625,989
2	2022	76.6°F	231,903
3	2021	76.3°F	215,878
4	2025	74.5°F	455,858
5	2023	74.3°F	201,029

Source: National Oceanic and Atmospheric Administration and CAISO Prior Trade Date Reports. July-Sep, 2021-2025

Next, the analysis considers California ISO emergency event days (summers: 2021 to 2025) and how they impact ambient gas plant derates. Table 32 summarizes the number and types of emergency event notifications from 2021-2025 (note that 2025 had no notifications). Most emergency notifications are Flex Alerts or restricted maintenance outage (RMO). 2024 had the largest amount of summer gas plant derated capacity, and the second largest number of emergency notification days. If we consider just RMO or transmission emergency days, then summer 2024 has the most emergency notifications. California ISO emergency notifications does not show strong correlation to ambient derates.

Emergency event day definitions for Table 32:

- **Flex Alert:** A Flex Alert is a call to consumers to voluntarily conserve electricity when the California ISO anticipates energy supply may not meet high electricity demand. Reducing energy use during a Flex Alert can prevent more dire measures, such as moving into EEA notifications (described below), emergency procedures, and even rotating power outages.
- **RMO:** When high demand is anticipated, the California ISO will caution utilities and transmission operators to avoid taking grid assets offline for routine maintenance to assure that all generators and transmission lines are available.
- **EEA Watch:** Analysis shows all available resources are committed or forecasted to be in use, and energy deficiencies are expected. This notice can be issued the day before the projected shortfall or if a sudden event occurs. Consumers are encouraged to conserve energy.
- **EEA 1:** Real-time analysis shows all resources are in use or committed for use, and energy deficiencies are expected. Consumers are encouraged to conserve energy.

- **EEA 2:** The California ISO requests emergency energy from all resources and has activated emergency energy programs. Consumers are urged to conserve energy to help preserve grid reliability.
- **EEA 3:** The grid operator is unable to meet minimum reliability reserve requirements and has declared the initial step of an EEA 3. The first step of an EEA 3 is to have utilities prepared for outages, but rotating outages have not been ordered. During an EEA 3, the second step is to require rotating outages. An EEA 3 can stop at the first step or continue to rotating outages.
- **Stage 2 Emergency:** Prior to 2022, a Stage 2 Emergency notice was declared by the California ISO any time it was clear that an operating reserve shortfall (less than 5 percent) was unavoidable or, when in real-time operations, the operating reserve was forecast to be less than 5 percent after dispatching all available resources. Stage 2 meant that the California ISO has taken all mitigating action and is no longer able to provide its expected energy requirements. This too was replaced by EEAs beginning in 2022.

Table 32: California ISO Emergency Event Days and Total Summer Derated Energy

Year	Flex Alert	RMO	EEA Watch	EEA 1	EEA 2	EEA 3	Stage 2	Total Event Days	Ambient Derate (MWh)
2021	6	12	0	3	0	0	1	**22**	215,878
2022	11	15	9	6	4	1	0	**46**	231,903
2023	0	6	2	1	0	0	0	**9**	201,029
2024	0	18	1	0	0	0	0	**19**	625,989
2025	0	0	0	0	0	0	0	**0**	455,858

Source: California ISO Emergency Notifications and California ISO Prior Trade Date Reports. July-Sep, 2021-2025

Table 33 shows monthly derated capacity as a percentage of nameplate capacity, for CCGTs and CTGs. CCGTs generally lose about 5 percent of their nameplate capacity during net-peak hours in summer months. CCGTs in SCE territory lost about 8 percent. CTGs, on average, lost about 7 percent of their nameplate capacity during summer net-peak hours. For all fossil gas plant types and utility areas, the percentage of derated capacity decreased from 2024 to 2025.

Table 33: Ambient Derate by Gas Plant Technology Type, During Net-Peak Hours

		Combined Cycle				Combustion Turbine			
Year	Month	CA	PG&E	SCE	SDG&E	CA	PG&E	SCE	SDG&E
2021	7	5.4%	4.8%	NA	5.8%	6.3%	7.3%	6.6%	5.0%
2021	8	5.2%	4.6%	NA	5.9%	6.0%	7.3%	6.1%	4.8%
2021	9	5.0%	4.4%	2.3%	5.9%	6.5%	9.6%	5.6%	4.7%
2022	7	5.1%	4.7%	NA	5.6%	5.8%	8.0%	5.2%	9.2%
2022	8	5.0%	4.6%	NA	5.3%	6.0%	7.8%	6.2%	5.7%
2022	9	5.7%	5.9%	5.5%	5.5%	6.0%	7.7%	5.8%	7.3%
2023	7	4.4%	4.4%	NA	4.5%	7.6%	7.6%	7.5%	13.4%
2023	8	4.2%	3.9%	NA	4.6%	9.7%	9.1%	10.3%	11.5%
2023	9	3.7%	3.5%	6.0%	3.6%	7.7%	6.2%	7.7%	11.5%
2024	7	7.9%	7.2%	11.7%	5.5%	7.5%	7.2%	9.5%	5.0%
2024	8	5.5%	6.8%	5.1%	5.6%	7.3%	6.3%	9.0%	5.6%
2024	9	5.3%	6.3%	4.5%	5.3%	6.6%	6.1%	7.8%	5.4%
2025	7	5.2%	6.8%	3.9%	3.8%	5.4%	4.7%	7.4%	3.5%
2025	8	5.2%	6.8%	5.2%	4.4%	6.4%	5.3%	8.0%	5.5%
2025	9	4.8%	5.9%	5.4%	4.3%	6.3%	5.6%	7.6%	5.3%
Minimum		**3.7%**	**3.5%**	**2.3%**	**3.6%**	**5.4%**	**4.7%**	**5.2%**	**3.5%**
Average		**5.2%**	**5.4%**	**5.5%**	**5.0%**	**6.7%**	**7.1%**	**7.3%**	**6.9%**
Maximum		**7.9%**	**7.2%**	**11.7%**	**5.9%**	**9.7%**	**9.6%**	**10.3%**	**13.4%**

Note: NA means that no derate data was available for that month.

Source: California ISO Prior Trade Date Reports.

APPENDIX B:
Summer Gas Demand Forecast Methodology

This appendix describes the methodology used to forecast summer 2026 (April-October) natural gas demand for SoCalGas and PG&E to support system reliability assessments.

The forecasting approach uses a hybrid modeling framework that combines a Prophet[178] time-series model, which is an open-source additive forecasting library, with a Long Short-Term Memory (LSTM) neural network, a deep learning model capable of capturing nonlinear temporal patterns. The hybrid framework is used to forecast both system-level and primary customer-class peak-day demand under high temperature climate conditions and monthly average demand under average and cold/dry conditions. The average scenario corresponds to the mean of climate projections, while the cold/dry scenario assumes slightly below-average temperatures and reduced hydroelectric availability.

The analysis focuses primarily on temperature-driven gas demand patterns. However, because electricity generation represents a large share of summer gas demand, an adjustment is applied to account for hydroelectric generation conditions, which influence the level of gas-fired electricity generation required during summer months.

Electric generation represents the largest component of summer gas demand for both utilities. Demand tends to increase during hotter periods as electricity demand for cooling rises, increasing dispatch of gas-fired generation. Hydroelectric availability can also affect gas demand, particularly during dry years when reduced hydroelectric output increases reliance on gas-fired electricity generation.

Model performance was evaluated by generating retrospective forecasts for historical periods and comparing them with observed demand. The hybrid model reduces peak-day forecast error by approximately 23 percent for SoCalGas and 30 percent for PG&E compared to the Prophet-only model. For monthly averages, forecast error declines by about 7 percent for SoCalGas and 3 percent for PG&E. These improvements come primarily from modeling electricity generation, which dominates summer demand and is highly sensitive to cooling-driven temperatures and hydroelectric availability.

178 Meta (Facebook). *Prophet: Forecasting at Scale*. Prophet is an open-source forecasting procedure implemented in R and Python, designed for time series data with strong seasonal effects. Available: https://facebook.github.io/prophet.

The resulting forecasts align closely to projections reported in utility filings submitted to the CEC's *2025 IEPR,*[179] with minor differences reflecting hybrid model's greater climate sensitivity and ex-post adjustments for hydroelectric generation.

Data Sources

Daily gas demand data from 2017 through 2024 were provided by SoCalGas and PG&E. Daily demand projections for 2025 and 2026 projections were obtained from utility filings submitted to the *2025 IEPR*. Gas demand data are disaggregated by customer class, including core, non-core, electric generation, and other categories.

Historical daily temperature data (1996-2025) were obtained from the NOAA. Daily climate change projections (2025-2050) were derived from datasets developed under the CEC's Electric Program Investment Charge (EPIC) program[180]. Temperature data were averaged across each utility's service area,[181] smoothed with a three-day weighted moving average[182] to reflect delayed demand responses, and converted into heating degree days (HDDs) and cooling degree days (CDDs)[183].

Monthly hydroelectric generation data for 2001 through 2017 were obtained from CEC's QFER[184] and PG&E's 2024 California Gas Report (CGR) working paper.[185]

Gas demand data were log-transformed prior to modeling to linearize the temperature-demand relationship, improve data distribution, and reduce the influence of outliers. For monthly analysis, daily demand values were aggregated to a monthly frequency.

Figure 32 illustrates the relationship between daily gas demand and average summer 2025 temperatures. Gas demand increases during the hottest months of summer when

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179 Kennedy, Robert and Gutierrez, Julio. 2024. *Forms and Instructions for Submitting Electricity Resource Plans: Prepared in Support of the 202 5 Integrated Energy Policy Report*. California Energy Commission, Publication Number: CEC-200-2024-008. https://www.energy.ca.gov/publications/2024/forms-and-instructions-submitting-electricity-resource-plans-and-transmission

180 Aydin, Mariko Geronimo, and Onur Aydin (Lumen Energy Strategy). December 19, 2023. *Key Findings in Climate Data Analyses for Demand Forecast Integration*. Presentation to the California Energy Commission IEPR Commissioner Workshop on the California Energy Demand Forecast Results Part II. Docket No. 23-IEPR-03, TN #253658. Available: https://efiling.energy.ca.gov/GetDocument.aspx?tn=253658

181 Burbank, Long Beach, Santa Barbara, Bakersfield, and Riverside in SCG' service area and Fresno, Oakland, Red Bluff, Sacramento, San Jose, San Luis Obispo, and Ukiah in PGE's service area. Station weights provided by CEC staff.

