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California Energy Commission

DRAFT STAFF REPORT

California Energy Resource and Reliability Outlook, 2025

Reliability Analysis Branch
Energy Assessments Division

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California Energy Commission

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ABSTRACT

The *California Energy Resource and Reliability Outlook* is the California Energy Commission's comprehensive, statewide assessment of electric and gas energy resource planning and reliability for the upcoming summer and midterm, spanning the next five years.

The intent of this *California Energy Resource and Reliability Outlook* is to provide a complete picture of planning and reliability for all investor-owned utilities and publicly owned utilities in California for the period of 2025–2029, based on available data. In contrast to the 2024 report, this report will include petroleum resources.

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's (CEC) comprehensive, statewide assessment of energy resource planning and reliability across the electric system, fossil gas system, and petroleum supply. This report examines California electric utility resource plans in relation to grid reliability planning standards, analyzes potential scenarios including extreme weather events similar to the heat waves in 2020 and 2022, and evaluates the impact of factors such as resource delays and potential infrastructure disruptions from wildfires. The report also reviews 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, providing a broad picture of California's energy sectors and resource adequacy.

Updated 2025 Summer Conditions

This report provides an overview of the conditions shaping the California energy landscape with a focus on the upcoming 2025 summer, 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, with projected peak demand comparable to the historical 2023 and 2024 peaks.
- Westwide weather: Summer climate forecasting predicts above normal temperatures in the entirety of the West this year, especially in California, Oregon, Washington, Idaho, Nevada, Utah, and Arizona. This prediction means that widespread heat events and challenging grid conditions are likely. A westwide heat event would be a particularly challenging scenario, reducing imports available to California when they are needed most.
- Westwide wildfire: Summer fire season can also impact reliability because of damage, interruption, or derating of equipment as a result of fires or indirect impacts, reducing the availability of supply or impacting transmission capacity into or within California. Based on the current early summer forecasts, significant fire potential is above normal in many areas of California, Oregon and Nevada in June and July. These are areas traversed by transmission paths feeding the major California load centers, including California's critical northwestern import paths in Oregon and Nevada. Much of British Columbia is in abnormally dry or moderate drought conditions with pockets of severe drought. Wildfire risk conditions are expected to remain normal there through April, but above normal wildfire potential is expected in most of British Columbia by June. The wildfire outlook will only cover those months with available forecasting at the time of this report writing.

The summer 2025 California outlook is cautiously optimistic for electric and fossil gas reliability, but contingency resources may be needed during coincident extreme events.

- New resources: California continues to grow its energy resource portfolio. Between January 2019 and December 2024, the state has added more than 25 gigawatts (GW) of new clean energy capacity, signaling a notable uptick in new resource additions. These additions are critical to meeting statewide reliability needs and include more than 14 GW of battery energy storage capacity, 12 GW of which are utility-scale battery storage, and more than 10 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 is declining.

California has added nearly 25 gigawatts of new resources since January 2019, signaling a promising uptick in new resource additions.

- Hydroelectric capacity conditions: Hydroelectric resources provide an average of 14.57 percent of the state's electricity needs, based on data collected 2001 through 2023, and up to 7,000 MW of peak capacity to support reliability. The Department of Water Resource's second snow survey of 2025 indicated the statewide snowpack was at 65 percent of average, a decline from 108 percent on January 1 due to an exceptionally dry January. However, reservoir levels across the state remain above average as of February 14.

Electric and Gas Reliability

California is experiencing a substantial shift in conditions affecting the electric grid as it transitions to a clean energy future while confronting the impacts of climate change. SB 100 (De León, Chapter 312, Statutes of 2018) set an ambitious target of powering all retail electricity sold in California with renewable and zero-carbon resources by 2045 to reduce greenhouse gas emissions and help improve air quality and public health. The implementation of SB 100 is resulting in the addition of unprecedented quantities of clean energy resources, primarily utility-scale solar and storage. As of 2022, non-fossil-fuel sources now make up 61 percent of retail electricity sales in California.

At the same time, climate change is causing substantial variability in weather patterns and an increase in climate-driven extreme events, which is resulting in more challenges to maintaining grid reliability.

- In 2020, a westwide heat event resulted in rotating outages on August 14 and 15. In 2021, dry conditions resulted in a wildfire in Oregon that impacted transmission lines, resulting in a loss of 3,000 MW of imports to the California ISO territory and 4,000 MW of overall import capacity to the state.
- In 2022, California experienced record high temperatures between August 31 and September 9. On September 6, 2022, the California ISO recorded a new record peak load at 52,061 MW, nearly 2,000 MW higher than the previous record.
- In late July 2023, parts of the West outside California experienced extreme heat, driving challenging and fast-moving market dynamics.
- In 2024, the Western Interconnection reached an all-time peak demand of 167,988 MW on July 10, driven by prolonged extreme heat across the region.

Western Coordination

California is part of a complex electrical system within the Western Interconnection, a network of transmission lines linking diverse generating resources to loads throughout the region. As such, coordination with many entities throughout the Western Interconnection is essential to ensuring efficient electricity market operation and transmission access. In the *2022 Integrated Energy Policy Report (IEPR) Update*, the CEC highlighted the importance of increasing integration of the western electricity systems through regional system planning and operation, with a particular focus on implementing new regional electricity markets such as the Extended Day-Ahead Market, encouraging transmission investment, and balancing energy supply and demand.

Since the *2022 IEPR Update,* the most significant progress is the ongoing work on the West-Wide Governance Pathways Initiative. The Pathways Initiative would create a new regional organization that would maintain authority over the rules that govern the California ISO's electricity markets. At its essence, this initiative elevates the governance of the California ISO's already successful Western Energy Imbalance Market and the upcoming Extended Day-Ahead Market to a new regional organization. The Western Energy Imbalance Market is a spot market for electricity that operates throughout the West. This market allows for entities to buy and sell electricity on a sub-hourly basis. The Extended Day-Ahead Market would allow more entities to participate in a 24-hour forward market for energy that the California ISO already operates in its footprint. The change in governance structure that the Pathways Initiative could achieve may allow for increased coordination across the West if more entities participating in Western Energy Imbalance Market voluntarily decide to participate in Extended Day-Ahead Market.

The Western Interconnection is a synchronous machine that allows 11 western states and two Canadian provinces to operate their generation and transmission at the same frequency.

The California ISO reports that Western Energy Imbalance Market has saved $6.6 billion for market participants since inception, with fourth quarter 2024 benefits of $374 million. This success signals to potential Extended Day-Ahead Market participants that the expanded market potential from the Extended Day-Ahead Market stands to unlock significant added value.

The Federal Energy Regulatory Commission (FERC), which, among other resources, regulates the interstate transmission of electricity, has approved the Extended Day-Ahead Market tariff, which is set to begin operating in 2026. California utilities, including investor-owned utilities, Los Angeles Department of Water and Power, the Balancing Authority of Northern California, and others have announced their intention to participate in the Extended Day-Ahead Market, as have PacifiCorp, Portland General Electric, and NV Energy.

Elsewhere in the Western Interconnection, the Southwest Power Pool (another independent system operator that primarily operates in the Eastern Interconnection) is designing a competing day-ahead market referred to as Markets+. In January 2025, the FERC conditionally approved Southwest Power Pool's Markets+ tariff.

Further increasing system resilience and the benefits of markets are at least eight new large 500-kilovolt (kV) transmission additions already operating, close to operation or under construction, including TransWest Express, Greenlink, Gateway South and West, and the Southwest Intertie. Taken together, resource and transmission additions, coupled with ongoing work to implement new regional electricity markets, have improved the reliability outlook for California.

Fossil Gas Plant Performance

Fossil gas power plants supply a significant portion of the peaking capacity and ramping requirements of California's electric grid and are critical to system reliability. 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.

Utilities are required to plan for resources beyond expected peak demand, which is known as *planning margins*. These planning margins consider an average level of fossil gas plant derates, although those numbers have not been revisited for years. An assessment of fossil gas plant derate types and timing during peak summer periods from 2021 to 2024, as explained below, provides insight into the impact that heat events have on the performance of the fossil gas fleet. Understanding how fossil gas plants respond during heat events will provide a better understanding of how these resources can impact system reliability.

Heat waves (California ISO heat event days) during summer months (July–September) in 2021–2024 during peak hours (4 p.m. through 9:59 p.m.) were associated with decreased derates of fossil gas plants by nearly 211 MW, or about 8 percent on average, compared to non-event days. However, some months and years saw increases. Nearly all heat events were attributable to ambient temperature derates, compared to non-heat-event days. During this period, the CEC observed different types of heat events and different levels of fossil gas derates. For example, in 2023, heat events increased derates by about 19 percent, or 244 MW, on average, compared to non-heat-event days. Staff will continue to analyze how heat events can affect fossil gas performance and availability.

Probabilistic Reliability Analysis

This report includes a statewide probabilistic assessment for 2025 to 2040 using the CEC's *2024 IEPR Update* forecast and the California Public Utilities Commission's (CPUC's) 2023 Preferred System Plan, the planning resource portfolio, for the California ISO territory. The target for probabilistic assessments is to evaluate whether resource planning is likely to achieve the reliability standard of one day of outage per 10 years. California is projected to meet the reliability standard under the current forecast in 2025 through 2035, assuming all planned resources come online. Because of increased demand in the 2030s compared to the previous demand forecasts, the demand for energy may outpace the currently planned-for supply in 2040. In 2035, the system risk begins shifting from summer to winter because of increased electrification loads, such as heat pumps and electric vehicle charging. By 2040, the primary time frame for system risks is the winter months, when solar production is lower.

Loss of Load Expectation analysis assesses whether a resource portfolio achieves a 1 day of outage per 10 years standard. The approach considers the probability of a wide range of key variables and relies on thousands of simulations drawing randomly from different combinations of demand, solar, and wind profiles, as well as unexpected plant outages.

Resource Stack Analysis

To determine the potential need for contingency resources under extreme grid conditions, CEC staff conducted a resource stack analysis comparing anticipated electric supply to projected demand during the peak summer months in the California ISO balancing area and statewide.

The resource stack analysis demonstrates significant improvements since the 2024 SB 846 Fourth Quarterly *Joint Agency Reliability Planning Assessment* because of more than 3,300 MW increase in total supply that includes more than 3,000 MW in existing resources, and more than 330 MW in new battery capacity. The additional resources, combined with only a modest 180 MW increase in the September 2025 peak demand forecast, indicate that California is expected to maintain surplus margins under all system conditions.

Under a planning standard/average scenario, the California ISO balancing area is forecasted to have a surplus of more than 5,500 MW. Even under the worst-case scenario, assuming a 40 percent resource delay during a 2022-equivalent event, staff projects a surplus of more than 700 MW. However, this projection does not account for coincident fire risk, which continues to pose additional reliability challenges and could reduce transmission capacity by up to 4,000 MW, potentially increasing the need for contingency resources during extreme events.

The statewide assessment indicates resource requirements of 64,500 MW under planning standard/average conditions and 69,200 MW under 2022 equivalent conditions. These anticipated system conditions are held against a total reliable statewide supply capacity of

73,400 MW, which would provide a 4,000 MW margin even in extreme events and create better coordination opportunities among California balancing areas.

The statewide assessment indicates total reliable statewide capacity is sufficient for average conditions and for events similar to what the state experienced in 2020 and 2022.

Lastly, it is crucial to acknowledge that real-time conditions may deviate from projections because of factors such as construction delays, weather, permitting issues, and extended outages. Thus, while the resource stack analysis offers valuable insights, it is essential for the state to continue to monitor system conditions and prepare for unforeseen situations where contingency resources, such as additional generation, demand response, and energy storage may be needed.

Gas System Reliability

CEC staff analyzed supply and demand conditions for the Pacific Gas and Electric Company's (PG&E's) and Southern California Gas Company's (SoCalGas's) gas pipeline systems for summer 2025. Staff developed this analysis to inform policy makers and the public about the risk of service interruptions, particularly as they may impact availability of gas for electric generation. Absent a multiday hot weather event combined with any additional infrastructure outages, the risk to PG&E and SoCalGas service reliability is low.

CEC staff expects that PG&E and SoCalGas will meet demand with no estimated curtailments during summer 2025. Furthermore, CEC staff expects that PG&E and SoCalGas will bring their underground gas storage facilities to full capacity by the start of the winter 2025–2026 gas season, November 1.

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

While summer fossil gas prices in California have been stable in recent years, unexpected events or conditions such as a pipeline outage or spike in gas demand due to a multiday heat wave can have an impact. Prices could become more volatile if something unusual occurs, such as an emergency event that reduces supply or increases demand or both.

Emergency Preparedness

In response to the Infrastructure Investment and Jobs Act requirement to update existing state energy security plans, the CEC began updating the state's existing Energy Assurance Plan in 2022 to create the California Energy Security Plan. The energy security plans are to be organized around the Section 40108 provisions of the act as follows:

- Address all energy sources.
- Provide an updated state energy profile.
- Provide an updated energy sector risk assessment and energy sector hazard assessment.
- Address multistate, tribal, and regional coordination.

In 2023 and 2024, the U.S. Department of Energy (U.S. DOE) notified CEC staff that the submitted draft California Energy Security Plans for each year met all requirements. This year, California plans to submit an updated California Energy Security Plan to the U.S. DOE to meet all requirements.

Petroleum System Reliability

As of March 2024, nine California refineries produced roughly 5 million barrels of California Reformulated Gasoline Blendstock for Oxygenate Blending per week. Moreover, supply of gasoline in the state is highly regionalized. Except for one small refinery in Central California (Kern Energy in Bakersfield), nearly all in-state supply in the near term will come from three refineries in Northern California and five refineries in Southern California.

Refineries typically operate at the maximum stated capacity when possible, with the total in-state utilization rate averaging 86.6 percent in 2024. The temporary reduction of refining capacity at a single refinery would represent a critical reduction. Supply shortfalls are met with marine imports, with one typical tanker ship of gasoline representing about one-third of the state's current daily demand of gasoline. Marine imports tend to have higher prices compared to in-state refining, which can increase retail prices.

California's gasoline demand is in continuous decline due to the increase of electric vehicles. As demand has declined, in-state refineries have converted to renewable fuels or closed completely. Large stepwise declines in gasoline supply creates potential supply-demand imbalances and subsequent price spikes. A strategy to bolster the state's imports of gasoline during these supply-demand discrepancies will be imperative to avoid these issues.

During 2024, gasoline retail prices steadily declined 15 percent from the high in April by October. This decline contrasts starkly with the large price increases during the same time of year in 2022 and 2023. This contrast indicates that there was sufficient supply to meet demand in the fall of 2024. No major refinery changes have occurred since then, and demand is anticipated to continue declining. Pending any unplanned refinery outages during the summer and fall of 2025, supplies should be sufficient to meet demand.

In the longer term, Phillips 66 announced plans to close its Wilmington refinery in Southern California during the fourth quarter (October–December) of 2025. The timing of this closure will not affect supply during the summer of 2025 but will reduce refining capacity by 139,000 barrels per day for the summer of 2026.

Conclusion

California's energy infrastructure continues to demonstrate a generally positive reliability outlook, with strengths in the electricity and gas sectors and evolving challenges in the petroleum sector. The electricity grid is expected to maintain sufficient capacity, with a projected surplus of up to 4,000 MW supported by ongoing statewide build-out of new battery storage and renewable generation, and availability of contingency resources. While gas storage withdrawals could be needed to meet demand in some summer scenarios, fossil gas supplies are anticipated to remain stable through 2025–2026, with underground storage reaching capacity by the start of winter and no expected service interruptions under normal conditions.

The petroleum sector faces greater uncertainty as declining gasoline demand, driven in part by increasing electric vehicle adoption, reshapes refinery operations and unplanned events introduce potential supply vulnerabilities. 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. Overall, while the projections are positive, unforeseen events could still present challenges across all energy sectors.

The CEC will continue to prepare and expand analyses for the *California Energy Resource and Reliability Outlook* annually to provide stakeholders and policy makers with a comprehensive resource for energy planning and reliability.

CHAPTER 1: Introduction

Background

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 such as solar, wind, and battery energy storage to reduce the impacts of climate change. In this transition, California is rapidly building new clean energy resources but continues to rely on an aging fossil-fueled power plant fleet for maintaining grid reliability, especially during times of high demand or when renewable sources are not producing enough power. At the same time, California is experiencing more frequent and prolonged extreme events as a result 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's comprehensive, statewide assessment of resource planning and reliability for the upcoming summer and the next five years. In 2021, the CEC's *Midterm Reliability Outlook*[1] provided an electric reliability outlook through 2026 and assessed the performance of critical resources such as battery storage and the fossil gas fleet. The *2024 CERRO*[2] 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. For the 2025 *CERRO*, the CEC is expanding content by including petroleum, a transportation fuel. Future reports will continue to provide more comprehensive analyses of energy resource planning issues, considerations, and trends. The CERRO effectively serves as

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1 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.

2 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.

a bridge document updating statewide energy sector planning relative to the state's clean energy policies, such as the *SB 100 Report*[3] that is issued every four years.

The CEC has a longstanding mandate under the Warren-Alquist Act[4] to serve as California's primary energy policy and planning agency. By providing annual summer assessments and preparing for extreme events, the CEC plays 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 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 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 that may not be in the scope of those reports but relevant to system reliability (for example, natural gas system reliability).

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:

- 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, as well as identify barriers to the procurement of these resources and possible pathways for additional procurement. The CEC posted the draft SB 423 Emerging Renewable and Firm Zero-Carbon Resources Report, Assessment of Firm Zero-Carbon Resources to Support a Clean, Reliable, and Resilient California Grid on August 2, 2024. A final report was submitted to the Legislature on March 21, 2025. Future IEPR

3 Gill, Liz, Aleecia Gutierrez, and Terra Weeks. March 2021. *2021 SB 100 Joint Agency Report.* California Energy Commission. Publication Number: CEC-200-2021-001, https://www.energy.ca.gov/publications/2021/2021-sb-100-joint-agency-report-achieving-100-percent-clean-electricity.

4 California State Legislature, *AB 1569*, https://legiscan.com/CA/text/AB1569/id/2814710.

updates will continue to refine this analysis, track emerging technologies, and assess policy options to support procurement.

- 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.
- 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 (PIIRA), added other requirements associated 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.
- 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 that the previously mentioned three-year assessment evaluate California's future import needs for crude oil and petroleum, as well as steps that could be taken to prepare ports and marine infrastructure to transport this quantity of petroleum products.

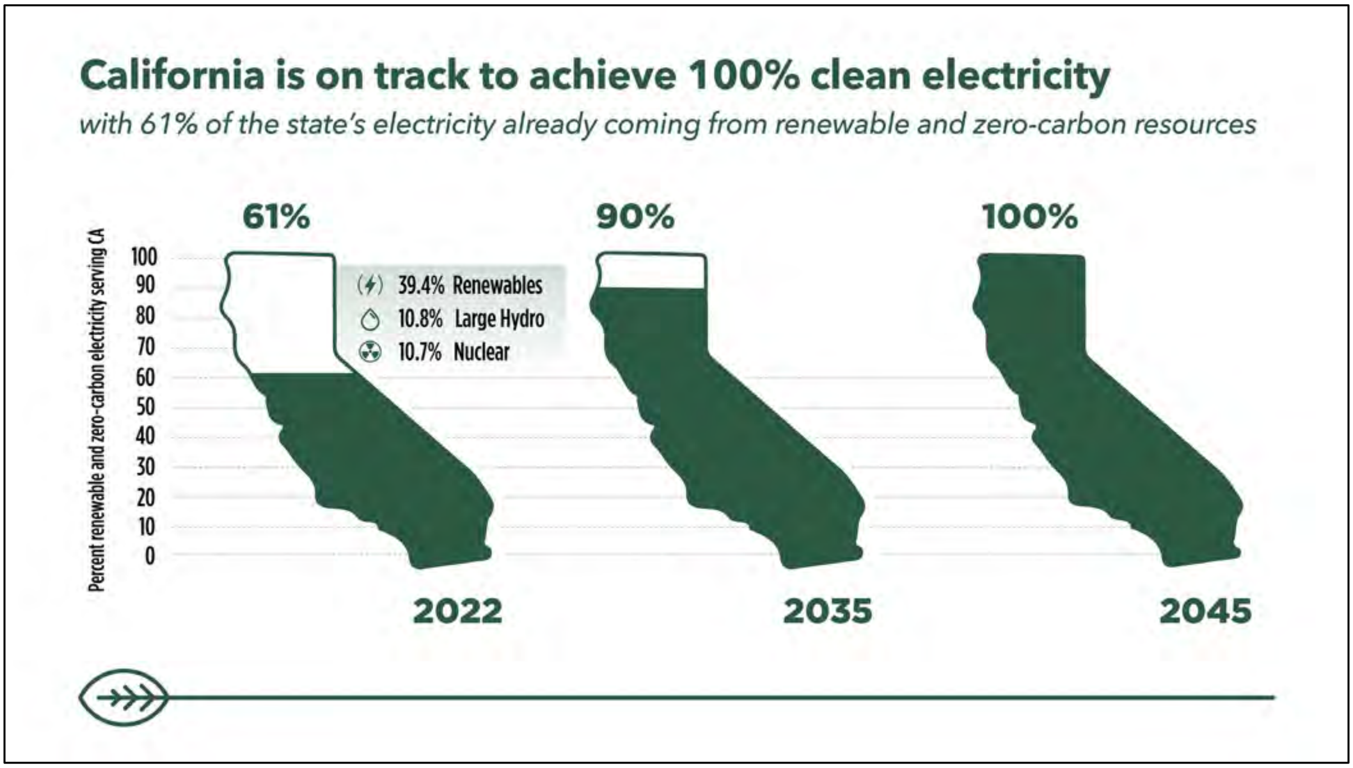
California's Electricity Planning and the Clean Energy Transition

The state is a world leader on policies that shift energy resources from fossil fuels to clean energy resources such as solar, wind, and battery energy storage to reduce the impacts of climate change. The electricity sector transition is primarily driven by the state's SB 100 goal of supplying 100 percent of retail sales with renewable and zero-carbon resources by 2045. At the same time, the 2045 economywide carbon neutrality goal requires the electric sector to reduce greenhouse gas emissions to 8 million metric tons (MMT) and support widespread electrification of other sectors, such as transportation and buildings. The state's electricity sector clean energy goals are largely achieved through the procurement efforts of the state's

80+ retail electricity providers. These include 40+ load-serving entities, primarily regulated by the CPUC, and 40+ publicly owned utilities, primarily regulated by their local governing boards.

As of 2022, California supplies 61 percent of electric retail sales with renewable and zero-carbon resources. Of this, 39.4 percent are supplied by Renewables Portfolio Standard- (RPS) eligible resources, keeping the state on track to meeting the 60 percent RPS target by 2030 and 100 percent renewable and zero-carbon target by 2045. Between January 2019 and December 2024, the state has added 25,000 MW of new clean energy capacity, including 12,000 MW of new battery storage.

Figure 1: Progress Toward Clean Energy Goals



Source: CEC

To achieve the state's clean energy goals while supporting widespread electrification, the 2021 SB 100 Report estimates that California utilities will need to, on average, deploy 8 gigawatts (GW) of new clean energy resources every year until 2045. These goals are achieved largely through retail providers' integrated resource planning and procurement processes. For CPUC-jurisdictional load-serving entities (LSEs), the CPUC's integrated resource planning proceeding directs LSEs to meet greenhouse gas (GHG) reduction goals set by CARB, in addition to SB 100 goals. The CPUC provides guidance to LSEs, who then each develop their LSE IRP to meet the state's requirements and any LSE-specific goals. The CPUC then develops a Preferred System Plan which is then transmitted to the California ISO for transmission planning. The CPUC also orders procurement by the LSEs to ensure reliability and clean energy goals are being met. Since 2019, the CPUC has ordered 18 GW of new net qualifying capacity to meet grid reliability needs through 2028.

The state's POUs each have their own planning and procurement process and submit integrated resource plans to the CEC at least every five years. POUs plan to meet the state's SB 100 and GHG reduction goals, in addition to local goals established by the POU's governing board. Of the 16 largest POUs that are required to submits IRPs, at least 7 have goals that exceed the SB 100 goals by either accelerating the achievement date or achieving zero or net-zero GHG emissions, or both.

CHAPTER 2: California Grid and Western Interconnection Overview

The CEC, CPUC, California ISO, and California utilities invest significant resources to undertake coordination with many other entities in the western United States. This investment is essential because California is a complex electrical system and is an integral part of the Western Interconnection (WI) — a synchronous machine that allows all 14 western states and two Canadian provinces to operate their generation and transmission at the same frequency. Should a link in the system fail to perform, reliability risk may be triggered, and the WI could experience a geographic loss of service. In 2011, for example, San Diego lost power because of a mechanical mistake in Phoenix, Arizona.

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 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 data across the West, and current information related to transmission infrastructure development.

Balancing Authority Areas in California

Balancing authority areas (BAAs) in California are critical in ensuring the reliability and stability of the state's electrical grid. As regions responsible for matching electricity supply with demand in real time, BAAs manage intricate networks of power generation, transmission, and sometimes distribution. In California, these BAAs are tasked with maintaining grid frequency, managing congestion, and simplifying seamless energy transfers across interconnected systems. BAAs are subject to North American Electric Reliability Corporation (NERC) reliability standards and compliance, which are delegated to the Western Electricity Coordinating Council (WECC).

In California, the largest BAAs include the California ISO and the Los Angeles Department of Water and Power (LADWP). The California ISO is the BAA 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 BAA within its service territory and for neighboring POUs in the Los Angeles Basin, managing the electricity supply and demand for Los Angeles and surrounding areas. LADWP also operates the largest direct current (DC) interties in the California system: the Pacific DC Intertie and the Intermountain Power Project DC intertie.

Figure 2 shows several smaller BAAs within California, such as the Balancing Authority of Northern California (BANC), PacifiCorp-West (PACW), Nevada Energy, Turlock Irrigation District (TID), Western Area Lower Colorado, and the Imperial Irrigation District (IID), which manage grid operations within their respective service territories. These BAAs work collaboratively to maintain grid stability and reliability across the state.

Figure 2: Map of Balancing Authorities in California

Source: CEC

California ISO

In addition to being a BAA, the California ISO also operates various markets, including the Western Energy Imbalance Market (WEIM), which enables participating utilities to balance supply and demand efficiently across the western United States, optimizing the use of renewable energy resources. Furthermore, the California ISO manages the day-ahead and real-time markets,[5] simplifying the scheduling and dispatch of electricity generation to meet forecasted and real-time demand. Through its market mechanisms and grid management tools, California ISO fosters competition, supports the integration of renewable energy, and maintains grid reliability, contributing to the effective functioning of California's electricity system and regional energy markets.

Other BAAs

The other BAAs outside the California ISO footprint provide similar functions to the California ISO. Some of the BAAs have additional functions that concern other utilities, such as water, or responsibilities that extend beyond the borders of California. For example, PACW and Nevada Energy serve customers in California and neighboring states. This service creates unique challenges geographically for optimizing and balancing supply and demand. However, many of these BAAs coordinate their electricity operations through the WEIM. By participating in the WEIM, BAAs can optimize the use of renewable energy resources, address grid imbalances, and reduce operational costs. Through this collaborative platform, utilities share surplus energy or access additional power when needed, enhancing grid reliability and resilience.

Western Coordination and Integration

In its *2022 IEPR Update*,[6] 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. Since the publication of the report, significant progress has been made, as highlighted below.

Western Markets: Enhancing Economics and Reliability

At least 38 balancing authorities function in the WI, dispatching their systems independently from one another. A central goal of regional integration is to bring these autonomous entities into more efficient coordinated methods of operating the electric grid. Wholesale markets are an essential mechanism to achieve this, including options for real-time (subhourly), day-ahead, and regional full-function markets.

Subhourly markets allow grid operators to manage and balance deviations (that is, imbalances) in their forecasts. Day-ahead markets allow grid operators to collect supply and demand bids 24 hours out from physical deliveries and optimize the system accordingly, along existing transmission pathways. Finally, regional full-function markets often include elements of transmission planning and cost allocation in addition to day-ahead and subhourly offerings. The real-time market of greatest interest to California is the WEIM. Established in 2014, the

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5 *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.

6 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.

WEIM is a real-time wholesale energy trading platform that allows participants from anywhere in the WI to buy and sell power. This market has attracted voluntary participation of 22 balancing authorities from 11 states and British Columbia.

The WEIM economic benefits reported for the fourth quarter (October–December) of 2024 were $374 million, with the cumulative total since its inception as $6.6 billion, far higher than anticipated.[7] The California ISO computes the WEIM economic benefits by analyzing the efficiency gains of power plant dispatch in the market. For example, transferring energy across balancing authorities within the WEIM can create economic benefits by finding new, cheaper ways of serving load. Of equal importance, markets enhance reliability during normal operations in addition to conditions where the electric grid is stressed.

Major steps forward have been taken in recent years to increase coordination of system dispatch to harness diversity, moving beyond real-time markets to day-ahead imbalance markets. The California ISO has pursued expansion of WEIM to the extended day-ahead market (EDAM), while the Southern Power Pool has engaged many stakeholders in developing its own version of day-ahead markets called Markets+. The Federal Energy Regulatory Commission (FERC) approved the California ISO's EDAM tariff, which is needed for the market to start operating. As a result of FERC's approval, the California ISO will start operating the market in 2026. FERC conditionally approved Southwest Power Pool's Markets+ tariff in January 2025.

Western Markets: The Pathways Initiative and Day-Ahead Market Developments

In July 2023, regulators throughout the WI called on the leadership of the Western Interstate Energy Board (WIEB) and the Committee on Regional Electric Power Cooperation (CREPC),[8] expressing a desire for broader coordination and integration of wholesale electricity markets across the West.[9] Those actions formed the basis of the Pathways Initiative (Pathways). The regulator's letter articulated a collective desire to maximize the benefits of organized power markets for the WI. At its essence, Pathways would see the creation of a new regional organization (RO) that would oversee the governance of the WEIM and the EDAM. The RO is proposed to form as a 501(c)(3) nonprofit that mirrors other regional market institutions across the United States.

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7 Market Performance and Advanced Analytics. 2025. *Western Energy Imbalance Market Benefits Report: Fourth Quarter*. California ISO, https://www.westerneim.com/Documents/iso-western-energy-imbalance-market-benefits-report-q4-2024.pdf.

8 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.

9 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.

On April 10, 2024, the Pathways Launch Committee issued its straw proposal, which laid out an incremental approach to greater coordination and integration of western electricity markets.[10] The approach is predicated on three steps outlined below.

- Step 1 works through existing law to modify the governance of the WEIM. Before Step 1, the California ISO maintained primary governance of WEIM. Step 1 effectively provides additional independent governance to the WEIM by vesting authority into the WEIM Governing Body rather than the California ISO's Board of Governors. On August 13, 2024, the California ISO Board of Governors and the WEIM Governing Body voted and unanimously approved Step 1.
- Step 2 creates a new and independent RO to further maximize independence while leveraging existing market infrastructure to minimize costs.[11] Step 2 establishes the new RO, which would have governance authority over market rules within the WEIM and the soon-to-launch EDAM approved by FERC. On November 22, 2024, the launch committee approved Step 2.
- Step 3 could continue to expand the scope of the different market functions and regional services offered by the RO, though it is beyond the scope of current electricity market offerings. Step 3 may occur if Step 2 is implemented successfully and ongoing stakeholder negotiations determine what, if any, additional services would be offered. The launch committee has previously noted that these services "could take many forms" and are "yet undefined."[12] To implement Step 2, legislative action in California is needed. At present, the launch committee has created a formation committee to undertake parallel work processes including the application for grant funding for the RO.

On January 24, 2025, the CEC convened a workshop on regional electricity markets and coordination to enable a public discussion on the potential benefits and risks of the Pathways Initiative for California.[13] The workshop sought to highlight an array of stakeholder groups and voices throughout the WI that are engaging on these issues. These organizations represented a diverse set of interests that included labor, environmental, publicly owned utilities, investor-owned utilities, and community choice aggregators. Regulators throughout the WI also participated and shared their perspectives. A full summary of the workshop is available as an appendix in the *2024 IEPR Update*. The workshop featured extensive discussions around the potential benefits and risks of Pathways. Notably, stakeholders appeared uniformly supportive

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10 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.

11 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.

12 Ibid.

13 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.

of Pathways and highlighted the incremental and stepwise nature of the initiative. The CEC is tracking these developments and will provide updates in future editions of the CERRO as needed.

Western Supply: The Market Continues to Grow

Electricity markets can provide value through the optimization of supply and transmission resources to meet demand. Value in these markets lies with the specific time frame, in addition to the relative size of the market footprint. For example, real-time markets provide economic and reliability benefits by smoothing deviations (that is, imbalances) in demand and supply forecasts. Day-ahead markets can provide substantially more value above real-time markets through the coordinated system optimization that takes place 24 hours before the physical delivery of power. A market operator can better manage the system when it schedules least-cost dispatch ahead of delivery and has visibility into transmission infrastructure. Optimizing and scheduling the least-cost flow of power allows the operator to find the cheapest transmission pathways to deliver power across a region.

Increasing transmission resources within a given region unlocks increased connectivity within the existing region. Expanding the physical footprint of a market increases the supply of capacity for the market and brings existing transmission resources for additional connectivity. However, the value of wholesale electricity markets is predicated on the existence of sufficient capacity to meet demand. While markets can effectively optimize a portfolio of resources to meet system demands, these markets alone do not create the needed supply to meet that demand. As such, the West must still build a sufficient supply of generation capacity outside organized electricity markets to meet forecasted demand. This section provides a high-level overview of forecasted regional capacity trends from WECC.

On December 3, 2024, WECC issued its *2024 Western Assessment of Resource Adequacy (2024 WARA)*.[14] The WARA is an annual report that examines the WI's reliability over a 10-year period. WECC uses a probabilistic analysis and applies it to each of the five subregions.[15] *The 2024 WARA* states that "the supply of electricity is not growing fast enough to keep up with demand growth."[16] This situation is driven by a few factors, including demand-side issues such as new large loads (for example, data centers) and new higher-than-expected demand forecasts, along with supply-side issues like supply chain disruptions, siting/permitting issues, and challenges with interconnection queues.

WECC collects data from the BAAs within the region that detail their planning and forecasted resource additions. Not every forecasted resource addition has the same likelihood of reaching commercial operations. Thus, WECC categorizes resource additions into the following tiers:

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14 Western Electricity Coordinating Council. 2024. *Western Assessment of Resource Adequacy 2024*. Western Electricity Coordinating Council, https://feature.wecc.org/wara/.

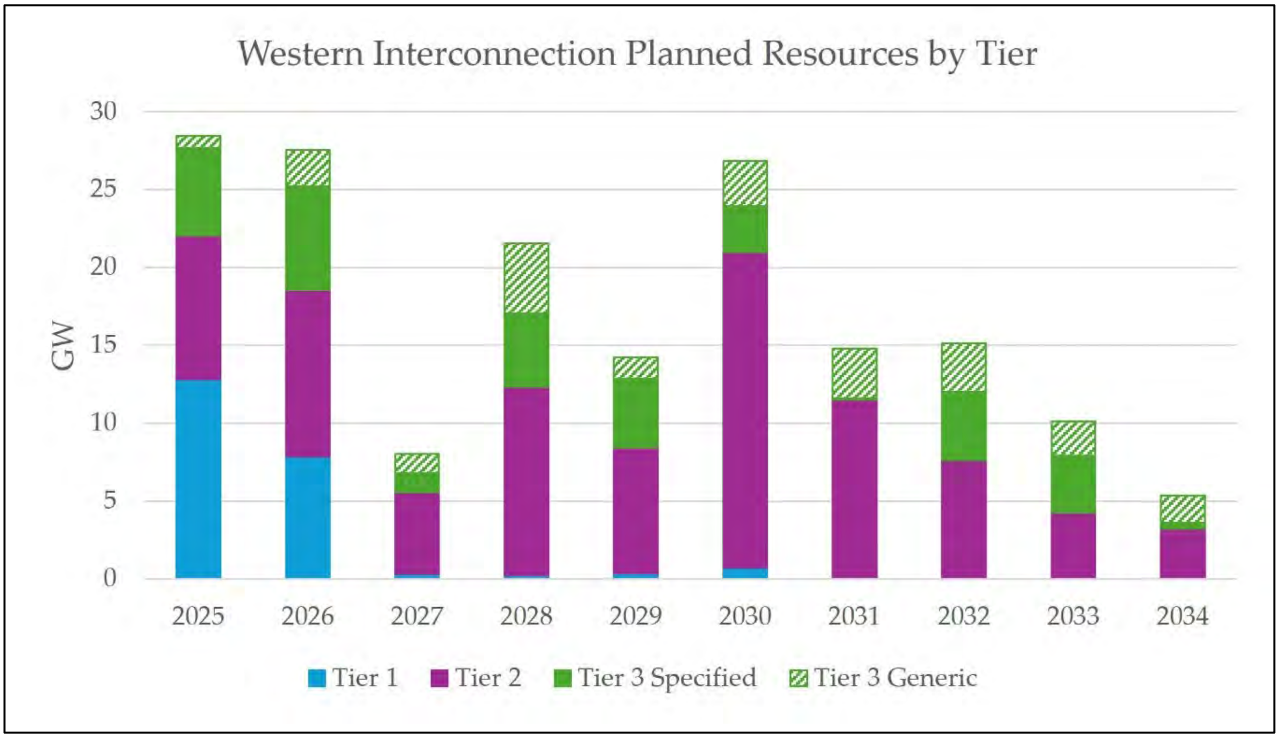
15 The five WECC subregions include CA-MX, NW Northwest, NW Northeast, NW Central, and Desert Southwest.

16 Western Electricity Coordinating Council. 2024. *Western Assessment of Resource Adequacy 2024*.

- Tier 1: Resources that are under construction and are expected to reach commercial operations for the year that they are studying.
- Tier 2: Resources that are under contract but have yet to start construction. These may reach commercial operations for the study year.
- Tier 3 Generic: Resources that the BAA has less certainty about.
- Tier 3 Specific: Resources that the BAA may have some insight into, but the commercial operation date is not known, and the project hasn't started construction.

Figure 3 provided by WECC details planned additions by year and tier.

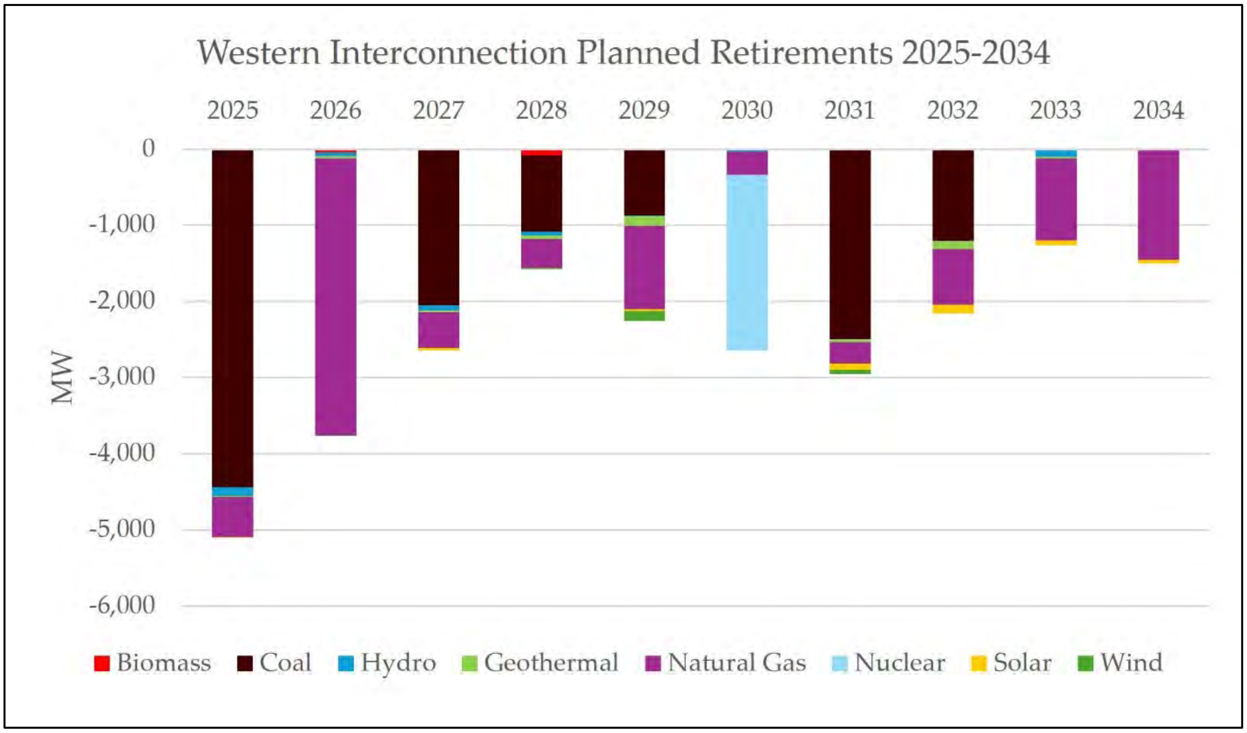
Figure 3: Forecasted WI Resource Additions by Tier



Source: WECC

Tier 1 resources appear primarily in 2025 and 2026. This timing is likely because most resource construction timelines take a couple of years. It is unlikely to have a project under construction that is expected to remain in that phase of project development for more than two to three years. There are, however, some Tier 1 additions in 2027–2030. WECC shows a large number of planned capacity additions currently classified as Tier 2. It is reasonable to anticipate more Tier 2 capacity will become Tier 1 in the next WARA, as projects move into construction now that they are under contract. Both Tier 3 Generic and Tier 3 Specific additions are harder to understand because so little information is available about them. WECC notes that large amounts of Tier 3 resources in a resource plan "likely overestimate the ability to build generation." WECC also documents planned resource retirements through 2034, as depicted in Figure 4.

Figure 4: Forecasted WI Resource Retirements by Energy Source



Source: WECC

Most planned capacity retirements are either coal or fossil gas (also known as natural gas and cited as such in the previous figure). WECC shows some nuclear capacity retiring in 2030, reflective of recent California developments delaying retirement of the Diablo Canyon Power Plant until 2030. WECC provided Tier 1 and 2 data to CEC staff. Below are additional data compiled by staff that integrate planned resource additions and planned resource retirements through 2030 together. Table 1 and Figure 5 should be considered as additive to WECC's analysis and show net planned resource additions by BAA. Table 1 below details net planned resource additions (T1 and T2) by BAA.

Table 1: T1 and T2 Planned Resource Additions and Retirements (GW) by BAA Through 2030

	2025	2026	2027	2028	2029	2030
Albert Electric System Operator (AESO)	4.56	0.63	0	0	0.2	0
Avista Corporation (AVA)	0	0	0	0	0	0
Avangrid Renewables (AVRN)	0.2	0.36	0	0	0	0
Arizona Public Service Company (AZPS)	1.81	1.78	0.91	0	0	0

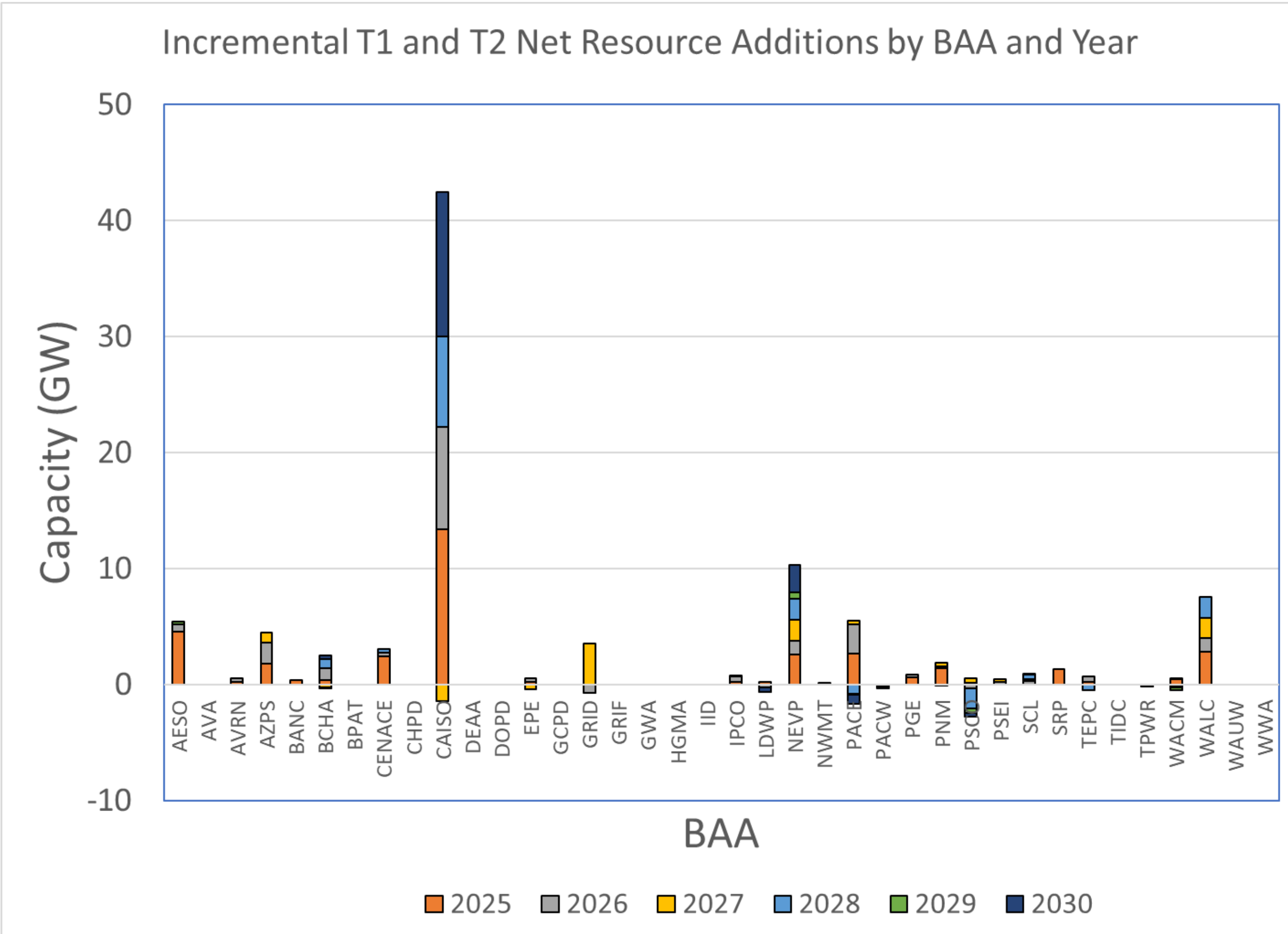
	2025	2026	2027	2028	2029	2030
Balancing Area of Northern California (BANC)	0.35	0	0	0	0	0
British Colombia Hydro-Authority (BCHA)	0.41	0.96	-0.26	0.80	-0.03	0.33
Bonneville Power Administration-Transmission (BPAT)	0	0	0	0	0	0
Centro Nacional de Control de Energía (CENACE)	2.45	0.3	0	0.3	0	0
Public Utility District No. 1 of Chelan County (CHPD)	0	0	0	0	0	0
California Independent System Operator (California ISO)	13.40	8.76	-1.39	7.83	0	12.47
Arlington Valley (DEAA)	0	0	0	0	0	0
Public Utility District No. 1 of Douglas County (DOPD)	0	0	0	0	0	0
El Paso Electric Company (EPE)	0.25	0.30	-0.41	0	0	0
Public Utility District No. 2 of Grant County (GCPD)	0	0	0	0	0	0
Gridforce Energy (GRID)	0	-0.73	3.51	0	0	0
Griffith Energy (GRIF)	0	0	0	0	0	0
NaturEner Power Watch (GWA)	0	0	0	0	0	0
New Harquahala Generating Company (HGMA)	0	0	0	0	0	0
Imperial Irrigation District (IID)	0	0	0	0	0	0
Idaho Power Company (IPCO)	0.24	0.42	0.12	0	0	0
Los Angeles Department of Water and Power (LDWP)	0.21	-0.23	0	0	0	-0.40
Nevada Power Company (NEVP)	2.60	1.18	1.77	1.81	0.60	2.30
Northwestern Energy (NWMT)	0.17	0	0	0	0	0
PacifiCorp East (PACE)	2.64	2.51	0.33	-0.82	-0.02	-0.80

	2025	2026	2027	2028	2029	2030
PacifiCorp West (PACW)	-0.07	-0.00	-0.03	-0.01	-0.08	-0.07
Portland General Electric (PGE)	0.61	0.21	0	0	0	0
Public Service Company of New Mexico (PNM)	1.39	0.19	0.3	0	-0.05	0
Public Service Company of Colorado (PSCO)	0.12	-0.35	0.44	-1.66	-0.42	-0.30
Puget Sound Energy (PSEI)	0	0.24	0.19	0	0	0
Seattle City Light (SCL)	0	0.28	0.2	0.35	0	0.1
Salt River Project (SRP)	1.29	0	0	0	0	0
Tucson Electric Power Company (TEPC)	0.2	0.52	0	-0.50	0	0
Turlock Irrigation District (TIDC)	0	0	0	0	0	0
Tacoma Power (TPWR)	0	-0.09	0	-0.02	0	0
Western Area Power Administration, Colorado-Missouri Region (WACM)	0.44	-0.17	0	-0.04	-0.29	0.09
Western Area Power Administration, Lower Colorado Region (WALC)	2.84	1.12	1.8	1.8	0	0
Western Area Power Administration, Upper Great Plains West (WAUW)	0	0	0	0	0	0
BHE Wind Watch (WWA)	0	0	0	0	0	0

Source: CEC staff

To understand overarching trends, these data are also presented visually. Below is a chart detailing net capacity additions (T1 and T2) by BAA, with each year grouped together for the respective BAA.

Figure 5: Net Planned Resource Additions (GW) by BAA Through 2030



Source: CEC staff

There are many BAAs throughout WECC that do not report any T1 or T2 capacity additions through 2030. Moreover, several report only a few GW of incremental T1 and T2 additions. The California ISO is forecasted to add the most net planned resource additions through 2030. The California ISO is projected to add 41 GW by 2030 after accounting for planned retirements. This amount is almost half of the 85 GW of net planned resource additions through 2030. While real-time and day-ahead markets can assist the West in optimizing the use of its resources, markets cannot build resources alone. WECC asserts that "resource plans seem overly optimistic" and that there are not sufficient compliance mechanisms in place to ensure resources will be built. The CEC will continue to track and report on the West's progress in developing new supply resources needed to meet regional needs.

Transmission: Regional Projects and New Planning Initiatives

"Transmission lifts all boats" is a phrase often used to reflect the benefit of adding new transmission capability. Simply stated, capacity essential to reliability may be available outside the state but can provide no support if not deliverable to load, that is, the customers who need reliable energy. Indeed, the transmission committed to the WEIM and the available capacity were important factors in the California ISO surviving the September 2022 heat wave. New lines being added (see below) are essential to delivering remote wind energy with high-capacity factors that operate when California wind may be dormant. Additional lines also add resilience in times of fires and outages anywhere in the WI.

Despite long-running challenges with regional coordination and WECC-wide transmission planning, incremental, major transmission is getting built. Many of these projects feature designs to enable power flows across the WI from wind resources in the east to load centers in the west. The eight regional projects now operating since the 2024 *IEPR Update* or otherwise making progress towards commercial operations include:

- Ten West Link, California and Arizona — merchant 500 kV line (2024).
- Gateway West, Wyoming to Idaho — 500 kV and 230 kV lines developed by PacifiCorp (2024).
- Gateway South, Wyoming to Utah — 500 kV line developed by PacifiCorp (2024).
- SunZia, New Mexico, and Arizona — merchant 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).

While there have historically been challenges in the development of regional transmission, there has been an elevation in engagement across the WI to develop solutions, as evidenced by the formation of the Committee on Regional Electric Power Cooperation Transmission Collaborative (CREPC TC)[17] in January 2024. CREPC TC has contracted with a consultant to develop an interregional transmission cost allocation framework that might support, and even promote, multistate transmission projects in the WI.

Interconnectionwide and Continent Transmission Assessments

A broad initiative led by the Western Power Pool[18], known as WestTEC, has been established to assess WECC-wide transmission needs, recognizing that the current approach to planning is insufficient. A WestTEC consultant will undertake WECC-wide power flow and production cost

17 The CREPC TC is a working group focused on regional transmission topics. The goal is to promote coordination on transmission development and to serve as a way of encouraging regional dialogue on transmission issues.

18 The Western Power Pool (WPP) is a group of organizations that share resources across the WI. WPP also provides additional services to its members including transmission planning and tariff administration.

modeling, focusing on 10-year and 20-year futures. The California ISO is directly engaged in this effort and will help ensure that accurate data and modeling are used in the study. Results of the study will highlight the most cost-effective and beneficial paths and lines 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. In September 2024, the WestTEC Steering Committee unanimously approved a study plan. WestTEC expects the 10-year future study to be completed by September 2025. The full report is expected in the first quarter (January–March) of 2027.

CHAPTER 3:
Electric Reliability and Recent Challenges

Electric reliability depends on maintaining sufficient energy and capacity to meet electricity demand at all times across daily and seasonal variations. There are temporal and spatial elements as electricity must be generated simultaneously to consumption (demand) and delivered over the complex transmission and distribution network to the point of use.

Planning for Reliability

Electric reliability planning is a broad process that covers real-time operations to long-term planning of more than 10 years. Given the long lead time required by electric infrastructure projects, especially those related to transmission, long-term planning is considered essential to supporting adequate infrastructure for contracting and operations. This planning occurs in California through the integrated resource planning process for CPUC-jurisdictional entities and individual planning processes for POUs, each aligned with broader policy goals like SB 100.

The CPUC's planning also informs the California ISO's transmission planning to ensure that future generation resources can be delivered to load. RA planning and contracting cover shorter time frames, from three years to one month ahead, with planning reserve margins (PRMs) increasing because of climate change and variability around renewables. The processes also include the assurance of local generation in constrained areas. Finally, RA also involves BAs managing electric demand in real time, requiring adequate resources with flexibility in the right places. Reliability planning frameworks will continue to evolve along with California's energy landscape.

Publicly Owned Utility Integrated Resource Plan Summary

SB 350 requires POUs whose average annual electrical demand between 2013 and 2015 exceeded 700 gigawatt-hours (GWh) to adopt an Integrated Resource Plan (IRP). Of the POUs in California, 16 met these criteria.[19] In their IRPs, filing POUs 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 (PUC) Section 9621 — meeting GHG emission reduction targets, meeting requirements to procure renewable energy, ensuring electricity reliability, and charging reasonable electricity rates. The CEC *Publicly Owned Utility IRP Submission and Review Guidelines* require filing utilities to provide data and supporting

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19 These 16 publicly owned utilities are Anaheim Public Utilities, Burbank Water and Power, City of Palo Alto Utilities, City of Redding Electric Utility, Glendale Water and Power, Hetch Hetchy Power, Imperial Irrigation District, Los Angeles Department of Water and Power, Modesto Irrigation District, Pasadena Water and Power, Riverside Public Utilities, Roseville Electric Utility, Sacramento Municipal Utility District, Silicon Valley Power, Turlock Irrigation District, and Vernon Public Utilities.

information sufficient to demonstrate that they meet these requirements.[20] Under PUC Section 9622, the CEC must review the integrated resource plans for consistency with the requirements of PUC Section 9621.

The legislation first required each of the sixteen qualifying POUs to adopt an IRP by January 1, 2019; all 16 utilities submitted these IRPs to the CEC for review by August 12, 2019. Subsequently, CEC staff reviewed the IRPs and determined that all were consistent with the requirements: The IRPs laid out plans to meet forecasted demand for 2019 to 2030 while meeting emission reduction, renewable procurement, reliability, and affordability requirements.

In general, POUs are increasing their procurement of renewable resources and energy storage, promoting electric vehicle adoption and building electrification, and investing in energy efficiency and demand response. While POUs are reducing their use of natural gas-fired generation, many retain these facilities for reliability. A major achievement is a joint POU agreement to advance the fuel switch at Intermountain Power Plant from coal to natural gas two years ahead of its originally planned date, now occurring in the summer of 2025. The POU IRPs show that they will meet the 60 percent RPS target and 2030 GHG emissions reduction goal. Some POUs plan on meeting the 2045 goal of net-zero carbon emissions earlier than required. However, for many POUs, meeting this target remains a challenge as they rely on commercialization of new technologies and must maintain affordable rates for their customers.

SB 350 also requires that the POUs update their IRPs at least once every five years, which meant each was to adopt an updated IRP by January 1, 2024. Again, all 16 filing POUs adopted updated IRPs and submitted them to the CEC for review. CEC staff is reviewing this second cycle of IRPs for consistency with the requirements. Staff anticipates completion of this review cycle in late 2025 and plans to provide information on the results in the *2026 CERRO.* Current guideline requirements will be revised to extend to 2045 and include new legislative requirements contained in SB 100, which some POUs have already incorporated into their IRPs.

Supply Forms

The 2024 supply forms[21] outline the information required by the CEC to support electricity planning for the *2025 IEPR.* It includes forms and instructions for load-serving entities, such as utilities and energy service providers, to report their plans for meeting future electricity capacity and generation needs. Under California Public Resources Code Sections 25300–25323, the CEC is mandated to assess energy supply and demand to guide policy recommendations for energy reliability, resource conservation, renewable energy development, and public health. Data collected guide statewide electricity planning, supports grid reliability studies by

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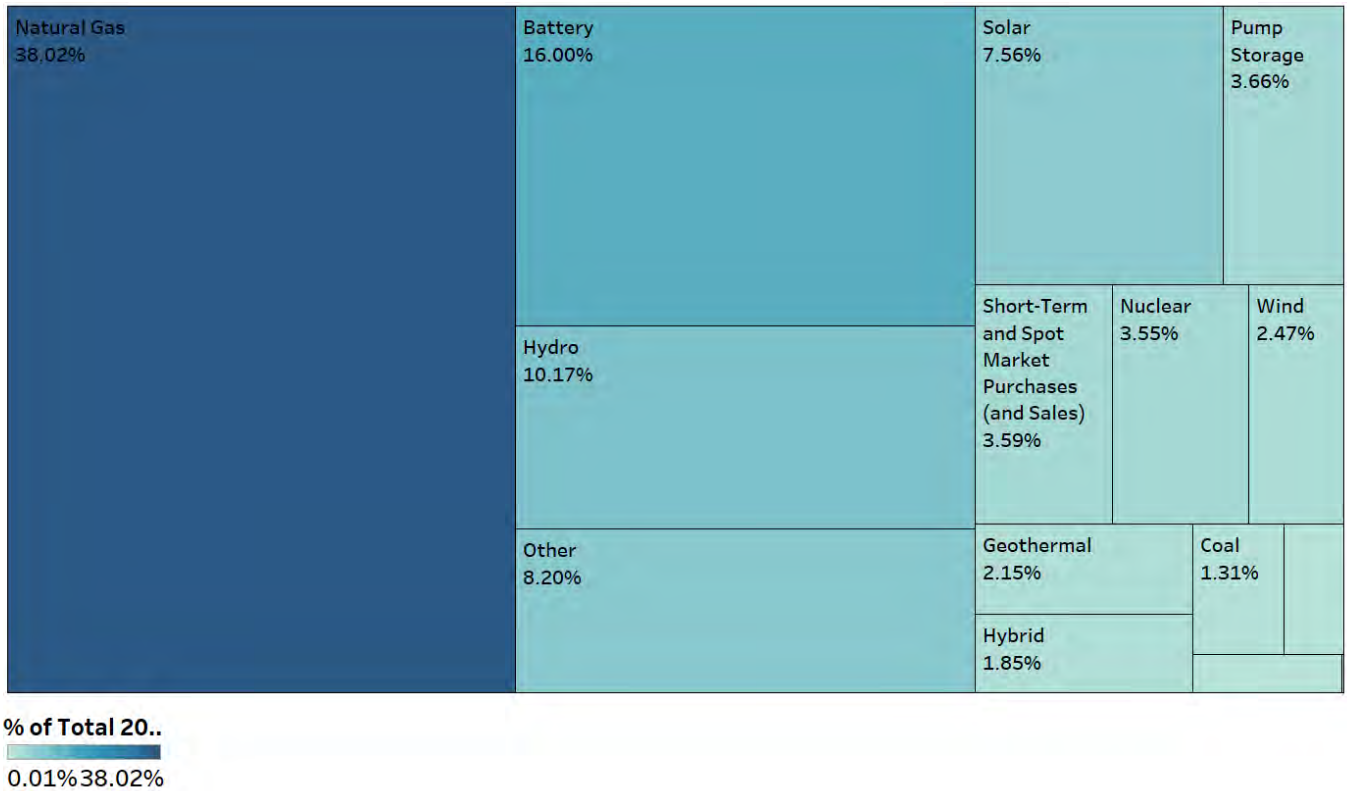
20 Vidaver David, Melissa Jones, Paul Deaver, and Robert Kennedy. 2018. *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines (Revised Second Edition)*. California Energy Commission. Publication Number: CEC-200-2018-004-CMF, https://efiling.energy.ca.gov/getdocument.aspx?tn=224889.

21 Kennedy, Robert, and Julio Gutierrez. 2024. *Forms and Instructions*. California Energy Commission, https://www.energy.ca.gov/publications/2024/forms-and-instructions-submitting-electricity-resource-plans-and-transmission.

the California ISO and other entities and help align procurement plans with local reliability requirements. The supply mix, reported for 2025 in the supply forms, is summarized in the below tree map, Figure 6. Natural gas continues to provide the majority of dependable capacity during peak periods at about 38 percent. However, battery, hydroelectricity, solar, wind, and geothermal resources provide a combined 44 percent of dependable capacity.

Figure 6: Supply Forms Summary – 2025 Capacity Estimates



Source: CEC staff with 2024 supply forms
*Values are summed based on net qualifying capacity, which is the amount of reliable capacity during peak-demand periods

Critical Variables for California's Electric Reliability

Several variables create significant uncertainties for electric reliability, including demand variability, supply challenges, hydroelectric availability, and import constraints. Climate change has made demand harder to forecast, with prolonged heat waves straining the grid, while growing electrification and data center expansions add new planning challenges. Supply chain disruptions, interconnection delays, and lengthy permitting processes slow new energy projects. Hydroelectric capacity fluctuates with annual water conditions, and California's reliance on imports faces risks from regional supply tightening, load growth, and wildfire threats to transmission. These factors collectively emphasize the importance of comprehensive planning to maintain electric reliability in the state.

Demand Variability

Demand variability has always been a critical uncertainty accounted for in electricity planning and operations. However, climate change has recently intensified heat waves, making them more frequent, widespread, and long-lasting than have been observed historically. For example, the September 2022 heat wave, which resulted in record demand in the California ISO BAA, was determined to be a 1-in-27-year event based on 30-year historical data, while only a 1-in-14-year event based on 20-year historical data.

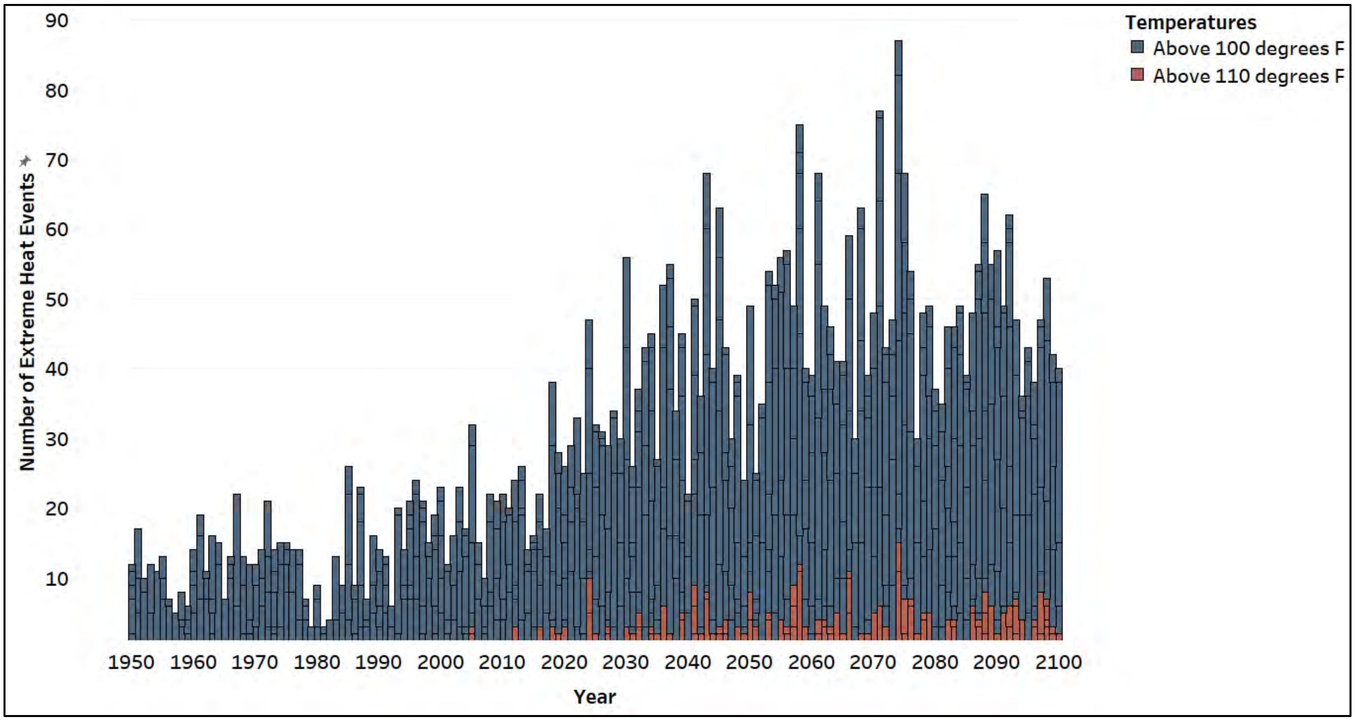
To address this, California is adapting its energy demand forecasts — traditionally based on historical demand and projected factors like economic growth — to incorporate climate change-informed datasets. These efforts are supported by ongoing research through the Electric Program Investment Charge, including tools like the Cal-Adapt Analytics Engine (Cal-Adapt).[22] In addition, many entities, including the CPUC's RA program, have increased their PRMs.

Figure 7 illustrates a projection of the frequency of heat events for the Sacramento region using the CanESM2 (average) model from Cal-Adapt. The graph shows an increase in the frequency of hot days (above 100 degrees Fahrenheit) and extremely hot days (above 110 degrees Fahrenheit). There is a clear upward trend in the frequency of heat events starting in the early 2000s. In addition to more frequent heat events, heat events are projected to be of longer duration, as seen in Figure 8. Consecutive heat event days can create greater stress on the electric grid because of extended use of air conditioning and grid assets cannot sufficiently cool overnight.[23] While Figure 7 and Figure 8 report on projections in the Sacramento Region, similar patterns may be seen in other areas across the state.

22 Eagle Rock Analytics. N.d. *Cal-Adapt Analytics Engine: Next generation Climate Data Analytics for California*. Cal-Adapt, https://analytics.cal-adapt.org/.

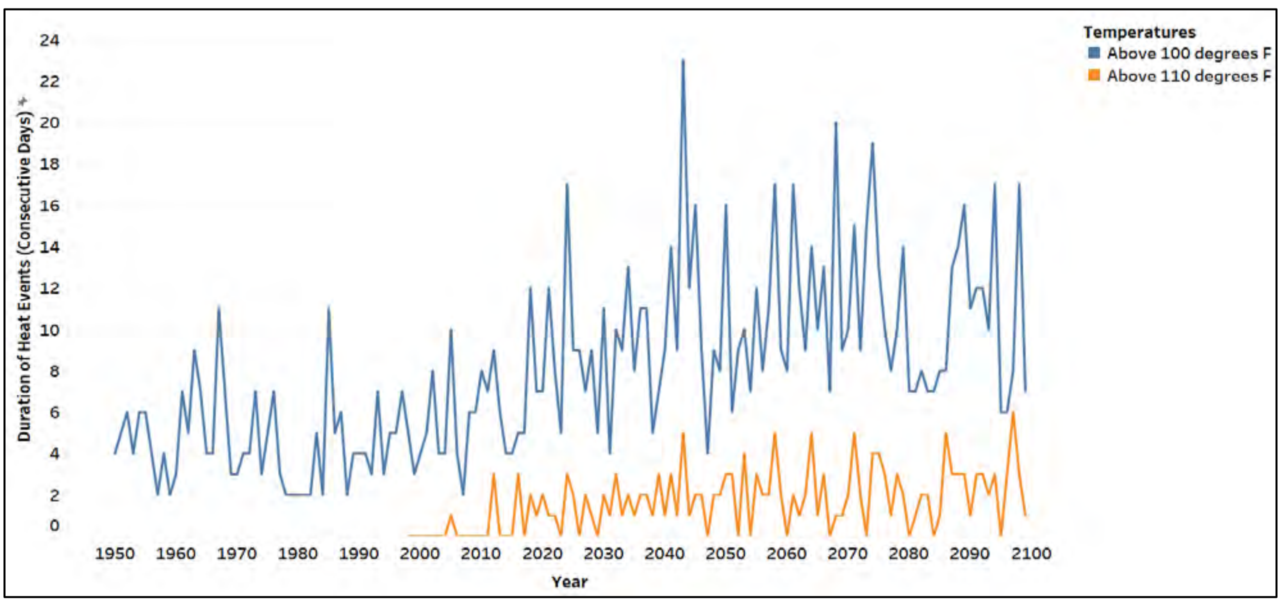
23 Wian, Casey. August 31, 2022. *CAISO Warns Excessive Heat Will Stress Power Grid*. Edison International, https://energized.edison.com/stories/caiso-warns-excessive-heat-will-stress-power-grid.

Figure 7: Projected Frequency of Extreme Heat Per Year – Sacramento Region



Source: CEC staff with Cal-Adapt data

Figure 8: Projected Duration of Extreme Heat Events — Sacramento Region



Source: CEC staff with Cal-Adapt data

While previous forecasts have considered expected increases in average temperature, the trends depicted in Figure 7 and Figure 8 highlight the importance of expanding climate considerations in the forecast to reflect novel weather patterns and changes to the magnitude, frequency, and duration of extreme temperatures.

Supply Challenges

Beyond adequate system planning, new resource build-out is another critical variable to California's electric reliability. Supply chain issues, interconnection delays, and permitting delays significantly impact the timely completion of new energy projects, posing challenges for system reliability. Supply chain disruptions can result in shortages of key components, such as circuit breakers and transformers, increasing costs and extending project timelines. In 2025, tariffs on utility and residential electrical equipment like circuit breakers, transformers, solar panels, and battery storage systems may significantly reshape market dynamics across the energy sector.

For utilities and renewable energy developers, tariffs can delay project timelines, create uncertainty, and increase installation costs, potentially delaying completion dates. Projects with long lead times could potentially be delayed further. The impact varies widely depending on domestic manufacturing capacity — areas with robust local production might see minimal disruptions, while sectors reliant on specialized imported components could experience substantial price increases and supply shortages.

Interconnection delays, often due to grid infrastructure limitations, construction, or lengthy administrative procedures, further postpone the integration of new energy projects. Furthermore, permitting processes can become lengthy, in part by the sheer volume of projects that are requesting permits and additional requirements to ensure project safety and environmental protection. These combined factors delay the availability of new capacity, potentially leading to capacity shortages and affecting the overall reliability of the electric system. Addressing these issues and preparing for uncertainties in resource build-out are crucial for ensuring a reliable system.

Hydroelectric Resource Availability

Hydroelectricity comprises, on average, about 14.57 percent of California's annual in-state electric generation.[24] This number can range from more than 40,000 GWh in a "high-hydro" year, where there is an above-average snowpack and reservoirs are significantly filled, to just 15,000 GWh during an extended drought. While the impact is less significant to reliability, as water can be "held back" to be available at the peak hours of the peak months, available capacity can vary from 6,000 to 7,000 MW,[25] depending on the availability of water that year. This variability creates uncertainty for entities that depend on hydroelectric capacity for meeting their RA needs and for the state in years that every MW of capacity is needed.

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24 California Energy Commission. N.d. "California Electrical Energy Generation." California Energy Commission, https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/california-electrical-energy-generation.

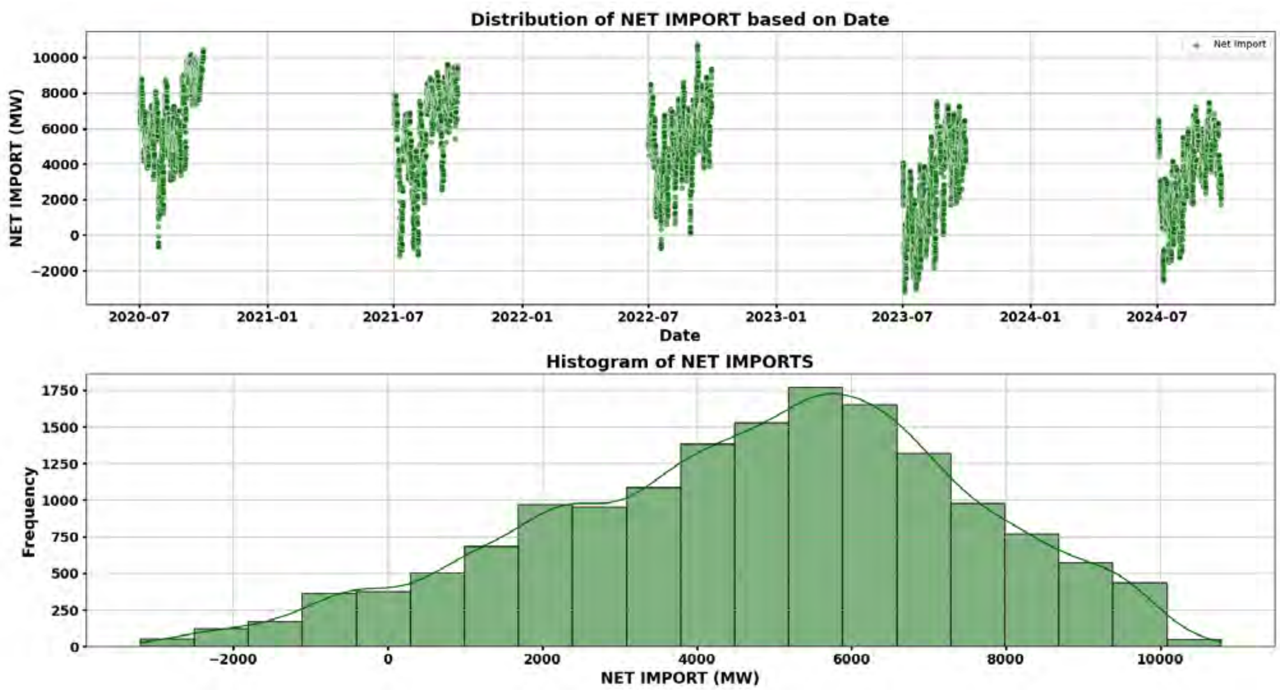
25 California Independent System Operator. N.d. "Resource Adequacy." California Independent System Operator, https://www.caiso.com/generation-transmission/resource-adequacy.

Import Availability

California is a net importer of electricity, particularly in the evening hours when electricity demand is highest. About 29 percent[26] of the state's electricity needs are served by imported electricity. Entities also depend on imports, through either long-term contracts or the short-term market, to meet their RA needs. Several trends in California and the WI create significant uncertainty in the availability of imports in the long term and, in some cases, the operational time frame.

Imports are a flexible resource used to meet supply and demand imbalances at times of peak demand or when in-state renewable generation is low. However, net imports are not fixed but are a function of the demand in California and the availability of new resources within the balancing area. As demand grows, it increases the need for imports, which are constrained by transmission capacity and the capability of neighboring regions to supply power. Meanwhile, as new in-state resources come on-line, reliance on imports will decline or shift to different times of day. Figure 9 illustrates the performance of net imports during peak demand periods in the last five years. Between 2020 and 2022, the California ISO relied more heavily on net imports due to high peak demand. Though in 2023 and 2024, the California ISO relied less on net imports because of new resources that came on-line in record quantities.

Figure 9: California ISO — Five-Year Summer Net Imports at Peak Hours



Source: CEC staff using California ISO OASIS data

26 California Energy Commission. N.d. "California Electrical Energy Generation." California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/california-electrical-energy-generation.

Recent Reliability Conditions in California

Energy reliability is increasingly impacted by highly variable weather events driven by climate change. California's electric system runs reliably most of the time, and the state has backup assets in place to provide power during extreme events to avoid outages. The state's greatest electric reliability concerns are driven by a small number of hours during increasingly intense heat waves when demand for electricity skyrockets and available supply is constrained. If these moments of extreme weather events coincide with other climate-driven extreme events, such as drought or fire, the state's energy system could be strained beyond the reliability contingencies planned for.

Between 2020 and 2022, California faced several major grid challenges, including rotating outages during a westwide heat event in 2020, a wildfire in Oregon that cut 3,000 MW of imports in 2021, and record-breaking temperatures in 2022 that pushed peak load to 52,061 MW. Despite demand-reduction efforts, these events highlighted the vulnerabilities of the grid amid extreme weather.

Since 2020, California energy agencies have taken steps to address supply and demand imbalances and have increased coordination on resource planning and reliability. The CEC, CPUC, and California ISO formed the Tracking Energy Development Task Force with the Governor's Office of Business Development to track clean energy projects and address development barriers. In December 2022, these entities signed a memorandum of understanding to better align resource procurement with transmission planning, recognizing the unprecedented need for new infrastructure to support reliability and clean energy goals. The CEC is also refining its IEPR demand forecast to better account for climate change impacts and demand increase due to new data centers.

In July and September 2024, the California ISO managed grid reliability through prolonged heat and wildfire risks that threatened the grid and access to imports from neighboring regions. During these periods, the California ISO issued "start-up" instructions for Strategic Reliability Reserve (SRR)[27] Units at Alamitos, Huntington Beach, and Ormond Beach to remain on standby at minimum operating levels as a precautionary measure. On July 10 and 11, high temperatures, wildfire threats, and a westwide heat wave posed risks to generation and imports, but as conditions improved, the units were not dispatched beyond minimum levels and were shut down by midnight July 11.

Similar conditions emerged in early September, prompting the California ISO to again activate SRR Units on September 5 and 6. While high system demand was forecasted, conditions improved, and the units were not required to ramp up beyond minimum operating levels. A final activation occurred September 9 in response to another forecasted heat wave, but as demand pressures eased, the units were not dispatched beyond minimum levels and were

27 The Strategic Reliability Reserve was developed in 2022 as part of AB 205 (Committee on Budget, Chapter 61, Statutes of 2022) to expand the resources capable of managing or reducing net-peak demand during extreme events.

shut down after the event. These actions highlight the California ISO's strategic use of reserve resources to reduce grid reliability risks during extreme weather conditions.

POU balancing area authorities also prepared for summer reliability challenges. In preparation for summer 2024, BANC conducted a reliability analysis, updated procedures, and engaged in training with the California ISO and other balancing authorities. Its assessment determined that resources were sufficient to meet typical and extreme load conditions, except for the low-probability scenario of a westwide heat wave causing a 1-in-20 load with reduced imports. Despite a hotter-than-normal summer and two major wildfires, BANC avoided any emergency energy alerts. The integration of additional solar and hydro generation supported reliability, while the WEIM further demonstrated its benefits. Ongoing efforts included enhanced communication, strategic use of emergency energy alerts to deploy demand response, and increased procurement, as necessary.

LADWP, however, faced significant system loading challenges during an early September 2024 excessive heat warning, with peak demand exceeding 5,000 MW on four days and surpassing 6,000 MW on two occasions.[28] The department reached a peak of 6,237 MW on September 6, 2024, but maintained system reliability without requiring emergency energy alerts. This success was attributed to effective dispatch of generation units, strategic real-time energy purchases, demand response activations, and restricted maintenance periods to minimize risks. While the bulk power system remained stable, the heat wave stressed LADWP's subtransmission and distribution network, leading to circuit and equipment overloads, which were reduced by careful power flow management. Looking ahead, LADWP remains focused on maintaining reliability through resource planning, operational adjustments, and coordination with broader energy markets.

Fossil Gas Plant Performance

Gas power plants are a critical contributor of electric system reliability, and thus it is crucial to understand the conditions where these resources are not able to operate at capacity (in other words, the associated capacity is derated). There are two types of derates — forced and planned. Forced derates are unplanned and occur with less than seven days' notice; planned derates occur with seven or more days of notice. Forced derates can occur because of high ambient temperatures,[29] plant trouble, unplanned maintenance, or other reasons (for example, unplanned unit testing, or an environmental limitation on the number of hours per year that the unit can run). Planned derates occur because of routine maintenance or other

28 The average peak demand for LADWP was about 3900 MW for September 2024.

29 Gas plants, like many generating resources, operate less efficiently when ambient temperatures are high. During these times, these plants are more susceptible to mechanical failure, reduced efficiency, and a reduced operating range (that is, the range of MW which the plant can output). A reduction in the MW capacity of a plant due to temperature is an "ambient temperature derate." Because ambient temperature derates often occur on very hot days, they correlate with the times when system load is at the highest, and thus generating capacity is needed most.

reasons (for example, planned unit testing or an environmental limitation on the number of hours per year that the unit can run).[30]

Previous analysis explored planned and unplanned derates following the 2020 heat events.[31] Staff used information from the California ISO Prior Trade Date Reports[32] to analyze gas plant performance during the summer months for 2021–2023 for the *2024 CERRO.*[33] For this *2025 CERRO,* the analysis is updated to include the summer months of 2024.

This updated analysis, expanded in Appendix A, assesses power plant performance during peak hours, considered 4:00 p.m. through 9:59 p.m., in the summer reliability months of July, August, and September for 2021–2024. The analysis focuses on the availability of gas facility capacity utilizing historical data on capacity outages and derates for resources in the California ISO system. Outage data, as published daily in the California ISO "Prior Trade Date Reports,"[34] was aggregated to assess outage and derate trends across resource types, outage types, and operating hours. This analysis provides insight into the impact that derates have on the performance of the gas fleet.