182 The most recent day's temperature is assigned a weight of 0.6, the previous day receives a weight of 0.3, and the temperature from two days ago is weighted at 0.1.

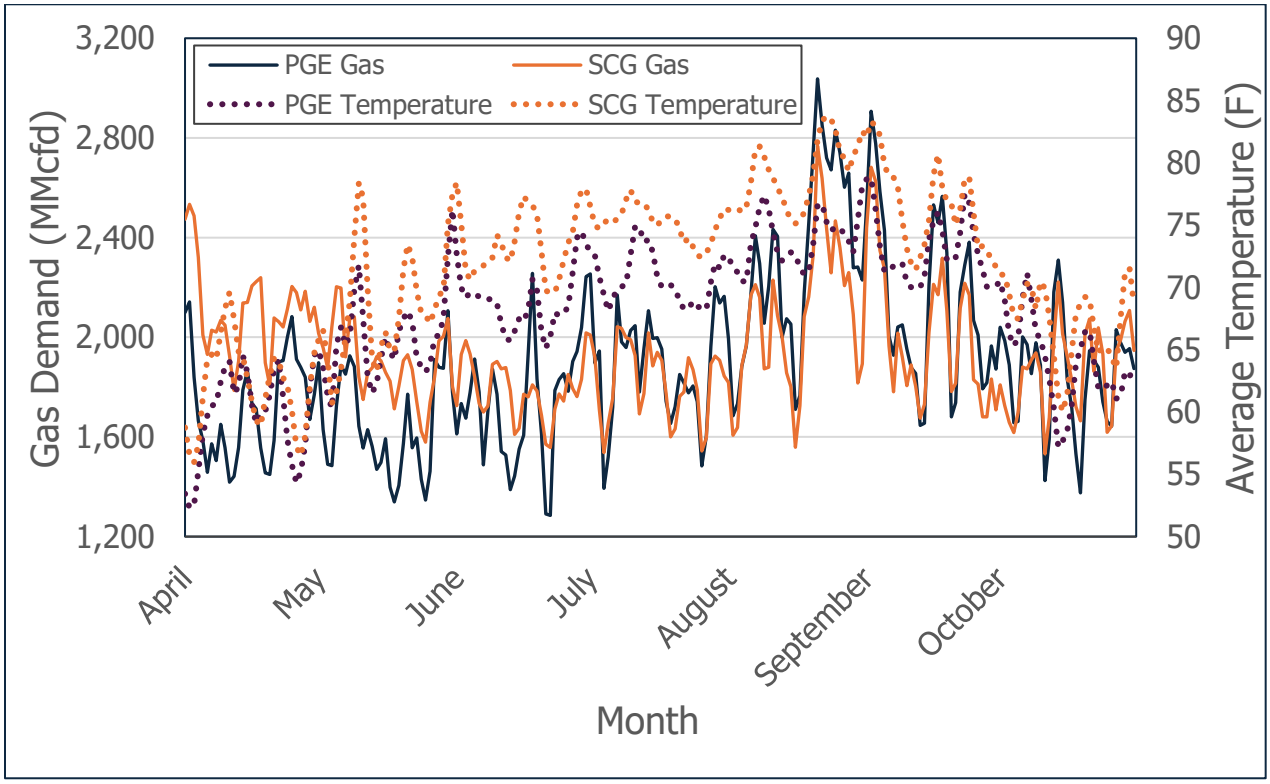
183 Cooling and heating degree days are calculated based on whether the average daily temperature is above or below the thresholds of 65°F or 55°F.

184 California Energy Commission Staff. N.d., *Energy Almanac: California Electricity Data*. California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/.

185 PGE Staff. 2024. *2024 California Gas Report Workpapers*. Pacific Gas and Electric Company, https://www.pge.com/assets/pipeline/docs/library/regulatory/downloads/24_CGR_Workpaper_On-System_Demand_Forecast.zip.core download.zip.

electricity demand for cooling is highest and declines towards early fall. Demand decreases on weekends and holidays compared with weekdays. PG&E shows greater demand volatility and sharper peaks than SoCalGas, which has higher average temperatures but smoother, more stable demand.

Figure 32: PG&E and SoCalGas Daily Gas Demand vs. Average Temperature



Source: CEC Staff

Hybrid Modeling Framework

The forecasting methodology uses a two-stage hybrid modeling framework. First, a Prophet[186] time-series model estimates baseline gas demand by capturing long-term trends, seasonal patterns, calendar effects, and temperature-driven demand variation. Second, an LSTM[187] neural network is trained on the residuals from the Prophet model (differences between historical demand and Prophet's predictions) to capture nonlinear and short-term volatility not explained by the baseline model. The

186 Sean J. Taylor and Benjamin Letham. 2018. *Forecasting at Scale. American Statistician, vol. 72, no. 1 (2018), pp. 37–45*. Taylor and Francis Online, https://www.tandfonline.com/doi/full/10.1080/00031305.2017.1380080.

187 Martín Abadi, Paul Barham, Jianmin Chen, Zhifeng Chen, Andy Davis, Jeffrey Dean, Matthieu Devin, et al. N.d. *TensorFlow: A System for Large-Scale Machine Learning*. Usenix, https://www.usenix.org/conference/osdi16/technical-sessions/presentation/abadi.

final hybrid forecast is generated by adding the LSTM-predicted residuals to the Prophet baseline forecast.

Prophet Baseline Model

Prophet decomposes time-series gas demand into trend, seasonal, and calendar components. Trends are modeled as piecewise linear functions with changepoints representing shifts in the long-term trend. Seasonal patterns are modeled using a time-varying Fourier series,[188] and calendar effects are represented using indicators that distinguish working days from weekends and holidays.

The model also incorporates temperature sensitivity through the inclusion of heating and cooling degree days as explanatory variables. A seasonal indicator distinguishes summer months (April-October) from winter months (November-March). Conceptually, the model is specified as a linear additive function of these components plus a residual:

$$\text{demand}_t = f(\text{trend}_t, \text{seasonality}_t, \text{holidays}_t, \text{regressors}_t) + \text{residual}_t$$

LSTM Residual Model

The LSTM[189] model is trained on the residual demand from the Prophet baseline model. The model captures trend persistence, nonlinear temperature effects, and short-term fluctuations that are not explained by the Prophet specification. LSTM models incorporate memory states that allow the model to retain information from prior observations. Gates within the network determine how information is retained, updated, or discarded as the model processes new inputs.
Residual forecasts are generated recursively and then added back to the Prophet baseline forecast to produce the final hybrid forecast as:

$$\text{Hybrid forecast}_t = \text{Prophet forecast}_t + \text{LSTM residual forecast}_t$$

Hybrid Model Tuning and Validation

Model tuning was conducted to identify the most predictive explanatory variables and model hyperparameters. Hyperparameter optimization was performed using Bayesian

188 Fourier series analysis decomposes time series data into sine and cosine functions with specific frequencies and amplitudes, revealing periodic patterns, trends, and seasonal variations.
189 In its simplest form, LSTM takes the most recent residual as input and stores information about it (e.g., spikes, dips, trends). Gates control updating its three memory-related states: what old information is kept, forgotten, or reused to update and predict the next residual. The predicted residual is fed back into the LSTM, allowing the model to repeatedly update its memory and forecast residuals further into the future, capturing recurring spikes, dips, and local residual dynamics.

optimization[190] to minimize the mean absolute percentage error (MAPE).[191] Model validation included both holdout training and testing subsets and rolling cross-validation across multiple time periods.

Key Prophet-tuned hyperparameters include the specification of piecewise linear trend, changepoints, and prior scales for seasonality, while LSTM-tuned hyperparameters include learning rate, network depth, batch size, and dropout settings. Although the same set of time-dependent explanatory variables (daily vs. monthly) is used across utilities and forecast types, specific hyperparameter values vary slightly by utility and forecast type.

The hybrid approach models gas demand separately for total system load, core demand, and electric generation demand. Noncore demand and other customer categories are estimated using historical ratios and growth projections from the 2022 and 2024 CGRs and the *2025 IEPR* filings.

Hybrid Model Forecasting Historical Performance (2017-2025)

The hybrid model improves forecast accuracy relative to the Prophet-only model (Table 34). Peak-day MAPE declines by approximately 23 percent for SoCalGas and 30 percent for PG&E, and monthly averages by 7 percent and 3 percent, respectively. Residual diagnostics indicate less bias and a more stable error distribution for monthly averages than for highly volatile daily-peak demand.