Figure 10 shows the monthly average of daily maximum capacity derates for summer months of 2021–2024. Most fossil gas plant derates result from ambient temperature or plant trouble events (generally 60 percent to 70 percent of the maximum daily derated capacity comes from these two event types combined). Derates are shown as either forced (beginning with “F-“) or planned (beginning with “P-“). Specifically:

- **F-Ambient**: forced capacity derate due to high ambient air temperatures.
- **F-Trouble**: forced capacity derate due to plant trouble.
- **F-Other**: forced capacity derate due to “other conditions” (unit testing, environmental limitations reached, and so forth).
- **F-Maint**: forced capacity derate due to maintenance.

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30 Please see the Business Practice Manual for definitions of these terms: California ISO staff. 2023. *Business Practice Manual for Outage Management.* California ISO, https://bpmcm.caiso.com/BPM%20Document%20Library/Outage%20Management/Outage%20Management%20BPM_Version_30_Redline.pdf.

31 California Energy Commission staff. 2021. *Electric System Reliability and Recent Role of California’s Fossil Fleet: Actions Taken to Prepare for Summer 2021*. California Energy Commission. Publication Number: CEC-700-2021-002, https://www.energy.ca.gov/sites/default/files/2021-10/CEC-700-2021-002.pdf.

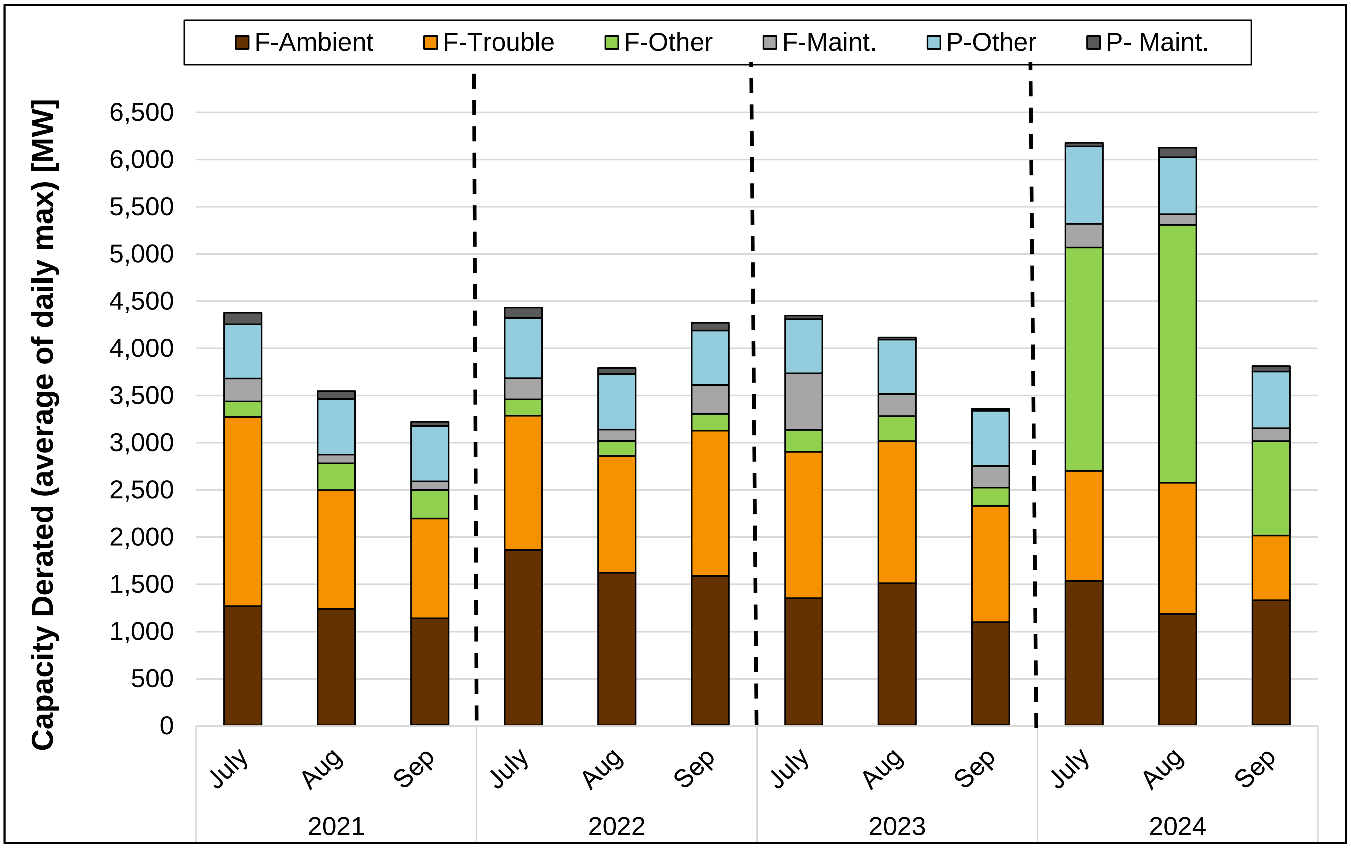
32 California ISO staff. N.d. “Curtailed and Non-Operational Generators.” California ISO, https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators.

33 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 Nyburg. 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.

34 California ISO. n.d. “Curtailed and Non-Operational Generators*.*” California ISO.

- **P-Other**: forced capacity derate due to planned other conditions (unit testing, environmental limitations reached, and so forth).
- **P-Maint**: forced capacity derate due to planned maintenance.

Figure 10: Fossil Gas Plant Derates



Source: CEC analysis of California ISO Prior Trade Date Reports, 2024: https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators.

Six once-through-cooling (OTC) units, listed in Table 2 below, experienced many hours of derates (no capacity available).[35] These derates occurred because, beginning January 1, 2024, these OTC resources are allowed to operate only for maintenance, air permit testing, during declarations of a heat event, or as needed to meet the Strategic Reliability Reserve Program[36] needs.[37] As these six OTC units are not part of the California ISO market, unless activated

35 Restrictions due to environmental regulations specific to a resource that limits the dispatchable capacity of that unit. See page 23 of California ISO. 2021. *Business Practice Manual for Outage Management*. https://bpmcm.caiso.com/BPM%20Document%20Library/Outage%20Management/Outage%20Management%20BPM_Version_28_redline.pdf.

36 California Energy Commission staff. N.d. “Strategic Reliability Reserve.” California Energy Commission. https://www.energy.ca.gov/data-reports/california-energy-planning-library/reliability/strategic-reliability-reserve.

37 California ISO staff. 2023. *Emergency Notifications*. California ISO, https://www.caiso.com/documents/emergency-notifications-fact-sheet.pdf.

through the SRR, they are considered separately in this analysis and excluded from most summary tables and charts.

These six OTC resources are listed in Table 2 below. These resources were completely unavailable for dispatch and had no capacity available for many hours during summer months in 2024. Even before being transferred to the SRR, the six OTC resources did not operate often, with annual capacity factors generally less than 5 percent and almost always less than 10 percent.

Table 2: OTC Units in SRR

OTC Resource Name	Nameplate Capacity (MW)	2021 CF (%)	2022 CF (%)	2023 CF (%)	2024 CF (%)
ALAMITOS GEN STA. UNIT 3	310	6.3%	10.5%	9.7%	0.5%
ALAMITOS GEN STA. UNIT 4	310	7.2%	10.2%	8.7%	0.3%
ALAMITOS GEN STA. UNIT 5	495	4.4%	2.6%	3.4%	0.4%
HUNTINGTON BEACH GEN STA. UNIT 2	218	4.7%	5.9%	9.2%	0.3%
ORMOND BEACH GEN STA. UNIT 1	806	2.1%	1.5%	1.0%	0.3%
ORMOND BEACH GEN STA. UNIT 2	806	4.3%	3.0%	2.8%	0.3%

Source: Environmental Protection Agency Clean Air Markets Program data, 2024, and staff analysis: https://campd.epa.gov/data/custom-data-download

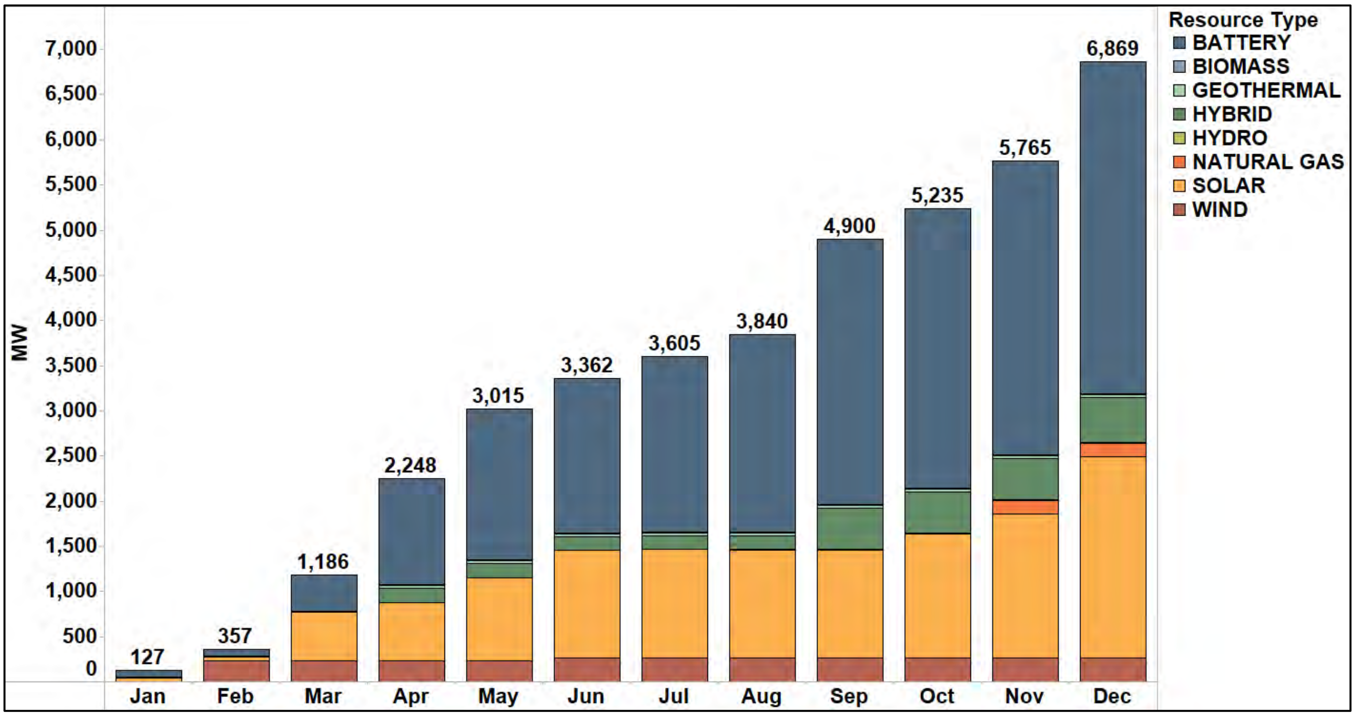
Staff found the following key themes with gas power plant performance:

- California ISO prior trade date report data appears reasonable to use for analyzing resource availability.
- For all resource types studied in the 2021–2024 summer months, cumulative derated capacity varies over time and does not show any strong year-over-year or month-over-month pattern.
- Event days (that is, when California ISO expects electricity supplies to not meet demand) during 2021–2024 were associated with increased daily peak loads (relative to non-event days) of about 7,400 MW (20 percent), on average. Adding 2024 data decreased the average over this period.
- In 2024, fossil gas resources reported about a 242 MW (8 percent) increase in derated capacity on event days vs. non-event days, during peak hours, 4:00 p.m. through 9:59 p.m., (that is, when California ISO expects electricity supplies to not meet demand). For 2023, this value was about negative 583 MW (1.8 percent decrease). The average for 2021–2024, July–September was about negative 211 MW (about a 5 percent decrease).
- For fossil gas resources, considering derated capacity due to ambient (high heat) conditions only, derated capacity from event days is larger than for non-event days (in all study months except August 2022). The difference ranges from about 150 MW to about 250 MW (10 percent to 20 percent) (for peak hours, for July–September). The average over 2021–2024 is 171 MW (a 13 percent increase).

Resource Build-Out Trends in the California ISO

Figure 11 shows the cumulative resource additions in 2024 based on the actual on-line date of the resource. From September through the end of 2024, year-to-date new capacity increases almost twofold. This increase shows that significant resource development continued through the end of 2024 and that capacity is available for summer 2025. More than 49 percent of the capacity, in 2024, was on-line before the start of summer, which contributed greatly to supporting grid reliability during the heat waves in July and September.

Figure 11: 2024 Cumulative Resource Additions

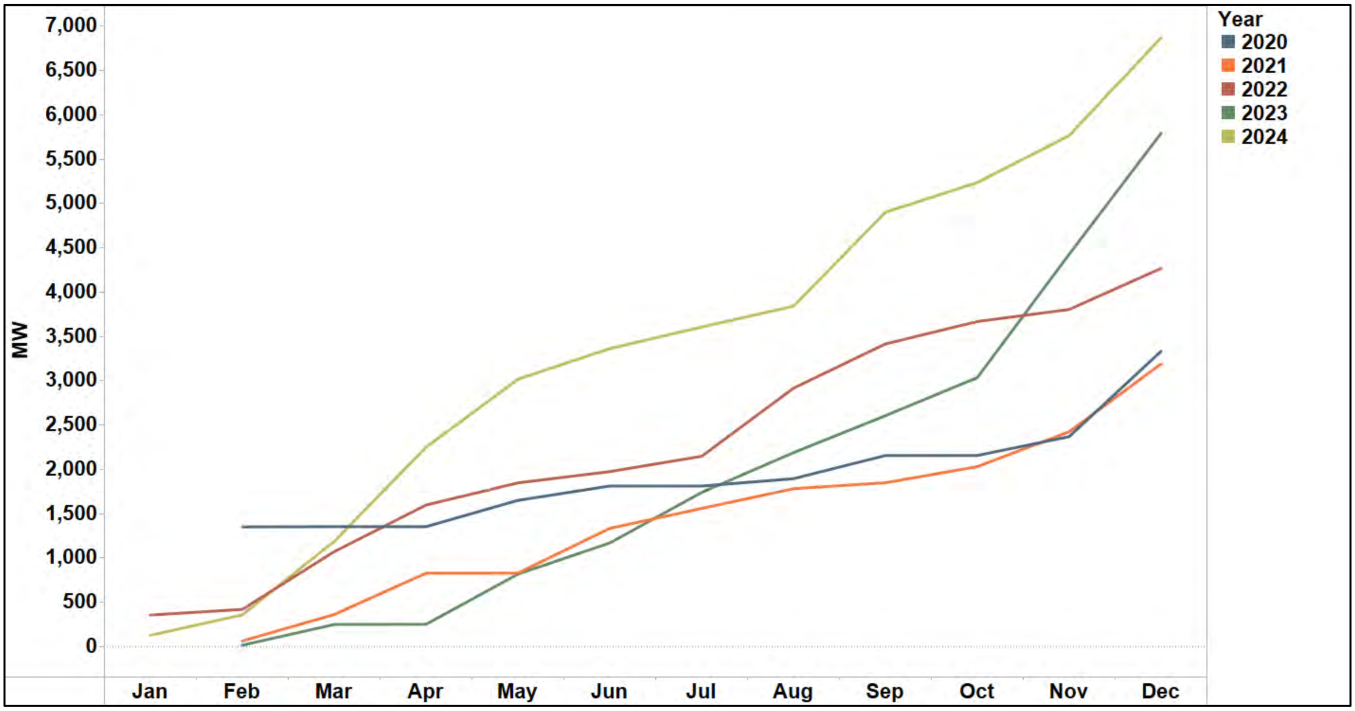


Source: California ISO master generating capability list 2/10/2025

Figure 12 shows the annual trends in new resource capacity by month. In 2020 and 2021, the resource builds were modest and gradually distributed across the months. However, 2022 and 2023 show steeper trendlines, indicating substantial amounts of capacity build-out. In 2024, the new capacity on-line set a new five-year record. The following provides two key takeaways for 2024:

- The year 2024 was another record year for resource development — adding more than 6,800 MW of new capacity.
- The year 2024 had more resources come on-line before the summer compared to the prior four years.

Figure 12: 2020–2024 Annual Trends



Source: California ISO master generating capability list as of 2/10/2025

CHAPTER 4: 2025 Summer Conditions

Demand Forecast

California's electricity demand forecast presents multiple scenarios. The baseline sales scenario extends existing trends into the future ("business-as-usual"). The managed sales 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 forecast scenarios used by utilities and other state agencies are the Planning Scenario and the Local Reliability Scenario.

In the most recent *2024 IEPR Update*, the Planning Scenario sales and the Local Reliability Scenario sales are marginally lower than baseline sales in the first few years of the forecast period, including the year 2025. However, both managed sales forecasts then increase to be more than 20 percent higher than baseline sales by 2040.

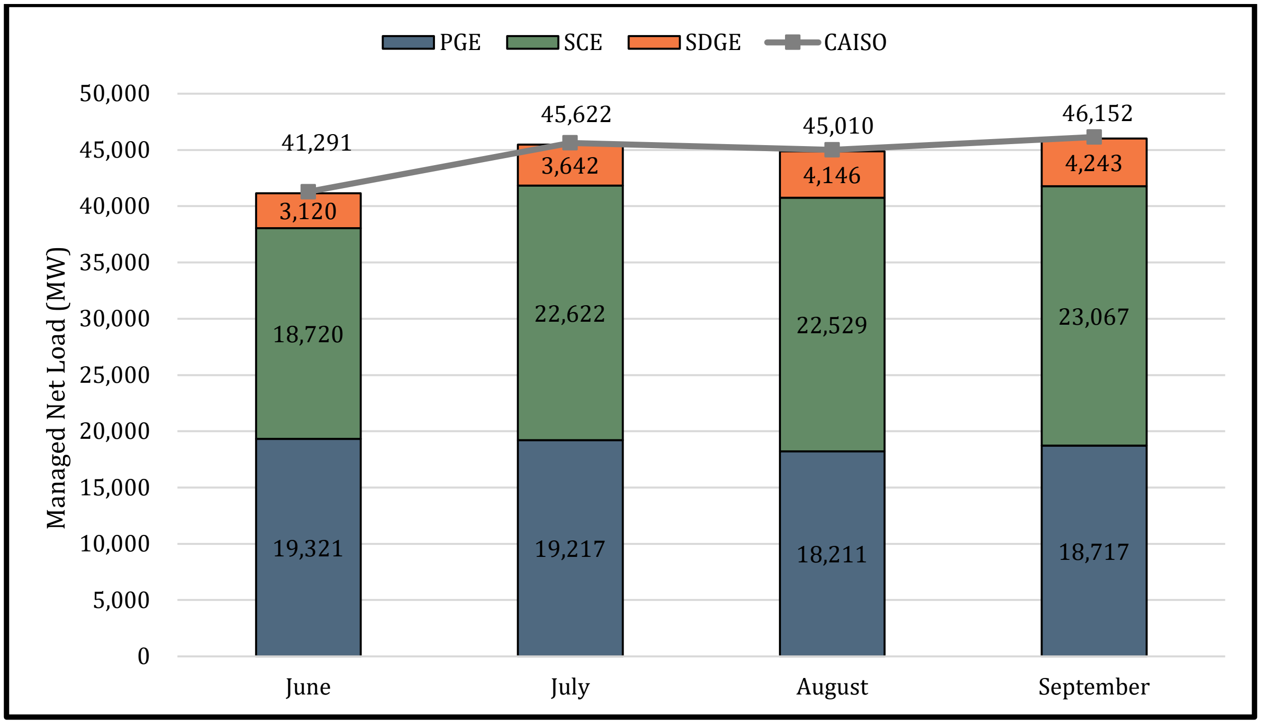
Per the *2024 IEPR Update* Planning Scenario, after subtracting out the energy generated from solar PV and other behind-the-meter resources, statewide energy sales for 2025 are forecast to be more than 245,000 GWh. This forecast represents a 1.5 percent increase over the historical sales recorded for 2023. The increase is due to a return to positive population growth, continued economic expansion as well as the growing impacts of transportation electrification and data centers.

Hourly electricity demand typically peaks in the summer months of July, August, or early September. The coincident peaks[38] forecast for the summer months of 2025 for the entire California ISO territory, composed primarily of the PG&E, Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) Transmission Access Charge (TAC) areas, are shown in Figure 13. Note that the annual system peak[39] for the California ISO territory of more than 46,000 MW is forecast to occur in September, but the July and August peaks have a comparable magnitude. The annual system peak could be reasonably expected to occur in any of these months.

38 *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.

39 The annual system peak is the point of highest demand experienced by the entire California ISO transmission system for a given year.

Figure 13: California ISO Coincident Monthly Peaks in Summer 2025

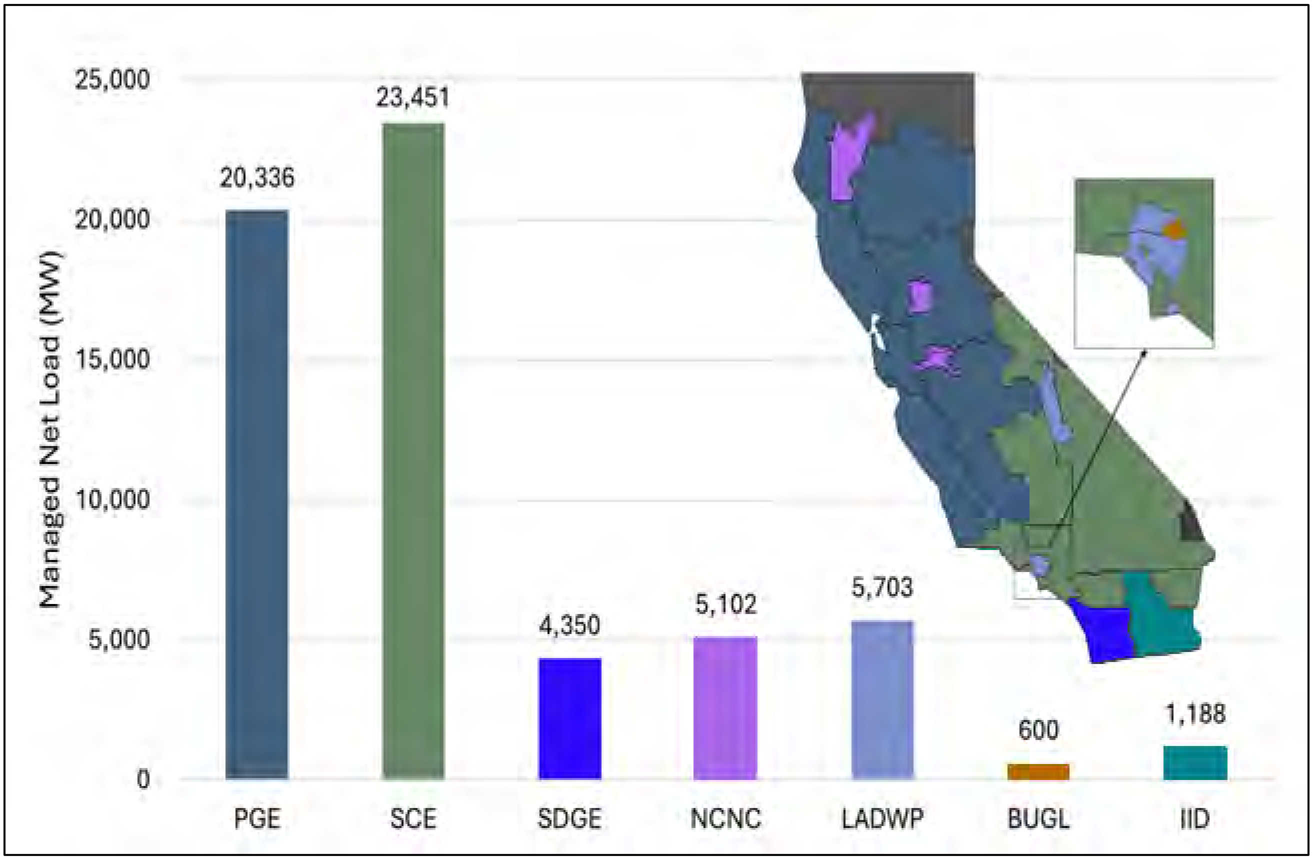


Source: CEC *2024 IEPR Update* Planning Forecast

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 supplied by the Valley Electric Association (VEA).

Figure 14 shows the annual noncoincident system peaks from the *2024 IEPR Update* Planning Forecast for the IOU TAC areas within the California ISO control area, as well as the four other main planning areas within California. The noncoincident TAC area peaks sum to a total of more than 48,000 MW, roughly 2,000 MW higher than the coincident California ISO system peak. In addition, the non-California ISO peaks sum to nearly 13,000 MW in 2025, for a statewide noncoincident total of nearly 61,000 MW.

Figure 14: Noncoincident Annual Peaks in 2025



Source: CEC *2024 IEPR Update,* 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 2025 summer temperature outlook suggests a high likelihood of above-normal temperatures throughout the West in the peak months of July, August, and September. The coincidence of high temperatures in California and other parts of the WI is a particularly bad weather scenario as imports become less available when power is needed most.

The Climate Prediction Center (CPC), under the National Weather Service and National Oceanic and Atmospheric Administration (NOAA), prepares forward-looking climate predictions on temperature and precipitation. The National Drought Mitigation Center at the University of Nebraska-Lincoln, NOAA, and the U.S. Department of Agriculture prepare jointly the U.S. Drought Monitor. The following information comes from the CPC three-month temperature and precipitation outlooks,[40] recent NOAA La Niña updates,[41] and U.S. Drought Monitor conditions and outlooks.[42]

La Niña conditions are one phase of the El Niño Southern Oscillation (ENSO), representing patterns of cooler-than-average sea surface temperatures in the tropical Pacific Ocean. 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. During late 2024, ENSO conditions transitioned from neutral to La Niña, with La Niña emerging in December and January. The CPC expects this La Niña to be weak and persist for several months, then potentially transition back to neutral by May. A transition to neutral conditions potentially means relatively cooler and wetter weather in the southern half of California compared to La Niña conditions, but ENSO neutral conditions make the climate less predictable.

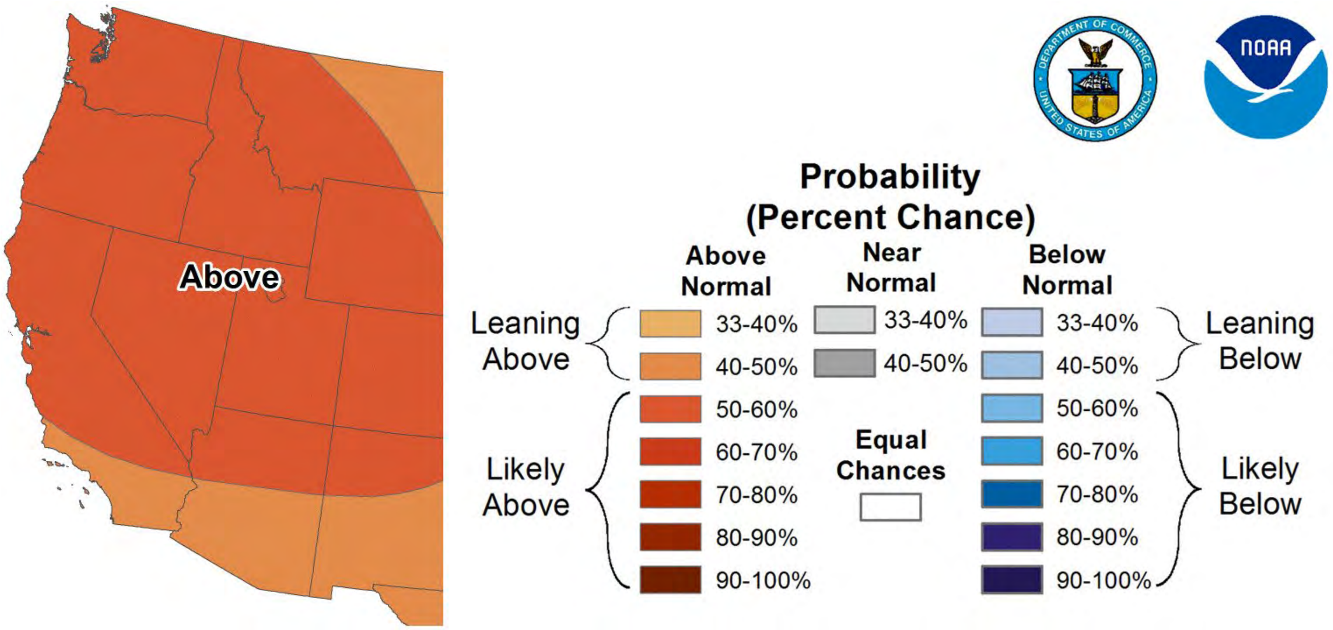
The CPC expects above-normal temperatures throughout the western United States for July through September. Most of California, the northern parts of Arizona, and the entirety of Oregon, Washington, Idaho, Nevada and Utah have a 50 percent to 60 percent chance of above normal temperatures this summer. Other portions of the western states range from 33 percent to 50 percent chance of above-normal temperatures. Given that normal summer temperatures are already hot in California, the outlook means a significant chance for westwide heat events corresponding with extreme temperatures in California, a recipe for challenging and stressful grid conditions for the California ISO and other balancing authorities. Figure 15 shows the CPC Seasonal Temperature Outlook for July, August, and September 2025.

40 Climate Prediction Center staff. N.d. *Three-Month Outlooks Official Forecasts.* National Oceanic and Atmospheric Administration National Weather Service. https://www.cpc.ncep.noaa.gov/products/predictions/90day/.

41 Becker, Emily. January 9, 2025. *January 2025 update: La Niña is here.* National Oceanic and Atmospheric Administration, Climate.gov. https://www.climate.gov/news-features/blogs/enso/january-2025-update-la-nina-here.

42 U.S. Drought Monitor. N.d. *Conditions & Outlooks*. National Drought Mitigation Center. https://droughtmonitor.unl.edu/ConditionsOutlooks.aspx.

Figure 15: CPC Seasonal Temperature Outlook for July, August, and September

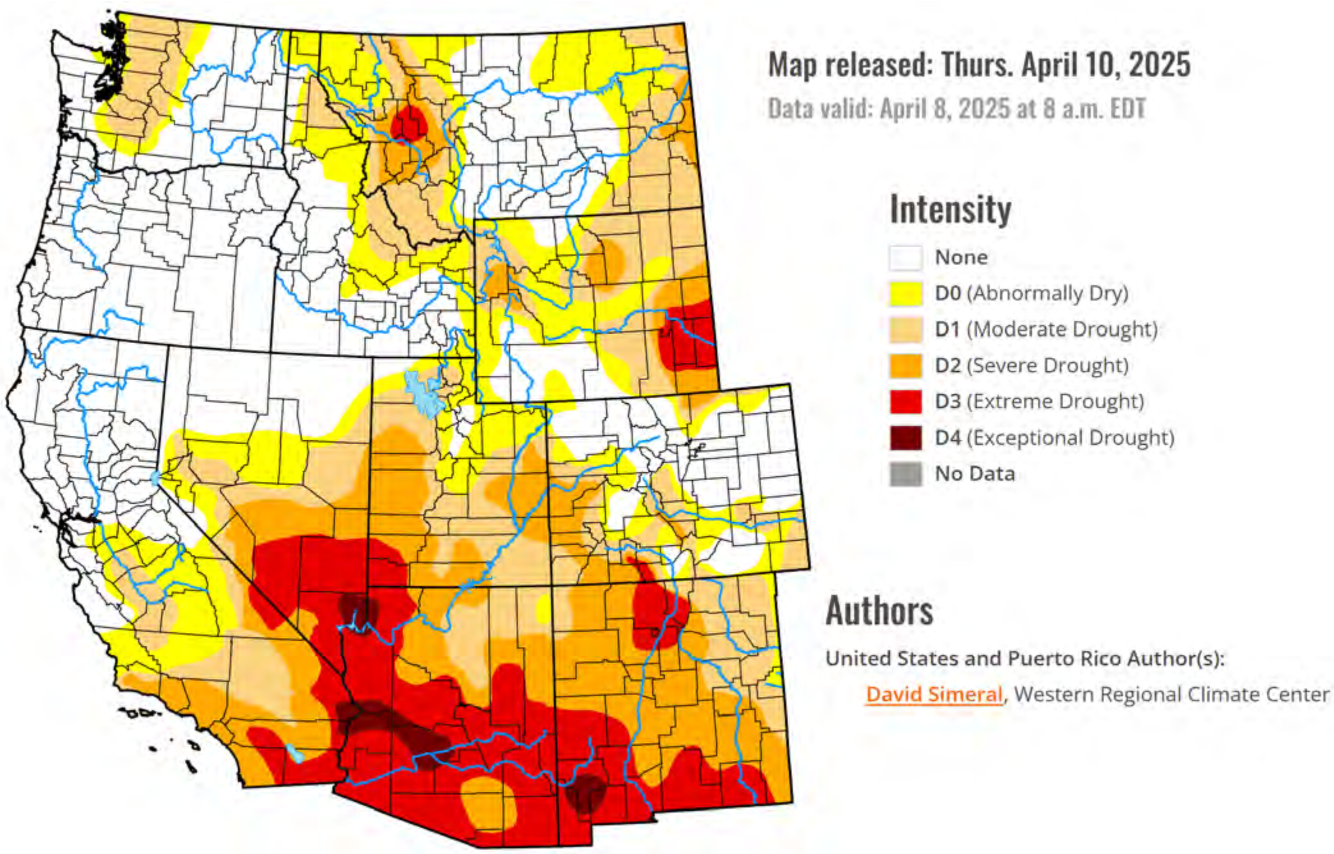


Source: CPC Seasonal Temperature Outlook for July-August-September 2025, valid March 20, 2025

One year ago, California was drought-free in most of the state[43] after many years of droughts, but dry conditions in Central and Southern California have brought drought back to these areas. Southern California has experienced almost no rain for most of fall and winter, resulting in severe and extreme drought conditions throughout the region. Drought is occurring throughout the western region and is expected to persist there during the current outlook period through June. The CPC expects normal precipitation levels throughout California for July through September, which means relatively little rain in most of the state to alleviate drought conditions for summer. Figure 16 shows the current U.S. Drought Monitor conditions for the western states. Figure 17 shows the CPC Seasonal Precipitation Outlook for July through September.

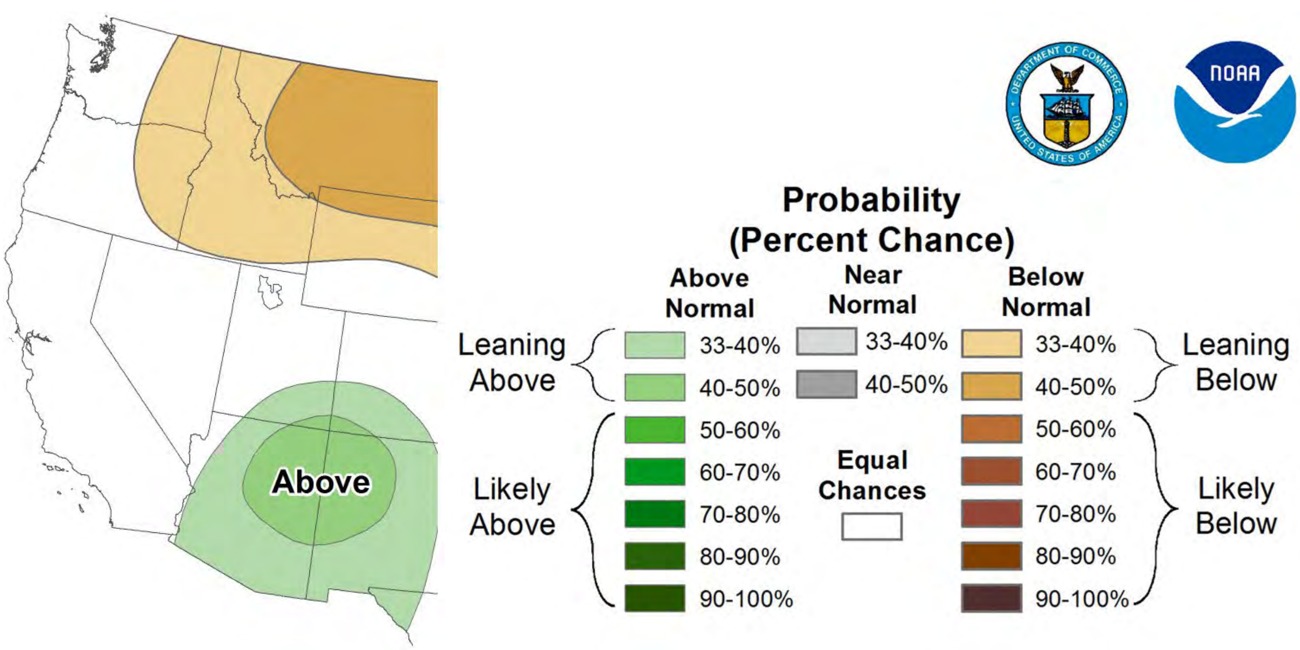
43 U.S. Drought Monitor. 2024. "Drought Conditions — February 13, 2024." National Drought Mitigation Center, https://droughtmonitor.unl.edu/data/png/20240213/20240213_west_date.png.

Figure 16: U.S. Drought Monitor Conditions for the Western United States



Source: U.S Drought Monitor for April 10, 2025

Figure 17: CPC Seasonal Precipitation Outlook for July, August, and September



Source: CPC Seasonal Precipitation Outlook for July-August-September 2025, valid March 20, 2025

California Wildfire Risk

Wildfire and risk of wildfire can disrupt energy systems directly and indirectly. Heat and smoke can directly damage equipment or disrupt 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 shutoff for firefighter safety.

Impacts to power lines near wildfires or within dangerous wildfire conditions can affect equipment in other parts of the electricity system, forcing physical impacts elsewhere. Proactive adjustments may also be needed once major equipment has been forced offline or derated to ensure the system can withstand other potential contingencies. For example, if a major power line is forced out of service, the system nearby may be less capable of resisting additional disturbances, so flows on other power lines may be proactively reduced. Because electricity equipment can cause ignitions, utilities may proactively shutoff certain power lines for safety during elevated wildfire conditions, a policy known as Public Safety Power Shutoffs.

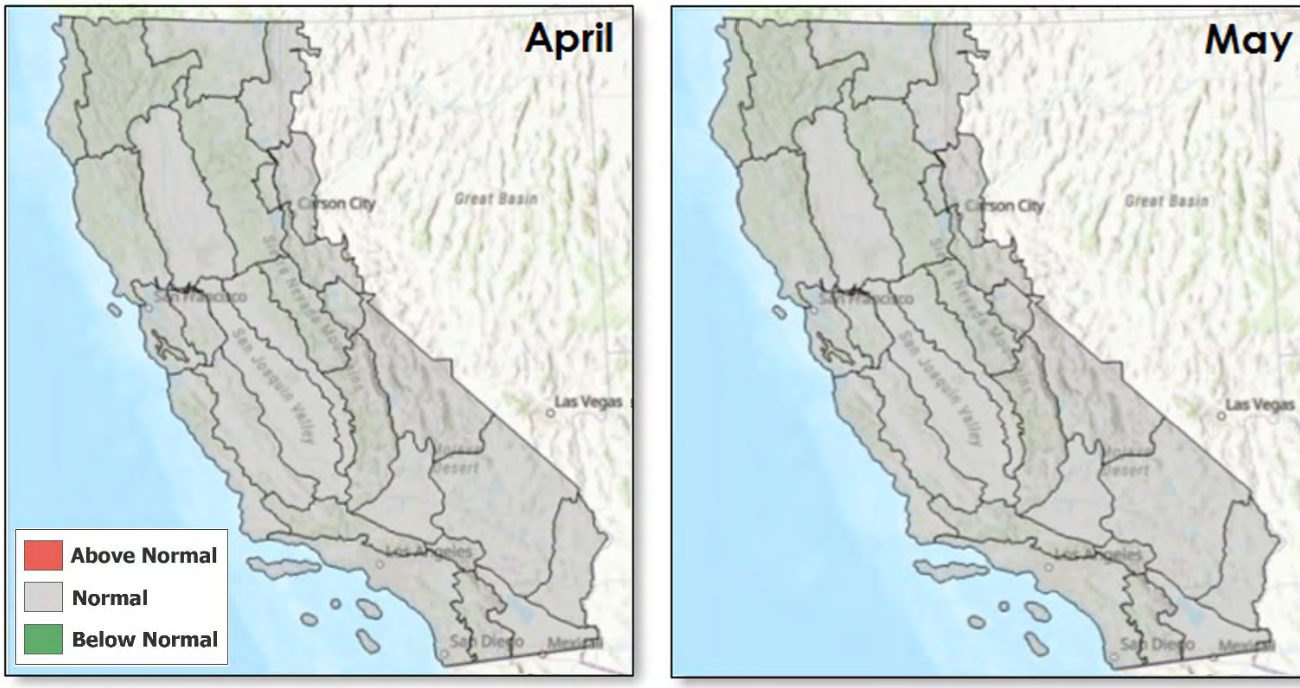
The Wildfire Forecast & Threat Intelligence Integration Center (WFTIIC) serves as California's central organizing hub for wildfire forecasting, weather information, threat intelligence gathering, analysis, and dissemination, including a monthly four-month outlook.[44]

The current WFTIIC four-month outlook forecasts normal conditions for wildfires throughout the state in April and May and above normal conditions in many areas throughout the state in June and July.[45] Northwestern transmission import paths feeding utilities throughout the state, and other transmission feeding Northern and Southern California's load centers, traverse these areas with above normal conditions. Significant wildfire potential is relative to the month and location and many areas are prone to wildfires in the summer and fall, so destructive fires can still occur even in normal or below normal conditions. Figure 18 shows the significant wildfire potential for California for April and May 2025. Figure 19 shows the significant wildfire potential for California for June and July 2025.

44 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/.

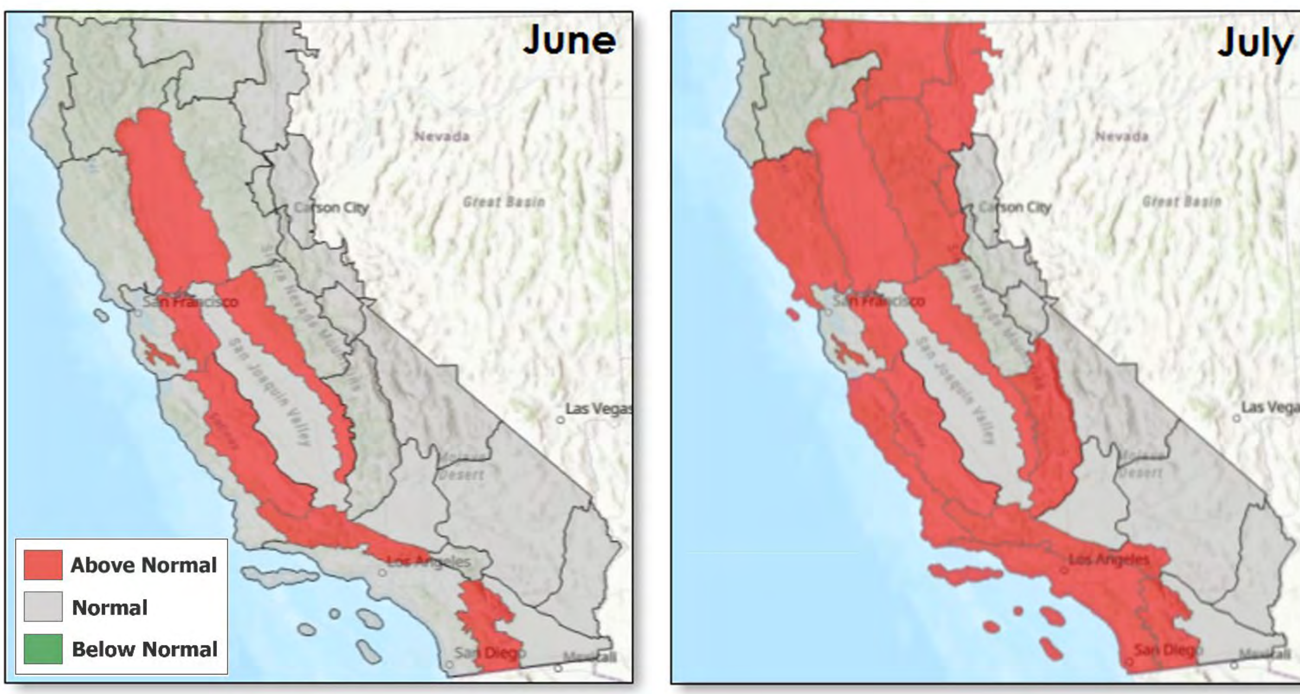
45 Wildfire Forecast and Threat Intelligence Integration Center staff. N.d. "WFTIIC Four Month Outlook Production." Wildfire Forecast and Threat Intelligence Integration Center, https://hub.wftiic.ca.gov/pages/four-month-outlook.

Figure 18: WFTIIC Significant Wildfire Potential for April and May



Source: WFTIIC Four-Month Outlook for April and May 2025 valid April 1, 2025

Figure 19: WFTIIC Significant Wildfire Potential for June and July



Source: WFTIIC Four Month Outlook for June and July 2025 valid April 1, 2025

Western Water and Wildfire

During California peak demand, imported power is essential for reliability. Some of these imports consist of hydroelectric power fed by reservoirs in the north and southwest regions of the WI and over transmission lines located in high-risk wildfire regions. Current water level observations indicate potential limitations on the availability of water this year for hydroelectric generation in the WI and consequently for imports into California. Significant wildfire potential in California, Oregon and Nevada presents a risk for California's critical northwest hydroelectric import paths.

The U.S. Bureau of Reclamation measures and reports water levels for major reservoirs in the western United States.[46] The organization also compares water level observations at each reservoir to a seasonal average based on 30 years of water level observations there for the same day of year. A final assessment of reservoir water levels usually occurs in April, so the observations below are preliminary for a summer assessment.

Most major reservoirs in California, Oregon, and Washington have reached or exceeded seasonal average water levels. Overall, water levels are at 123 percent of average for major reservoirs in California, 141 percent of average for Oregon, and 113 percent of average for Washington. The current reservoir levels suggest California water will likely be available this year for electricity generation and use in the state.

Water levels are below seasonal average at many other major reservoirs in the WI. In fact, for Lake Mead and Lake Powell, the two largest reservoirs in the western United States, seasonal water levels are the lowest recorded in the last 30 years, at 55 percent and 57 percent of the seasonal averages, respectively. For comparison, the capacities at Lake Mead and Lake Powell are each greater than those of all major reservoirs in California, Oregon, and Washington combined. Although Lake Mead and Lake Powell hydroelectric generation provides a relatively small portion of California load, 1 percent or less over a year, lack of water supply could result in water at other reservoirs being prioritized for uses other than electricity.

Oregon and Nevada include areas with elevated wildfire potential traversed by the California-Oregon Intertie and the Pacific DC Intertie, the two critical north-to-south hydroelectric import paths into California. The California-Oregon intertie provides up to 4,800 MW of import capacity to Northern California utilities, while the Pacific DC Intertie provides up to 3,200 MW of import capacity to Southern California utilities.[47] Current forecasts predict normal fire conditions in the Pacific Northwest states through June, but normal conditions in some of these areas indicate significant potential for major wildfires, particularly in Oregon.[48] By July,

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46 Reclamation Information Sharing Environment staff. N.d. "Reservoir Conditions." United States Bureau of Reclamation, https://data.usbr.gov/visualizations/reservoir-conditions/.

47 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.

48 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.

above normal wildfire potential is expected in many areas of California, Oregon and Nevada. This fire potential creates a risk of losing northwest hydroelectric import capacity on these lines because of direct or indirect fire impacts.

Much of British Columbia is experiencing abnormally dry or moderate drought conditions with pockets of severe drought.[49] Wildfire risk conditions are expected to remain normal in British Columbia through April, but normal conditions still mean significant potential for major wildfires.[50] Starting in May, above normal wildfire conditions are expected to develop in British Columbia, with most of the province above normal by June. Similar drought conditions are present in Alberta, although hydroelectric resources are minimal in this region. The drought in British Columbia is a reliability concern as close to 90 percent of the region's capacity is derived from hydroelectric resources.

California Hydroelectric Conditions

While early-season storms in November and December boosted snow levels in the Northern Sierra, the Central and Southern Sierra have remained below average. The DWRs second snow survey[51] of the 2025 winter season recorded a snow depth of 22.5 inches at Phillips Station, with a snow water equivalent[52] of 8 inches — 46 percent of the historical average for the location. Statewide, the snowpack is at 65 percent of average, a decline from 108 percent on January 1 due to an exceptionally dry January. Officials warn that sustained dry conditions could further impact the state's water outlook despite expected storm activity in February.

Despite the snowpack decline, California's reservoirs remain well-managed and above historical averages. Lake Oroville is at 126 percent of average, and San Luis Reservoir is at 101 percent. Southern California reservoirs are also near or above average, though the region remains below normal for yearly precipitation. In response, the Department of Water Resources has deployed more than 30 watershed protection specialists to help lower debris flow risks in wildfire-impacted areas.

New California Resources

In 2025, the California ISO is set to bring on-line a range of new energy resources to enhance grid reliability and the state's clean energy goals. These additions include new solar, wind, and battery storage capacity. As California continues to adapt to increasing electricity demand and

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

50 Carr, Richard, Ginny Marshall, Jim Wallmann, Julie Osterkamp, Steve Larrabee, Martin Ibarra Ochoa, Dario Rodriguez Rangel, Alejandro J. Garcia Jimenez, and Jose L. Solis Aguirre. 2025. *North American Seasonal Fire Assessment and Outlook: Outlook Period April 2025 Through June 2025*. National Interagency Fire Center, https://www.nifc.gov/nicc-files/predictive/outlooks/NA_Outlook.pdf.

51 California Department of Water Resources staff. 2025. "Snowpack Dips Well Below Average in Second Snow Survey of the Season." California Department of Water Resources, https://water.ca.gov/News/News-Releases/2025/Jan-25/Snowpack-Dips-Well-Below-Average-in-Second-Snow-Survey-of-the-Season.

52 Amount of liquid water in the snow.

climate-related challenges, these new resources will play a critical role in maintaining system reliability and meeting long-term energy goals. With a total of more than 2,100 MW of new capacity expected to come on-line before the start of summer, the state continues to support a stable and sustainable power supply.

Table 3: California ISO Queue Cumulative Expected Resources (in MW) as of April 1, 2025

Resource Type	Jan	Feb	Mar	Apr	May	Jun
Battery	1	3	844	1,429	1,662	1,722
Geothermal	0	0	0	0	0	0
Hydro	0	6	6	6	6	6
Natural Gas	0	0	64	64	64	131
Other	0	0	0	0	3	3
Solar	17	23	77	77	227	227
Wind	0	0	27	27	27	27
Total Expected	**18**	**32**	**1,018**	**1,604**	**1,989**	**2,116**

Source: California ISO New Resource Interconnection

Status of Energy Storage

Battery energy storage continues to be an important technology that extends the reach of intermittent renewable energy by shifting energy to periods of peak demand. Specifically, energy storage addresses the variability associated with solar and wind power by capturing this energy that might otherwise be lost and delivering it later in the day during high-demand periods. The rapid expansion of battery energy storage has occurred across the residential, commercial, and utility sectors in California. It is useful in stabilizing the electric grid over the short term and enabling time-shifting of energy deliveries over the longer term throughout each day.

Deployment of battery energy storage in California has grown significantly over the past few years. At the start of 2021, California had 1,475 MW of installed storage capacity, with 850 MW at the grid level and 625 MW installed behind the meter. Three years later, on April 25, 2024, Governor Gavin Newsom announced that California had reached a major storage milestone: surpassing 10,000 MW of installed battery energy storage capacity.

California closed the year with more than 14,000 MW of storage installed across the state and an additional 740 MW of storage directly connected to the California ISO grid from Arizona and Nevada. About 12,000 MW is from 190 utility-scale storage systems serving the grid within the state.

The rapid growth of behind-the-meter installations in the residential and commercial sectors also continued through 2024. It is estimated that there are more than 200,000 behind-the-meter battery energy storage systems installed across the state. Together, these two sectors add almost 2,000 MW of distributed behind the meter storage resources.

A comprehensive interactive Tableau dashboard is available on the CEC website.[53] The dashboard tracks battery energy storage installations and includes filters for zip codes, county, and date installed. The dashboard is updated semiannually with the next update planned for mid-April.

Resource Adequacy

Tight RA[54] supply conditions have been influenced by several factors, including more extreme weather events that increase demand and reduce generation, as well as reduced hydroelectric availability due to drought. Delays in bringing new resources online — caused by permitting, interconnection issues, and supply chain challenges — have further constrained supply. Moreover, regional constraints, such as tight supply westwide[55], within the WI have reduced the availability of imports to California.

Regulatory changes have also played a role. For example, adjustments to how to account for variable energy resources like wind and solar in meeting RA requirements and the authorization for IOUs to exceed planning reserve margin targets have affected the supply available to other load-serving entities. Requirements on energy imports[56] to ensure that those imports are associated with a physical resource may have also reduced the availability of western resources for contracting with CPUC jurisdictional entities.

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53 California Energy Commission staff. N.d. "California Energy Storage System Survey." California Energy Commission, https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/california-energy-storage-system-survey.

54 CalCCA staff. N.d. "Resource Adequacy: California's RA Supply Problem." CalCCA, https://cal-cca.org/resource-adequacy/.

55 WECC staff. N.d. "Western Assessment of Resource Adequacy 2024." WECC, https://feature.wecc.org/wara/#group-section-Summary-eSoUDW1Hw8.

56 California Public Utilities Commission staff. N.d. *Decision Adopting Resource Adequacy Import Requirements*. California Public Utilities Commission, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF?.

CHAPTER 5: Electric Reliability Analysis

This chapter provides the electric reliability analysis for summer 2025 through 2030. California is projected to meet system reliability standards through 2030 even with a 40 percent reduction in planned new resources. For summer 2025, there are no shortfalls expected under extreme conditions, but a coincident wildfire impacting transmission could create tight conditions and a need for contingency resources.

The CEC uses two methods that provide valuable, but different, perspectives on the reliability outlook — a loss-of-load expectation (LOLE) and a resource stack analysis. A loss-of-load expectation, or RA analysis, 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. RA analyses allow resource planners and policy makers to determine whether enough resources are being planned for or procured. A resource stack analysis is also used to evaluate the potential need for contingency resources under a variety of conditions. A resource stack analysis can capture specific circumstances that may not be under the control of resource planners and policy makers, such as extreme weather events and resource delays, to guide contingency planning and is best used for near-term planning.

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.[57] This approach is a deterministic analysis spanning near-term horizons, with a focus on the peak summer months, July to September. The analysis compares anticipated supply against projected demand, incorporating a 17 percent PRM, equivalent to the current RA planning standards for CPUC-jurisdictional entities.

California ISO Area: Updated Resource Stack Analysis Results for Summer 2025

As shown in Table 4, several changes have been made to the resource stack since the release of the 2024 Fourth Quarterly *Joint Agency Reliability Planning Assessment.* This analysis focuses on Hour 18 of September, a period of high demand coupled with lower supply, making it the most critical time for evaluating potential shortfalls. The most notable update is the addition of more than 2,800 MW to total supply, driven primarily by the increase in existing resources. The increase is due to an NQC value being assigned to new resources or scheduling coordinator modifications of NQC values for existing resources since the last report or both. In

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

addition, new battery capacity projections increased by more than 300 MW, while solar capacity grew by more than 20 MW.

On the demand side, the updated 2024 California Energy Demand forecast increased the projected peak demand for September 2025 by 180 MW, bringing it to 46,152 MW. This modest demand increase, combined with higher supply, has improved the overall reliability outlook.

Table 4: Comparison of Summer Assessment Results for September 2025 – Hour 18

	2024 4th Quarterly Report	2025 1st & 2nd Quarterly Report	Change Since Last Update
Supply			
Demand Response	1,052	1,033	▼ **19**
Existing Resources	44,992	48,032	▲ **3,040**
New Batteries Nameplate	1,383	1,722	▲ **339**
Wind	1,326	1,305	▼ **21**
Solar	1,738	1,765	▲ **27**
RA Imports	6,000	5,500	▼ **500**
Total (MW)	**56,491**	**59,357**	▲ **2,866**
Demand			
Sept. Peak Demand	**45,972**[58]	**46,152**[59]	▲ **180**
Surplus/Shortfalls			
Planning Standard	3,265	5,512	▲ **2,247**
2020 Equivalent Event	753	2,980	▲ **2,227**
2022 Equivalent Event	-845	1,368	▲ **2,213**

Source: CEC staff with California ISO data

*Existing resources adjusted to align with Department of Water Resources' (DWR) forecasted hydroelectric generation for summer 2025.

Wildfire Risk and Reliability Impacts

Coincident fire risk continues to pose a significant challenge to California's electric grid. Wildfires like the 2021 Bootleg Fire, which reduced import capacity by 3,000 MW within the California ISO territory and 4,000 MW overall, can have serious impacts on the system. This critical transmission path was again affected in 2024 when the Pine Fire caused a similar

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58 For 2024 summer using 2023 California Energy Demand Data

59 2024 California Energy Demand Data. Note: There is an error in the demand forecast that does not significantly impact the results of the stack analysis in this report. The overall conclusions and forecasted conditions remain the same, despite the error. The data will be updated with the revised demand forecast in the next quarterly report.

reduction in imports. These types of events can sharply reduce surplus capacity during peak demand periods, increasing the risk of electricity shortages.

While tight system conditions are considered in the stack analysis, these projections do not fully account for wildfire-related risks, which could lead to losses of up to 4,000 MW. As climate change continues to drive more extreme weather, large wildfires, like the Los Angeles fires in January earlier this year, remain a serious threat to reliability. Table 5 highlights the combined impact of wildfires and extreme heat, showing that California could face supply shortfalls under extreme conditions if major transmission lines are forced offline by fire.

Table 5: Impact of Wildfires on Reliability

System Conditions	Surplus/Shortfalls
Planning Standard	**1,512 MW**
2020 Equivalent Event	**-1,020 MW**
2022 Equivalent Event	**-2,632 MW**

Source: CEC staff

Statewide Resource Stack Analysis

This section expands the Resource Stack Analysis to include supply and demand from all load-serving entities (LSEs) and publicly owned utilities (POUs) statewide. The 2024 *CERRO* included the three largest POUs by load (LADWP, IID, and the Sacramento Municipal Utility District [SMUD]), outside the California ISO Balancing Area, cumulatively serving more than 10 GW[60] of customer peak demand. These were included by way of the electric resource plans submitted to the CEC in 2022 through the supply forms and instructions. In this report, the 2025 Resource Stack Analysis used data collected through the 2024 supply forms[61] to evaluate the amount of reliable capacity and net qualifying capacity (NQC) against average and extreme conditions as defined in Table 6.

For the planning standard case, each LSE's and POU's reported peak demand is applied a planning reserve margin (PRM), as reported in the submitted supply forms. The summation of all LSE and POU peak demand plus PRM results in a statewide resource requirement of 64,500 MW to meet California customer load under average conditions and planning standards. In extreme events, such as equivalent events observed in 2020 and 2022 (Table 6), the statewide resource requirements to ride through those conditions increases to 67,200 MW and 69,200 MW, respectively. However, in 2025, the total reliable capacity reported in the supply forms is 73,400 MW, which includes existing and planned supply capacity. In comparing the resource requirements and total reliable capacity, Figure 20 shows that there is at least a

60 California Energy Commission staff. N.d. "Utility Plans From 2022." California Energy Commission, https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/utility-plans-2022.

61 California Energy Commission staff. N.d. "California Energy Commission: Docket Log: 24-IEPR-02." California Energy Commission, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=24-IEPR-02.

4,000 MW margin in the most extreme events (2020 and 2022 equivalent events). The overall statewide situation is positive under extreme events, which creates greater opportunities for coordination among balancing areas within California.

Table 6: 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– 17% Statewide Average Planning Standard – 16.92%	6%	5%	6%	4,000 MW	Statewide Average is primarily driven by 50 entities using 17% PRM or above while only 17 entities use a 15% PRM.
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, 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 20: 2025 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 interconnection outages. Coincident fire risk affecting major transmission lines could impact grid conditions by limiting the availability of imported supply by up to 4,000 MW.

Loss of Load Expectation Analysis

CEC consultant Telos Energy performed a probabilistic assessment of the reliability outlook from 2025 to 2040 under the supply forecast in the CPUC 2023 Preferred System Plan (PSP). This analysis sought to determine if California is meeting the reliability criterion of 1 day in 10-year loss of load expectation (LOLE), or 0.1 days/year LOLE, under a variety of scenarios related to the resource build and import uncertainty. Unlike previous assessments that focused on summer reliability risk, this analysis was conducted across the entire year to better understand the shifting of resource adequacy risk over the study horizon due to changes in the load and resource mix. Several resource adequacy risks are assessed in this analysis, combining uncertainty in resource availability, hourly demand, unexpected generator outages, lower-than-expected imports, and delays in resource builds.

The study finds that the California power system has sufficient resources to meet or exceed the 1 day in 10-year loss of load expectation (0.1 days/year LOLE) resource adequacy criterion and serve load under challenging demand and resource additions in 2025. Furthermore, if California's LSEs successfully integrate new resources identified in the California Public Utilities

Commission (CPUC) Preferred System Portfolio (PSP), the state will have sufficient resources to exceed the 0.1 days/year LOLE resource adequacy through 2035, even with projected increases in electricity demand compared to when the portfolio was developed.

System reliability is expected to continue to significantly improve in the near term compared to previous assessments. This is due to (1) significant new resource additions (including utility-scale solar, wind, and batteries, and distributed rooftop solar), (2) new energy efficiency and demand response programs, (3) the near-term retention of Diablo Canyon Power Plant (DCPP), and (4) projected reduction in summer peak demands relative to those that were used to design the generation mix used in this study (the 2023 PSP). Results of the scenarios and sensitivities are provided in Table 7.

The study did not evaluate all potential risk, and future work is being conducted to evaluate other aspects of power system reliability, including the impacts of transmission outages and alternative load scenarios, such as increased or different electric vehicle charging patterns. While the Base Case study results show that California is expected to meet or exceed its resource adequacy targets, higher-than-expected temperatures across the Western Interconnection, drought conditions, or transmission outages could lead to loss of load, or a combination.

Table 7: Resource Adequacy Results Across Scenarios

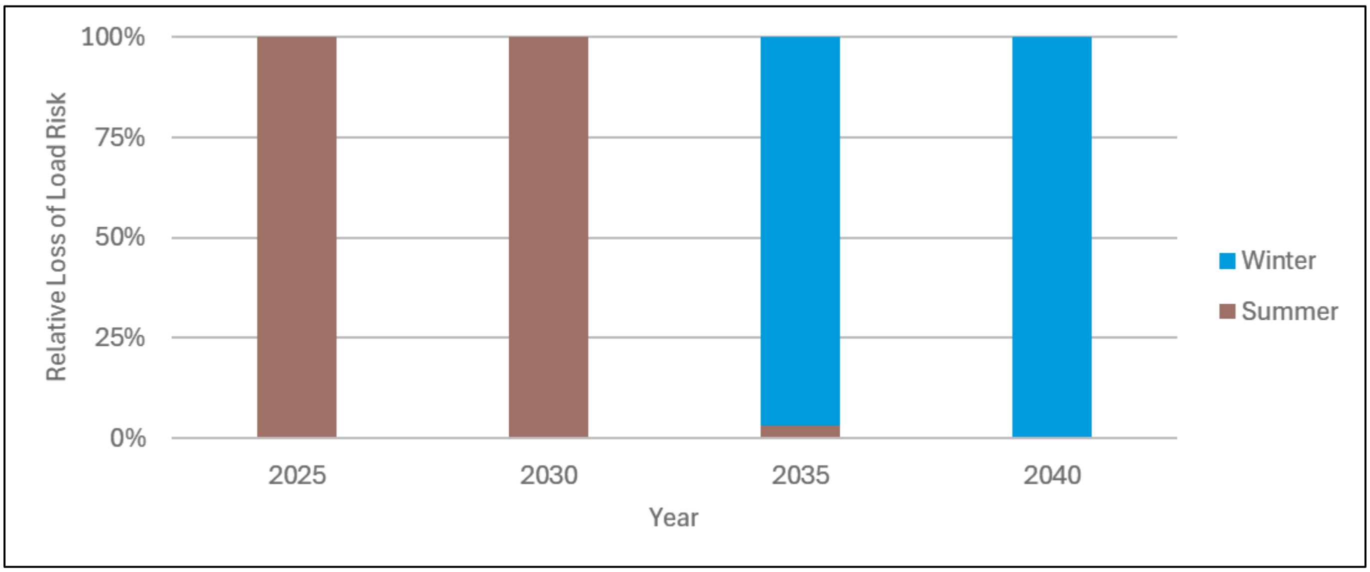
Scenario	Metric	2025	2030	2035	2040
Base Case LOLE	LOLE (days/year)	0.00	0.00	0.01	0.90
Base Case Effective Surplus / Deficit	GW	10+ GW Surplus	9-10 GW Surplus	4-5 GW Surplus	1-2 GW Deficit
Extend DCPP	LOLE (days/year)			0.00	0.57
Full PSP, No Imports	LOLE (days/year)	0.00	0.00	6.62	Greater than 10
40% Reduction in PSP	LOLE (days/year)	0.00	0.00	0.79	Greater than 10
40% Reduction in PSP + No Imports	LOLE (days/year)	0.003	0.17		

Source: Telos Energy

Over the study horizon, projected increases in electricity demand — notably from the increased adoption of electric vehicles and heat pumps — could significantly change the timing and season of California's resource adequacy risk. Historically, the greatest resource adequacy risk of California's power system has been during hot summer afternoons. With the increased adoption of solar PV, resource adequacy risk has shifted to later in the evening. As demand from heating electrification increases, resource adequacy risk is projected to shift to overnight and early morning periods in the winter, when solar production is low or nonexistent. This projected shift is a marked departure from California's longstanding challenges that focus on summer resource adequacy risk and will require evaluating whether system planning, maintenance scheduling, demand response programs, and other investments will need adjustments to address winter reliability risks.

The figure below[62] shows how the risk is distributed between summer and winter by study year. The near-term (through 2030) risk is dominated by summer reliability events, consistent with California's historical stress. As noted in the section "Characterizing System Risk," 2035 represents either a winter-risk or a dual-risk year depending on the scenario under study. By 2040, the system is dominated by winter risk.

Figure 21: Relative Resource Adequacy Risk by Season Across the Study Horizon



Source: Telos Energy

Model Development and Key Assumptions

To evaluate the resource adequacy (RA) of California's power system under a variety of scenarios, a probabilistic, hourly, chronological resource adequacy simulation was conducted in the PLEXOS modeling software. Other California entities use the software for RA analysis, including the California Independent System Operator (California ISO). This California RA model was developed using public information to the maximum extent possible. Where relevant, the CEC aligned key inputs and assumptions with the California Public Utilities Commission (CPUC) Resource Adequacy Study and the California ISO Summer Reliability Assessments.

62 Each year is brought to a 0.1 LOLE criterion by either adding firm load or perfect generation. Results presented here are those closest to 0.1 days/year LOLE. The figure shows the share of unserved energy (MWh) occurring in each season.

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. On balance, these changes have increased the resource adequacy risk for California. The list below provides an overview of the major changes implemented in the model.

- **Demand update** — The CEC issued a new Integrated Energy Policy Report California Energy Demand (IEPR CED, or simply "2024 CED"). This 2024 CED reworked major portions of the net load forecast, including reducing the behind-the-meter solar forecast, increasing the fuel substitution layer, and adding gigawatts of new data center load. The net peaks throughout the 2030s increased relative to the previous CED version and the load forecast used to develop the PSP.
- **Inclusion of 2022 and 2023 weather years** — The weather years underpinning the analysis were expanded to include 2022 and 2023. This expansion was done across load, wind, and solar profiles. Notably, the addition of the 2022 weather year is expected to increase the observed LOLE as a heat wave in September of that year stressed the system.
- **Stochastic loads** — The CEC developed underlying stochastic load profiles aligned with historical weather patterns. These new profiles replaced previous implementations that relied upon other data sources. These new profiles ensure the simulated electricity demand follows similar chronological weather patterns as the simulated solar and wind profiles.
- **Renewable availability profiles** — In addition to adding 2022 and 2023 weather years across the utility-scale solar (UPV), distributed solar (DPV), and land-based wind (LBW) profiles, the underlying development of the profiles was updated for utility-scale plants to capture increased granularity of project siting to improve modeling accuracy. In addition, the LBW profiles make use of the new NREL dataset[63] for weather years 2015–2023 and incorporate a bias correction method to align simulated wind generation with observed performance in California ISO.
- **Updated outage modeling** — Following a review of California ISO daily generation reports,[64] the natural gas outage sampling in PLEXOS was updated to better align to the NERC GADS Forced Outage Factor. The net effect reduced the modeled forced outage rate, making the gas fleet more reliable and aligned with California ISO observations over the last three years (2021–2024).

63 Buster, Grant, Pavlo Pinchuk, Luke Lavin, Brandon Benton, and Nicola Bodini. 2025. "Bias Corrected NOAA HRRR Wind Resource Data for Grid Integration Applications." National Renewable Energy Laboratory, https://data.openei.org/submissions/6218.

64 California ISO staff. N.d. "Outage Management." California ISO, https://www.caiso.com/library/outage-management.

Model Topology

The CEC's RA model is California-centric, meaning power plants for the state are modeled in detail, but areas 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), which are grouped together as California ISO when appropriate, as well as four publicly owned utility balancing authority areas (BANC, TID, LADWP, and IID). Further information on model topology and import assumptions is detailed in Appendix C.

Demand Forecast

This analysis uses the 2024 Integrated Energy Policy Report Update California Energy Demand (IEPR CED) forecast. The model uses weather-correlated demand and renewable shapes for 17 weather years representing 2007 to 2023. The underlying demand and behind-the-meter solar layers are assumed to be weather-dependent and varied across weather years. All other load modifiers (such as electric vehicles, energy efficiency, and so forth) do not vary in peak or energy by weather year, but the profiles are shifted to align with the historical calendar used in each weather year.

Of note, the 1-in-20 net peak[65] forecast modeled in this report is 1,600 MW lower in 2025 as compared to the 2022 CED used to develop the resource mix in the 2023 PSP.[66] This reduction is attributed to a variety of factors, including reduced correlation between electricity and temperature and a larger-than-anticipated adoption of behind-the-meter solar generation. However, when compared to previous versions of the CED demand forecast, load is projected to grow faster throughout the study horizon. By 2028, the 1-in-20 peak roughly aligned between the forecast vintages. However, the updated 2035 summer 1-in-20 net peak forecast exceeds the forecast used to develop the PSP supply mix by more than 7,500 MW.[67] As a result of this demand forecast change, the PSP may now have fewer resources than necessary to meet long-term reliability targets.

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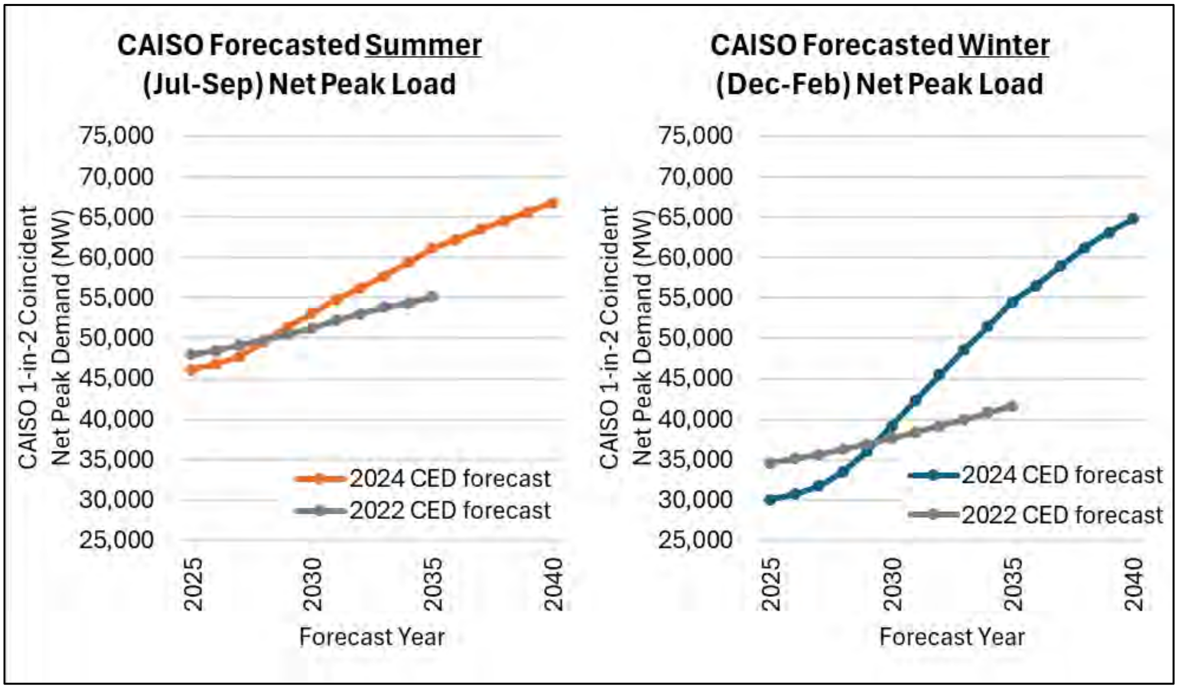
65 "Net peak" load throughout this report, consistent with the IEPR CED Forecast terminology, means the load that is expected to be served by utility-scale generation. Thus, it includes all load modifiers and the effects of distributed solar generation.

66 The demand forecasts used across efforts are the latest that are available. In the case of the 2023 PSP effort, the CPUC team used the 2022 IEPR Update CED Forecast. For this modeling exercise, the team is using the 2024 IEPR Update CED, which was released in January 2025.

67 Even though the official 2022 IEPR Update CED forecast stops in 2035, the 2023 PSP includes resources built to serve load through 2045 based loads that were either defined through the 2021 IEPR High Electrification Interagency Working Group (HEIAWG) dataset or linearly extrapolated.

Figure 22: Statewide Coincident Peak Demand Forecast



Source: Telos Energy

In addition to the growth in overall peak demand, the updated 2024 CED also includes higher load growth in winter months compared to previous iterations. This growth is most apparent in the 2030s, with the 2024 CED forecasting a California ISO net peak in February 2035 of 54,500 MW, compared to 41,600 MW forecasted in the 2022 iteration, a difference of nearly 13,000 MW. While all regions in California are forecast to be summer peaking throughout the horizon (2025–2040), the winter peak in California ISO is only 2,000 MW below the summer peak in 2040. Coupled with decreased solar generation during winter months, the study shows that winter becomes the primary season of resource adequacy risk even if California remains a summer peaking system.

Resource Additions

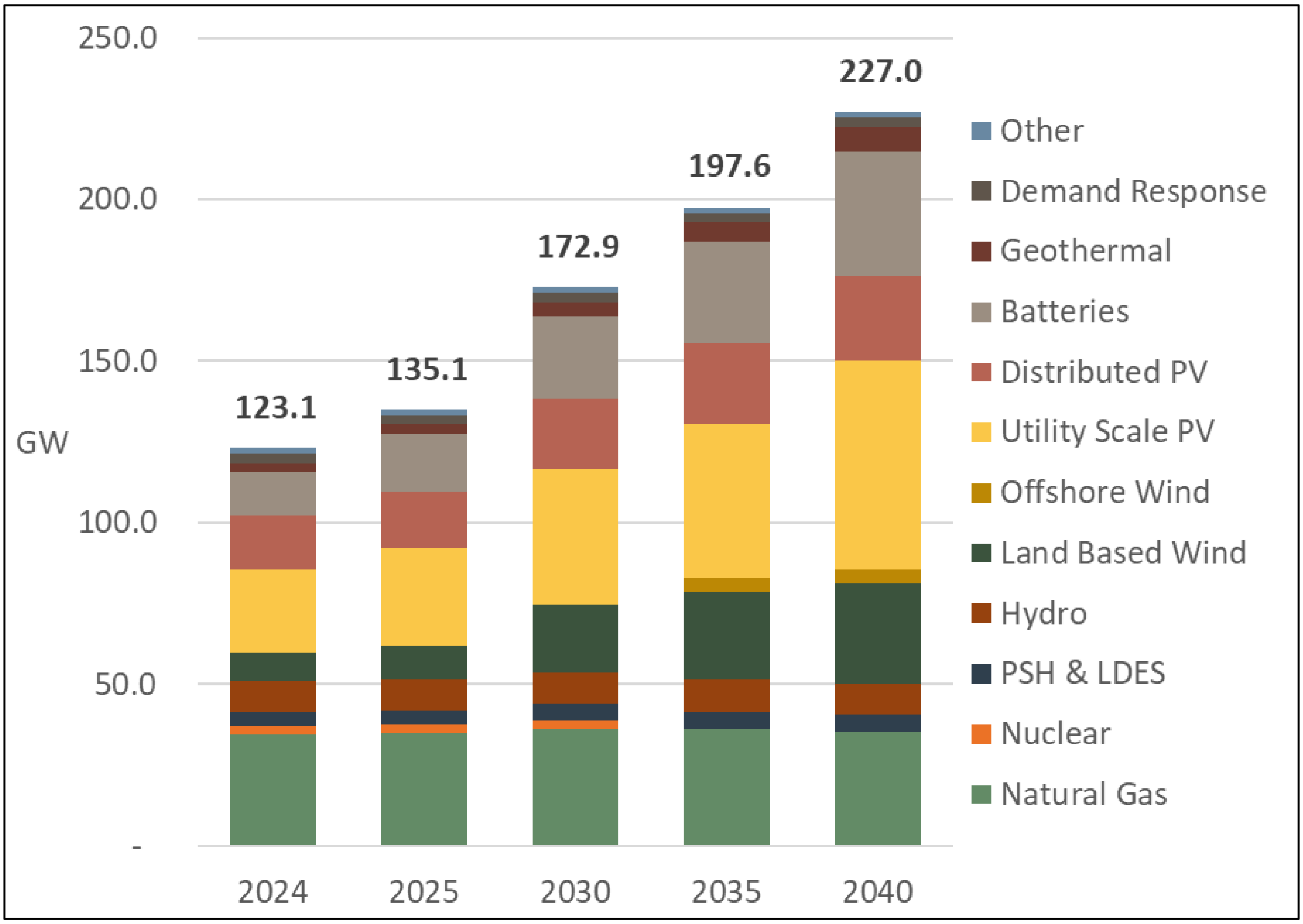
All resource additions and retirements for California ISO and non-California ISO regions were sourced from the CPUC-adopted 2023 PSP released in February 2024.[68] Expansion resources include in-development resources already under contract and generic resource additions generated from the CPUC's capacity expansion modeling using the RESOLVE modeling platform. Figure 23 shows the total installed resources projected across California for each year, including out-of-state resources intended for use by California. Appendix C provides further information on resources projected to come on-line each year.

68 California Public Utilities Commission staff. N.d. "2022–2023 IRP Cycle Events and Materials." California Public Utilities Commission, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials.

The planning reserve margin constraint in the PSP is often nonbinding, meaning that the PSP resource build is driven primarily by the need for new zero-carbon and renewable resources to meet GHG reduction targets — and battery energy storage to shift production to high load periods — rather than resource adequacy needs. For that reason, it is expected that the PSP resource build will meet the 0.1 days/year LOLE criterion.

The projected retirements used in this analysis also align with the PSP. The once-through cooling and generic gas retirements are balanced against the gas additions such that the gas amounts align with the PSP. Notably, this analysis includes Diablo Canyon as available through 2030–2031, while the PSP assumed the nuclear power plant retired at the previous planned retirement dates as directed by SB 846.

Figure 23: Total Installed Capacity Across California by Study Year



Source: Telos Energy

Additional Inputs and Assumptions

Further detail on inputs and assumptions are provided in Appendix C.

Results and Discussion

Base Case Results

With all new PSP resources successfully deployed, the modeling results project that California will exceed the reliability criterion, beginning in summer 2025, and extending through the mid-2030s. The results indicate that the California system is expected to have sufficient resources — under normal hydro and transmission conditions — to meet the 0.1 days/year LOLE criterion in these future study years provided that the PSP resources are added as expected. The resulting resource adequacy metrics are provided below.

- 2025 Base Case: No shortfall events
- 2030 Base Case: No shortfall events
- 2035 Base Case: No shortfall events
- 2040 Base Case: 0.9 days/year LOLE

The 2025, 2030, and 2035 Base Case results are largely consistent with recent reports from the CEC, including the 2025 SB 846 Combined Q1 and Q2 report[69], 2024 Q1 report,[70] and the 2024 California Energy Resource and Reliability Outlook[71] released in August 2024.

With this report, staff is able to model the future 2040 calendar year. Under base case assumptions, 2040 sees an LOLE of 0.9 days/year, which is nine times higher than the LOLE criterion. As noted in the section "Notable Updates From Previous CEC Reliability Reports" above, the updated demand forecast includes significant winter load growth in the 2030s primarily due to heat pump adoption. This load growth forecast was not an input into the development of the PSP used in this study and, once reflected, will likely drive resource plans in subsequent resource planning cycles. These findings, further highlighted in characterizing risks, elevate the need to evaluate how to adapt resource planning frameworks to account for the seasonal and overnight shift of system risk.

These results indicate that the probability of resource shortfalls is very low in the near term, provided that the PSP additions are brought on-line as planned and under normal hydro and transmission conditions. However, California could face a variety of additional challenges that

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69 Yee Yang, Chie Hong, and Brendan Burns (CPUC). April 2025. *Joint Agency Reliability Planning Assessment*. California Energy Commission. Publication Number: CEC-200-2025-004, https://www.energy.ca.gov/publications/2025/joint-agency-reliability-planning-assessment-covering-requirements-sb-846.

70 Yee Yang, Chie Hong, and Sarah Goldmuntz (CPUC). May 2024. *Joint Agency Reliability Planning Assessment*. California Energy Commission. Publication Number: CEC-200-2024-006, https://www.energy.ca.gov/publications/2024/joint-agency-reliability-planning-assessment-covering-requirements-sb-846-first.

71 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.