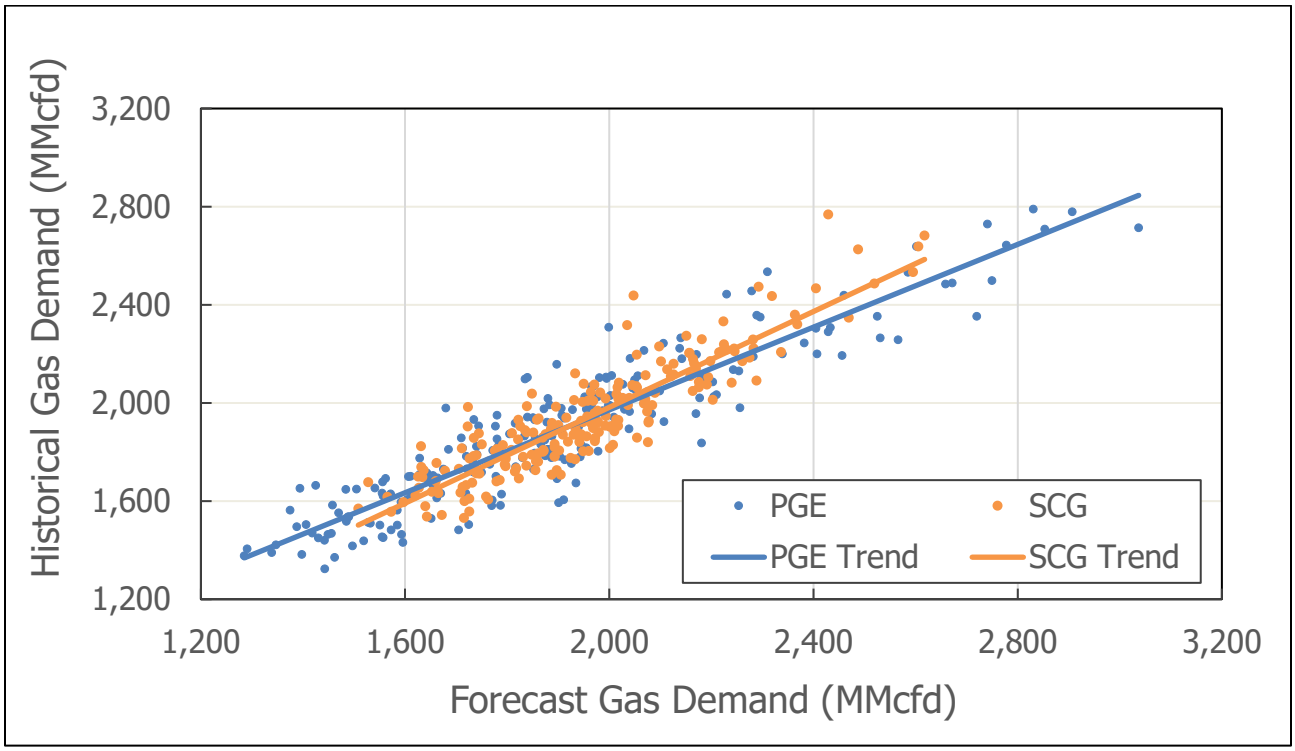
Table 34: Comparing Utility's MAPE of Peak-Day and Monthly Average Forecasts

Forecast	Utility	Prophet	Hybrid	Delta
Peak-day	SCG	4.61%	3.55%	-22.99%
Peak-day	PGE	6.17%	4.35%	-29.50%
Monthly Averages	SCG	2.12%	1.98%	-6.60%
Monthly Averages	PGE	2.70%	2.63%	-2.59%

Source: CEC Staff

190 Bayesian optimization is a probabilistic model-based optimization technique. It uses a Gaussian process surrogate model to approximate the objective function (model performance). This surrogate model is efficiently trained on previous evaluations to predict performance while exploring the hyperparameter space for near-optimal values minimizing the number of function evaluations required.
191 A MAPE of 3% means the model's predictions are, on average, 3% away from the actual value over all predicted points.

Figure 33: 2025 Summer Historical vs. Forecast Gas Demand



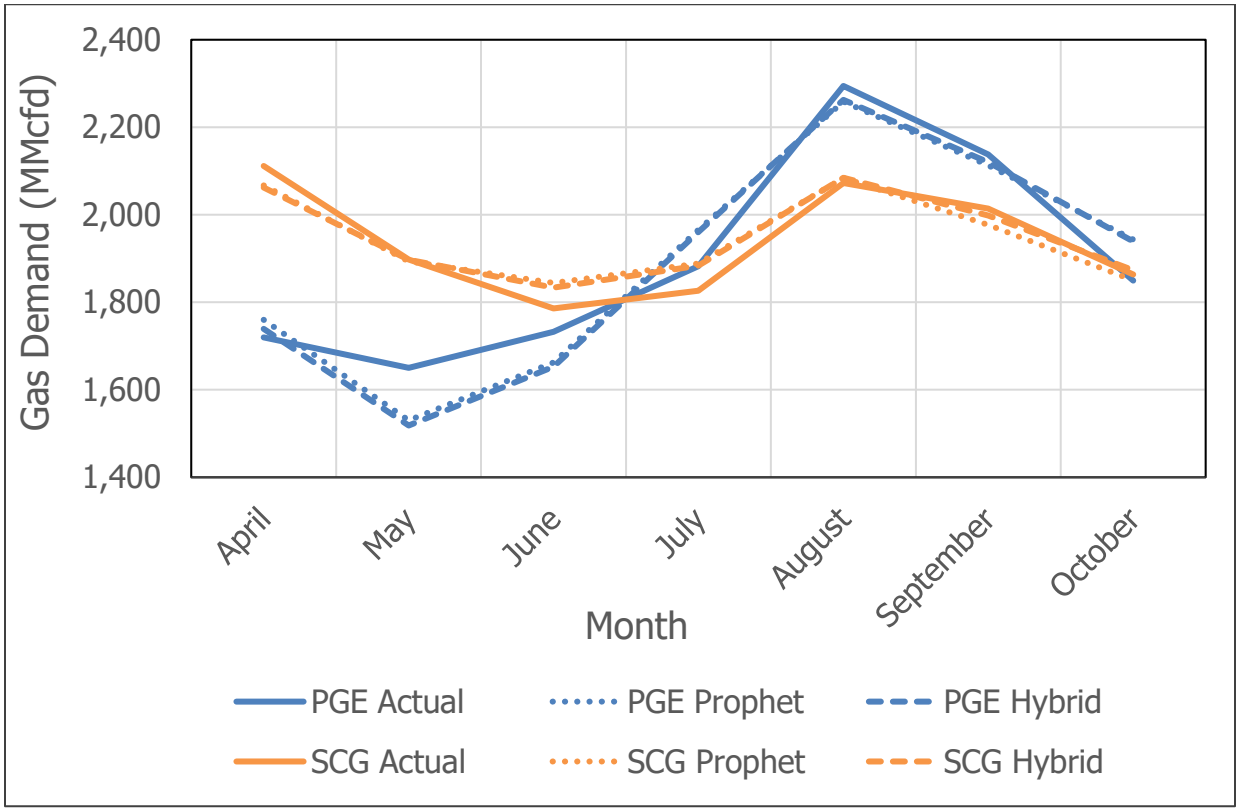
Source: CEC Staff

Figure 33 and Figure 34 show that 2025 hybrid peak-day and monthly-average forecasts closely track historical demand, particularly during high-volatility and peak-load periods, whereas the Prophet-only model provides a smoother but less responsive baseline.

In Figure 33, utilities' hybrid forecasts cluster closely around their respective linear trend lines, indicating strong alignment with historical demand. Accuracy is highest on non-peak days, with some over-forecasting during peak periods. SoCalGas shows a slightly steeper trend, implying marginally higher sensitivity to historical demand levels.

In Figure 34, monthly average demand is lower in late spring and early summer, peaks in August, and then declines into October, reflecting seasonal cooling and gas use for electric generation. Although Prophet and hybrid lines are similar, hybrid line more accurately tracks historical demand during periods of high volatility and peak times, while Prophet line provides a more stable baseline but slightly underpredicts during high-load months.

Figure 34: Monthly Average Historical Gas Demand Compared With Prophet and Hybrid Forecasts for SoCalGas and PG&E in Summer 2025



Source: CEC Staff

Hybrid Summer 2026 Forecast Results

The hybrid model forecasts peak-day and monthly-average gas demand for summer 2026, using hyperparameters and external regressors derived from historical relationships adjusted for climate-driven temperature projections, cooling degree days (CDDs), and assumed hydroelectric availability. CDD projections reflect anticipated warming trends, with EPIC's quantile-based downscaling showing larger, more pronounced shifts in CDD distributions within PGE's service area than in SoCalGas's.

Peak-day demand (90th percentile)

Electric generation represents the largest share of peak-day demand for both utilities (Table 35 and Table 36). For SoCalGas, electric generation accounts for roughly 60 percent of peak demand. Core and noncore demand remain similar in size, smaller, and relatively stable. Other demand and SDG&E core loads together account for less than 5 percent of total demand. For PGE, electric generation represents approximately 55 percent of peak demand. Industrial demand accounts for nearly half of total electric generation. Off-system deliveries make up 12 percent of demand, with core customers accounting for a similar share. PG&E shows greater peak sensitivity to climate conditions, reflecting higher volatility in electric generation demand.

Table 35: Summer Peak-Day Gas Demand Forecast for SoCalGas in 2026 (MMcfd, 90th percentile)

Core	Noncore	Other core	SDGE Core	Electric Gen	Total
571	562	59	80	1,860	3,133

Source: CEC Staff

Table 36: Summer Peak-Day Gas Demand Forecast for PG&E in 2026 (MMcfd, 90th percentile)

Core	Industrial	Electric Gen	Off System	Total
342	664	1,655	371	3,031

Source: CEC Staff

Monthly average demand (Average and Cold/dry scenarios)

Monthly demand follows a consistent, strong seasonal pattern (Table 37 and Table 38). Demand is lower in late spring, increases through early summer, and peaks in July and August, driven by cooling-related electricity generation, which accounts for 39 percent of total demand for SoCalGas and 42-49 percent for PG&E. It then declines into early fall. Compared with average conditions from July through October, cold/dry PG&E electric generation increases by 25 percent, whereas SoCalGas increases slightly by 6 percent.

Table 37: Average and Increased Electric Generation Scenarios for Monthly Average Gas Demand Forecast for SoCalGas in Summer 2026 (MMcfd)

Climate	Month	Core	Noncore	Other Core	SDGE Core	Electric Gen	Total
Average	4	1,011	459	47	207	482	2,206
Average	5	710	426	40	161	396	1,734
Average	6	637	424	40	163	443	1,706
Average	7	643	459	47	206	857	2,212
Average	8	639	474	49	280	919	2,360
Average	9	621	464	43	203	691	2,021
Average	10	731	460	47	213	708	2,158
Increased EG	4	1,011	459	47	207	449	2,173
Increased EG	5	710	426	40	161	424	1,761
Increased EG	6	637	424	40	163	466	1,730
Increased EG	7	643	459	47	206	903	2,258

Increased EG	8	639	474	49	280	978	2,420
Increased EG	9	621	464	43	203	729	2,060
Increased EG	10	731	460	47	213	750	2,201

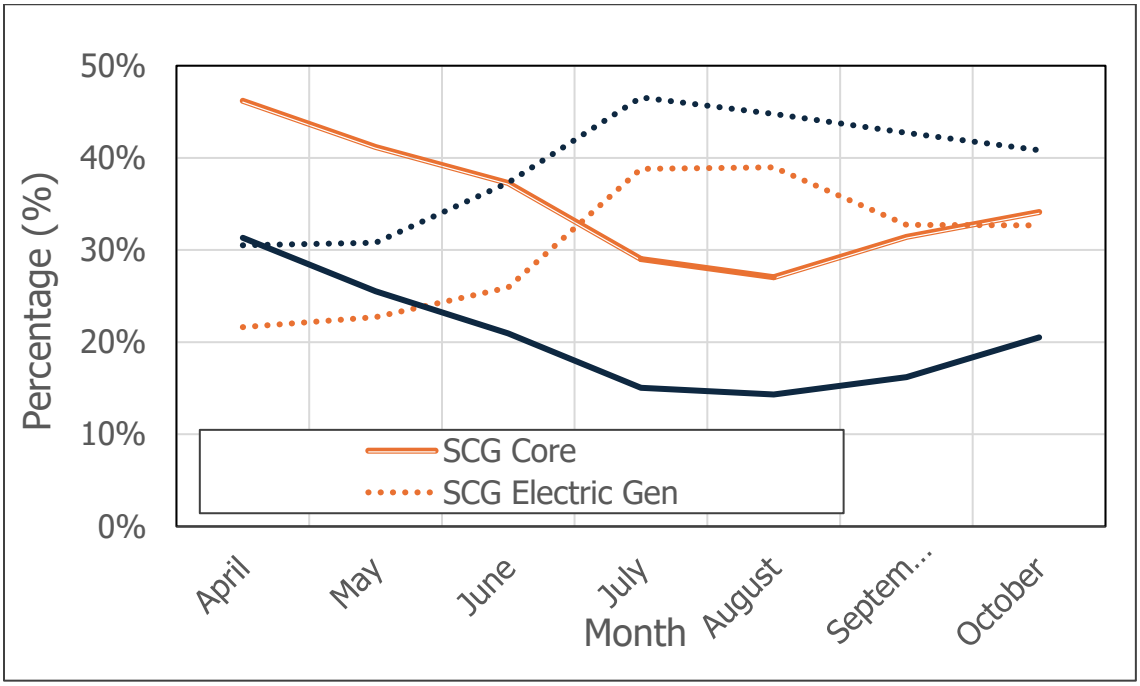
Source: CEC Staff

Table 38: Average and Cold/Dry Scenarios for Monthly Average Gas Demand Forecast for PG&E in Summer 2026 (MMcfd)

Climate	Month	Core	Industrial	Electric Gen	Off System	Total
Average	4	648	456	590	361	2,056
Average	5	463	455	529	355	1,801
Average	6	397	457	612	349	1,815
Average	7	313	481	867	329	1,990
Average	8	310	566	883	329	2,088
Average	9	345	567	842	320	2,074
Average	10	452	517	849	355	2,172
Increased EG	4	648	456	701	361	2,166
Increased EG	5	463	455	592	355	1,865
Increased EG	6	397	457	798	349	2,001
Increased EG	7	313	481	1,152	329	2,275
Increased EG	8	310	566	1,097	329	2,302
Increased EG	9	345	567	1,071	320	2,303
Increased EG	10	452	517	984	355	2,308

Source: CEC Staff

Figure 35: Monthly Average Percentage of Total Demand for Core and Electric Generation Summer 2026



Source: CEC Staff

Figure 35 shows the combined[192] monthly average percentage of total demand for core and electric generation. These customer classes account for 63-66 percent of total demand for SoCalGas and 55-64 percent for PG&E, with similar curve shapes but different overall values. Other customer-class demands remain relatively stable. Electric generation shows larger mid-summer shifts than core, which tend to decline overall. In mid-summer, electric generation surpasses core. Electric generation shows a significant peak around July, followed by a decline toward October. Core consistently shows the lowest values across months. SoCalGas's core peaks in April, gradually decreases by August, and then rises slightly towards October. Electric generation starts at its lowest in April, rises steadily to a peak near July, and then gradually declines.

Projections for noncore and other customer class demand, which are less sensitive to temperature and seasonality, are first scaled to core and electric generation demands,

192 Because monthly values for average and cold/dry scenario differences are small relative to overall seasonal variation, results are combined into a single series for each utility to improve readability without losing any information.

then projected over time using historical ratios and growth assumptions from the 2022 and 2024 CGR[193], and utility filings for the *2025 IEPR*.

Conclusions

The hybrid Prophet-LSTM modeling framework provides an improved forecast of summer 2026 natural gas demand for SoCalGas and PG&E. The hybrid approach improves peak-day and monthly-average forecast accuracy compared to the Prophet-only model and performs reasonably well under extreme conditions. The resulting forecasts align closely with utility planning forecasts while providing an independent analytical framework for evaluating summer gas system reliability.

Future work could incorporate additional long-term demand drivers, such as socioeconomic factors, electrification, energy efficiency, and expanded climate and hydrologic assumptions.

193 California Gas and Electric Utilities staff. 2022. *2022 California Gas Report*. California Gas and Electric Utilities,https://www.socalgas.com/sites/default/files/Joint_Utility_Biennial_Comprehensive_California_Gas_Report_2022.pdf, and California Gas and Electric Utilities staff. 2024. *2024 California Gas Report*. California Gas and Electric Utilities, https://www.socalgas.com/sites/default/files/2024-08/2024-California-Gas-Report-Final.pdf.

Appendix C: Resource Availability and California's Future Electric System: Technology Feasibility, Cost Trajectories, and Wind and Land Use

This appendix discussed CEC's long-term capacity expansion planning approach, detailing models and assumptions. It also presents some additional results and details to provide further insight into trends amongst results and specific comparisons between modeling scenarios.

Approach: Model Setup and Key Assumptions

Capacity expansion models optimize for the least-cost resource build across a future horizon. This is a computationally intensive process that requires simplifying the future time horizon into representative days or hours to complete in reasonable computation time. Portfolio results are further analyzed through a production cost model to provide more granular information about the reliability and GHG-reduction achievement of a given portfolio. The production cost model simulates every day in a year consecutively. The CERRO modeling approach used three models to build and evaluate resource portfolios.

- CEC's PLEXOS LT™ capacity expansion model builds the resource portfolio.
- CEC's PLEXOS™ production cost model runs the resource portfolio in an hourly model to ensure it meets SB 100 and GHG targets and that the resource build is sufficient to meet electricity demand in all hours.
- CEC's PLEXOS™ stochastic reliability simulation runs the resource portfolio through multiple weather years and generator outage possibilities to ensure it meets reliability targets.

There are a few key considerations and caveats that should be kept in mind when evaluating this analysis' results:

- The model simplifies many real-world constraints on transmission, distribution, and generator. In particular, it does not conduct powerflow analysis and accordingly does not consider transmission or distribution utilization, outside broad import limits, nor system voltage or stability needs. One primary simplification is assuming that there are no transmission/distribution limitations within a utility territory.
- It is also a zonal model at the balancing authority level and does not evaluate local generation, capacity, or other reliability needs.
  - Many important components of ratepayer costs, including transmission and distribution internal to utility areas, are not included as part of the resource selection process. The directional costs of different resource mixes are estimated

after the modeling process to put scenario costs in context, but these costs are not calculated for all scenarios, nor do they reflect actual costs that ratepayers could ultimately pay for the future system. Relative costs for scenarios therefore do not incorporate the differences in non-modeled costs.[194]

Additional Details on Scenario Results

The following sections mirror sections in the main *2025 CERRO* Report, but include added details and discussion on modeling results.

2035 Results

Meeting the 2035 GHG target of 20 MMT CO_2e by 2035 will require reducing annual gas generation by about 50 percent while load increases by 40 percent. About 50 GW of zero-carbon resources are built between 2030 and 2035, in addition to the 50 GW of planned resources built between 2025 and 2030. This represents about 10 GW of new generation every year through 2035. All scenarios well exceed reliability and SB 100 compliance metrics, suggesting GHG reductions will be the primary driver of new resource builds through 2035.