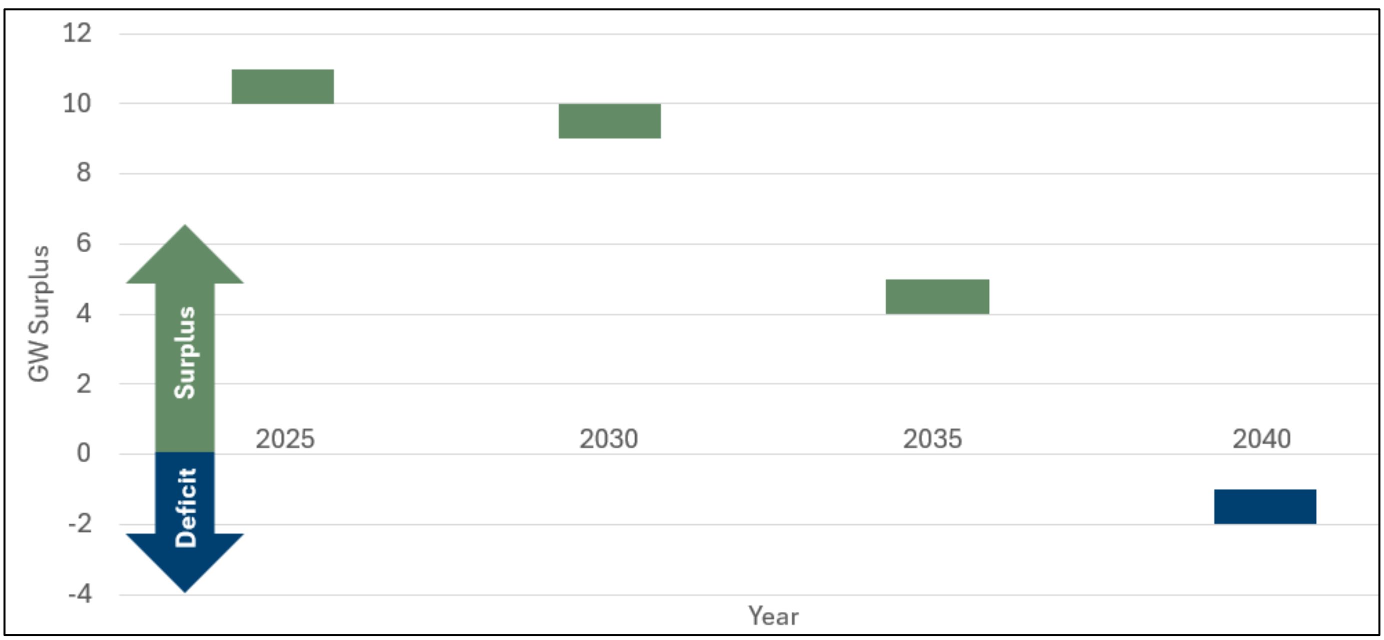
could lead to resource adequacy deficits. Staff evaluated additional sensitivities to test system reliability if things do not go according to plan, including a reduction in future generator build-out, removing California's ability to import power from neighbors, modifying California ISO's import ability during periods of high system stress in future years, and varying hydroelectric generation availability. Widespread western drought or wildfires or both could also pose a resource adequacy risk but were not explicitly considered in this analysis.

Surplus Calculations

To provide additional information, the CEC quantified the amount of that 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 24 below. This analysis indicates that California's statewide surplus is expected to diminish across the study horizon, from 10-11 GW in 2025, to 9–10 GW in 2030, 4–5 GW of surplus in 2035, and ultimately a deficit of 1–2 GW is expected in 2040. These surpluses assume the full PSP resource build is successful and assumes normal hydro conditions and transmission capability, including that the California ISO Total Import Constraint is at 11,655 MW in all hours except for summer evenings. Again, this level of near-term reliability is driven by resource additions built for greenhouse gas emissions reductions, a reduced near-term load forecast relative to the one used to design the resource mix, and the retention of Diablo Canyon through 2030–2031.

Figure 24: Expected Surplus Capacity Across California (Full PSP, Full Imports)



Source: Telos Energy

Shifting Nature of System Risk

California's power system risk has historically been defined by periods of high temperature, low solar 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 RA 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. Rather than heat waves driving shortfalls, a combination of cold snaps and cloudy conditions will likely be the largest source of grid stress. Importantly, this analysis reveals that by 2035, California's system likely becomes either winter risk or dual-risk across the winter and summer months, depending on the scenario. By 2040, the risk is primarily observed in the winter, regardless of the scenarios considered.

The figures below show the percentage of unserved energy from across the year that occurs within any given hour. These 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. The percentages in each table add up to 100 percent within any study year and provide an indication of when resource adequacy risk occurs.

While each case is calibrated to roughly 0.1 days/year, the underlying nature of the resource adequacy risk shifts across the study horizon as the resource mix and load profiles evolve. Figure 25 shows how unserved energy is distributed throughout the day and year. It shows that resource adequacy risk shifts later in the day, from early evening in 2025 to overnight periods and winter periods in 2035 and 2040. In 2025, resource adequacy risk is predominately driven by capacity deficits, when there is insufficient available capacity to serve load. As nearly 20 GW of battery storage is added to the system, the resource adequacy risk shifts to overnight periods. In rare instances, the battery storage discharges all available energy and has insufficient state of charge to continue discharging in overnight periods.

Figure 25: Distribution of Unserved Energy (MWh) Across the Year for Each Study Year

2025 No Imports / 40% Reduction in PSP												
Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	0%		0%	0%	0%
19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%		0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%		0%	0%	0%

2030 + 9GW Fixed Load												
Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0%	0%	0%	0%	0%	0%	0%	0%		0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	0%		0%	0%	0%
19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%		0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%		0%	0%	0%

2035 + 4GW Fixed Load												
Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
1	0%	0%	0%	0%	0%	0%	0%	0%		0%	0%	
2	0%	0%	0%	0%	0%	0%	0%	0%		0%	0%	
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
4	0%	0%	0%	0%	0%	0%	0%	0%		0%	0%	
5	0%	0%	0%	0%	0%	0%	0%	0%		0%	0%	
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
7		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
8		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	

2040 + 1GW Perfect Generation												
Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0		0%										
1		0%										
2		0%										
3		0%										
4		0%										
5		0%										
6		0%										
7												
8		0%										
9		0%										
10		0%										
11	0%	0%										
12	0%	0%										0%
13	0%	0%										0%
14	0%	0%										0%
15	0%	0%										0%
16	0%	0%										0%
17	0%	0%										0%
18	0%	0%										
19	0%	0%										
20	0%	0%										
21	0%	0%										
22	0%	0%										
23		0%										

Source: Telos Energy

While the chart above shows 2035 as primarily a winter risk season, the dual-risk nature of 2035 is revealed when examining additional scenarios. For example, when another gigawatt of firm load is added to the system for a total of 5 GW, the risk profile shifts dramatically. To ensure that this is not just a function of distorted load profiles due to large amounts of fixed load, an additional scenario is shown that captures 2035 with a full-year California ISO constraint and 40 percent reduction in PSP resources, with these sensitivities discussed more in the sections that follow. The relative ratio of summer vs. winter risk varies depending on the scenario, but loss of load risk is consistently observed in summer and winter months in 2035. Appendix X further validates this point through examining two weather years that drive the largest deficits in the 2040 base case and information detailing the size, frequency and duration of shortfall events.

Moving into the 2030s, California planners can no longer consider just heat waves when assessing power system risk. Grid stress conditions are a function of weather conditions, and the resource mix designed to serve load. Planners must increasingly consider a broad set of conditions that are likely to challenge resource adequacy.

Sensitivity Analysis: 40 Percent Reduction in Future Resources

In addition, California's resource adequacy was evaluated with a 40 percent reduction in future resource additions assumed in the PSP to assess whether the system can maintain resource adequacy if procurement delays, or project cancellations occur. This evaluation represents a hypothetical risk assessment and does not imply that a 40 percent reduction in the PSP is likely or expected. For the 40 percent reduction scenario, CEC staff and consultant Telos Energy evaluated resources reductions for future generating resource additions in the California ISO regions (PSP) and non-California ISO regions. This 40 percent reduction was applied across all resource types, from utility-scale solar to new firm resources, such as natural gas and geothermal.

The 40 percent reduction scenario shows minimal reliability risk in 2025 and 2030, with 0 LOLE in either year. This scenario indicates that even if some new resources additions are delayed, resource adequacy can still be maintained. However, when PSP additions are reduced by 40 percent and retirements of Diablo Canyon and other gas generators are assumed by 2035 as is in the base case, the system shows increased LOLE risk (0.79 days/year), exceeding the reliability criterion. This trend is exacerbated in 2040, where LOLE risk exceeds the 0.1 days/year reliability criterion by more than 100 times in a scenario where the PSP resource build is reduced by 40 percent. This finding shows the dependence of the future system on achieving the resource additions identified in the PSP as the system undergoes evolution.

Additional sensitivity analyses are available in Appendix X.

Future Work

While this analysis evaluates resource adequacy risks for California, it is not exhaustive. 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 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 2035, California's primary reliability risk period could be winter 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 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 that changes, 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.

Drought Conditions and Wildfire Risks

The results presented in this analysis assume normal hydro conditions and do not assess potential impacts of wildfires, including both of transmission and reduced solar production from smoke. Potential drought conditions and impacts of climate change will need to be better assessed in future studies to help prepare the state, and its power system, for potential challenges.

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 future 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 electric vehicles, 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:
Extreme Event Preparedness

Coordinated planning and a high degree of communication continue to factor into the successful response to challenging grid conditions. This response includes maintaining and implementing the California ISO's operational playbook, which fosters collaboration and communication with entities such as state agencies, load-serving entities, and other balancing authorities. In addition, the Strategic Reliability Reserve (SRR) ensures that programs are available for addressing reliability risks during extreme events.

Strategic Reliability Reserve

The SRR provides funding to secure conventional generation, capacity expansion at existing power plants, demand response, distributed energy resources, and energy storage. The SRR consists of three programs, two of which are administered by the CEC, and one is administered by DWR. Table 8 shows on-line or expected capacity from each program for the 2025 summer months.

Table 8: Strategic Reliability Reserve Expected Program Capacity (MW), Summer 2025

Strategic Reliability Reserve Program	July	August	September
DWR Electricity Supply Strategic Reliability Reserve Program	3,079	3,079	3,079
CEC Demand Side Grid Support	530	540	545
CEC Distributed Electricity Backup Assets	0	0	0

Source: CEC staff

- **The Demand-Side Grid Support (DSGS) Program** provides statewide incentives for electricity customers to reduce load and dispatch backup generation on an on-call basis. The DSGS is similar to the CPUC's Emergency Load Reduction Program, which is limited to customers in IOU territories, but is available to IOU and non-IOU customers and continues to expand participation options to enroll more clean energy resources.

  Launched in August 2022, the program has undergone guideline updates to increase participation and bring more zero-emission resources on-line. Key revisions include expanded eligibility, additional participation options for clean resources such as virtual power plants, streamlined processes, and the inclusion of bi-directional electric vehicle chargers in the virtual power plants. By the end of the 2024 program season, the DSGS program had more than 269,000 participants and a total enrolled capacity of 514 MW. This capacity is incremental to the RA supplies procured by load-serving entities in accordance with the normal reliability planning standards.

On March 17, 2025, the CEC adopted the Fourth Edition of the DSGS Program Guidelines, refining the program for the 2025 summer season. Major modifications include adding Energy Emergency Alert triggers for the storage virtual power plants and a new emergency load flexibility virtual power plant participation option.

- **The Distributed Electricity Backup Assets Program** offers incentives for the construction of clean and more efficient distributed energy resources. The CEC adopted program guidelines in October 2023, with funding to be made available through grants. The first grant opportunity, released in December 2023, allocated $150 million for efficiency upgrades and capacity additions at existing bulk grid power plants. In April 2024, the CEC announced a proposed award of for 9 projects, which would add about 297 MW of new capacity by 2027. Three of these agreements have been approved, with more expected throughout the year.

  In February 2024, the CEC released a draft concept proposal for the second grant funding opportunity focused on distributed energy resources. The CEC anticipates releasing the final version of this grant opportunity pending the 2025–2026 state budget.

- **The Electricity Supply Strategic Reliability Reserve Program (ESSRRP)** is managed by DWR and provides additional generation capacity to support grid reliability. Program actions include extending the operating life of existing generation facilities planned for retirement, procuring temporary power generators, procuring energy storage, or reimbursing the above market costs for imports beyond traditional planning standards.

  In August 2023 the State Water Board approved the extension of the once-through cooling compliance dates. As part of the ESSRRP, these once-through cooling plants are only called upon to support grid operations in anticipation of or during extreme events and no longer provide power to the market on a consistent basis. They are also allowed to operate to conduct maintenance and for annual air permit testing.

When fully operational, the SRR could provide up to 3,500 MW of additional capacity. In summer 2022, DSGS and ESSRRP were activated to provide resources. In addition to the SRR, the state has identified an additional 1,500 MW of supplemental contingency resources that may be available during an extreme event. In total, California has roughly 5,000 MW of contingency resources between the SRR programs and supplemental resources. Currently, the SRR programs can expend funds until at least June 2031.

California Energy Security Plan Update

The 2021 Infrastructure Investment and Jobs Act[72] required updating existing state energy security plans to:

- Include and address all energy sources.
- Provide an updated state energy profile.

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72 Defazio, Peter A. 2021. [H.R.3684 — Infrastructure Investment and Jobs Act](https://www.congress.gov/bill/117th-congress/house-bill/3684). 117th United States Congress, https://www.congress.gov/bill/117th-congress/house-bill/3684.

- Provide updated energy sector risk and hazard assessments.
- Address multistate, tribal, and regional coordination.

In 2022, the CEC began updating the state's existing Energy Assurance Plan to create a California Energy Security Plan (CESP) that satisfies these requirements. Each year, through 2025, all states are required to submit an approved energy security plan or a Governor's letter affirming the plan meets the requirements to the U.S. Department of Energy.

State energy security plans play a key role in strengthening resilience during emergencies. The goals of these updated plans are to describe the state's energy landscape, people, processes, and strategy to build energy resilience.

Specifically, the updated plans must detail how the state, working with energy partners, can:

- Secure energy infrastructure against physical and cybersecurity threats.
- Lower the risk of energy supply disruptions.
- Enhance the response to, and recovery from, energy disruptions.
- Ensure the state has secure, reliable, and resilient energy infrastructure.

The CESP chapters discuss the state energy profile, sector risks, energy security and emergency response authorities, energy security planning and preparedness efforts, energy resiliency and mitigation measures, and energy emergency response. The CESP appendices provide more information for the energy and risk profiles, organizational and operational structures, regional coordination efforts, cybersecurity authorities, agencies data and situational tools, resiliency efforts, and contingency programs.

In 2023 and 2024, the CEC successfully satisfied the requirements of the Infrastructure Investment and Jobs Act by submitting a draft CESP to the U.S. Department of Energy. This year, the CEC plans to submit an updated CESP to again satisfy these requirements.

The CEC team continues to engage with the Office of Cybersecurity, Energy Security, and Emergency Response and the National Association of State Energy Officials on topics relevant to energy security. Once the 2025 CESP has been updated, other emergency procedures and documentation at the CEC will be updated to improve training and response support.

CHAPTER 7: Gas System Reliability

2025 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 2025.[73] In addition, this chapter provides a qualitative outlook of fossil gas prices in California for the summer of 2025.

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 season 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 staff expects that PG&E and SoCalGas will meet demand with no curtailments during summer 2025.

For this independent assessment, the CEC prepared and forecasted demand scenarios for monthly normal temperature, hot temperature/dry hydro, and peak days of the PG&E and SoCalGas systems. CEC staff 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.

Modeling Tools

The CEC also reviewed the monthly normal temperature gas demand forecasts that PG&E and SoCalGas provided in the *California Gas Report (CGR)*.[74] Both utilities track historical summer days with high sendout days,[75] but PG&E does not provide a monthly hot temperature gas demand forecast nor a summer peak-day forecast. SoCalGas and SDG&E also provide an

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

74 Prepared in compliance with California Public Utilities Commission Decision (D.) 95-01-039, the *California Gas Report (CGR)* presents a comprehensive outlook for gas requirements and supplies for California. This report is prepared in even-numbered years, followed by a supplemental report in odd-numbered years. The supply and demand projections in California Gas Reports are used for long-term gas system planning.

75 The summer months for the gas system are April through October of each year. A sendout is the portion of the available gas supply that is delivered to customers for consumption. For information on summer days with high sendout, see pg. 209, "Table 16- Estimated California Highest Summer Sendout, 2019-2023 Mmcfd" in the 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.

estimate of expected demand during a summer high sendout day for 2024 through 2030 in the *2024 CGR*.[76]

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 to meet demand during ramp up or to stop injections. This assessment evaluates whether hot summers and dry hydro years 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 balances — This consists of tables that compare estimated supply capacity and forecasted demand.
- Hydraulic models[77] — These are 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 inputted conditions.
- Stochastic models — This is an hourly gas balance that uses 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 2025 and refill underground gas storage facilities to help meet demand in winter 2025–2026.

Gas Demand Forecast

Table 9 and Table 10 present CEC's findings from the monthly normal temperature, hot temperature/dry hydro 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 2,921 million cubic feet per day (MMcfd). This amount 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.[78]

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76 The California Gas and Electric Utilities staff. 2024. *2024 California Gas Report*, pg. 160.

77 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.

78 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.

Table 9: CEC Forecast of PG&E Monthly Demand

Demand Scenario	April 2025	May 2025	Jun 2025	Jul 2025	Aug 2025	Sep 2025	Oct 2025
Normal Temperature Demand (MMcfd)[79]	1,876	1,528	1,664	2,220	2,192	2,133	2,076
Hot Temperature/Dry Hydro Demand (MMcfd)[80]	2,158	1,745	2,016	2,740	2,662	2,553	2,502

Source: CEC staff

CEC staff estimated that peak gas demand on the PG&E system for a summer day would be an estimated 2,921 million cubic feet per day (MMcfd). This amount compares to the highest recorded daily summer demand on the PG&E system since 2015 of 3,388 MMcfd, which occurred September 9, 2021.[81]

Table 10: CEC Staff Forecast — PG&E Summer Peak-Day Demand

Demand Type	Summer Peak Day (MMcfd)
Core[82]	344
Noncore — Non-Electric Generation[83]	648
Noncore — Electric Generation[84]	1,571
Off System[85]	358
Total Demand	**2,921**

Source: CEC staff

79 Average daily demand by month in a normal year.

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

81 PG&E staff. N.d. "Historical Archives: Supply and Demand Archive." PG&E, https://www.pge.com/pipeline/en/operating-data/historical-archives/cgt-supplydemand-search.html.

82 Customers with average usage less than 20,800 therms per month. These are mainly residential and small commercial customers.

83 Commercial and industrial customers whose average usage exceeds 20,800 therms per month, not including power plants.

84 Power plant customers whose average usage exceeds 20,800 therms per month.

85 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 Pipeline Capacity

For the summer assessment, staff estimated available pipeline capacity and storage inventory on the PG&E system (Figure 26). The pipeline capacity estimates are used in all scenarios.

PG&E's backbone transmission system[86] 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,[87] 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.

Figure 26: Map of the PG&E Gas Transmission System

Source: PG&E

86 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.

87 PG&E staff. N.d. "About California Gas Transmission: Welcome to CGT." PG&E, https://www.pge.com/pipeline/en/about-cgt.html.

Staff took a conservative approach in estimating pipeline capacity for summer 2025, 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.[88] Maintenance is scheduled on both systems from April through October, including in-line inspections, working on compressor and regulator stations, and pipeline maintenance.

In January 2025, PG&E announced the proposed date for retiring the Tionesta Compressor Station[89] on the Redwood system as May 7, 2025.[90] Table 11 below lists PG&E capacity assumptions that include the estimated impact from this retirement.

Table 11: PG&E Pipeline Capacity Assumptions

Supply (MMcfd)	April 2025	May 2025	Jun 2025	Jul 2025	Aug 2025	Sep 2025	Oct 2025
California Source Gas	22	22	22	22	22	22	22
Baja Path	565	683	830	588	779	863	661
Redwood Path	1,991	2,045	1,925	1,988	2,000	1,914	1,945
Sub Total Pipeline Receipts*	**2,577**	**2,750**	**2,778**	**2,597**	**2,801**	**2,799**	**2,627**

***Some totals may not sum correctly due to rounding.**

Source: CEC staff estimates.

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 deliveries gas from the Rockies) at Malin, Oregon. Staff assumes 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.[91]

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88 PG&E staff. 2025. "CGT Prospective Maintenance." PG&E, https://www.pge.com/assets/pipeline/docs/operations/pipeline-maintenance/ProspectiveMaintenanceCGT.xlsx.

89 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.

90 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.

91 Events that significantly reduce deliveries to California are rare and are reflected when they are known.

PG&E and Independent Storage Providers

PG&E owns and operates the Los Medanos and McDonald Island underground gas storage facilities, which[92] have a combined maximum working gas capacity of about 49 billion cubic feet (Bcf). Staff assumes a working gas inventory of 36 Bcf at the end of the beginning of the summer season (April 1, 2025).

Independent storage providers that are 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[93] identifies maintenance activities that would reduce injection or withdrawal capacities at PG&E underground gas storage facilities for the remainder of 2025. However, PG&E reported in CPUC Application 24-07-020[94] 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 (CalGEM) safety regulations for underground gas storage facilities. For winter 2025–2026, PG&E reported plans to add 102 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 hot temperature/dry hydro, and summer peak-day demand (see Table 12, Table 13, and Table 14).

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92 A third field, Pleasant Creek, is no longer in operation. In July 2023, PG&E, Pleasant Creek Gas Storage Holdings, LLC, and eCorp Natural Gas Storage Holdings, LLC, filed a joint application with the CPUC for the approval of PG&E's sale of the Pleasant Creek Gas Storage Field to the latter two companies. See Jorrie, Katie, Anna Fero, Steven Frank, and P. Lauren Ruby. 2023. *Joint Application of Pacific Gas and Electric Company (U 39 G), Pleasant Creek Gas Storage Holdings, LLC and ECorp Natural Gas Storage Holdings, LLC for Approval of the Sale of the Pleasant Creek Gas Storage Field under Public Utilities Code Section 851, Transfer of Certificate of Public Convenience and Necessity, and Designation as an Independent Storage Provider*. California Public Utilities Commission. Filing Number: A-23-07-007. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M514/K599/514599766.PDF.

93 PG&E staff. N.d. "Pipeline Maintenance". PG&E. https://www.pge.com/pipeline/en/operating-data/current-pipeline-status/pipeline-maintenance/foghorn.html.

94 Middlekauff, Charles, and Jonathan Pendleton. 2024. *Application of Pacific Gas and Electric Company For Approval of Updated Peak Day Supply Standard Pursuant to Decision 23-11-069 and Request for Expedited Approval*. California Public Utilities Commission. Filing Number: A2407020. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M536/K706/536706078.PDF.

Table 12 shows the monthly gas balance for April–October 2025 using the CEC's forecast for normal temperature demand. This analysis captures planned pipeline maintenance as reported by PG&E in January 2025 and is reflected in available pipeline capacity, where relevant.

Table 12 and Table 13 below capture pipeline and storage field planned maintenance as of January 2025 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 hot temperature/dry hydro demand scenario in July 2025, staff analysis shows enough pipeline capacity to refill storage during the remainder of the summer. In both scenarios, storage is full by November 2025.

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 2025 under the hot temperature/dry hydro scenario, the CEC estimated 292 MMcfd could go off-system, of which only 80 MMcfd is contractually firm. This means 212 MMcfd is interruptible. Thus, under this scenario, PG&E could reduce off-system deliveries to 80 MMcfd and shift from storage withdrawals in July 2025 to storage injections if it chooses.

Table 12: PG&E Monthly Gas Balance Normal Temperature Demand

Average Demand	April 2025	May 2025	Jun 2025	Jul 2025	Aug 2025	Sep 2025	Oct 2025
Demand (MMcfd)	1,876	1,528	1,664	2,220	2,192	2,133	2,076
Available Pipeline Capacity (MMcfd)	2,577	2,750	2,778	2,597	2,801	2,799	2,627
PG&E Injection/(Withdrawal) (MMcfd)	137	137	137	0	0	0	0
PG&E End-of-Month Inventory (Bcf)	40	44	49	49	49	49	49

Source: CEC staff forecasts and estimates

Table 13: PG&E Monthly Gas Balance Hot Temperature/Dry Hydro Demand

Average Demand	April 2025	May 2025	Jun 2025	Jul 2025	Aug 2025	Sep 2025	Oct 2025
Demand (MMcfd)	2,158	1,745	2,016	2,740	2,662	2,553	2,502
Available Pipeline Capacity (MMcfd)	2,577	2,750	2,778	2,597	2,801	2,799	2,627

Average Demand	April 2025	May 2025	Jun 2025	Jul 2025	Aug 2025	Sep 2025	Oct 2025
PG&E Injection/(Withdrawal) (MMcfd)	137	137	137	(143)	137	0	0
PG&E End-of-Month Inventory (Bcf)	40	44	49	44	49	49	49

Source: CEC staff forecasts and estimates

Based on staff analysis, the PG&E gas transmission system can meet demand under the normal temperature demand and hot temperature/dry hydro scenarios.

PG&E Peak-Day Analysis

Table 14 presents the results staff analysis of a summer peak day demand scenario where electric generation comprised the bulk of the demand. The electric generation forecast of 1,571 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 2025 used on the normal temperature demand and hot temperature/dry hydro 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. Under the peak demand scenario, the CEC estimated 358 MMcfd could go off-system, of which only 80 MMcfd is contractually firm. This means 278 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. By July 2025, 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 189 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 14: PG&E Peak Demand Day Gas Balances

Demand Type, Available Pipeline Capacity, and Needed Withdrawal	Peak Summer Day (MMcfd)
Core Demand	344
Noncore-Non-Electric Generation Demand	648
Electric Generation Demand	1,571
Off System Demand	358
Total Demand	**2,921**
Available Pipeline Capacity	2,732

Demand Type, Available Pipeline Capacity, and Needed Withdrawal	Peak Summer Day (MMcfd)
Needed Withdrawal*	**(189)**

* Needed Withdrawal = Total Demand – Available Pipeline Capacity
Source: CEC staff forecasts and estimates.

PG&E Hydraulic Analysis

Staff used the Synergi Gas hydraulic modeling platform to assess PG&E gas system operations.[95] PG&E's hydraulic model for its Baja and Redwood transmission systems estimates system capacity using demand scenarios input by a user. The hydraulic analysis also identifies 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 2,732 MMcfd from the gas balances and that 189 MMcfd would be available for withdrawal on a peak day in either July, August, or September. In its 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 2025. 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 gas transmission system to meet demand in summer 2025 and to refill underground gas storage facilities to help meet demand in winter 2025–2026.

Gas Demand Forecast

Table 15 and Table 16 present the CEC's findings from the monthly normal temperature demand, hot temperature/dry hydro demand, and summer peak demand forecasts for the SoCalGas system. The CEC monthly average forecasts are slightly higher than SoCalGas' in the *CGR*. The *CGR* does not include a hot temperature and summer peak demand forecast for SoCalGas.

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

Table 15: CEC Forecast of SoCalGas Monthly Demand

Demand Scenario	April 2025	May 2025	June 2025	July 2025	August 2025	September 2025	October 2025
Normal Temperature Demand (MMcfd)[96]	2,211	1,891	1,832	2,227	2,284	2,052	2,102
Hot Temperature/Dry Hydro Demand (MMcfd)[97]	2,283	1,947	1,878	2,299	2,365	2,114	2,171

Source: CEC staff

The CEC estimates show peak gas demand on the SoCalGas system for a summer day at around 3,269 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.[98]

Table 16: CEC Forecast — SoCalGas Summer Peak Day Demand

Demand Type	Summer Peak Day (MMcfd)
Core	703
Noncore — Non-Electric Generation	549
Noncore — Electric Generation	2,017
Total Demand	**3,269**

Source: CEC staff

SoCalGas Pipeline Capacity

For the summer assessment, staff estimated available pipeline capacity and storage inventory on the SoCalGas system (Figure 27). The pipeline capacity estimates are used in the average, hot, 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 a 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

96 Average daily demand by month in a normal year.

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

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

also developed a stochastic model that estimates intraday peak-day trends for the SoCalGas system.

Figure 27: Map of the SoCalGas System

Source: CEC Docket 21-IEPR-05

Staff took a conservative approach in estimating pipeline capacity for summer 2025 (Table 17). The estimates were generated by staff analyses of information posted on the SoCalGas Envoy website.[99] These estimates include capacity available to its customers for scheduling and maintenance and outage events that impact the capacity. Per the SoCalGas Envoy

99 SoCalGas Envoy staff. N.d. "SoCalGas Envoy." SoCalGas Envoy, https://www.socalgasenvoy.com/index.jsp#nav=/Public/ViewExternal.showHome.

website, scheduled maintenance projects include pipeline remediation[100] work, inline inspections,[101] and work at the Aliso Canyon and Honor Rancho storage fields.

Table 17: SoCalGas Pipeline Capacity Assumptions

Supply (MMcfd)	Apr 2025	May 2025	Jun 2025	Jul 2025	Aug 2025	Sep 2025	Oct 2025
California Line 85 Zone	40	40	40	40	40	40	40
Wheeler Ridge Zone	460	682	705	765	765	765	765
Blythe (Ehrenberg) into Southern Zone	650	600	650	650	650	650	650
Otay Mesa into Southern Zone	0	0	0	0	0	0	0
Kramer Junction into Northern Zone	550	550	550	550	550	550	550
North Needles/Topock into Northern Zone	559	643	800	800	800	800	800
Total Supply	**2,259**	**2,515**	**2,745**	**2,805**	**2,805**	**2,805**	**2,805**

Source: CEC staff estimates

SoCalGas' Northern and Southern Zones, referenced in Figure 27 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.

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 of 68.6 Bcf,

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100 *Pipeline remediation* is a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event. See United States National Archives and Records Administration. 2025. "United States Code of Federal Regulations 49 CFR Part 192 Subpart O." United States National Archives and Records Administration, https://www.ecfr.gov/current/title-49/subtitle-B/chapter-I/subchapter-D/part-192/subpart-O.

101 A technique used to assess the integrity of natural gas transmission pipelines from the inside of the pipe. This involves the use 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. The tool records condition data such as wall thickness, corrosion, dents, etc. as it moves through the pipeline. See Southern California Edison staff. 2013. *In-Line Inspection of Pipelines*. Southern California Edison, https://www.socalgas.com/documents/news-room/fact-sheets/In-LinePipelineInspection.pdf.

which was authorized by CPUC Decision 23-08-050. Staff assumes a working gas inventory of 75 Bcf on the first day of summer (April 1, 2025).

SoCalGas Gas Balance

Table 18 shows the monthly gas balance for April–October 2025 using the CEC's forecast for normal temperature demand.

Table 18 and Table 19 capture pipeline and storage field planned maintenance as of February 2025 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 hot temperature/dry hydro 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 2025.

Based on staff analysis, the SoCalGas transmission system can meet demand in the normal temperature and hot temperature/dry hydro demand scenarios.

Table 18: SoCalGas Monthly Gas Balance Normal Temperature Demand

Average Demand	Apr 2025	May 2025	Jun 2025	Jul 2025	Aug 2025	Sep 2025	Oct 2025
Demand (MMcfd)	2,211	1,891	1,832	2,227	2,284	2,052	2,102
Available Pipeline Capacity (MMcfd)	2,589	2,939	2,665	2,720	2,720	2,720	2,720
SoCalGas Injection/(Withdrawal) (MMcfd)	211	211	211	211	211	211	211
SoCalGas End-of-Month Inventory (Bcf)	81	88	94	100	107	113	120

Source: CEC staff forecasts and estimates.

Table 19: SoCalGas Monthly Gas Balance Hot Temperature/Dry Hydro Demand

Average Demand	Apr 2025	May 2025	Jun 2025	Jul 2025	Aug 2025	Sep 2025	Oct 2025
Demand (MMcfd)	2,283	1,947	1,878	2,299	2,365	2,114	2,171
Available Pipeline Capacity (MMcfd)	2,589	2,939	2,665	2,720	2,720	2,720	2,720
SoCalGas Injection/(Withdrawal) (MMcfd)	211	211	211	211	211	211	211

Average Demand	Apr 2025	May 2025	Jun 2025	Jul 2025	Aug 2025	Sep 2025	Oct 2025
SoCalGas End-of-Month Inventory (Bcf)	81	88	94	100	107	113	120

Source: CEC staff forecasts and estimates

SoCalGas Peak-Day Analysis

Table 20 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 2,017 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 549 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 MMcfd) between July and September 2025. This amount is more than sufficient to allow the needed storage withdrawals of 549 MMcfd projected in Table 20. 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 20: SoCalGas Peak-Demand Day Gas Balances

Demand, Withdrawal, and Net Demand Type, Available Pipeline Capacity, and Needed Withdrawal	Peak Summer Day (MMcfd)
Core Demand	703
Noncore-NonEG Demand	549
EG Demand	2,017
Total Demand	**3,269**
Available Pipeline Capacity	2,720
Needed Withdrawal	**(549)**

Source: CEC staff forecasts and estimates

SoCalGas Stochastic Analysis

Staff performed an additional stochastic[102] gas balance analysis for the 2025 summer season that provides insight into intraday ramping of demand while aiming to identify hours of the day that are the highest curtailment risk. The stochastic gas balance incorporates the peak-day pipeline capacity and storage withdrawal assumptions assumed in the peak-day analysis above. First, staff generates probability distributions based on 14 years of hourly historical data from SoCalGas. This type of modeling is referred to as “stochastic” because the load shape that is developed by randomly selecting probability distributions for each hour. For reach 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.

Staff used the same method as in prior assessments to craft the hourly stochastic demand but added one more year of observations to the data set and allowed receipts to vary stochastically. This method demonstrates receipts fluctuating by about 5 MMcfd from average over a day. Staff also estimated withdrawal curves for SoCalGas based on observed historical withdrawals and storage inventory levels from 2017 to 2024 at its underground gas storage facilities. The resulting withdrawal curves offer a baseline for available storage withdrawal to meet demand during the summer peak day.

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 21 and Figure 28, 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 178 MMcf per hour at 7 p.m. To meet demand in the afternoon and evening, the results show some withdrawals are required.

Table 21: 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	112	114	113	119	125	135	143	154	161	166	172	174	178	178	170	154	130	119	110	109	108	108	107	109	3,269
Receipts	114	114	113	114	112	111	110	111	112	112	113	112	112	113	113	114	113	115	115	116	115	115	115	115	2720

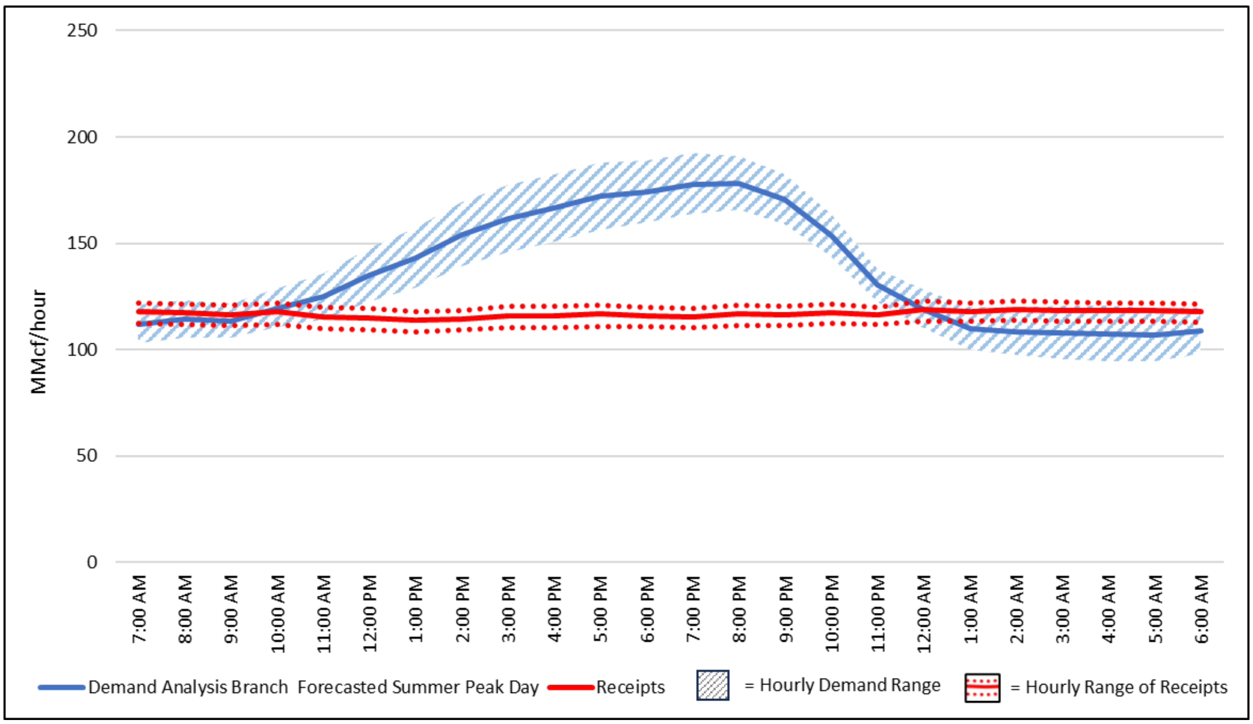
102 This analysis is further explained in Long, Joe. 2012. *Winter Assessment 2022-2023 Stochastic Gas Balance Analysis*. Aspen Environmental Group, https://efiling.energy.ca.gov/GetDocument.aspx?tn=247777, and in Wong, Lana, Jason Orta, and Miguel Cerrutti. 2022. *Winter 2022–2023 SoCalGas Reliability Assessment*. California Energy Commission. Publication Number: CEC-200-2022-007. Appendix B of this report offers detailed documentation of the stochastic gas balance method.

Required Withdrawal	0	0	0	6	13	24	33	43	49	54	59	62	66	65	57	40	17	4	0	0	0	0	0	0	592
MinCurtail*	(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)

***Minimum curtailment required in each hour**

Source: Aspen Environmental Group, reproduced by CEC staff

Figure 28: 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, as well as the load profiles prepared by utility and submitted to the CEC in 2024. Staff used the pipeline supply of 2,720 MMcfd assumed in the gas balances ratably, meaning the same quantity every hour.[103] SoCalGas then used storage injections and withdrawals to meet the difference between hourly demand and flat supply flowing in from the

103 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.

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 world implications for the summer operation of the gas system. As solar 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 normal temperature day, hot temperature/dry hydro day, and summer peak-day scenarios, staff estimates that SoCalGas can meet demand with available pipeline capacity combined with some storage withdrawal capacity or other measures. Furthermore, staff estimates that the SoCalGas underground gas storage facilities will be at capacity under all scenarios by the end of summer 2025. Absent a multiday, hot-weather event with additional infrastructure outages, the risk to reliability is low.

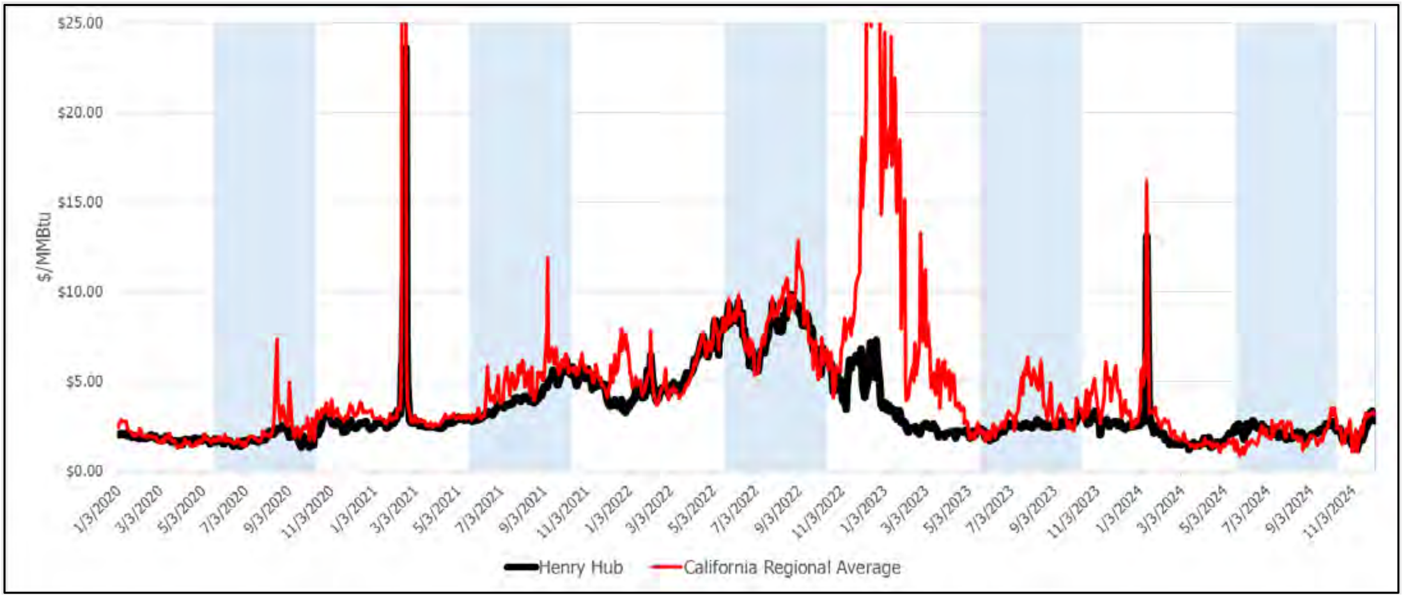
Qualitative Outlook of Fossil Gas Prices

This section provides a qualitative outlook of fossil gas prices in California for the summer of 2025. Summer prices in California in recent years have been relatively stable and track along the national benchmark, Henry Hub.[104] As shown in Figure 29[105,] the average summer price for Henry Hub (summers 2020–2024) was $3.71/Million British thermal unit (MMBtu), while the California Regional Average price was $4.29/MMBtu. The Energy Information Administration's (EIA) Short-Term Energy Outlook forecasts the Henry Hub price to average around $2.90/MMBtu in 2025 compared to $2.19/*MMBtu in 2024 as demand increases for U.S. liquefied natural gas. Prices this summer look to follow this pattern if pipeline capacity and fossil gas production remain at current levels.*

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

105 The Average California Regional price is the volume weighted average price of Malin, PG&E Citygate, Citygate, Southern Border, PG&E, SoCal Border average.