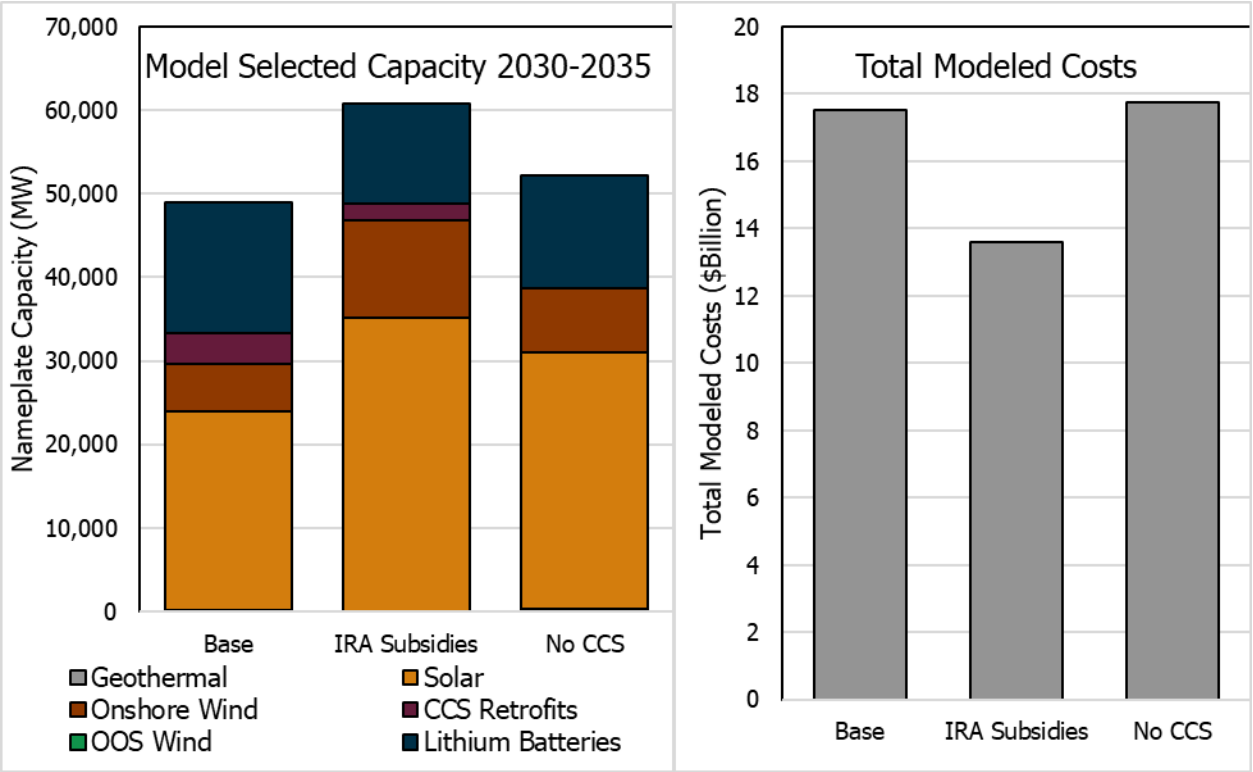
Scenarios generally build similar resource portfolios through 2035, as the only emerging resource picked up by the model before 2040 is CCS retrofits of existing natural gas facilities. The removal of the IRA subsidies raises modeled costs by about 30 percent and reduces the economic value of wind and solar PV relative to gas CCS or other firm resources. Compared to the base scenario, the IRA subsidies scenario builds about a third as much CCS and an additional 15 GW of wind and solar PV.

Removing CCS from the portfolio increases the amount of solar PV that needs to be built to meet GHG targets, but has a limited impact on costs in 2035. Solar, storage, and wind is generally a cost-effective way to meet the 20 MMT CO_2e interim GHG target in 2035, under current cost projections.

The graphs below show the resource build and modeled costs for the Base, IRA Subsidies, and NO CCS Scenarios. These scenarios were chosen to display as they have the most significant divergences.

194 Non-optimized costs are those that are not directly modeled – or "optimized" – in capacity expansion models. These include all utility costs for delivery, generation, and programs plus certain customer-borne costs.

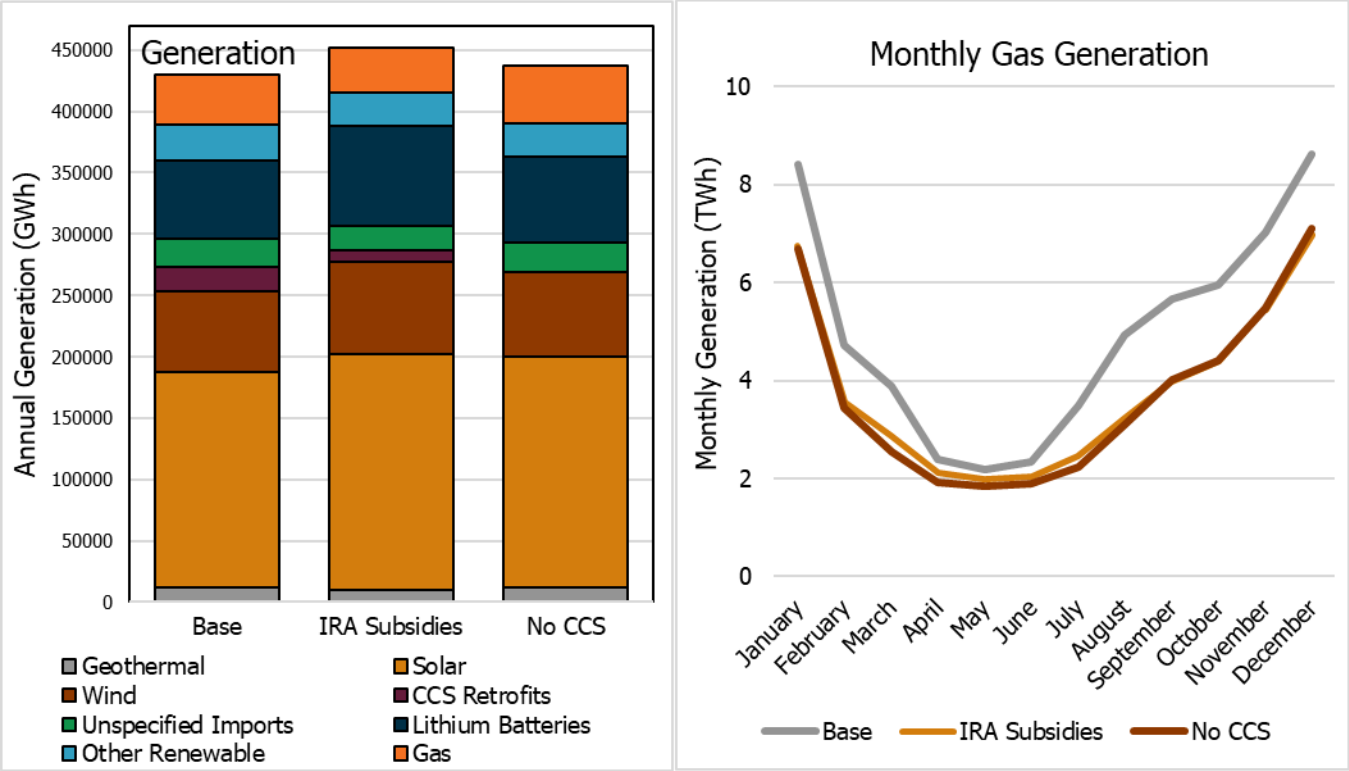
Figure 36: Model Capacity and Costs in 2035 for Select Scenarios



Source: CEC Staff

The graph on the left below shows the annual generation for the three scenarios. CCS Retrofits provide only about 5 percent of total generation, so scenarios are similar on an annual basis. Solar and wind together provide over half of generation and two thirds of energy. About 10-15 percent of wind and solar PV is curtailed. The significant buildout of solar PV and batteries reduces gas generation in summer to levels well below winter, even though summer still features significantly more load than winter in 2035 under the *2025 IEPR* Forecast.

Figure 37: Annual Generation by Fuel Type and Monthly Gas Generation in 2035



Source: CEC Staff

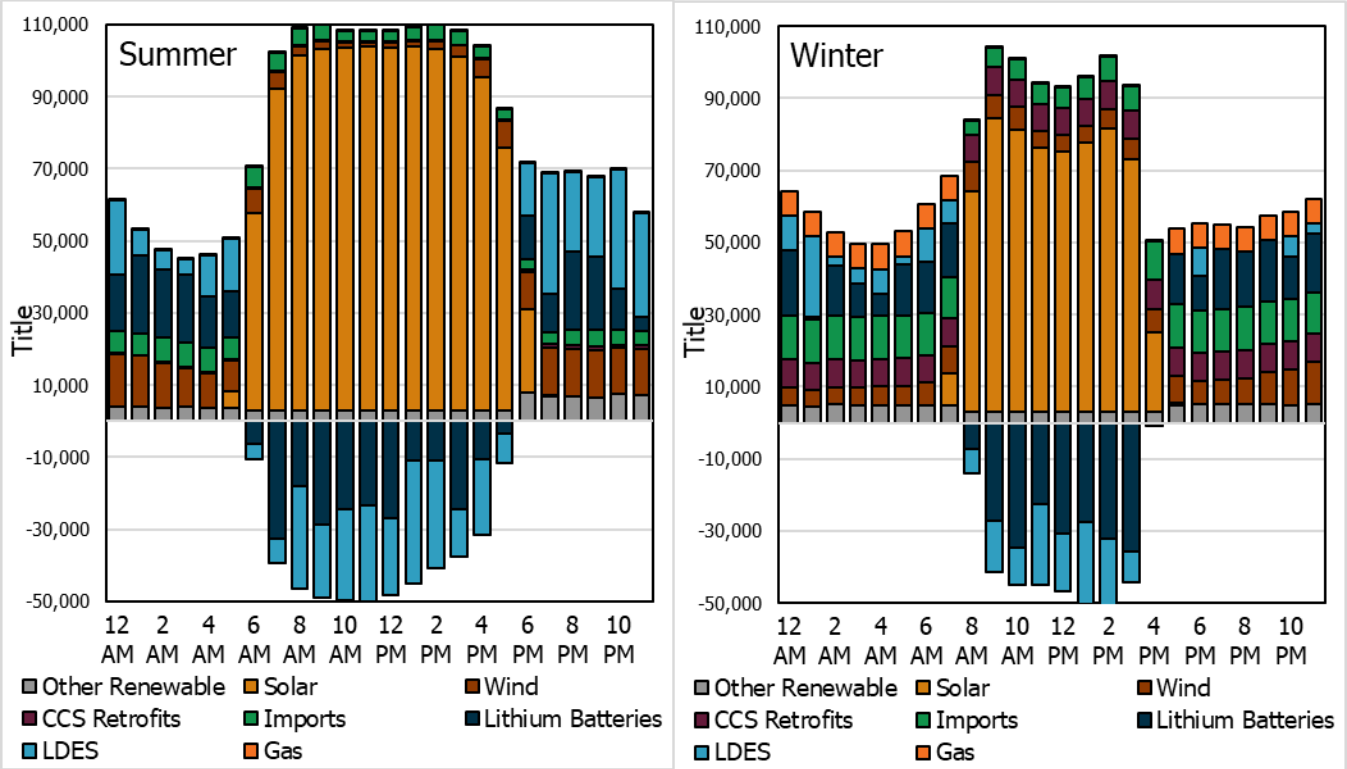
Feasibility Scenarios: Resource Adequacy

Because such a significant portion of the Base scenario resource mix is made up of CCS retrofits, which reduce GHG emissions without adding new generation capacity, the base scenario experiences more unserved energy in the RA model, making resource adequacy is a significant driver of resource build, increasing the total solar PV and battery build by 30 GW above what is strictly necessary to meet the GHG target. The graph on the left below compares the LOLE of the three feasibility scenarios, while the graph on the right below shows the month-hour distribution of unserved energy in the Base scenario. Unserved energy does not occur during hours with the highest net load across the weather years in any of the scenarios. Instead, unserved energy occurs in weather years where relatively high loads coincide with low-solar days, and the unserved energy generally occurs at night when batteries are depleted. The primary resource adequacy challenge in 2045 is meeting energy needs, even with the entire gas fleet retained, and meeting load growth reliably will require extensive buildout of new generation resources.

Price Reduction Scenarios: LDES Performance on Summer and Winter Days

Medium-duration batteries (8-12 hour capacity) tend to be more effective at reducing GHG than longer-duration batteries with low efficiencies. In a solar-heavy renewable system like California's, longer duration batteries with low efficiencies tend to be less effective in winter than summer and thus the model must still rely heavily on CCS retrofits to meet the GHG target. In the summer, the sun shines for ten to twelve hours a day, meaning a twelve-hour LDES battery can regularly reach a full state of charge in this season. In winter, by contrast, even on good solar days the sun shines for only seven to eight hours a day. Thus, LDES never gets above a 50 percent state of charge between December and January, because it never has more than about 8 hours in which to charge. Adding additional hours of battery capacity does not improve its ability to support the system in winter, because the main limiting factor in winter is charging capacity and not battery energy capacity. Low-cost batteries do, however, reduce overall costs and reduce the amount of gas burned in summer and fall from both retrofitted and unretrofitted plants. The graphs below show the generation mix on a typical summer and typical winter day in the low-cost LDES scenario, with loads and solar PV generation that are about average in these seasons.

Figure 38: Hourly Generation in LDES Scenario

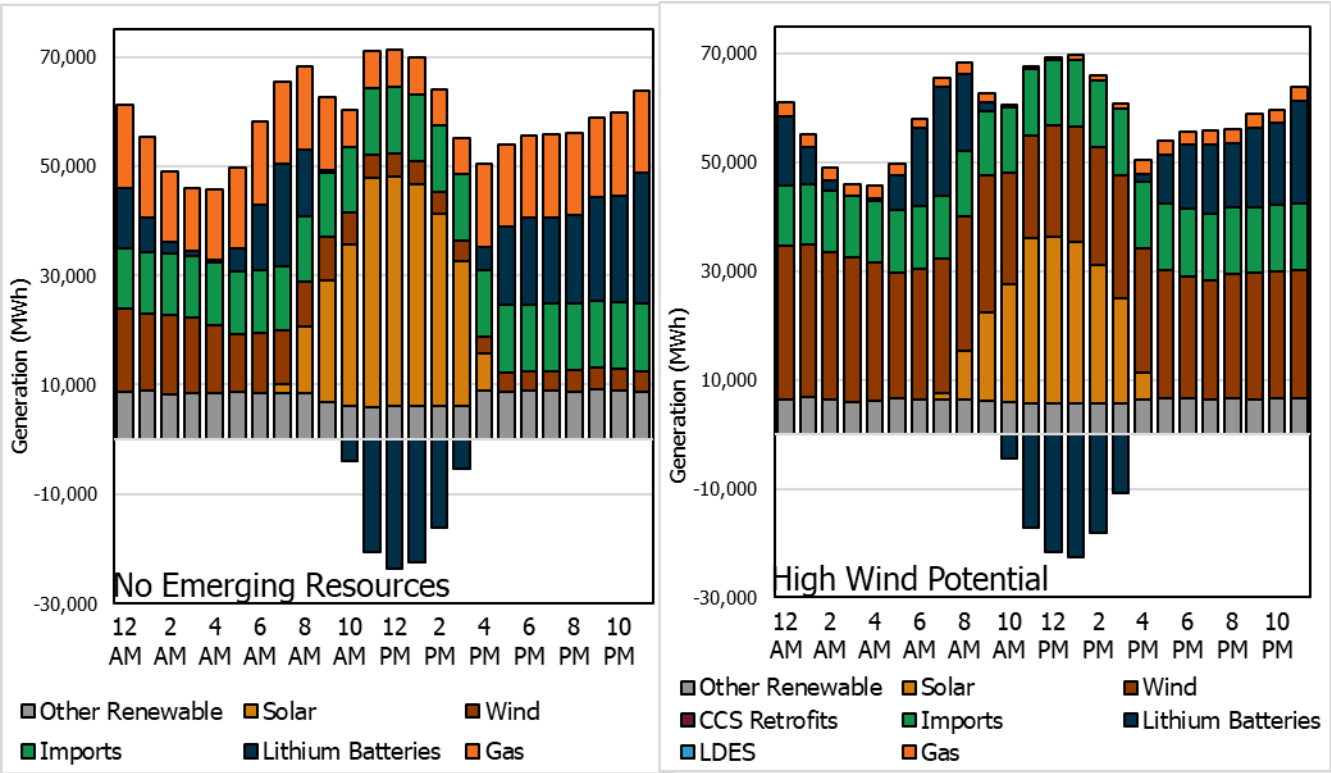


Source: CEC Staff

Changes in Wind Potential: Hourly Generation Patterns on Low-Solar Days

The model values resource diversity in part because solar PV production is vulnerable to cloud cover, and without complementary zero-carbon resources like wind, geothermal, or CCS the model must burn a significant amount of gas on days when solar PV production is low. The graph below shows one of these low-solar days in both the No Emerging Resources and the High Wind Potential scenario. In the left graph showing the No Emerging Resources scenario, a 120 GW solar PV fleet barely reaches 30 GW of generation in the middle of the day. To make up for this, the combined cycle fleet runs at near-full capacity overnight and generates a significant amount of energy in the middle of the day. This single day alone consumes almost 3 percent of the entire GHG budget for the year, making the total GHG production very sensitive to the exact number of days with high cloud cover. Cloudy low-solar days usually coincide with stormy, high-wind days, however, so in the High Wind Potential scenario wind is able to provide a complimentary generation profile and comparatively little gas is burned throughout the day. This allows the model to build fewer resources overall and save generation costs.

Figure 39: Hourly Generation for High Wind Potential Scenario



Source: CEC Staff

Appendix D: Loss of Load Expectation Analysis

This appendix discussed CEC's probabilistic reliability assessment approach, detailing models and assumptions. It also presents some additional results and details for 2031 & 2036.

Approach: Model Development

To evaluate the reliability of California's electric system under a variety of scenarios, a probabilistic RA simulation was conducted in the PLEXOS modeling software. This software is also utilized by other California entities for reliability assessments, including the California ISO. This California-specific RA model was developed using public information to the maximum extent possible. Where relevant, CEC aligned key inputs and assumptions with the CPUC Resource Adequacy Study and the California ISO Summer Reliability Assessments.

CEC's stochastic RA methodology evaluates hundreds of iterations for the full year at an hourly scale to capture system variability across a range of weather years impacting load, solar PV and wind generation, and generation resource outages. This results in different simulations for each scenario with unique load, variable resource, and generator outages in each run. The model dispatches resources to co-optimize demand and reserve requirements subject to operational constraints reflecting the California system and selected scenario assumptions. The resulting distribution of unserved load is used to calculate the system's LOLE by scenario.

Modeling Inputs and Assumptions

The CEC's RA model represents California power plants in detail while power plants outside the state are represented as generic imports. California is modeled as seven regions, including the three investor-owned utility service areas (PG&E, SCE, and SDG&E) grouped together as California ISO, as well as four publicly owned utility BAs (Balancing Authority of Northern California, Turlock Irrigation District, Los Angeles Department of Water and Power, and Imperial Irrigation District). Transmission is represented between the regions. The California ISO regions have a total import limit of 11,665 MW per California ISO's Maximum Import Capability limit. This import limit is reduced to 5,500 MW during morning and evening reliability risk hours (i.e., H8-11, H16-22) throughout the year to reflect California ISO's net import limit.[195] Imports into

195 California Independent System Operator. May 2025. *2025 Summer Loads and Resources Assessment*. California ISO, https://www.caiso.com/documents/2025-summer-loads-and-resources-assessment.pdf.

California, as a whole, are limited to 12,450 MW in all hours of the day, subject to monthly energy limits.

The RA model utilizes the *2025 IEPR* Forecast. Underlying demand and behind-the-meter solar PV are weather correlated and vary across 17 weather years representing weather in 2007 to 2023. All other load modifiers (i.e., building electrification, electric vehicles, and energy efficiency) do not vary by weather year.[196]

All resource additions and retirements for both California ISO and non-California ISO regions were sourced from Form EIA 930, Form EIA 860, QFER, and the California ISO Master Control Area Generating Capability List. Resource additions are based on CPUC procurement order NQC capacity requirements for LSEs. The retirements for existing plants in the database utilized in this analysis align with retirements identified in From EIA 860 or otherwise announced.

196 *See* 2025 IEPR CED Forecast.

A summary of RA model inputs and assumptions are provided below in Table 39.