Figure 29: Monthly Henry Hub and Average California Regional Prices, 2020–2025



Source: EIA, CEC staff

While summer fossil gas prices in California have been stable in recent years, unexpected events or conditions can result in some price volatility. For example, during the summer of 2024,[106] the smoke from numerous fires in California led to decreased solar generation output. At the same time, the high winds that fueled the fires caused wind generation to decrease. Further, the fire 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.

2025 Summer 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 expects that PG&E and SoCalGas will meet demand with no estimated curtailments during summer 2025. Moreover, CEC staff expects that PG&E and SoCalGas will bring their underground gas storage facilities to capacity by the start of the winter 2025–2026 gas season November 1. As 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 or increases demand or both. Throughout summer 2025 and beyond, staff will continue to track the operations of California gas utilities and trends in fossil gas prices to inform future analyses and provide support, if needed. Reliability and prices are intertwined as market participants will procure gas from the most economic sources and use the appropriate

106 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/.

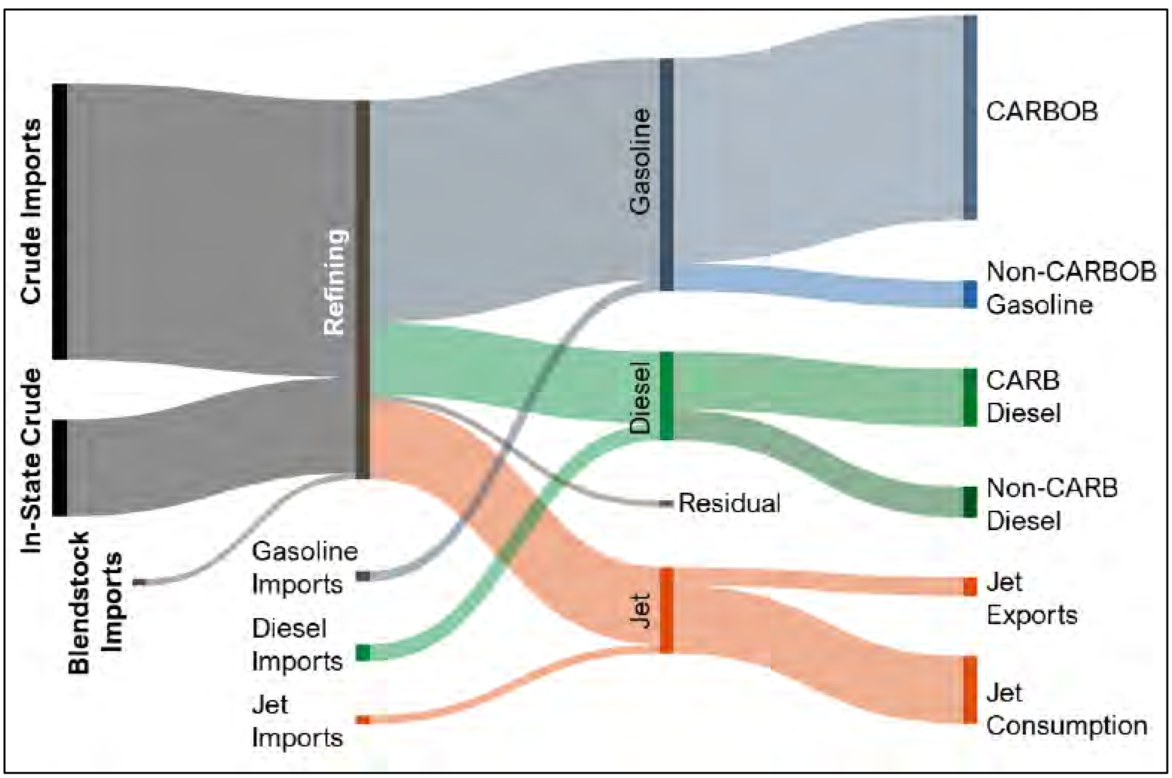
pipelines and infrastructure to deliver the fuel to where it will be consumed or stored. Prices and reliability are impacted by unexpected weather and maintenance events. Data from decades of operation can inform expectations and actions in a coming season. Those enable the development of inputs, models, and analysis that guide this assessment.

CHAPTER 8: Petroleum

Introduction to the Petroleum Fuels Market

In 2023, Californians consumed approximately 13.6 billion gallons of gasoline, 3 billion gallons of diesel fuel, and 207 million gallons of jet fuel. This demand is roughly 10 percent of total U.S. consumption and has historically been served almost entirely by California refineries. Imported gasoline and blending components have accounted for only 3 to 7 percent of supply. California refineries are currently structured to produce gasoline to California's unique gasoline specifications, known as California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB). Since 2010, gasoline in California contains a maximum of 10 percent ethanol, known as E10. Figure 30 shows a Sankey chart of petroleum fuel pathways for California.

Figure 30: Approximate Fuel Pathways and Magnitudes for Crude Oil, Other Imports, and Finished Petroleum



Source: CEC

Crude oil for refining comes mostly from foreign sources. In 2023, 60.7 percent of crude oil was produced in other countries, with the top producers being Iraq, Saudi Arabia, Brazil, and

Ecuador.[107] Only 23.4 percent of crude oil refined in California was produced in-state, while the remaining 15.9 percent was imported from Alaska.[108] Crude oil produced in-state travels via pipeline from the main oil fields in Kern County to the refining centers located in Los Angeles and the San Francisco Bay area. Figure 31 shows the number of wells in each county that reported oil production in 2020. Figure 32 shows California crude oil production has been in steady decline since 1985.[109] This decline is due to the geological properties of the crude, the age of the wells, and the associated production costs.[110] The number of permits issued does not directly correlate to the amount of oil extracted, because not all permits are for drilling new wells. Since 2019, more permits have been issued to plug and permanently seal existing wells than to drill new ones.[111] Imported crude oil arrives via marine imports on tanker vessels.

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107 California Energy Commission Media & Public Communications Office. N.d. *Foreign Sources of Crude Oil Imports to California*. California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/foreign-sources-crude-oil-imports.

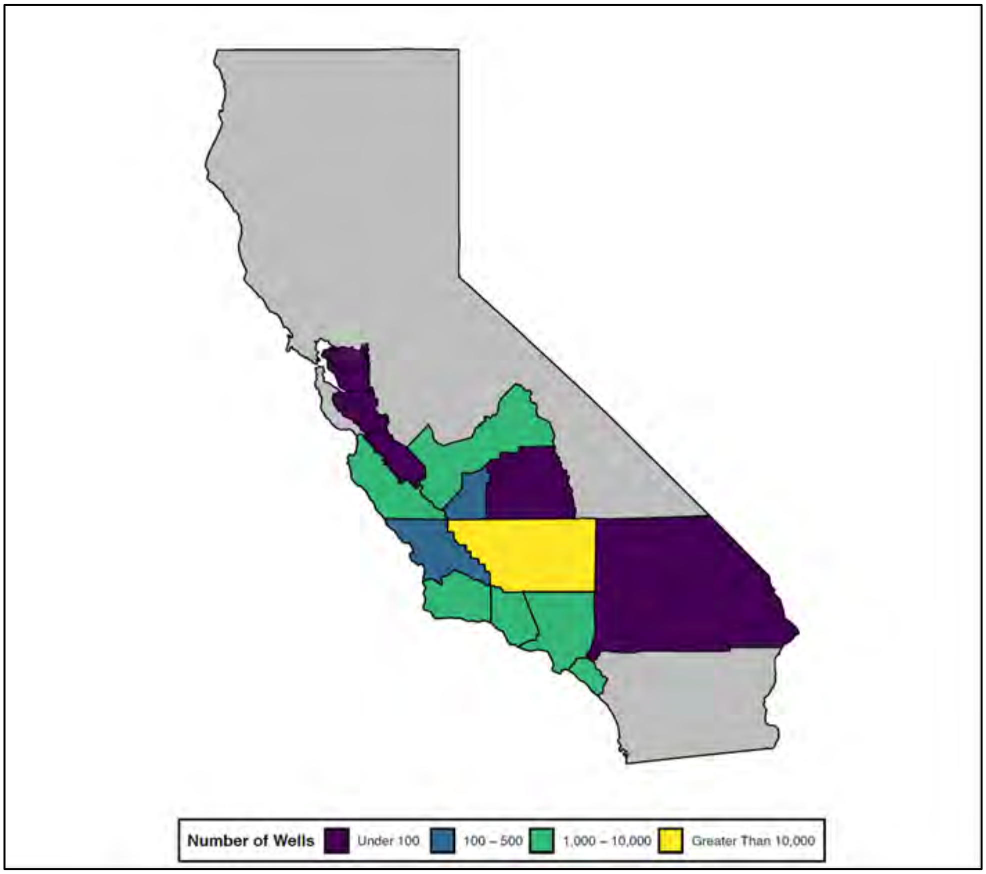
108 California Energy Commission Media & Public Communications Office. N.d. *Annual Oil Supply Sources to California Refineries.* California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/annual-oil-supply-sources-california.

109 U.S. Energy Information Administration. 2025. *Petroleum & Other Liquids*. U.S. Energy Information Administration. https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPCA1&f=A.

110 Geological properties of crude oil include but are not limited to density, sulfur content, viscosity, hydrocarbon makeup, dissolved gases, salinity, wax content, and trace metals.

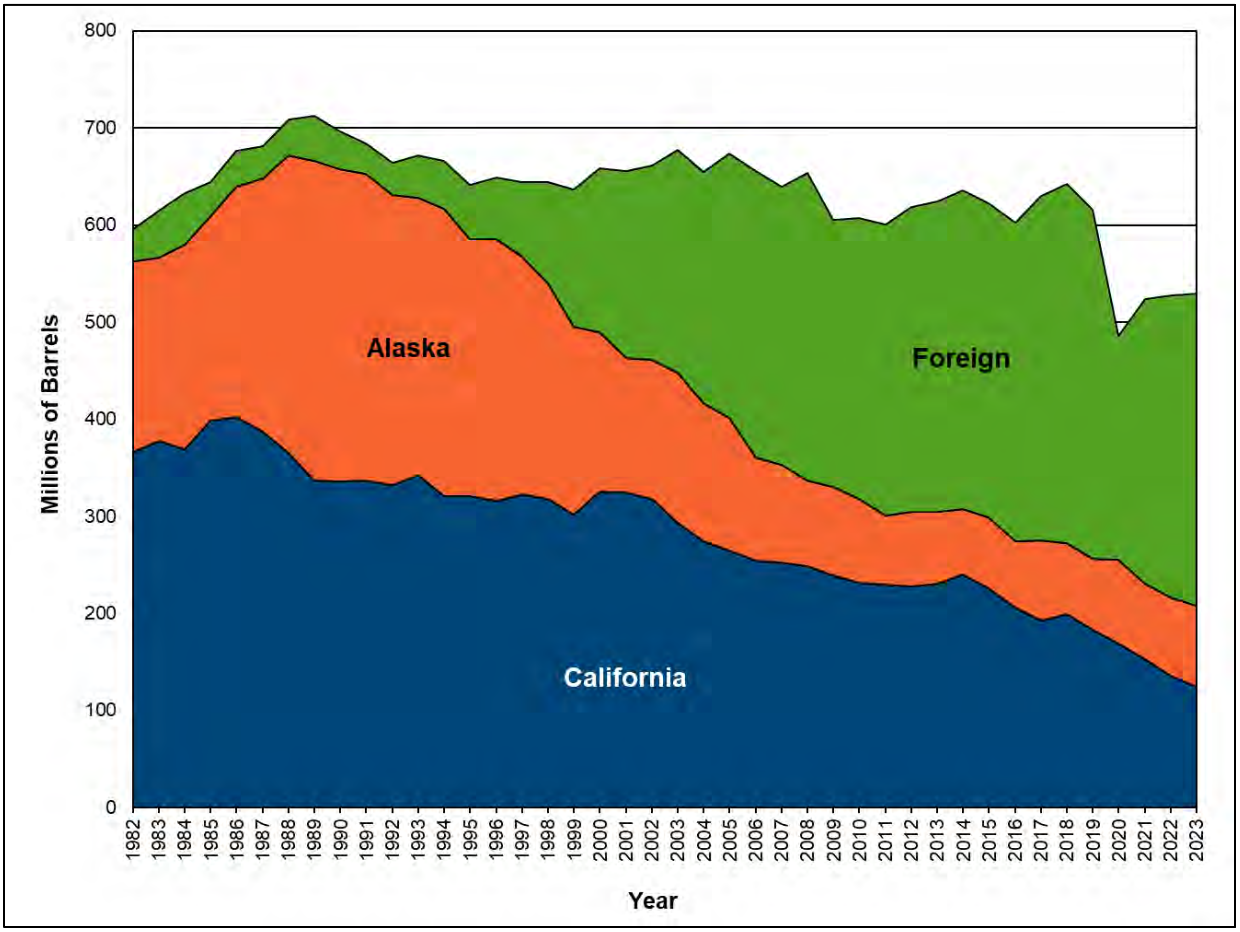
111 California Department of Conservation. N.d. *California Oil and Gas Permits.* California Department of Conservation. https://www.conservation.ca.gov/calgem/Pages/permits.aspx.

Figure 31: California Oil Well Producing Well Counts by County (2020)



Source: CEC analysis of CalGEM data

Figure 32: Sources of California's Crude Oil



Source: CEC

Once crude oil has been refined into finished petroleum products, primarily gasoline, diesel, and jet fuel, it is shipped from refineries by pipeline to over 60 distribution terminals. Most of the refineries dispense a smaller portion of their output into tanker trucks.

Ethanol is not transported via pipeline. Rather it distributed to terminals via tanker trucks from rail hub terminals and blended at terminals before being trucked to individual retail outlets. Most of the ethanol used in California was imported in rail tank cars from ethanol plants in the Midwest, although California does receive some marine imports of ethanol from Brazil.

Gasoline is distributed and sold in over 10,900 fueling locations in California.[112] Fuels also are trucked directly from refineries or nearby product terminals to local retail outlets. Airports are typically connected via pipeline to the refineries and receive jet fuel directly. Interstate pipelines are for exports to Arizona and Nevada, states with no refining capacity of their own.

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112 California Energy Commission Media & Public Communications Office. N.d. *California Retail Fuel Outlet Annual Reporting (CEC-A15) Results*. California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/transportation-energy/california-retail-fuel-outlet-annual-reporting.

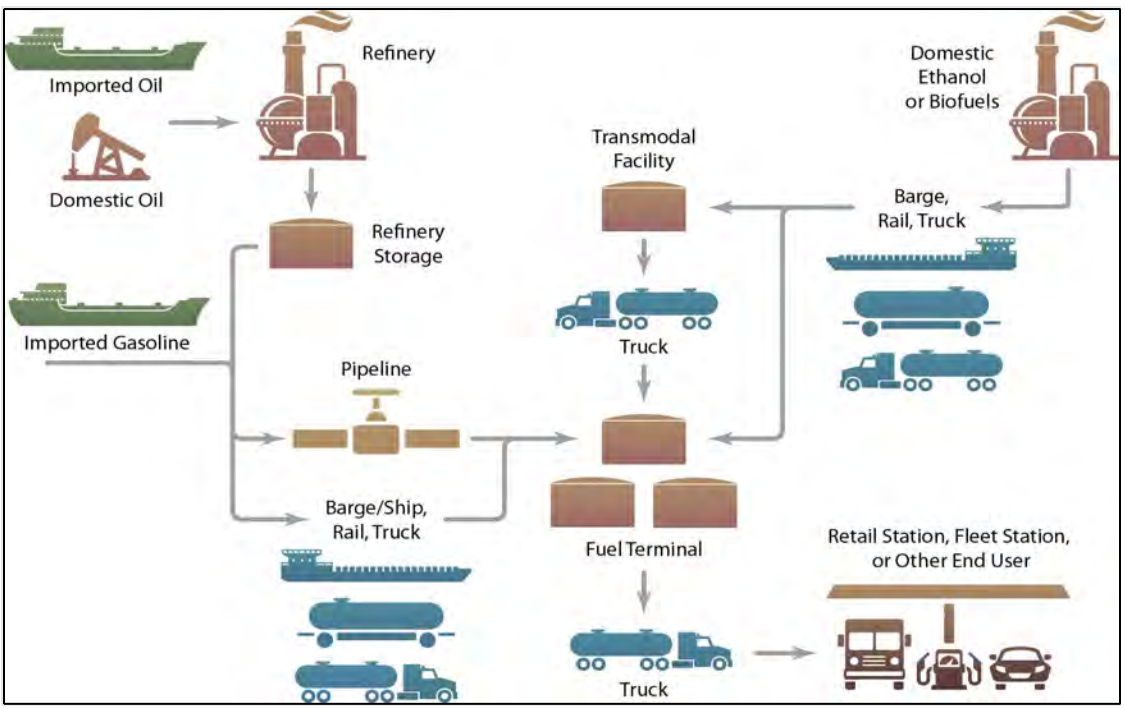
California provides roughly 90 percent of Nevada's and a third of Arizona's petroleum fuel supply.

Storage tanks are vital to the continuous flow of petroleum products into and through California. Tanks are located at docks, refineries, terminals, and tank farms and serve different storage purposes that include:

- Unloading of marine vessels
- Receiving pipeline shipments
- Feeding truck loading facilities
- Operational buffering for safe and efficient refinery operation
- Holding inventories in advance of planned maintenance
- Strategic storage that can be used for emergencies or periods of rapid price increases.

The number of refineries producing CARBOB has steadily declined, from 25 in 1996 to 15 in 2020, and just 9 by 2024.[113] Figure 33 shows a summary of the distribution flows for transportation fuels.

Figure 33: Distribution Flows for Transportation Fuels



Source: U.S. Department of Energy, *Alternative Fuels Data Center*[114]

113 California Energy Commission Energy Assessments Division. 2024. *California's Oil Refineries*. California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/californias-oil-refineries.

114 Alternative Fuels Data Center. N.d. *Ethanol Production and Distribution*. United States Department of Energy. https://afdc.energy.gov/fuels/ethanol-production.

Legislatively Mandated Data Collection

Petroleum refiners, transporters, and other industry participants are required to submit weekly, monthly, and annual data to the CEC under the PIIRA.[115] Analysis of data collected under PIIRA is an important part of the CEC's responsibility to create a thorough understanding of the operations of the petroleum industry in California. PIIRA, which the Legislature enacted in 1980, enables a complete response to possible shortages or other disruptions. The information also helps develop and administer energy policies in the interest of the state's economy and the public's well-being. While much of the information collected is confidential, aggregated information is made publicly available when possible.[116]

SB X1-2 (Skinner, Chapter 1, Statutes of 2023) amended PIIRA and added other requirements associated with the CEC's oversight of the petroleum industry, including the creation of the Division of Petroleum Market Oversight.[117] Furthermore, SB X1-2 revised and introduced several new petroleum industry reporting requirements, with submittals beginning in July 2023. 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 reporting requirements provide new insight about petroleum markets and more immediate information on marine imports and refinery operations, which increases the CEC's situational awareness.

AB X2-1 (Muratsuchi, Chapter 1, Statutes of 2023) requires the CEC to consider the effects of refiners' inventory on the price of transportation fuels in California. The bill authorizes the CEC to develop requirements for refiners operating in the state to maintain minimum levels of inventories and to plan for resupply of lost production during planned maintenance and turnarounds. AB X2-1 builds upon SB X1-2, which aims to improve transparency into the petroleum industry and prevent price spikes.

Near-Term Petroleum Supply and Demand Outlook

As of March 2024, nine California refineries produce CARBOB. Supply of gasoline in the state is highly regionalized. Except for one small refinery in central California, nearly all in-state supply in the near term will come from three refineries in Northern California and five refineries in Southern California. Refineries typically operate near their maximum stated capacity. The temporary reduction of refining capacity at a single refinery in either the north or the south

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115 California Energy Commission Energy Assessments Division. N.d. *Petroleum Industry Information Reporting Act Reporting Requirements – PIIRA*. California Energy Commission. https://www.energy.ca.gov/rules-and-regulations/energy-suppliers-reporting/petroleum-industry-information-reporting-act-piira.

116 California Energy Commission Energy Assessments Division. N.d. *California Gasoline Data, Facts, and Statistics*. California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/transportation-energy/california-gasoline-data-facts-and-statistics.

117 California Energy Commission Energy Assessments Division. *SB X1-2 Implementation*. California Energy Commission. https://www.energy.ca.gov/proceeding/senate-bill-x1-2-implementation.

would represent a critical reduction of refining capacity for each respective region because the regions are not connected via pipeline, though waterborne transportation is available.

Figure 34 illustrates roughly estimated gasoline refining capacity (at 60 percent stated crude processing capacity), along with recent refinery closures, remaining capacity, and the maximum monthly demand for CARBOB alone and CARBOB with gasoline exports. In the spring of 2020, the Marathon Golden Eagle refinery went idle due to low demand caused by the COVID-19 pandemic. The facility was never brought back online. Instead, petroleum operations ceased and the facility underwent conversion to a renewable diesel facility. Renewable diesel production began in late 2022 and reached full capacity in 2023.

In early 2024, Phillips 66 Rodeo ceased petroleum operations. Instead, Phillips 66 made investments in renewable fuels production, with production starting in the spring of 2024. This facility is capable of producing both renewable diesel and renewable jet fuel. On October 16, 2024, Phillips 66 announced plans to close its Wilmington refinery during the fourth quarter of 2025.[118] The timing of this closure will not affect supply during the summer of 2025, but will reduce refining capacity for the summer of 2026. Figure 34 shows the effect these facility closures have on estimated CARBOB production.

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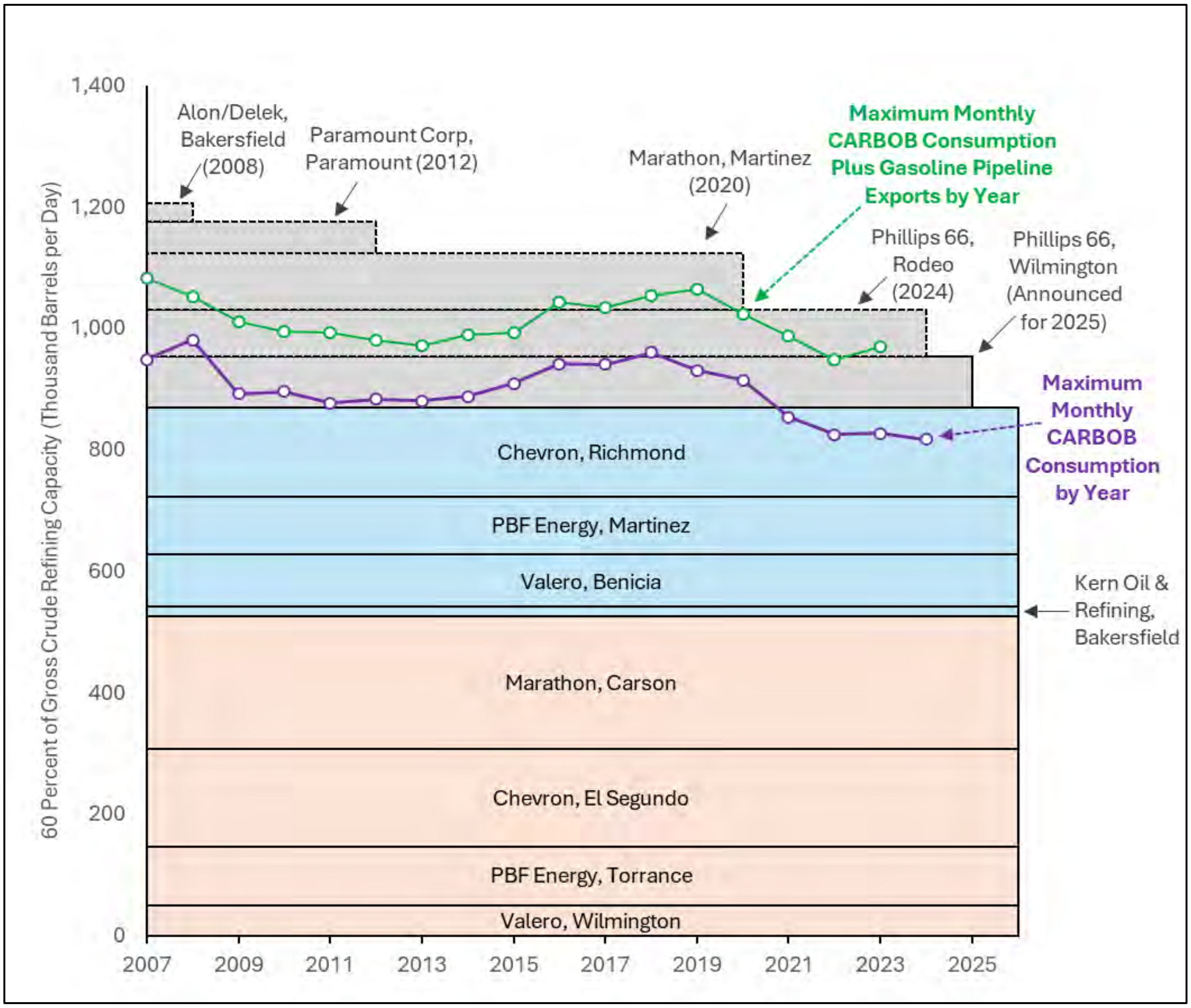
118 Dietart, Jeff, Owen Simpson, and Thaddeus Herrick. 2024. *Phillips 66 provides notice of its plan to cease operations at Lose Angeles-area refinery.* Phillips 66. https://investor.phillips66.com/financial-information/news-releases/news-release-details/2024/Phillips-66-provides-notice-of-its-plan-to-cease-operations-at-Los-Angeles-area-refinery/default.aspx.

Figure 34: Estimated California Gasoline Refining Capacity

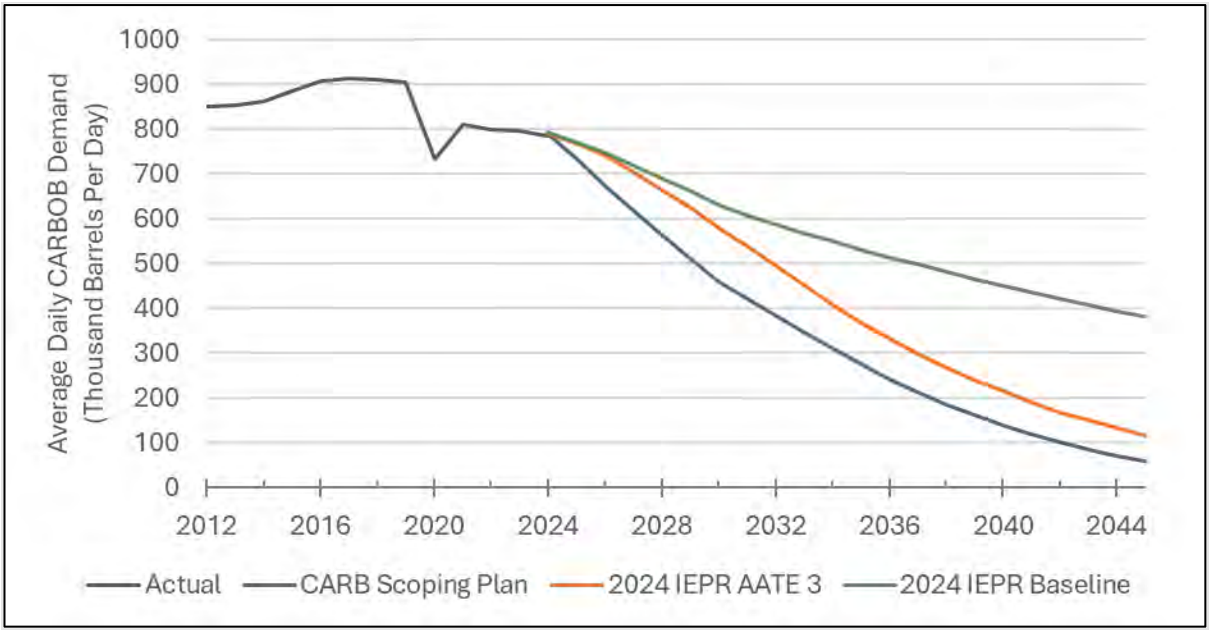


Source: CEC

Figure 35 shows historical consumption and three demand scenarios of gasoline associated with potential zero-emission electric vehicle (ZEV) adoption and customer behavior changes. The scenarios are drawn from CARB's 2022 Scoping Plan and CEC's *2024 IEPR* Update. The fastest declining scenario is based on CARB's 2022 Plan Update for Achieving Carbon Neutrality (CARB Scoping Plan). The CARB Scoping Plan discusses a series of strategies for achieving its goal of reducing vehicle miles traveled, but there are no statutory or regulatory mandates that require vehicle miles traveled to decline or an adopted state strategy to reduce vehicles miles traveled. The next scenario in order of petroleum decline is an extension of the CEC's 2022 transportation energy demand forecast scenario called Additional Achievable Transportation Electrification Scenario 3 (2024 IEPR AATE 3). The 2024 IEPR AATE 3 scenario incorporates ZEV adoption through 2035 as required with then-current CARB regulations, such as Advanced Clean Cars II and Advanced Clean Fleets. The most gradual declining scenario is an extension of the IEPR transportation forecast baseline forecast (2024 IEPR Baseline). The

2024 IEPR Baseline scenario is not driven by CARB regulations, only market trends, and has lower ZEV adoption than the other scenarios.

Figure 35: Gasoline Consumption and Demand Scenarios Under Consideration for the Transportation Fuels Assessment



Source: CEC

The Transportation Fuels Assessment explores pathways for future scenarios and potential actions the state may take to assure an affordable and reliable supply of gasoline.[119] One pathway has the decline in refining capacity coincide with the decline in demand, with California having adequate supplies to meet demand, resulting in refinery closures. Another pathway is for refiners to pivot towards exports of refined fuels or blendstocks. However, if refineries close, or if export strategies result in lower CARBOB production capacity, demand could quickly outpace supply and price spike risk will increase.

Balancing Supply and Demand

California is a fuel island; it does not have pipelines to bring finished product into the state and it also requires a special blend of gasoline not used by the rest of the U.S. Currently, most of the state's consumed gasoline is refined in-state, with a limited portion of the supply coming from out-of-state or overseas refineries. At present, the only practical way to import finished fuel and blending components is by marine imports. There are no pipelines for refined fuel (e.g., diesel, jet, and gasoline) going into the state, only pipelines for export out of the state (to Arizona and Nevada). Rail could theoretically be a source of imports, but so far this import

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119 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.

approach has not been seen at any significant scale. It would take three to five 100-car trains of gasoline or gasoline blending components to match the capacity of one ship. Thus, routine marine imports are likely the most feasible option navigating the uncertainties arising from refineries reducing or stopping production (i.e., losing tens of thousands of barrels of daily production) while demand reduces in a much more gradual manner.

Marine imports of refined fuel from Washington state and Southeast Asia are already a regular source of fuel, helping to balance out a sophisticated market of multiple flows in various directions. Imports also come sporadically from other locations, including Canada and Europe. One typical tanker ship of gasoline represents about one third of the state's current daily demand of gasoline. Marine imports generally tend to have higher prices compared to in-state refining, as ships can be expensive to operate compared to pipelines and present different environmental risks.

As demand continues to decline and in-state refineries convert to renewable fuels or close completely, a strategy to bolster the state's imports of gasoline will be imperative to avoid potentially systemic undersupply problems. In Northern California, a single refinery outage could represent up to a 42 percent reduction of regional refining capacity. In Southern California, a temporary closure of a single refinery could represent up to a 35 percent reduction of regional capacity. Because intrastate movements of fuel must occur by marine cargos, supply shocks can pose immediate challenges. Harbor traffic is another issue to consider for any strategy relying on increased marine imports. CEC data show that imports appear to be increasing in Northern California, the likely result of one large refinery conversion in 2020.

When there are disruptions to supply, market fundamentals dictate that the price will increase until demand decreases enough to be in balance with the reduced supply. Gasoline demand is considered relatively inelastic in nature, meaning that it takes large changes in price to see small changes in demand. Therefore, small imbalances between supply and demand can create large price changes. Disruptions to refinery operations, the conversion of refineries to renewable diesel production, the presence of large suppliers that no longer have refining facilities in state, and other factors necessitate more frequent imports of refined gasoline into the state. While marine imports can relieve some market pressure, the long transportation time and generally higher price reduce the effectiveness of imports as an instant remedy to supply disruptions.

The petroleum refining industry has relatively few market participants due to high fixed costs and other barriers to entry. This makes it possible for firms to exercise degrees of market power that would not be possible in perfectly competitive markets. In California, this risk of market power appears to be more pronounced than in other states.

A relatively small portion of this California-specific gasoline is traded on California's local commodity markets, called spot markets, in which a market-wide price is set. In the spot market, there are limited trades reported to public sources and fewer participants compared to a national market. Despite this characteristic of the market, the spot market price is linked through contracts to a large portion of all wholesale and thus retail gasoline sold in the state.

Spot market trades can have an outsized influence on gasoline prices, with the potential susceptibility to market manipulation. With publicly available price reporting based on voluntary reports of trading, the lack of spot market transparency has contributed to incomplete information, leading to volatility in retail prices contrary to consumer interests.

California has two gasoline blends, one for summer and one for winter. These blends are for emission and vehicle operation reasons. The winter blend allows for different blending components that are cheaper to manufacture.[120] Typically, this is observed in prices as an increase in retail price in the spring and a decrease in the fall. Two of the more recent price spikes occurred in September 2022 and September 2023. These price spikes occurred in the lead up to California's blend switch from summer to winter blend in the fall. These price spikes were above and outside of the normal historical trends. In response to extraordinarily high prices, Governor Newsom sent a letter to CARB at the end of September in both 2022 and 2023 calling for an early transition to winter blend fuel specifications to increase supply, which allows refiners to produce higher gasoline volumes at a lower production cost. In both occurrences, this switch in fuel blend immediately caused the retail price to decline.

In addition to price spike risk, Californians have paid consistently higher gasoline prices compared to the rest of the U.S. that cannot be fully explained by differences in fuel formulations and gasoline taxes or fees. This unexplained premium paid by California drivers has been identified by academic researchers as California's "mystery gas surcharge."

Risks to Petroleum Reliability

Risks to petroleum reliability in California can be divided into two broad categories: supply and demand imbalances, and interruption of petroleum supply. Interruption of the petroleum supply can be caused by international incidents, such as trade embargos, equipment failures, and natural disasters, such as fires and earthquakes.

International incidents have historically been rare, but notable. In 1973, the Arab members of the Organization of Petroleum Exporting Countries imposed an embargo against the United States, resulting in long lines and gasoline shortages.[121] Russia's further invasion of Ukraine in 2022 increased international crude oil benchmarks higher than $100 per barrel, increasing refiner crude oil acquisition costs and retail prices.[122]

Equipment failures can be caused by natural disasters or simply through wear. Earthquakes can cause disruptions to normal refinery operation, whether through power outage or to

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120 California Energy Commission. 2020. *Petroleum Watch, September 2020*. California Energy Commission. https://www.energy.ca.gov/sites/default/files/2020-09/2020-09_Petroleum_Watch_ADA.pdf.

121 Office of the Historian, Foreign Service Institute. N.d. *Oil Embargo, 1973-1974*. United States Department of State. https://history.state.gov/milestones/1969-1976/oil-embargo.

122 United States Energy Information Administration. 2022. *This Week In Petroleum, March 9, 2022*. United States Energy Information Administration. https://www.eia.gov/petroleum/weekly/archive/2022/220309/includes/analysis_print.php.

assess potential equipment damage and ensure safe continued operation.[123] Fires, such as the multiple fires that occurred in Los Angeles in January 2025, can cause power outages that affect petroleum pipeline pumping station operation and disrupt supplies.[124] However, less dramatic equipment failures can also cause significant supply disruptions, such as in February 2023 when an equipment failure caused a pipeline outage that lead to the Governor of Nevada declaring a State of Emergency over potential supply shortages.[125]

Large equipment failures are infrequent but do occur and have greater consequence. In 2015 the explosion of a processing unit at the Torrence refinery, then owned by ExxonMobil, caused the equivalent of a 1.7 magnitude earthquake and injured four workers.[126] While the damage and repercussions could have been more severe had this explosion affected more volatile and hazardous processing units, it still caused a temporary outage at the facility with widespread repercussions. Processed fuel imports increased 10-fold after the incident, increasing wholesale and retail prices.[127] This incident also marked the appearance of aforementioned unexplained price premium on California gasoline. This price premium did not disappear when the Torrence refinery returned to service and has become known as the "mystery gasoline surcharge."[128]

In times of emergency, California's Governor can activate the Petroleum Fuels Set-Aside Program. The program is triggered when voluntary conservation, market forces, or other mandatory programs cannot supply fuel for disaster response. The program ensures fuel is available to emergency responders during a severe shortage or catastrophe. A catastrophe, such as an earthquake, may make it hard for emergency responders to obtain fuel. This fuel is needed to safeguard the lives, safety, and property of Californians. The program allows the

123 Reuters. October 15, 2019. *Operations at two California refineries hit by earthquake*. Reuters. https://www.reuters.com/article/business/environment/operations-at-two-california-refineries-hit-by-earthquake-idUSKBN1WU2AG/.

124 Seba, Erwin, and Shariq Khan. January 9, 2025. *Kinder Morgan shuts two Los Angeles fuel pipelines due to power outages*. Reuters. https://www.reuters.com/business/energy/kinder-morgan-fuel-pipelines-shut-due-power-outages-southern-california-2025-01-10/.

125 Lombardo, Joe. 2023. *Declaration of Emergency: Proclamation Declaring a State of Emergency due to Gas Pipeline Disruption.* State of Nevada Executive Department. https://gov.nv.gov/Newsroom/Proclamations/2023/Feb/Proclamation_Declaring_a_State_of_Emergency_due_to_Gas_Pipeline_Disruption/.

126 United States Chemical Safety and Hazard Investigation Board. 2017. *Investigation: ExxonMobil Torrance Refinery Electrostatic Precipitator Explosion*. United States Chemical Safety and Hazard Investigation Board. https://www.csb.gov/exxonmobil-torrance-refinery-explosion-/.

127 Hamilton, Mason T. 2015. *Today In Energy: California's gasoline imports increase 10-fold after major refinery outage*. United States Energy Information Administration. https://www.eia.gov/todayinenergy/detail.php?id=23312.

128 Borenstein, Severin. 2018. *Trying to Unpack California's Mystery Gasoline Surcharge*. Energy Institute Blog. https://energyathaas.wordpress.com/2018/10/15/trying-to-unpack-californias-mystery-gasoline-surcharge/.

CEC to direct petroleum production and storage facilities to hold petroleum as needed. All petroleum production and storage facilities in California are subject to this program.[129]

Conclusion and Long-Term Outlook

As demand for gasoline continues to decline in California, refineries will likely cease refining petroleum. They may permanently close or convert to refining renewable or bio-based fuels. A single supply shock in the north or south, be it from an unplanned maintenance event, a severe accident, a criminal act, or a natural disaster, would make it even more difficult to supply transportation fuel needs in the coming decade.

Outside of crude oil dynamics, refined gasoline supply is influenced by three primary factors: production capacity, storage, and gasoline or gasoline blendstock imports. Statewide petroleum refinery capacity has declined in recent years, closely following or even exceeding the ongoing decline in demand that is due in part to consumer adoption of ZEVs. The petroleum refining industry in California appears to have sufficient infrastructure to produce, procure, and store enough gasoline to meet current levels of demand. However, as discussed, unique conditions in California make it more difficult to stabilize supply when there are acute disruptions.

With reduced demand or more flexible consumer demand, supply shocks should become less impactful. Where travelers can substitute electricity, active transportation, or other alternative travel approaches in lieu of gasoline, price spikes may be easier to manage and have less of an effect on Californians. While increased use of light-duty electric vehicles is decreasing demand for gasoline in the state, more analysis is needed to fully understand the effects of these developments on California’s long-term fuel supply and demand.

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129 California Energy Commission Transportation Fuels Data Unit. N.d. *Petroleum Fuels Set-Aside Program*. California Energy Commission. https://www.energy.ca.gov/rules-and-regulations/state-energy-management/response-energy-emergencies-california/petroleum.