Table 39: Additional RA Model Inputs and Assumptions

Model Input	Data Source	Description
Hourly Demand Profiles	CPUC Weather-Sensitive Load	• Shapes based on 2022 CPUC shapes • Energy and peaks scaled to *2025 IEPR* CED • Load modifiers from *2025 IEPR* CED
Resource Outage Rates	NERC[197] Generating Availability Data System California ISO Daily Outage Reports	Forced outage rates and maintenance rates are based on U.S. averages, which vary by plant size and fuel type. Battery data based on analysis of California ISO daily outage reports.
Plant Capacities	QFER	QFER Data reported in 2025
Solar Shapes, 2007-2023	National Renewable Energy Laboratory (NREL) National Solar Radiation Database	Unique solar PV profiles developed using the NREL System Advisor Model for each significant existing solar PV plant with capacity-weighted aggregation to regional profiles.
Wind Shapes, 2007-2023	NREL Wind Toolkit (2007-2014) NREL Bias Correcting High Resolution Rapid Refresh (2015-2023)	Simulated wind production profiles were calibrated to align with actual monthly generation totals from California ISO subpoena data and checked against monthly generation totals reported to EIA 923
Transmission Line Ratings	WECC Path Limits	Applied to imports from WECC regions, Path 46, and for transfers within California.
Hydroelectric Monthly Maximum Ratings	Hourly hydro generation reported in Form EIA-930	Hydro resources are limited in maximum output based on historical observations, wherein fleetwide maximum generation is well below fleetwide installed capacity. The 2019 hydro year, a relatively average hydro year, is used across simulations.
Hydroelectric Energy Budget	Monthly hydro generation reported in Form EIA-923, QFER	Maximum hydro generation within a month based on historic generation patterns.
Operating Reserves	6% of Load	Assumes operating reserves of 6 percent of net load (after reductions for behind the meter-PV) are held during loss of load events. All other reserves are assumed to be curtailed prior to load shed.

Source: CEC staff

197 North American Electric Reliability Corporation

Additional Details for 2031 and 2036 Resource Adequacy Results

Characterizing the Timing of System Risk

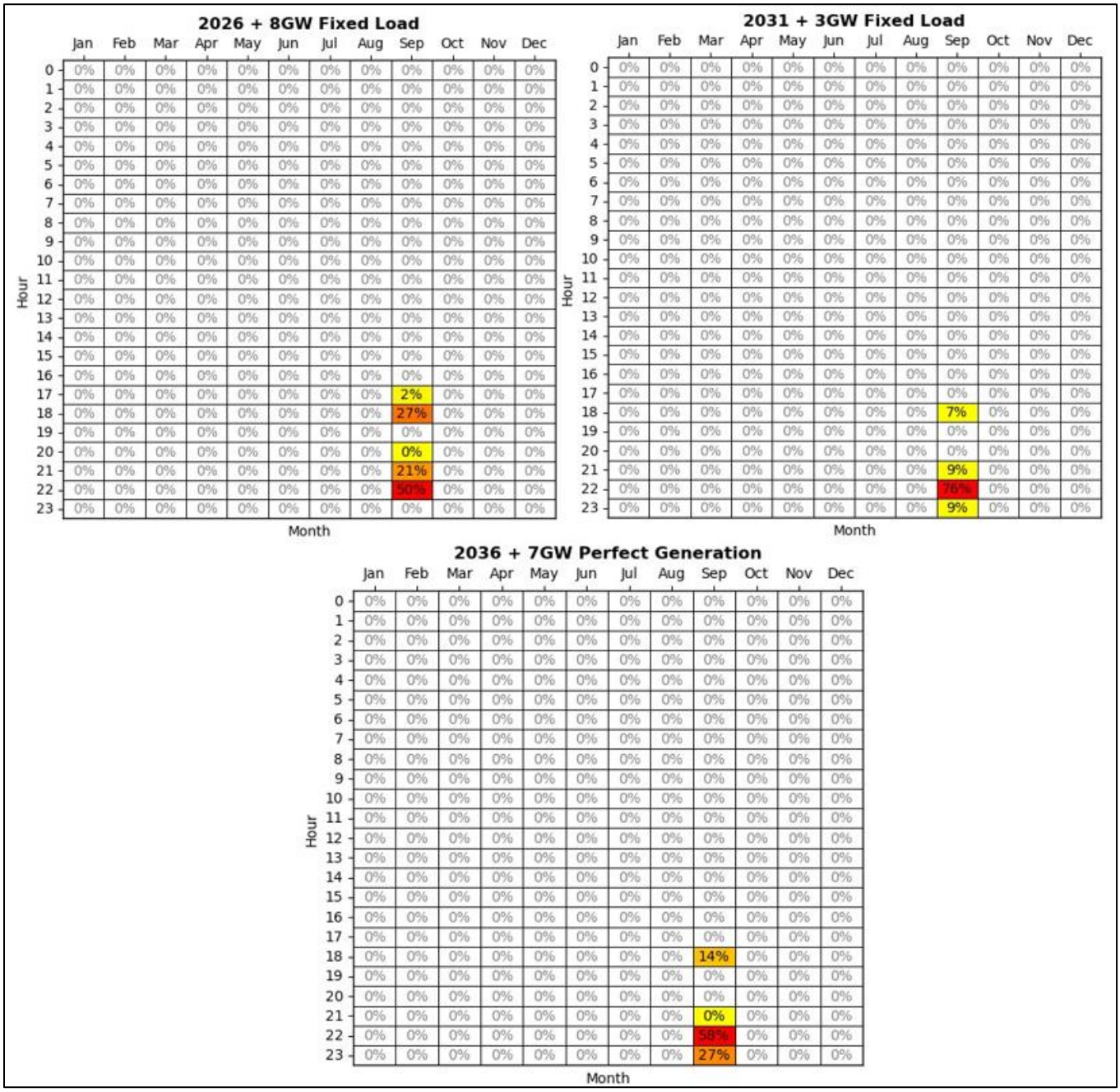
California's power system risk has historically been defined by periods of high temperature, low solar PV production, and low hydro availability. Near-term resource adequacy risk remains oriented around similar, or even more extreme, heat waves. These heat waves tend to dissipate as the sun sets, meaning that resource adequacy events are relatively short.

As California's power system increasingly electrifies buildings via fuel substitution, these historically significant events will be replaced by a new set of challenges. In addition to heat waves driving shortfalls, a combination of cold snaps and cloudy conditions will also contribute to grid stress. Prior analyses, for example the *2025 CERRO,* have indicated that by the 2030s, California's system likely becomes a winter-risk system or dual-risk across the winter and summer months, depending on the scenario. However, the new *2025 IEPR* Forecast has changed this expectation with different assumptions around winter demand.

Figure 40 below indicates the percentage of unserved energy from across the year that occurs within any given hour. These figures are shown for study years with LOLE close to 0.1 days/year, achieved by adding either firm load or perfect generation to the system until the LOLE criteria is achieved. It should be noted that these results are provided for a system that was brought to the 0.1 days/year LOLE criterion by adding a constant, firm load (or perfect generation) applied equally to all hours. For that reason, the demand profile or generator mix is not necessarily representative of the current or future demand or generation mix. While this is standard practice in resource adequacy modeling, actual risk periods may be different as load grows and resources retire.

The percentages in each table add up to 100 percent within any study year and provide an indication of when resource adequacy risk occurs. The chart shows 2026, 2031 and 2036 as having summer risk with the summer risk primarily occurring in evening hours of September.

Figure 40: Distribution of Unserved Energy (MWh) Across the Year for Each Study Year



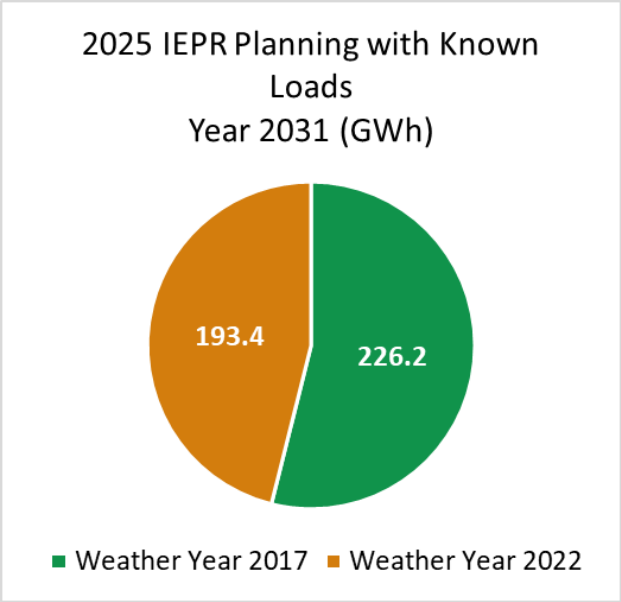
Source: CEC staff

Further analysis of these shortfall events indicates they extend from 1 hour to 3 hours in length, at the median, closer to 1 hour in the near term and increasing in duration in future years.

Unserved Energy by Weather Year

The 2025 IEPR Planning with Known Loads Scenario for the year 2031 has a 0.150 LOLE, relying on resources to be procured through 2028. Figure 41 indicates the distribution of this unserved energy by weather year. The weather years used in the reliability analysis were from 2007 to 2023. Weather years 2017 and 2022 had the largest amount of unserved energy with model year 2031 at 226.2 GWh and 193.4 GWh, respectively. These weather years experienced extensive heat waves in the summer months.