CHAPTER 9: 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 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 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 2025 and Winter 2025-26 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.

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 2025 Outlook Key Takeaways

- 2025 Stack Analysis Results: The latest 2025 stack analysis projects a surplus of more than 5,500 MW under average conditions, 2900 MW under a 2020 equivalent event, and more than 1,300 MW under a 2022 equivalent event. In the worst-case scenario, combining a 2022-equivalent event with wildfires that disrupt transmission lines, the analysis indicates a contingency need exceeding 2,600 MW.

- Electricity Demand: California's electricity demand continues to rise, peaking in summer. The *2024 IEPR Update* forecasts a coincident peak of nearly 46,000 MW for the California ISO in summer 2025.
- New Resources: California's resource portfolio continues to expand. A conservative estimate projects over 2,100 MW (nameplate) of new resources coming online before September, with 81 percent of that capacity from battery storage. An optimistic scenario includes an additional 5,800 MW, of which 61 percent is expected to be battery storage and 28 percent solar PV. These additions would further strengthen grid reliability heading into summer 2025.
- Climate outlook: Currently forecasted above average temperatures West-wide could mean extreme or even worst-case scenarios involving coincident peak demands throughout the WI this summer.
- Wildfire outlook: Currently forecasted above normal wildfire potential for many areas of California, Oregon and Nevada in June and July means potential risks for electric transmission lines delivering power to California's load centers, including the critical northwestern import paths.
- Western Interconnection: Day-ahead electricity market development continues in the WI, with EDAM to begin operations in 2026 and a FERC approval of SPP's Markets+ Tariff. In the meantime, BAAs across the WI are building new resources and refining their ongoing demand forecasts. Approximately 20 GW of new incremental capacity is forecasted to come online in the WI in 2025, although it is not currently known how much of that will be operational by the summer.
- Gas outlook: Absent a major, unexpected pipeline outage and a substantial period of increased gas burns from power plants resulting from hot weather, California's gas transmission systems should meet expected demands with a low risk of curtailment.
- Petroleum: California's petroleum refining industry appears to have sufficient infrastructure to produce, procure, and store enough gasoline to meet this summer's demand. However, an unplanned refinery maintenance outage could reduce this capacity, necessitating increased levels of refined product imports and causing increased prices.

APPENDIX A: Fossil Gas Plant Performance

Power plant performance represents a critical aspect of system reliability. Previous staff analysis explored this relationship following the 2020 heat events,[130] and in the 2024 *CERRO,* staff analyzed power plant performance during summer reliability months (July-September) for 2021-2023. For this year's report, staff analyzed power plant performance during the summer reliability months of July, August, and September 2024 and compared to the years 2021-2023.

The analysis focuses on the resource availability part of performance as represented by capacity outages and derates for facilities in the California ISO.[131] Generally, a capacity 'outage' represents the loss of the entire operational capacity of a facility. A capacity 'derate' is usually more variable and tied to reasons like: environmental conditions, plant trouble, plant maintenance, or unit testing, and can be thought of as a partial outage, meaning that only a portion of the total capacity was lost.[132] This analysis uses the term 'derate' to refer to both an outage and a partial outage, to avoid confusion.

The California ISO Outage Reporting -- The California ISO Department of Market Monitoring (DMM) provides independent oversight and analysis of the California ISO market. The DMM Annual and Quarterly Reports for the years 2020 through 2024 show that aggregate outages in September increased year over year, except for a slight decrease in 2023 due to milder temperatures and lower loads. The DMM analyses measure similar metrics and may help inform analysis on fossil gas capacity derates.

Reporting on derates from the California ISO is almost exclusively focused on the RA program perspective, except for the DMM reporting. Since there are some resources without any RA capacity and other resources with only partial RA capacity, derate reporting with this limited focus does not extend to the entire California ISO fleet and may be inappropriate to support outage analysis needed for situations when every MW counts.

Findings and trends in resource availability and derates can inform planning but require careful analysis. Facility derates occur as both 'planned' (defined by California ISO as at least 7 days of advanced notice) and unplanned or 'forced' events (defined as less than 7 days of advanced

130 California Energy Commission staff. 2021. *Electric System Reliability and Recent Role of California's Fossil Fleet: Actions Taken to Prepare for Summer 2021*. California Energy Commission. Publication Number: CEC-700-2021-002. https://www.energy.ca.gov/sites/default/files/2021-10/CEC-700-2021-002.pdf.

131 California ISO staff. N.d. *Curtailed and non-operational generator reports*. California ISO. https://www.caiso.com/library/curtailed-and-non-operational-generator-reports.

132 Capacity derates can also occur on gas facilities that consist of multiple combustion and steam turbines, leading to partial capacity going offline as each unit in the facility could experience different types of capacity derates.

notice), and for a wide range of reasons at different times throughout the year. Derates are not inherently bad if timed effectively, as maintenance is required for long-term, reliable availability of facilities.

The following are California ISO outage definitions: [133]

- Planned Outage (derate) -- A period of time during which a Generation or Transmission Operator (i) takes its transmission facilities out of service for the purposes of carrying out routine planned maintenance, new construction work or for work on de-energized and live transmission facilities (e.g., relay maintenance or insulator washing) and associated equipment; or (ii) limits the capability of, or takes out of service, its generating unit or system unit for the purposes of carrying out routine planned maintenance, or for the purposes of new construction work. Facility provides at least 7 days of advanced notice to system operator.
- Forced Outage (derate) -- An outage for which sufficient notice cannot be given to allow the outage to be factored into the Day-Ahead Market or Real-Time Market bidding processes. California ISO-defined forced outages include the following (among others): annual, monthly, short-term, or other use limit reached, transmission induced, plant maintenance, plant trouble, ambient due to high temperatures, ambient not due to high temperatures, ambient due to fuel insufficiency, power system stabilizer, new generator test energy, environmental restrictions, and contingency reserves management. Facility provides less than 7 days of advanced notice.

Table 22 lists the dates that the California ISO issued any restricted maintenance outage (RMO), alert, warning, or emergency notices during the study period. On May 1, 2022, the California ISO changed some emergency alert definitions to align with federal reliability standards. The 'Warning' and 'Stage 1-3' emergency notice designations were incorporated into various Energy Emergency Alert (EEA) designations, although there were differences that did not translate one for one.

The California ISO event declarations in summer months roughly correspond with heat events that bring heavy loads and stressed system conditions. California ISO can declare, and issue notice of, official operating events for any conditions that threaten electric or transmission grid capability (extreme heat, equipment failure, etc.). These declarations include flex alerts, RMOs, and different levels of EEAs. This section defines a California ISO Event Day as any day that the grid operator has issued one or more alert, warning, or emergency operations notice to its market participants.

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133 California ISO staff. N.d. *Outages*. California ISO. https://www.caiso.com/market/Pages/OutageManagement/Default.aspx.

Table 22: California ISO Event Days

July	August	September
7/9/2021	8/11/2021	9/8/2021
7/10/2021	8/12/2021	9/9/2021
7/12/2021	8/13/2021	9/10/2021
7/27/2021	8/16/2021	9/1/2022
7/28/2021	8/15/2022	9/2/2022
7/29/2021	8/16/2022	9/3/2022
7/20/2023	8/17/2022	9/4/2022
7/25/2023	8/18/2022	9/5/2022
7/26/2023	8/19/2022	9/6/2022
7/2/2024	8/31/2022	9/7/2022
7/2/2024	8/15/2023	9/8/2022
7/3/2024	8/16/2023	9/9/2022
7/4/2024	8/17/2023	9/4/2024
7/5/2024	8/28/2023	9/5/2024
7/6/2024	8/29/2023	9/6/2024
7/7/2024	8/30/2023	9/6/2024
7/8/2024	8/5/2024	9/7/2024
7/9/2024	8/6/2024	9/9/2024
7/10/2024	8/7/2024	
7/11/2024		
7/12/2024		
7/15/2024		
7/15/2024		
7/18/2024		
7/19/2024		
7/24/2024		
7/25/2024		

Source: CEC staff analysis of California ISO data[134]

134 California ISO staff. 2025. *Summary of Restricted Maintenance Operations, Flex Alarts, Transmission and Energy Emergencies Issued from May 2022 to Present*. California ISO. https://www.caiso.com/documents/grid-emergencies-history-report-1998-to-present.pdf.

In 2024, during July-September, there were 27 California ISO event day notifications; most of which were for RMO and a few were related to transmission emergencies.[135] In 2024, most California ISO event days occurred in July. In 2023, there were nine California ISO event days (mostly RMO days). Although the summer months in 2024 did not have the largest amount of California ISO event days as compared to 2021-2023 summer months, they did have the largest number of RMO days. Table 23 outlines the energy event day alerts by type and year. Definitions are below the table.

Table 23: List of California ISO Event Day Notification by Type (July-September)

Year	Flex Alert	RMO	EEA Watch	EEA 1	EEA 2	EEA 3	Transmission Emergency	Warning	Stage 2	Total
2021	6	12	0	0	0	0	0	3	1	22
2022	11	15	9	6	4	1	4	0	0	50
2023	0	6	2	1	0	0	0	0	0	9
2024	0	18	1	0	0	0	8	0	0	27

Source: California ISO emergency notifications (https://www.caiso.com/emergency-notifications) and staff analysis

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.

Restricted Maintenance Operations (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.

Energy Emergency Alert Watch (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.

Energy Emergency Alert 1 (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.

Energy Emergency Alert 2 (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.

135 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. See: California ISO staff. 2023. *Fact Sheet: Emergency notifications*. California ISO. https://www.caiso.com/documents/emergency-notifications-fact-sheet.pdf.

Energy Emergency Alert 3 (EEA 3): The grid operator is unable to meet minimum reliability reserve requirements and has declared the initial step of an EEA 3. Utilities have been alerted to prepare for outages, but rotating outages have not been ordered. During an EEA 3, rotating outages may or may not be required by the California ISO.

Transmission Emergency: Declared for any event threatening or limiting transmission grid capability, including line or equipment overloads or outages. A transmission emergency notice can be issued on a system-wide or regional basis.

Warnings: Until 2022 when warnings were replaced by EEAs, warnings were used to indicate that grid operators anticipate using operating reserves. A warning would also activate demand response programs to decrease overall demand.

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.

Findings

Staff found the following key themes in relation to fossil gas power plant performance.

- California ISO prior trade date report data has inconsistencies but appears reasonable to use for this analysis of resource availability. Data providers do not seem to use a consistent approach for reporting their data.
- For all resource types studied in the 2021-2024 summer months, cumulative derated capacity varies over time and does not show any strong year-over-year or month-over-month pattern.
- Heat events during 2021-2024 were associated with increased daily peak loads of about 7,400 MW (20 percent) on average compared to non-heat events. The addition of the 2024 data to the 2021-2023 data decreased the overall average.
- In 2024, fossil gas resources reported about a 242 MW (8 percent) increase in derated capacity on event days versus non-event days, during net peak hours. For 2023, this value was a decease about -58 MW (negative 1.8 percent). The average decrease (not increase) in maximum daily derated capacity for event days compared to non-event days during peak hours, for years 2021-2024 from July-September is about -211 MW (negative 1.2 percent) on average.
- For fossil gas resources, considering derated capacity due to ambient (high heat) conditions only, the derated capacity difference between event and non-event days widens (for net peak hours, for July-September):
    - 2024: Increase in maximum daily derated capacity of 157 MW, or about 13 percent

- 2023: Increase in maximum daily derated capacity of 243 MW, or about 19 percent
  - 2022: Increase in maximum daily derated capacity of 201 MW, or about 13 percent
  - 2021: Increase in maximum daily derated capacity of 194 MW, or about 17 percent
  - 2021-2024 average: Increase in maximum daily derated capacity of 171 MW, or about 13 percent.
- The California ISO DMM reports for the years 2020-2024 show that aggregate outages in September increased year over year except for a slight decrease in 2023 due to milder ambient temperatures and lower loads.
- Beginning January 1, 2024, six OTC resources were only allowed to operate for maintenance, air permit testing, an extreme event, or as needed to meet the SRR Program needs. In July-September of 2024, these OTC resources reported large capacity derates due to environmental restrictions, which is a required outage designation for these units for compliance with SRR program requirements and California ISO Operating Procedures. These resources rarely operate; they have annual capacity factors of around 5 percent.

Data Collection and Analysis

Staff constructed a data set using California ISO resource derates from the publicly available Prior Trade Date Reports published by California ISO covering the summer months of all available years, 2021-2024.[136] Working with the Prior Trade Date Report derate data proved more challenging than expected. Extended derates and overlapping derates made the handling of multiple Prior Trade Date files particularly difficult. Using a staff-constructed data set, staff took two views of capacity derates to better understand trends in derates outlined below.

- **Maximum Hourly Derated Capacity**: The maximum instantaneous derated capacity in an hour. For example, derates of 20 MW from 17:00 to 17:50 and 300 MW from 17:51 to 18:00 would have a maximum hourly derate of 300 MW. This measure considers sub-hourly peak derates and is effectively instantaneous.
- **Average Hourly, Duration Weighted, Derated Capacity**: The average derated capacity over an hour. If a derate amount changes within an hour, then each derate value is weighted by its minutes of duration to show an average derate over the hour. From the previous example, the average hourly derate would be: 20MW*(50/60) + 300MW*(10/60) = 17 MW + 50 MW = 67 MW.

Staff found these two measures of derated capacity produce similar results so staff will use the average hourly capacity estimates for all but Figure 38.

136 California ISO staff. N.d. *Curtailed and non-operational generators*. California ISO. https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators.

In addition to covering only the summer months of the years 2021-2024, much of this analysis is further focused on the most critical hours of the day from a grid reliability perspective, consistent with the CPUC RA program. The peak hours, which span the period from 16:00 to 21:59[137] (4:00 p.m. through 9:59 p.m.), represent a portion of the day when grid conditions are more likely to be stressed, and fossil gas units are needed to ramp up and replace declining solar supply.

For the figures and tables below, some resources have more derated capacity than others (for example, fossil gas has more derated capacity than solar). These differences are primarily due to the amount of installed capacity. For example, there is a substantial quantity of fossil gas installed capacity in the California ISO, so fossil gas capacity derates will be larger than other resources with less installed capacity. For many of the summaries that follow, it is valuable to consider how derated capacity changes between years for the same resource type, or groups of resource types.

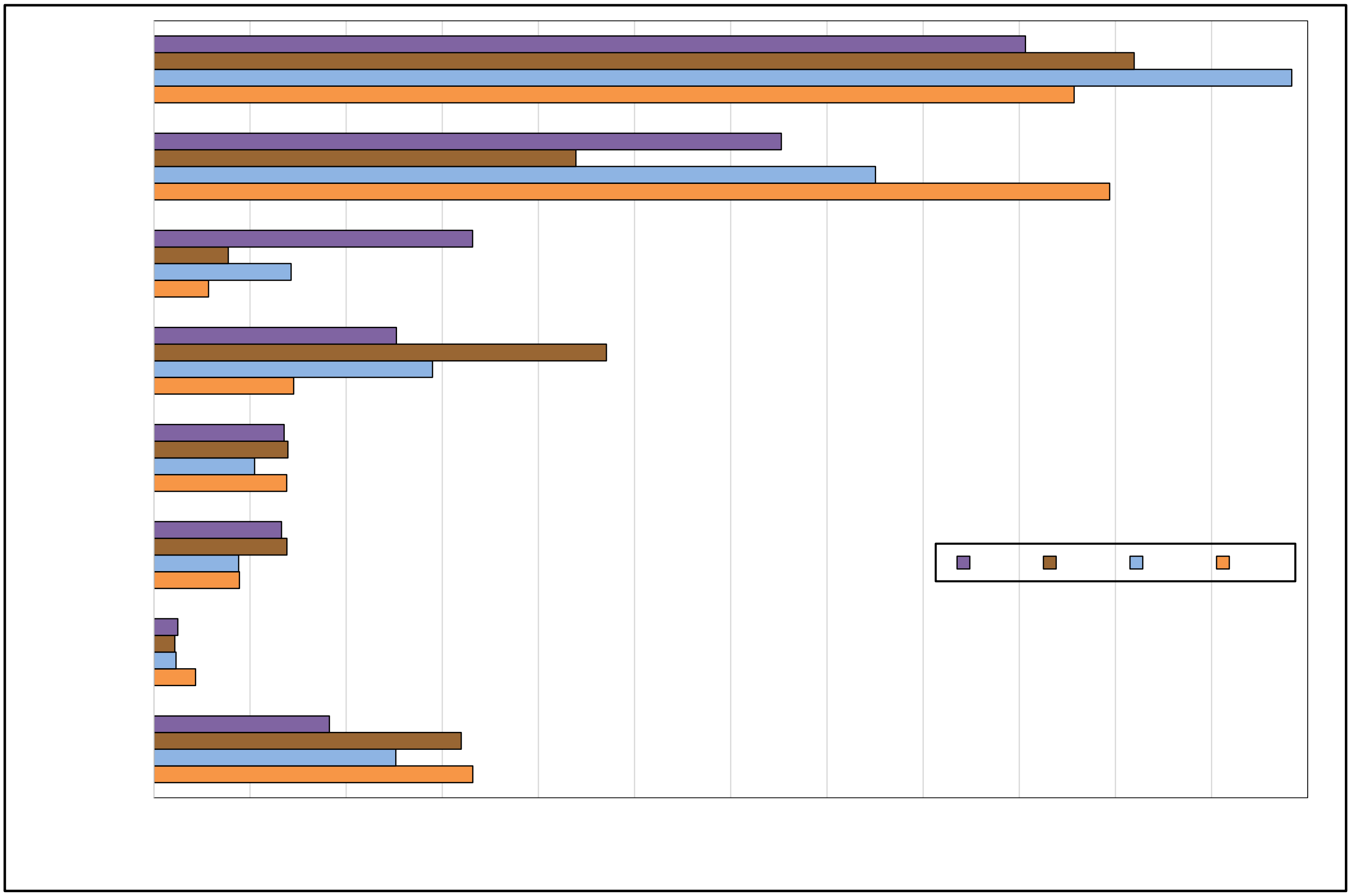
Figure 36 shows the monthly cumulative hourly derated capacity for September, by energy source, over the peak hours of 16:00 through 21:59 for years 2021 through 2024. This is determined from the capacity derate (MW) multiplied by the number of hours the capacity was derated over the whole month during net peak hours. This provides a high-level view of the magnitude of derated capacity by energy source. These values measure the scheduling coordinators reported resource capacity derate to the California ISO. This data informs readers of the California ISO reports of resource capacity that is not available.

Over the last four Septembers, fossil gas, hydroelectric, and solar resources accounted for the majority of the cumulative monthly derated capacity compared to the remaining fuel types (including ‘other’ in Figure 36).[138] In fact, in every summer month in 2021-2024, fossil gas resources make up the largest amount of cumulative derated capacity among energy sources. This is expected as fossil gas has the most installed capacity of the resource types studied. Also, September 2024 did not have the most cumulative derated capacity for any resource type, and cumulative derated capacity varies year to year for the summer months.

137 16:00 to 21:59 means any outage that starts on 16:00 up to and including starting on hour 21:00, so an outage could start on 21:15. No outage will be included that goes into hour 22:00 or beyond.

138 In the California ISO controlled grid, natural gas resources comprise over 30,000 MW of nameplate capacity with combined cycle plants accounting for about half of that total.

Figure 36: Total Cumulative Monthly Derated Capacity by Energy Source



Source: [California ISO Prior Trade Date Reports](https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators): https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators, and staff analysis.

The values in Figure 37 represent the scheduling coordinator reporting resource derated capacity to the California ISO to inform them of what is potentially available to be dispatched. Figure 37 shows the monthly cumulative derated capacity in the same manner as the previous figure but is categorized by resource type instead of energy source.

Using this categorization, the figure charts the cumulative derated capacity over the peak hours of 16:00 through 21:59 for September in 2021, 2022, 2023, and 2024. Combined cycle fossil gas plants show the most cumulative derated capacity in all September months, except for hydroelectric resources in year 2021. Once again, fossil gas and hydroelectric resources have the most installed capacity so they will have cumulative derated capacity compared to other resources.

The cumulative derated capacity (MW) represents the sum of the capacity that was derated over the whole month during net peak hours. Ten of the 13 resource types listed in Figure 37 had more cumulative September capacity derated in 2024 than in at least one of the two previous years (2023 or 2022). For both fossil gas and hydroelectric resources, September 2022 had more cumulative derated capacity compared to both 2023 and 2024. For any one energy source or resource type, the cumulative monthly derated capacity can change each year based on many factors (temperature, use cycle, load, operating decisions, etc.).

In both Figure 36 and Figure 37, the derated capacities measure the cumulative hourly average capacity that was derated during the month. This, however, does not mean the California ISO called upon this derated capacity and the resource could not respond.[139] These values compare the overall monthly magnitude of derated capacity among resource types and energy sources, and year.

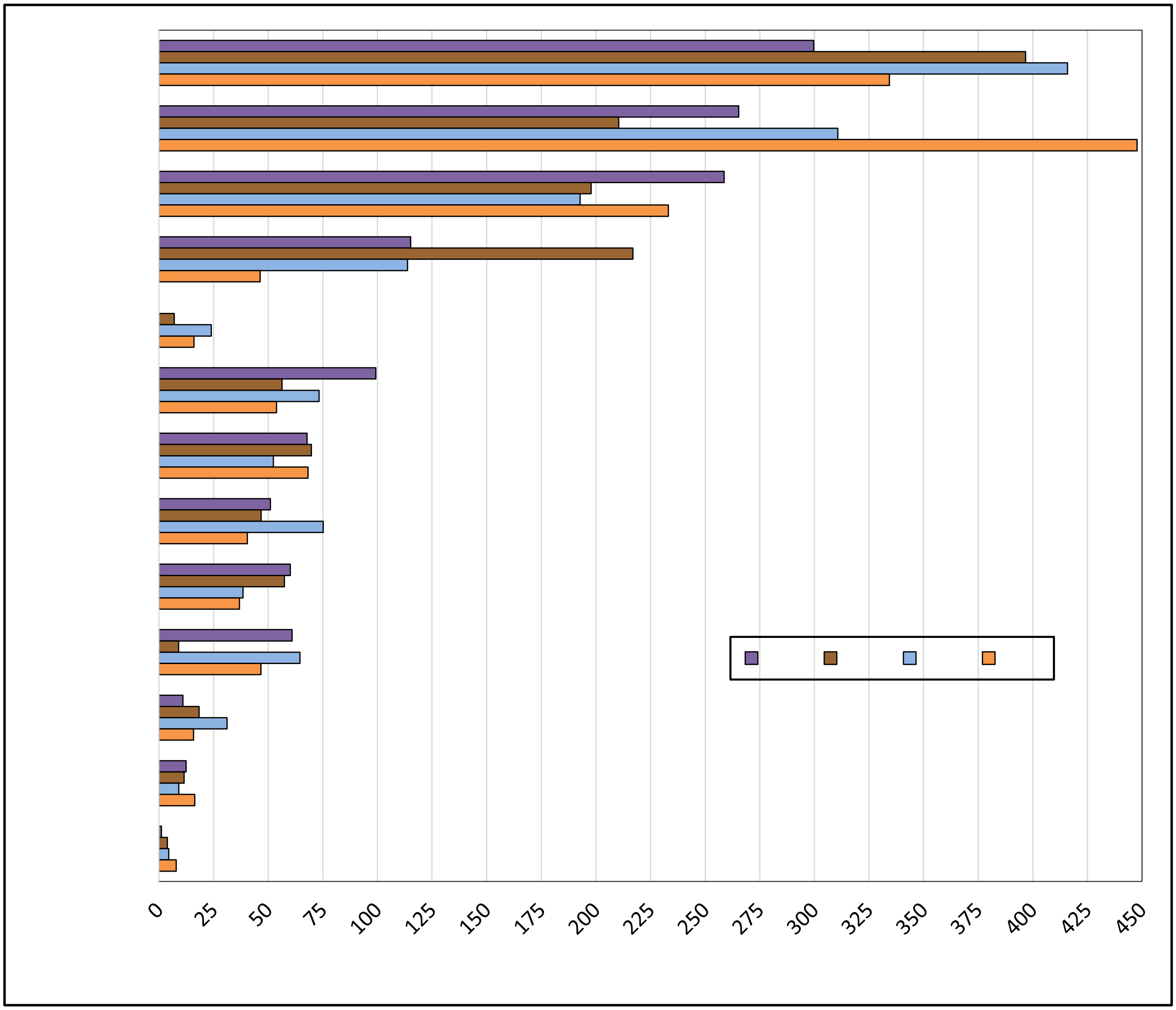
Figure 37 shows some evidence that cumulative September derated capacity has increased for many resource types (including fossil gas), although there is no strong pattern of increase. Scheduling coordinators report resource derated capacity to the California ISO to inform them of what is potentially available to be dispatched.

The resource types in Figure 37 are defined as follows:

- CC—Combined Cycle
- Hydro—Hydroelectric Power Generation
- Other—Not otherwise defined.
- PV--- Photovoltaics
- OTC—Once-through Cooled Electric Boilers
- Peaker—Simple Cycle Combustion Turbines
- Wind—Wind
- CHP—Combined Heat and Power
- Geo—Geothermal Electric Power Plants
- Pump—Pumped Hydroelectric Storage Facilities
- CSP—Concentrating Solar Power Facilities
- SteamBio—Steam Boilers not OTC
- Simple Cycle—Some fossil gas peaker plants are designated as ‘simple cycle.’

139 The remaining capacity (capacity not derated) is available for California ISO to call upon if needed.

Figure 37: Total Cumulative Monthly Derated Capacity by Resource Type September 2022



Source: [California ISO Prior Trade Date Reports](https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators): https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators, and staff analysis.

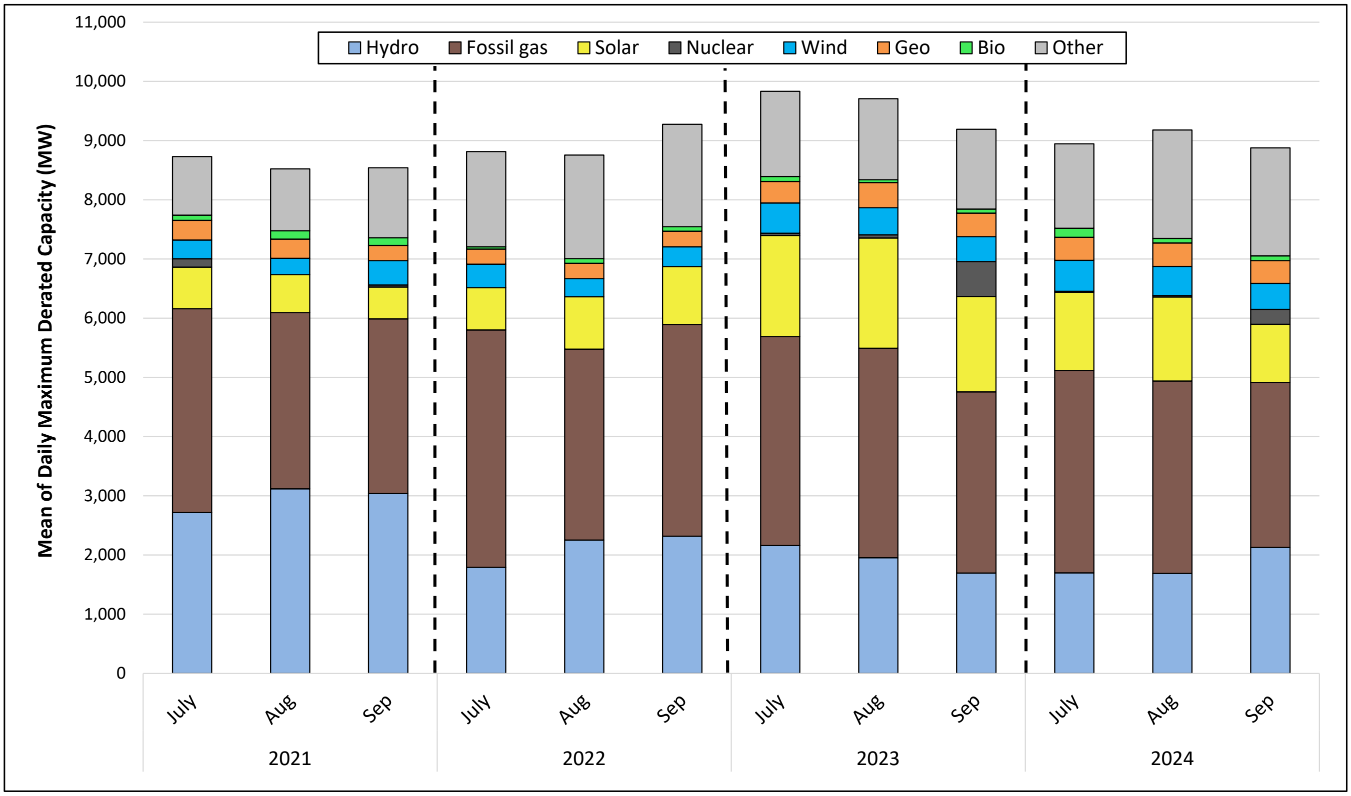
Figure 38 shows monthly averages of the maximum daily capacity derates which are defined as the maximum instantaneous hourly capacity derate observed during the peak hours (16:00 through 21:59). For example, the maximum hourly derated capacity for all fossil gas resources averaged about 4,200 MW a day in July 2021.

Each resource type capacity derate changes slightly from month to month and year to year; however, for July and August 2024, fossil gas derated capacity was about 50 percent higher than the same months in 2023, and 20 percent higher for September (2024 compared to

2023). These two months in 2024 experienced the largest derated capacity values, compared to other energy sources and years. See Figure 38.

Overall, the summer months from 2021 through 2024 show slightly increasing daily maximum amounts of derated capacity, although 2023 showed larger capacity derates than 2024. From 2021 through 2024 the maximum daily capacity derate (maximum hourly capacity derate of the day, full or partial hour) from the fossil gas fleet (in CAISO) averaged around 3,300 MW. The maximum fossil gas daily derate is larger in years 2022-2024 compared to 2021.

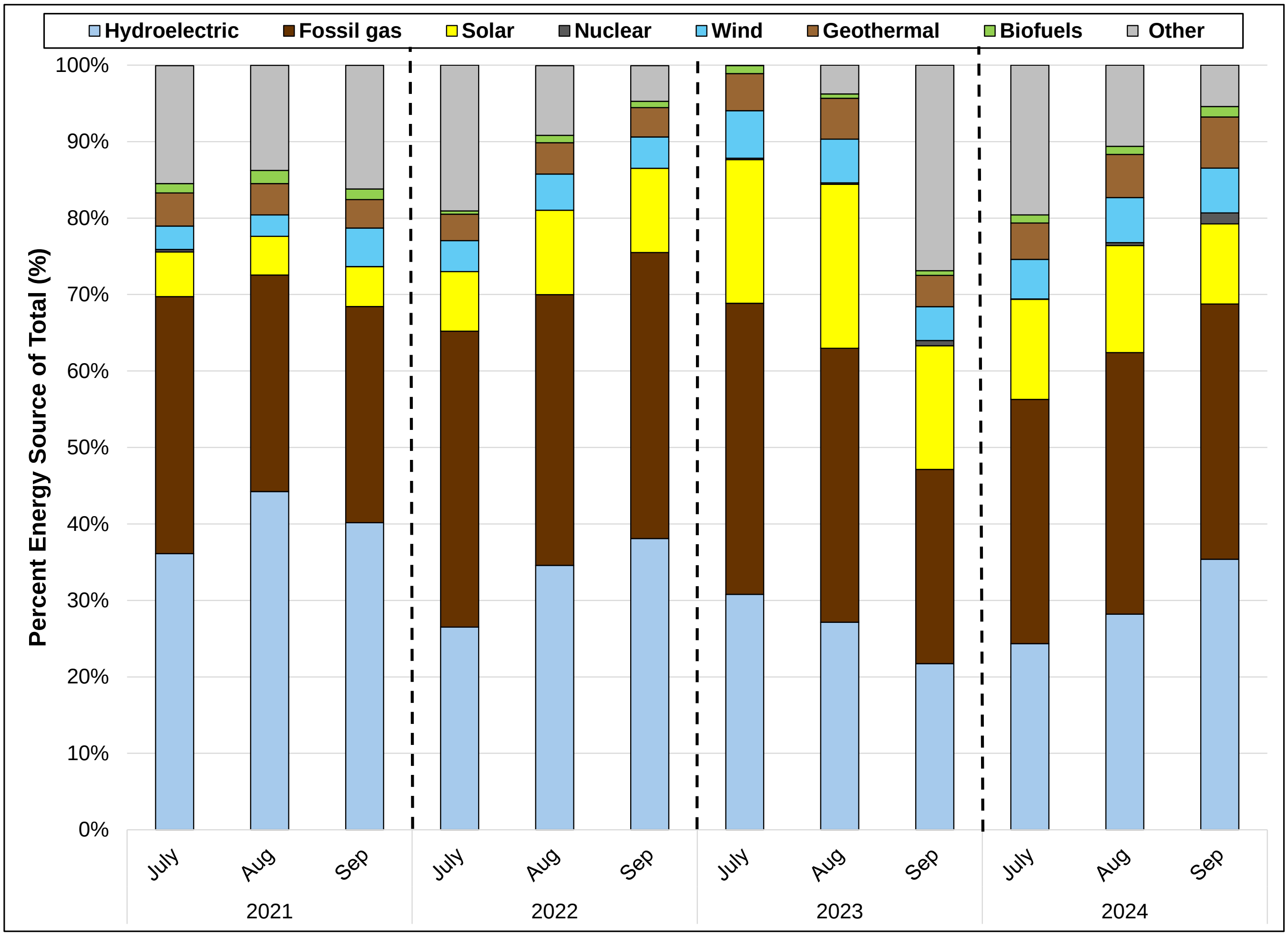
Figure 38: Monthly Average of Daily Maximum Capacity Derate by Energy Source



Source: [California ISO Prior Trade Date Reports](https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators): https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators, and staff analysis.

Figure 39 shows the percentage of total derated capacity by fuel type. Fossil gas and hydroelectric resources make up most of the derates (between 50 percent and 70 percent of monthly cumulative derated capacity). Fossil gas derated capacity makes up about 20 percent to 30 percent of total cumulative derated capacity; this distribution is similar for summer months 2021-2024. See Figure 39.

Figure 39: Percent of Derated Capacity by Resource Type



Source: [California ISO Prior Trade Date Reports](https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators): https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators, and staff analysis.

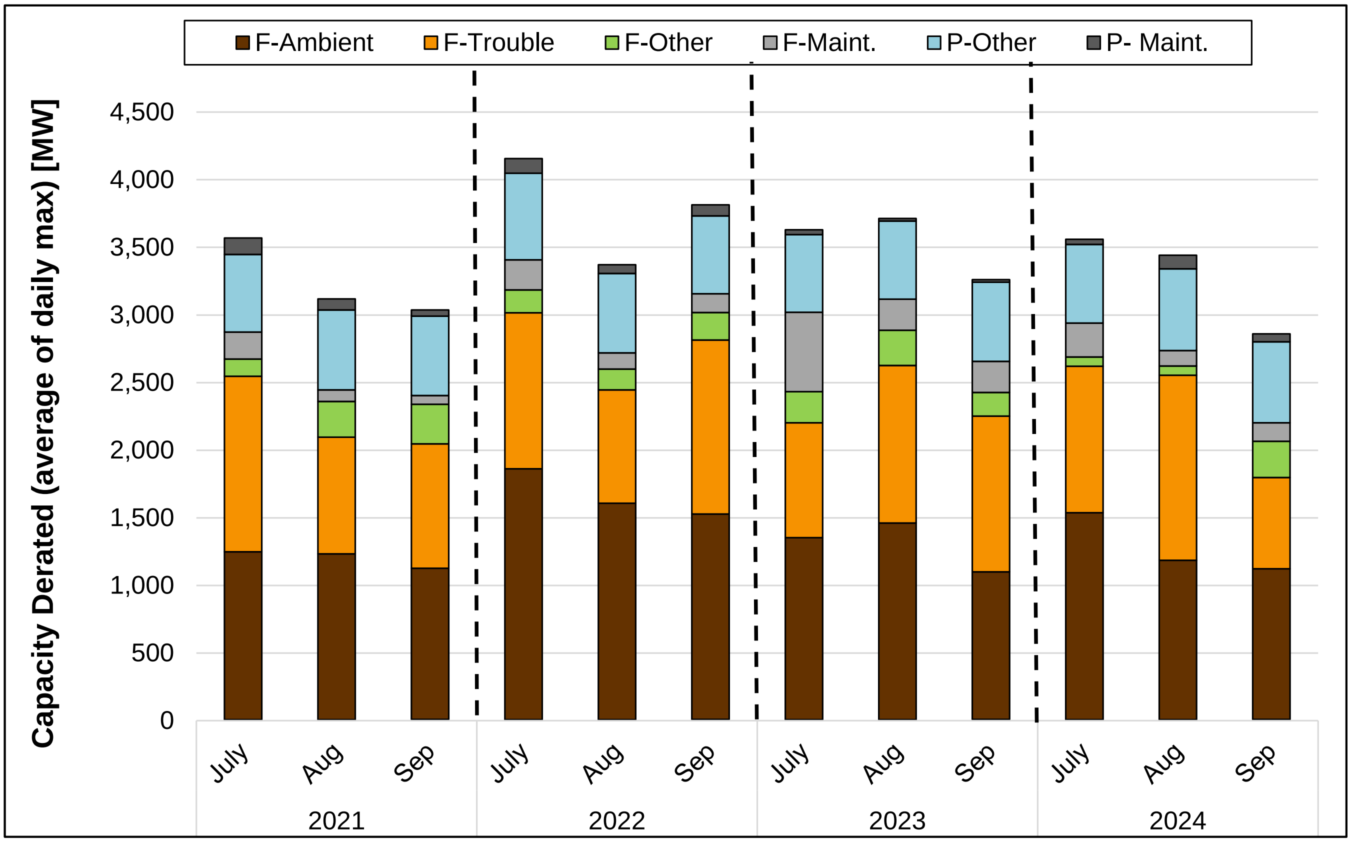
Figure 40 shows forced derates and planned derates by type of derate. Derates among months, each year, remain relatively similar, except for 2024.

For Figure 40 and Figure 41, definitions of derate types are as follows.

- F-Ambient: Forced derate due to high ambient air temperature
- F-Trouble: Forced derate due to various types of plant trouble
- F-Other: Forced derate due to other factors (unit testing, environmental restrictions, etc.)
- F-Maint: Forced derate due to plant resource maintenance
- P-Other: Planned derate due to other factors (unit testing, environmental restrictions, etc.)
- P-Maint: Planned derate due to plant resource maintenance.

For fossil gas resources, 'Forced ambient' and 'forced plant trouble' capacity derates make up most of the daily maximum capacity derates; these two derate types generally make up 2,000 to 3,000 MW out of the total 3,500 4,200 MW maximum daily capacity derates (60 percent to 70 percent). See Figure 40.

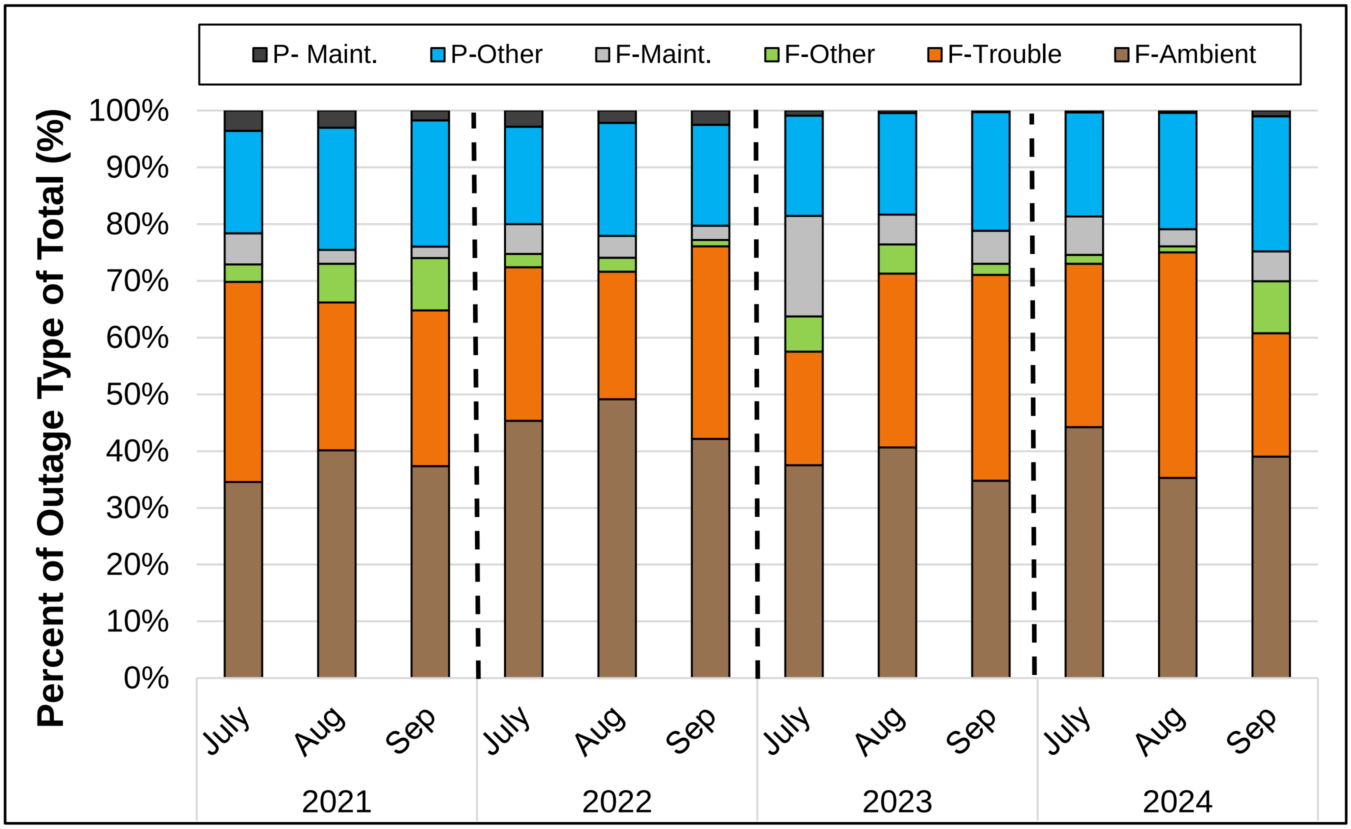
Figure 40: Fossil Gas Resources: Monthly Average of Maximum Daily Capacity Derate



Source: [California ISO Prior Trade Date Reports](https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators): https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators

Figure 41 shows the percentage of total derated capacity by type of derate.