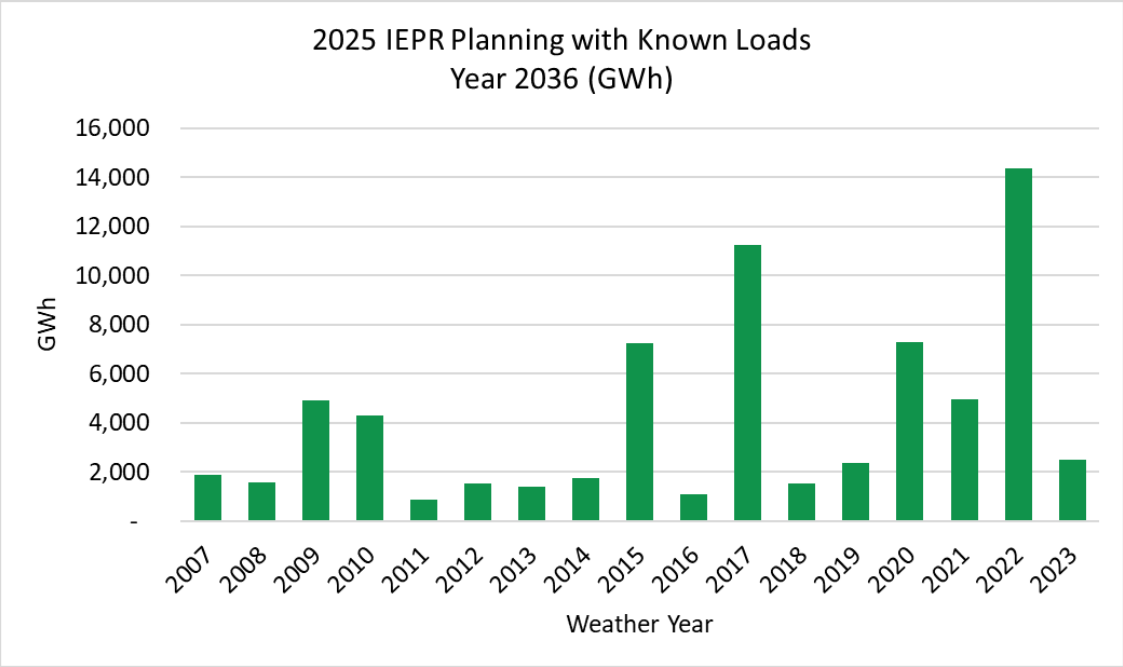
Figure 41: Year 2031 - Distribution of Unserved Energy by Weather Year



Source: CEC staff

For model year 2036, the 2025 IEPR Planning with Known Loads scenario had a significant amount of unserved energy. This is largely due to the CPUC MTR Procurement orders only extending up to the year 2028 as modeled. As seen in Figure 42, weather years 2017 and 2022 also show a significant amount of unserved energy, which follows the trend displayed by model year 2031. Weather years 2015 and 2020 follow behind due to these weather years also experiencing high heat summers.

Figure 42: Year 2036 – Distribution of Unserved Energy by Weather Year



Source: CEC staff

APPENDIX E: Abbreviations

Acronym	Definition
AB	Assembly Bill
AI	Artificial Intelligence
ATB	Annual Technology Baseline
BA	Balancing Authority
BAA	Balancing Authority Area
BANC	Balancing Authority of Northern California
CARB	California Air Resources Board
CARBOB	California Reformulated Gasoline Blendstock for Oxygenate Blending
CCA	Community Choice Aggregator
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CDD	Cooling Degree Day
CDTFA	California Department of Tax and Fee Administration
CEC	California Energy Commission
CED	California Energy Demand Forecast
CERRO	California Energy Resource and Reliability Outlook
CGR	California Gas Report
CO_2	Carbon Dioxide
COI	California-Oregon Intertie
CPC	Climate Prediction Center
CPUC	California Public Utilities Commission
CREPC	Committee on Regional Electric Power Cooperation

Acronym	Definition
CREPC TC	Committee on Regional Electric Power Cooperation Transmission Collaborative
DAC	Direct Air Capture
DCPP	Diablo Canyon Power Plant
DEBA	Distributed Electricity Backup Assets
DER	Distributed Energy Resources
DR	Demand Response
DSGS	Demand-Side Grid Support
DWR	Department of Water Resources
EDAM	Extended Day-Ahead Market
EGS	Enhanced Geothermal System
EIA	Energy Information Administration
EIM	Energy Imbalance Market
ELCC	Effective Load Carrying Capability
ENSO	El Niño Southern Oscillation
EPA	Environmental Protection Agency
EPIC	Electric Program Investment Charge
EqSCR	Equivalent Short Circuit Ratio
ERCOT	Electric Reliability Council of Texas
ESSRRP	Electricity Supply Strategic Reliability Reserve Program
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GHG EI	Greenhouse Gas Emissions Inventory
GW	Gigawatt
GWh	Gigawatt-hour

Acronym	Definition
HDD	Heating Degree Day
HE	Hour Ending
IBR	Inverter-Based Resource
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
IOU	Investor-Owned Utility
IRA	Inflation Reduction Act
IRP	Integrated Resource Planning
ISO	Independent System Operator
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LDES	Long-Duration Energy Storage
LOLE	Loss of Load Expectation
LSE	Load-Serving Entity
LSTM	Long Short-Term Memory
MAPE	Mean Absolute Percentage Error
MMBtu	Million British Thermal Units
MMcfd	Million Cubic Feet per Day
MMT	Million Metric Tons
MW	Megawatt
MWD	Metropolitan Water District of Southern California
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation

Acronym	Definition
NOAA	National Oceanic and Atmospheric Administration
NQC	Net Qualifying Capacity
NREL	National Renewable Energy Laboratory
OOS	Out of State
OSW	Offshore Wind
OTC	Once-Through Cooling
PG&E	Pacific Gas and Electric Company
PIIRA	Petroleum Industry Information Reporting Act
PLEXOS LT	PLEXOS Long-Term Capacity Expansion Model
POI	Point of Interconnection
POU	Publicly Owned Utility
PRM	Planning Reserve Margin
PSP	Preferred System Plan
PV	Photovoltaic
QFER	Quarterly Fuels and Electricity Report
RA	Resource Adequacy
RPS	Renewables Portfolio Standard
SB	Senate Bill
SCR	Short Circuit Ratio
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SMR	Small Modular Reactor
SoCalGas	Southern California Gas Company
SRR	Strategic Reliability Reserve
SWIP	Southwest Intertie Project

Acronym	Definition
TAC	Transmission Access Charge
TID	Turlock Irrigation District
TRL	Technology Readiness Level
U.S.	United States
VEA	Valley Electric Association
VPP	Virtual Power Plant
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market
WI	Western Interconnection

APPENDIX F: Glossary

Term	Definition
Ancillary Services	Grid support services that help maintain reliable operation of the electric system, such as voltage control and frequency regulation.
Balancing Authority	An organization responsible for balancing electricity supply and demand within a specific geographic area in real time.
Balancing Authority Area (BAA)	The geographic area over which a balancing authority is responsible for maintaining the balance between electricity supply and demand.
Black Start Capability	The ability of a power plant to restart and begin generating electricity without relying on electricity from the grid.
Capacity Expansion Planning	A modeling process used to evaluate what new electricity resources may be needed to meet future demand and policy goals.
Capacity Value	The contribution a resource makes toward meeting peak electricity demand and reliability needs.
Carbon Capture and Storage (CCS)	A technology that captures carbon dioxide emissions and stores them underground to prevent their release into the atmosphere.
Coincident Peak	The electricity demand within a service area at the time the overall system reaches its peak demand.
Contingency Resources	Emergency or backup resources that may be used during extreme grid conditions to help maintain reliability.
Data Center	A facility that houses computer servers and related equipment used to process, store, and manage digital information.
Demand Flexibility	The ability to reduce, shift, or modify electricity use in response to grid conditions.
Demand Response	Programs that encourage customers to reduce or shift electricity use during periods of high demand or grid stress.
Derate	A reduction in the amount of electricity a generating resource can provide compared to its normal capability.
Electrification	The replacement of technologies that use fossil fuels with technologies powered by electricity.
El Niño Southern Oscillation (ENSO)	A recurring climate pattern in the Pacific Ocean that influences temperature and precipitation patterns across North America.
Enhanced Geothermal	Geothermal technology that improves or creates underground pathways to access heat resources for electricity generation.
Energy Imbalance Market (EIM)	A regional electricity market that allows participating utilities to buy and sell electricity in near real time.

Term	Definition
Extended Day-Ahead Market (EDAM)	A regional electricity market that allows participants to buy and sell electricity one day before it is needed.
Firm Zero-Carbon Resource	A resource that can reliably generate electricity when needed while producing little or no greenhouse gas emissions.
Fossil Gas Plant	A power plant that generates electricity using natural gas as its primary fuel source.
Fusion Energy	A developing energy technology that generates power by combining atomic nuclei.
Grid Strength	The ability of an electric system to maintain stable voltage and frequency during disturbances.
Hydroelectric Resource	A facility that generates electricity using flowing or stored water.
Inverter-Based Resource (IBR)	A resource such as solar, wind, or battery storage that connects to the grid through power electronics rather than a traditional generator.
Known Load	Future electricity demand identified through utility planning processes that may not yet be fully reflected in statewide forecasts.
Load Forecast	A projection of future electricity demand.
Long-Duration Energy Storage (LDES)	Energy storage capable of discharging electricity for extended periods, typically longer than conventional battery systems.
Loss of Load Expectation (LOLE)	A reliability metric that estimates how often electricity demand could exceed available supply.
Managed Net Load	Electricity demand after accounting for the effects of demand modifiers and expected resource contributions used in planning forecasts.
Net Load	Electricity demand remaining after accounting for generation from variable resources such as solar and wind.
Noncoincident Peak	The highest electricity demand reached within an individual service area, regardless of when the overall system peak occurs.
Offshore Wind	Wind turbines located in ocean waters that generate electricity from offshore wind resources.
Peak Demand	The highest level of electricity demand during a specified period.
Planning Reserve Margin (PRM)	Additional electricity supply maintained above expected peak demand to help ensure reliability.
Probabilistic Reliability Assessment	A reliability analysis that evaluates a range of possible future conditions and uncertainties rather than a single scenario.
Resource Adequacy (RA)	A regulatory framework designed to ensure sufficient electricity resources are available to meet demand and reliability requirements.
Resource Stack Analysis	A method of comparing available electricity supply with expected demand under various conditions and scenarios.

Term	Definition
Small Modular Reactor (SMR)	A smaller nuclear reactor design intended to be manufactured in modules and deployed more flexibly than traditional nuclear plants.
Supply Margin	The difference between available electricity supply and expected demand.
Technology Readiness Level (TRL)	A scale used to describe the maturity of a technology, from early-stage research to commercial deployment.
Unserved Energy	Electricity demand that cannot be met because available supply is insufficient.
Utility-Scale Battery Storage	Large battery systems connected to the electric grid that store electricity for later use.
Voltage Instability	A condition in which the electric system cannot maintain stable voltage levels, potentially affecting reliability.
Western Interconnection	The interconnected electric grid serving the western United States, western Canada, and parts of Mexico.