Figure 41: Fossil Gas Resources: Percent of Derate, by Derate Type



Source: [California ISO Prior Trade Date Reports:](https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators) https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators.

As mentioned earlier, staff separately analyzed the six OTC units that joined the SRR in January of 2024. These six OTC resources experienced many hours of capacity derates due primarily to environmental restrictions[140] during summer months in 2024 (See Table 24). Beginning on January 1, 2024, the six OTC units were moved into the SRR instead of shutting down to support grid reliability. [141] Since they were moved into the Reserve, these facilities are only allowed to operate for maintenance, for air permit testing, if there is a declaration of an extreme event, or otherwise as needed to meet the requirements of the Program. Otherwise, they are not allowed to operate.

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140 The CAISO Business Practice Manual defines environmental restrictions as: "Restrictions due to environmental regulations specific to a resource that limits the dispatchable capacity of that unit. Also to be used outside extreme event periods for resources that may only operate as necessary to respond to extreme events under the state of California Strategic Reliability Reserve (SRR) Program." P. 24 in California ISO staff. 2023. *Business Practice Manual for Outage Management*. California ISO. https://bpmcm.caiso.com/BPM%20Document%20Library/Outage%20Management/Outage%20Management%20BPM_Version_30_Redline.pdf.

141 California Energy Commission Energy Assessments Division staff. N.d. *Strategic Reliability Reserve*. California Energy Commission. https://www.energy.ca.gov/data-reports/california-energy-planning-library/reliability/strategic-reliability-reserve.

The six OTC facilities being placed on the Reserve list is the reason that the total derated capacity due to "environmental restrictions"[142] drastically increased in 2024. This, and the fact that these six resources rarely operate (annual capacity factors at around 5 percent). See Table 24:

Table 24: Annual Capacity Factors: OTC Units in SRR

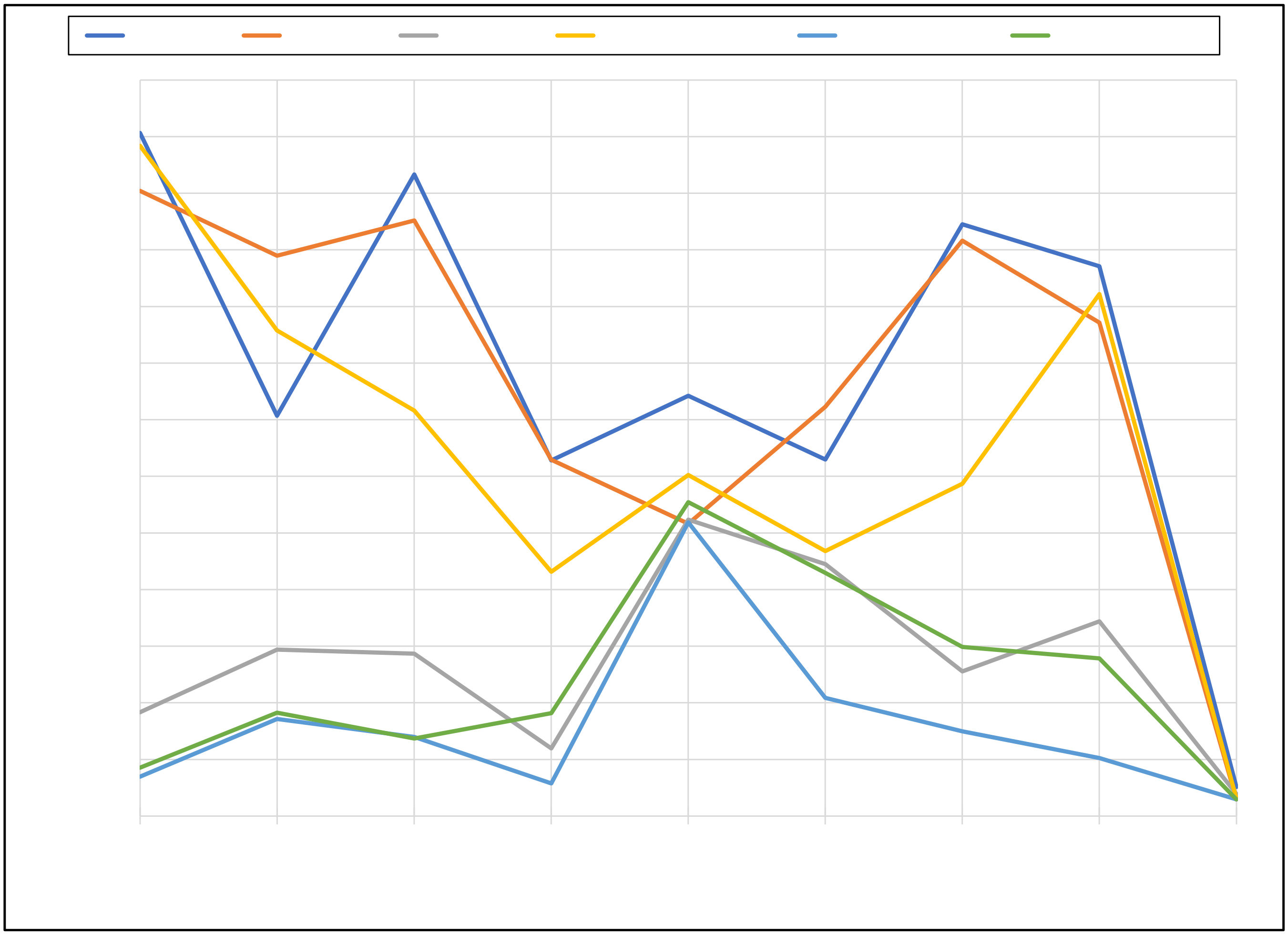
OTC Resource Name	Nameplate Capacity (MW)	2021 CF (%)	2022 CF (%)	2023 CF (%)	2024 CF (%)
ALAMITOS GEN STA. UNIT 3	310	6.3%	10.5%	9.7%	0.5%
ALAMITOS GEN STA. UNIT 4	310	7.2%	10.2%	8.7%	0.3%
ALAMITOS GEN STA. UNIT 5	495	4.4%	2.6%	3.4%	0.4%
HUNTINGTON BEACH GEN STA. UNIT 2	218	4.7%	5.9%	9.2%	0.3%
ORMOND BEACH GEN STA. UNIT 1	806	2.1%	1.5%	1.0%	0.3%
ORMOND BEACH GEN STA. UNIT 2	806	4.3%	3.0%	2.8%	0.3%

Source: Environmental Protection Agency Clean Air Markets Program data, 2024, and staff analysis: https://campd.epa.gov/data/custom-data-download

Next, staff graphed the annual capacity factors for these six OTC resources. For most OTC resources and years, the annual capacity factor is less than 10 percent. The annual capacity factors for all OTC units have been mostly decreasing since 2016 (2020, 2022, and 2023 saw small increases). Annual capacity factors in 2024, for all six OTC units, are lower than any previous year. See Figure 42.

142 See the long start strategic reliability reserve (LS-SSR) resources in California ISO operating procedure number 4420 that requires these six OTC units to remain derated (out) due to environmental restrictions until called upon: California ISO. 2025. *Operating Procedure: System Emergency*. California ISO. https://www.caiso.com/Documents/4420.pdf.

Figure 42: Annual Capacity Factor for OTC Units in SRR (2016 – 2024)



Source: [Environmental Protection Agency Clean Air Markets Program data](https://campd.epa.gov/data/custom-data-download), 2024, and staff analysis: https://campd.epa.gov/data/custom-data-download

Comparison of Event versus Non-event Days:

As described at the start of this Appendix (page A-2). The California ISO event days roughly correspond to heavy loads and stressed system conditions.[143] Many event days are classified as RMO, meaning some resource maintenance (planned and or forced) can be restricted on these days and postponed to days where the resource capacity is needed less. This type of event day (RMO) could lessen, for some resources, the amount of derated capacity. However, during RMO events days, resources are more likely to experience derated capacity from extreme heat (ambient temperature derated capacity). This is discussed below and illustrated in Table 25 and Table 26.

During the study period, daily peak loads averaged nearly 37 GW. On non-event days, which comprise most days in the study period, daily peak loads averaged slightly lower at nearly 36

143 California ISO. 2023. *Emergency Notifications Fact Sheet*. California ISO. https://www.caiso.com/Documents/Emergency-Notifications-Fact-Sheet.pdf.

GW. Over the 60 days of the study period associated with California ISO Event Day declarations, daily peak loads averaged nearly 43 GW, about 20 percent higher than non-event days.

Peak load levels are not the only aspect of the system affected by heat events. These stressed conditions can also impact resource performance. In particular, the performance of flexible, dispatchable capacity, primarily from resources fueled by fossil gas, can be affected.

Within the combined-cycle category, heavy-duty, or ‘frame’ combustion turbines have an inlet air compression ratio of less than 20:1 while ‘aeroderivative’ combustion turbines have an inlet air compression ratio of up to 40:1. As a result, aeroderivative combustion turbines lose capacity (MW) during periods with high ambient temperatures more than frame combustion turbines. Also, depending on the frequency of higher ambient temperatures, some facilities use inlet air treatment (cooling or chilling) to offset this loss of capacity.

To better understand how California ISO event days affect fossil gas resources, staff compared derated capacity for event and non-event days, for each year and month in the study period. This is a simple comparison, and a more detailed look at extreme weather days, combustion turbine types and the presence or absence, and use of, inlet air treatment (if data are available) could provide additional insights. Table 25 compares the average of the maximum daily derated capacity of all fossil gas generators combined for event and non-event days.

The table shows that some months have higher average maximum daily derated capacity (for all derate types combined) during event days, and some lower, compared to non-event days. During the study period, the daily maximum derate averaged nearly 3,200 MW for these resources during event-days, with no significant change in the metric during non-event days. Some event days classified as RMO can restrict a fossil gas plant from derating it’s capacity, so it is not unreasonable to see some decreased capacity derates during these event days. Notably, August tends to have less derated capacity during event days, compared to non-event days.[144] For example, August 2023 experienced less fossil gas derated capacity during event days compared to non-event days (about 8 percent less) when considering all derate types (maintenance, plant trouble, ambient temperature, etc.). However, when considering just ambient temperature (extreme heat) capacity derates, August 2023 experienced more derated capacity during event days compared to non-event days (about 14 percent more).

144 July 2022 and September 2023 had no event days.

Table 25: Fossil Gas Derated Capacity for Event and Non-Event Days

Year	Month	Non-Event Day Derate (MW)	Event Day Derate (MW)	Percent Difference	Non-Event Day Ambient Derate (MW)	Event Day Ambient Derate (MW)	Percent Difference (Ambient)
2021	**7**	3,401	3,213	-5.5%	1,210	1,363	12.6%
2022	**7**	3,922			1,904		
2023	**7**	3,436	3,298	-4.0%	1,326	1,428	7.7%
2024	**7**	3,202	3,475	8.5%	1,496	1,545	3.2%
2021	**8**	2,956	2,661	-10.0%	1,202	1,385	15.2%
2022	**8**	3,161	3,142	-0.6%	1,608	1,592	-1.1%
2023	**8**	3,485	3,185	-8.6%	1,396	1,590	13.9%
2024	**8**	3,145	3,249	3.3%	1,142	1,242	8.8%
2021	**9**	2,885	2,734	-5.2%	1,094	1,341	22.6%
2022	**9**	3,356	3,818	13.8%	1,284	2,009	56.5%
2023	**9**	2,978			1,075		
2024	**9**	2,642	2,994	13.3%	1,044	1,367	30.9%

Source: California ISO prior trade date report and staff analysis

Table 25 also shows ambient derated capacity. In the summer months, fossil gas resources appear to have more capacity derated (due to high ambient temperatures) during event days compared to non-event days. Even during RMO days total fossil gas derated capacity can increase from high ambient temperatures. On average, ambient temperature derated capacity was about 1,500 MW (15 percent) higher in July and August and nearly 1,500 MW (27 percent higher in September on event days, compared to non-event days, over years 2021-2024). This September increase (27 percent) may be due to more extreme ambient temperature in the first few weeks of the month, followed by milder conditions later in the month (so in September, fossil gas resources can experience derates from both ambient temperatures and maintenance). As summer operating stress eases, resources have more opportunity to perform maintenance, contributing to elevated derated capacity levels.

Table 26 below compares event day[145] and non-event day capacity derates for combined cycle (CC) and combustion turbine (CT) fossil gas facilities (for ambient temperature capacity derates only). Combined cycle facilities have the largest daily maximum capacity derates, on average, and event days increase capacity derates for this resource type by 16 percent and combustion turbines by 8 percent, compared to non-event days.

145 There were no events declared in the months of July 2022 and September 2023.

Table 26: Fossil Gas Derated Capacity for Event and Non-Event Days, by Technology Type

		CC (MW)	CC (MW)	CC (MW)	CT (MW)	CT (MW)	CT (MW)
Year	Month	Non-Event	Event	Percent Difference	Non-Event	Event	Percent Difference
2021	7	887	1,123	27%	71	82	16%
2022	7	1,539	n/a	n/a	58	n/a	n/a
2023	7	915	936	2%	80	82	3%
2024	7	1,107	1,127	2%	115	78	-32%
2021	8	854	986	15%	72	76	6%
2022	8	1,276	1,165	-9%	73	84	15%
2023	8	920	1,042	13%	100	112	12%
2024	8	791	824	4%	68	73	8%
2021	9	771	965	25%	64	75	19%
2022	9	947	1,443	52%	62	85	39%
2023	9	749	n/a	n/a	90	n/a	n/a
2024	9	733	942	29%	68	68	-2%

Source: California ISO prior trade date report and staff analysis

Once again, looking at just California ISO event days, rather than the specific event types and event totals for each day, represents a simplistic categorization for extreme heat days that does not consider that some event days may be more severe than others. Staff could consider more detailed event day categorizations, making use of event types or weather data, in future analyses to provide added perspective for different event days.

APPENDIX B:
Gas Demand Forecast Methodology

Methodology for Gas Demand Forecasting

This section outlines the methodology for predicting gas demand for Southern California Gas (SoCalGas) and PG&E during the summer of 2025. The approach aims to forecast gas demand by considering variations among customer classes, weather patterns, hydroelectric generation, and the effects of climate change.

Datasets

The fossil gas dataset contains daily historical demand data, measured in MMcfd, from 2017 to 2023, categorized by customer class for both utilities.

Historical daily maximum and minimum temperature data, measured in degrees Fahrenheit, were obtained from NOAA with assistance from CEC staff. Daily weighted average temperatures for utility service areas were calculated by multiplying the data from each relevant weather station by its assigned CEC weight and then summing the results.[146]

Potential impacts of climate change on temperatures for 2024 and 2025 were estimated using downscaled, bias-corrected data provided by Electric Program Investment Charge grant recipients in collaboration with CEC staff.[147]

Additionally, staff provided historical hydroelectric generation data, measured in GWh, covering the years 2001 to 2017 from the Quarterly Fuel and Energy Report.[148] This data helps evaluate the indirect effects of hydroelectric generation on fossil gas demand, particularly during dry seasons when reduced water availability limits hydroelectric capacity, leading to an increase in gas demand. The PG&E CGR workpaper for August 2024 included hydroelectric generation data for Northern California (PG&E region) and Southern California (SoCalGas region), along with scenarios for both average and high demand in 2024.[149]

Exploratory data analysis

A preliminary analysis showed that temperature significantly impacts gas demand nonlinearly. There are clear seasonal patterns, with increased demand for cooling in the summer and

146 Burbank, Long Beach, Santa Barbara, Bakersfield, and Riverside in SoCalGas' service area and Fresno, Oakland, Red Bluff, Sacramento, San Jose, San Luis Obispo, and Ukiah in PG&E's service area.

147 Aydin, Mariko G. 2023. *Presentation – Key findings in climate data analyses for demand forecast integration*. Lumen Energy Strategy. https://efiling.energy.ca.gov/GetDocument.aspx?tn=253658.

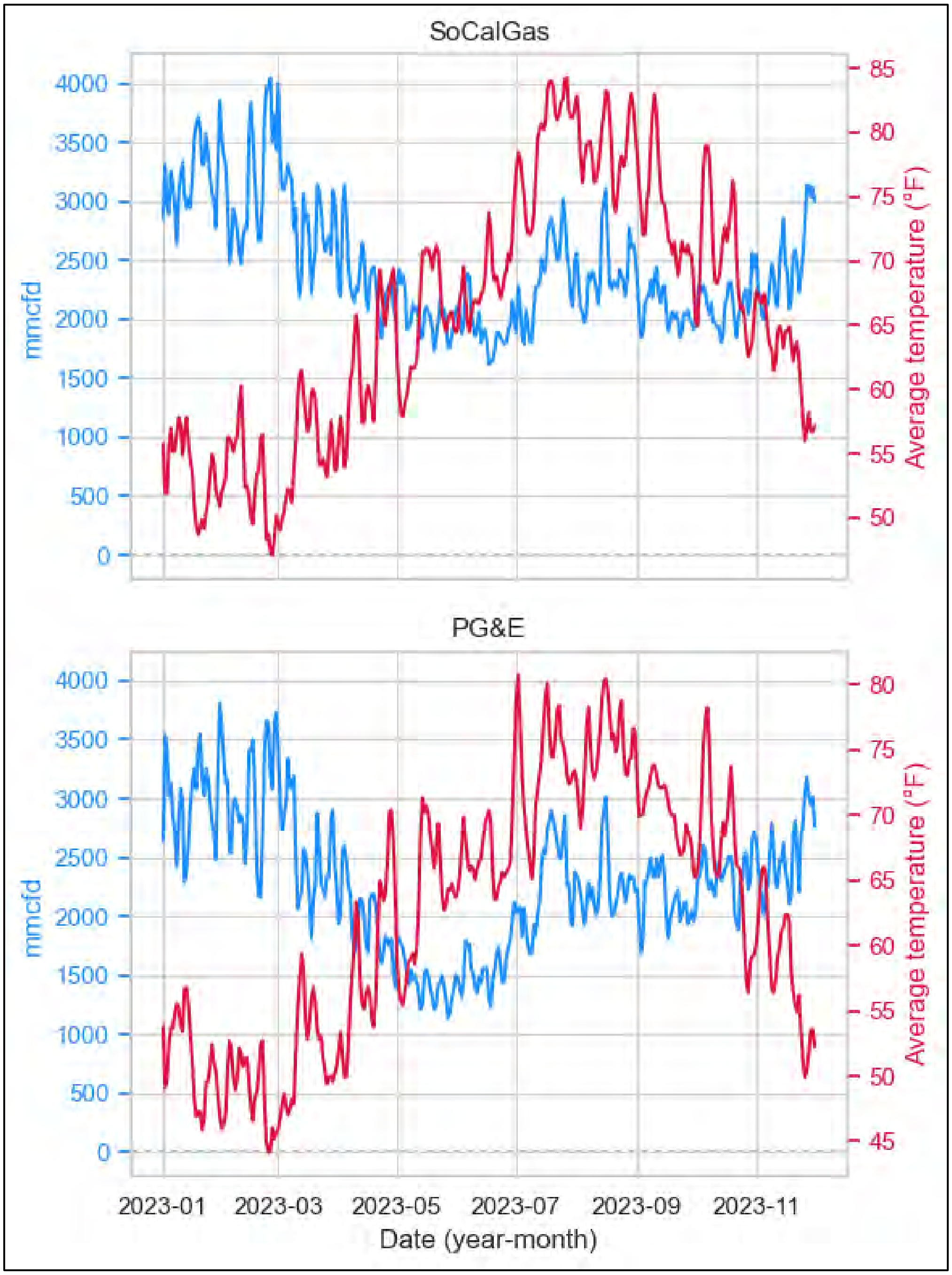
148 California Energy Commission staff. N.d. *Energy Almanac: California Electricity Data*. California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/.

149 PG&E staff. 2024. *2024 California Gas Report* workpapers. PG&E. https://www.pge.com/assets/pipeline/docs/library/regulatory/downloads/24_CGR_Workpaper_On-System_Demand_Forecast.zip.coredownload.zip.

heating in the winter. Notable lagged effects of temperature are also present, and different customer classes show varying sensitivities to changes in temperature.

Figure 43 illustrates the relationship between temperature and gas demand for 2023. The data show a clear positive correlation with seasonal trends in summer, characterized by spikes in demand due to cooling needs. Conversely, there is a negative winter correlation driven by heating requirements. Additionally, although not elaborated upon here, gas demand typically decreases during weekends compared to weekdays and tends to decline even further on holidays.

Figure 43: SoCalGas and PG&E 2023 MMcfd vs. Average Temperature (Degrees Fahrenheit)



Source: CEC

A three-day weighted moving average of temperature accounts for short-term fluctuations and effectively captures variability over multiple days. In this approach, the temperature from the most recent day is given a weight of 0.6, the previous day's temperature is weighted at 0.3, and the temperature from two days ago is weighted at 0.1.

The continuous temperature and gas demand datasets are merged and resampled to monthly frequencies. This process allows for calculating the average daily demand for each month. A log transformation is applied to normalize the data and linearize the relationship between temperature and gas demand for model estimation. This transformation helps reduce the impact of extreme values and minimizes serial correlation.

In addition to the primary temperature data, cooling degree days and heating degree days were calculated,[150] along with the differences between these values over consecutive one-day periods. These metrics help capture short-term fluctuations in demand by measuring how much a day's average temperature is above or below the threshold temperatures of 65 degrees Fahrenheit for cooling and 55 degrees Fahrenheit for heating.

The models use years, months, and weeks as time markers to identify seasonal patterns. Additionally, they incorporate binary indicators for the summer season (from April to October) and the winter season (from November to March), as well as for non-working days, which include weekends and holidays.

Modeling Approach

The Prophet time series forecasting algorithm[151] was chosen for its flexibility in capturing different patterns within the data. Prophet decomposes a time series into three components: trend, seasonal, and holiday terms. It models each component separately and combines them additively to generate a forecast.

The trend can be described as either flat or piecewise linear. It illustrates demand shifts over time, with breakpoints indicating trend direction changes. Using Fourier series analysis[152], the seasonal component addresses recurring patterns that occur annually, monthly, or weekly. The holiday component accounts for demand fluctuations during holidays or specific events, while a normally distributed residual error term captures any unexplained variations.

There are two modes of seasonality: additive and multiplicative. The additive mode assumes a consistent seasonal component that influences the trend over time, while the multiplicative mode assumes a variable effect. Additionally, explanatory variables related to time and temperature are incorporated as external regressors to enhance forecast accuracy. The non-working calendar variable, which captures holidays and weekends, eliminates the need to include a separate holiday term in Prophet modeling. The model now consists of terms related to trend and seasonality.

Bayesian optimization[153] selects explanatory variables and tunes hyperparameters, aiming for optimal model performance while minimizing the risks of overfitting and underfitting. It applies

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150 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.

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

152 Fourier series analysis decomposes time series data into sine and cosine functions with specific frequencies and amplitudes, revealing periodic patterns, trends, and seasonal variations.

153 Bayesian optimization creates a probabilistic model of the function to optimize. It iteratively refines the model based on its previous results and uses that knowledge to select the next set of parameters for evaluation.

Bayes' Theorem to update prior variable and hyperparameter combinations, yielding updated posterior combinations for inference.

Multiple hyperparameters determine how well the Prophet model fits the data. These hyperparameters include, besides those related to the underlying Bayesian framework, those specified for the trend, seasonality, and holiday components. The adjustable hyperparameters include those about changepoints, which control the flexibility of the trend and its evolution. Seasonality and holiday-related hyperparameters regulate the strength of seasonal and holiday effects, such as weekly, monthly, and yearly variations. Higher hyperparameter values allow for greater flexibility in trend, seasonal, and holiday patterns, while lower values lead to smoother patterns. Additional hyperparameters related to seasonality determine whether seasonal patterns are modeled using an additive or multiplicative approach. The selected explanatory variables include non-working days for holiday and weekend effects, cooling degree days and heating degree days at a 65°F threshold, daily variations in degree days, and seasonal factors.

Cross-validation using a rolling forecast window evaluates model performance with the optimal variables and hyperparameters. Historical data is used for training, while accuracy is assessed by testing either the last 12 months of daily data or the previous month of monthly data. Model accuracy is evaluated through residual analysis and the mean absolute percentage error (MAPE). Additionally, each model is reviewed based on its interpretability and capacity for manual hyperparameter tuning.

Historical Forecasting Performance (2017-2023)

After validating the models, they were refitted using the complete historical data set to predict fossil gas demand based on historical peak days and monthly average demand data up to 2023. The same optimal variables were used for both the peak day and monthly average forecasts; however, the optimal hyperparameters varied slightly between different utilities and depended on whether the forecast was for a peak day or the monthly average. Notably, the seasonality hyperparameter is additive for peak day modeling and multiplicative for monthly average modeling.

For peak day modeling, linear piecewise trends accounted for non-working days, and the Fourier series was applied to handle additive seasonality across yearly, monthly, and weekly periods. In contrast, the monthly average modeling focused on annual seasonal patterns by utilizing linear piecewise trends while incorporating multiplicative seasonal effects.

Cross-validation performance metrics indicate that the average MAPE ranged from 5.5 percent to 7.8 percent for peak days and from 3.3 percent to 5.4 percent for monthly averages. These metrics highlight variations in forecasting performance among different utilities, with SoCalGas slightly outperforming PG&E during various periods.

A residual analysis indicated that the errors were normally distributed, remaining between 7 percent and 9.5 percent for peak days and between 4.4 percent and 6.6 percent for monthly averages. The forecasts revealed no significant patterns or systematic deviations compared to historical data. This suggests that the models effectively captured the underlying trends in the data, with monthly averages exhibiting more stable patterns than the highly volatile daily peak demand.

Predictive Forecasting Performance (2025)

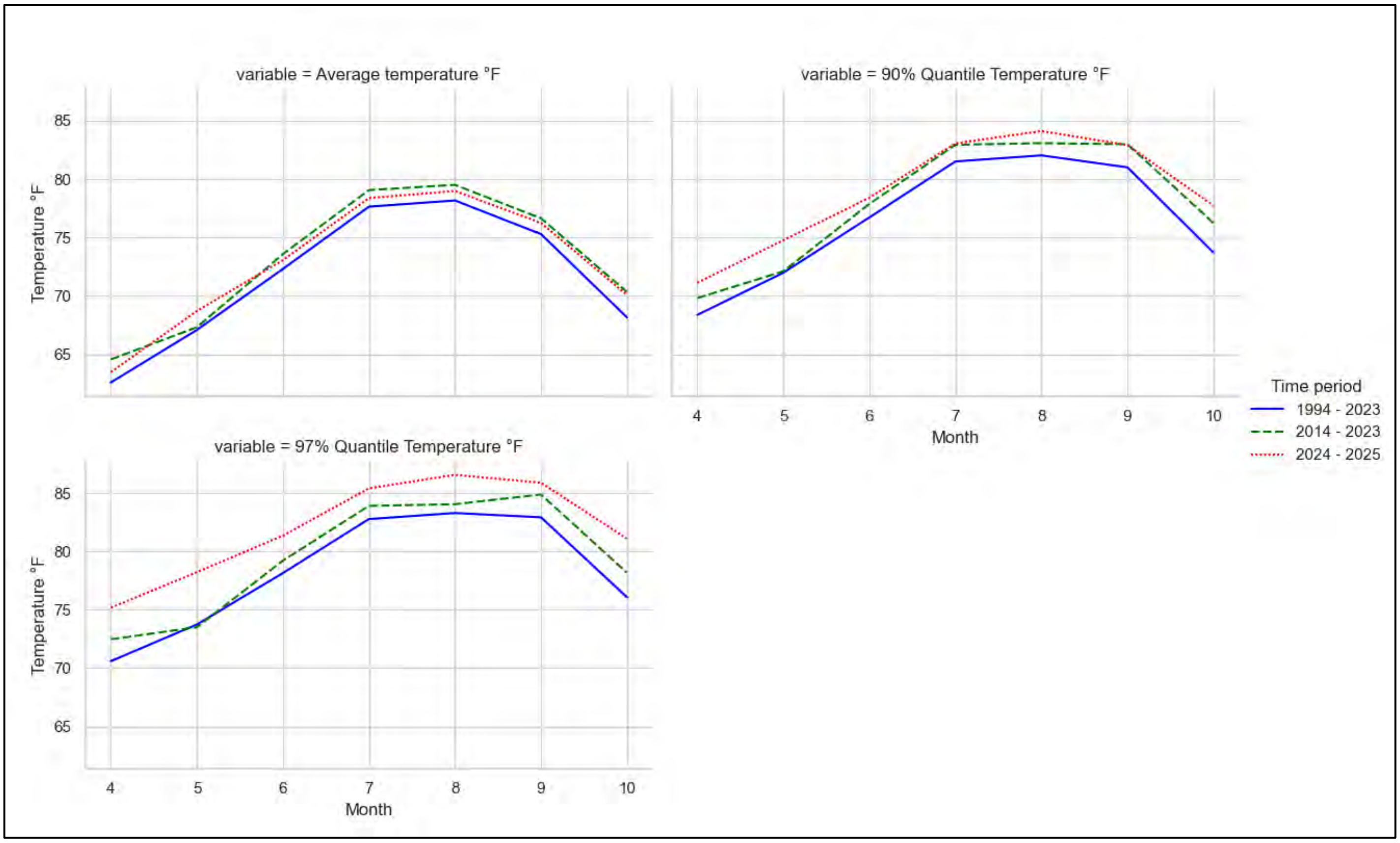
After refining the models and selecting the best performers using historical data, these models extrapolate the most recent linear trends to predict peak day demand and average daily demand for the summer months in 2025. This approach assumes that underlying trends will continue, with adjustments for spikes driven by climate factors. Depending on the specific model, either peak day or monthly averages may be predicted, incorporating periodic functions—weekly, monthly, and yearly—to capture cyclical patterns. Additionally, temperature-related and time-dependent explanatory variables, including climate change projections, are considered. The coefficients derived from historical data are utilized to adjust future predictions accordingly.

The forecasts suggest a slight overall decline in demand over time, likely due to changing consumption patterns related to climate change. However, the need for cooling significantly increases demand from power plants during the summer months. Climate change projections are incorporated into demand forecasts, resulting in higher demand during the summer months. To assess the impacts of climate change, gas demand is analyzed under two scenarios: average and hot/dry hydro climate events. The hot event assumes that temperature patterns correspond with the mean of climate change projections, while the dry event assumes slightly below-average temperatures. These two scenarios help quantify how fluctuations in climate change may affect gas demand, accounting for both long-term trends and short-term climate variability.

Before incorporating climate change projections, the initial predictions are adjusted by comparing historical temperature data with climate changes to account for temperature variations. The analysis uses downscaled climate projections for 2023-2025, comparing the detrended temperature forecasts with historical temperature trends. This comparison examines both detrended and moving average temperatures over various periods and quantiles: 30 years (1994-2023), 20 years (2004-2023), 10 years (2014-2023), the most recent 5-year span (2019-2023), and the previous year (2023) at the 50th, 90th, and 97th quantiles. This approach highlights the differences between short-term fluctuations and long-term trends within the historical data and climate projections. It reveals the effects of climate change, its impact on extreme temperatures, and how it may influence fossil gas demand.

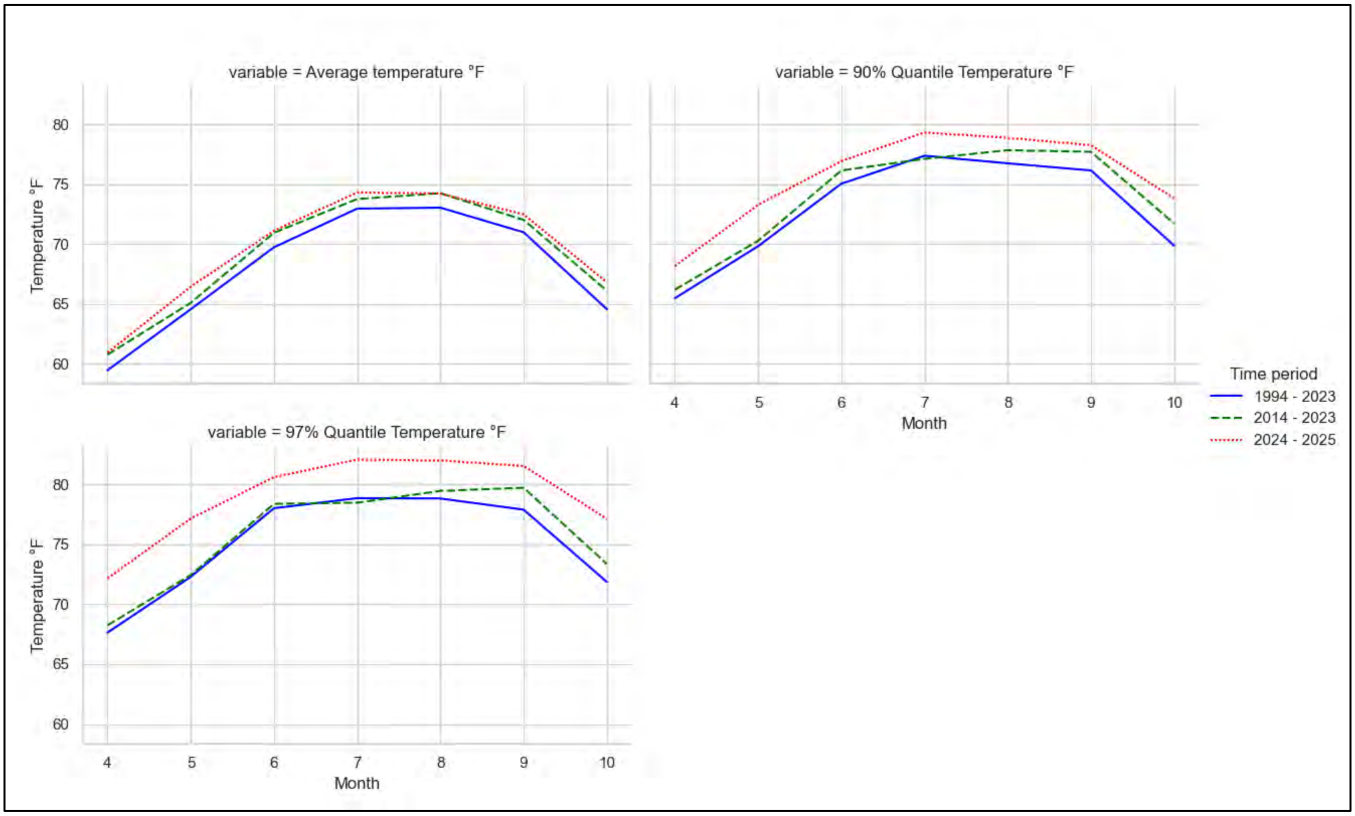
Figure 44 shows the monthly probability distribution of temperatures over several timeframes, including 30 years, 10 years, and projections for 2024-2025. This figure highlights changes in temperature patterns and increased variability, especially at higher quantiles. While there is a slight shift at the 50th quantile, more significant changes are evident at the higher quantiles (90th and 97th). These higher quantiles exhibit more significant variability, particularly in months when extreme temperatures are more likely to occur.

Figure 44: SoCalGas Monthly Distribution of Temperatures at the 50 Percent, 90 Percent, and 97 Percent quantiles over periods



Source: CEC

Figure 45: PG&E Monthly Distribution of Temperatures at the 50 Percent, 90 Percent, and 97 Percent quantiles over periods



Source: CEC

The PG&E region shows more pronounced changes due to significant climate change impacts, while the SoCalGas region experiences subtler shifts, indicating less extreme variations in temperature patterns. This variability in quantile distributions over different periods offers a clearer understanding of how predicted temperature patterns are expected to evolve and how these changes may affect fossil gas demand overall.

Customer Classes - Historical and Predictive Forecasting

The peak-day and monthly average profiles as a percentage of historical and projected total demand for core and electric generation are modeled and forecasted separately using the additive models previously described. These two customer classes strongly correlate with the selected explanatory variables.

The projected profiles are used to calculate the peak-day and monthly average demand values, which help determine the final projected demands for each customer class over a two-year forecasting period. In contrast, the profiles for the other customer classes are less affected by temperature and seasonality. Their projected demands are adjusted based on the values obtained from the core and electric generation customer classes. Essentially, the demands of the less sensitive classes are forecasted using the historical trends of the more sensitive classes, assuming they will follow similar growth patterns over time.

The profiles are adjusted using historical data and growth rates, including those reported in the 2022 and 2024 editions of the CGR,[154] as reference points to ensure the projections align with historical trends.

Hydroelectricity Production - Impact on Gas Demand

Hydroelectric generation significantly impacts the demand for gas. During periods of dry conditions, reliance on gas-powered generation increases as the output from hydroelectric sources declines. While this report mainly focuses on demand driven by temperature changes, an initial post hoc analysis[155] considers the influence of hydroelectricity by incorporating hydroelectric output into future monthly forecasts for gas demand based on typical dry scenarios.

To assess the impact of dry conditions on hydroelectric output and the consequent rise in reliance on gas-powered generation, the annual daily average demand from gas-power plants was calculated using data from 2001 to 2021. This timeframe encompasses typical hydroelectric generation and dry conditions, offering valuable insights into how gas demand fluctuates with changes in hydroelectric output.

The 2024 CGR working paper from PG&E divides hydroelectric generation into Northern California (the PG&E region) and Southern California (the SoCalGas region). Dry conditions impact gas demand differently in these areas. The PG&E region is expected to see a more substantial increase in gas demand due to its greater reliance on hydroelectric power than the SoCalGas region.

Monthly gas demand profiles are developed by comparing the monthly gas consumption for electric generation to the annual average. These profiles capture seasonal variations in gas-powered generation demand, which are linked to the availability of hydroelectric output. Typically, peak generation occurs in mid-to-late summer. Increased gas demand correlates with reduced hydroelectric output during dry conditions or in months with limited water availability. The central assumption is that decreases in hydroelectric production result in higher gas demand due to a greater reliance on gas-powered electricity generation.

Results

While historical and predictive forecasting uses year-round data, this report specifically focuses on the summer gas season, from April to October. Below are the projected demands for peak days and average monthly consumption for PG&E and SoCalGas for 2025.

154 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.

155 Catherine Elder and Joseph Long from Aspen Environmental Group conducted a preliminary analysis and made it available.

Table 27: Summer peak day demand (MMcfd) for SoCalGas in 2025.

Core	Noncore	Other Core	SDGE Core	Electric Gen	Total
566	549	57	80	2,017	**3,269**

Source: CEC Staff

Table 28: Summer average monthly demand (MMcfd) for SoCalGas in 2025.

Climate	Month	Core	Noncore	Other Core	SDGE Core	Electric Gen	Total
Average	4	912	463	24	304	666	**2,702**
Average	5	697	467	20	328	582	**2,686**
Average	6	609	453	20	275	520	**2,240**
Average	7	577	459	24	174	814	**2,111**
Average	8	545	449	25	174	814	**2,111**
Average	9	576	478	22	243	756	**2,458**
Average	10	648	447	23	280	793	**2,761**
Cold/Dry	4	952	460	24	250	597	**2,283**
Cold/Dry	5	714	464	21	202	546	**1,947**
Cold/Dry	6	612	452	20	184	611	**1,878**
Cold/Dry	7	577	457	24	171	1,068	**2,299**
Cold/Dry	8	545	449	25	163	1,184	**2,365**
Cold/Dry	9	578	477	22	170	867	**2,114**
Cold/Dry	10	659	445	23	181	864	**2,171**

Source: CEC Staff

Table 29: Summer peak day demand (MMcfd) for PG&E in 2025

Core	Industrial	Electric Gen	Off System	Total
344	648	1,571	358	**2,922**

Source: CEC Staff

Table 30: Summer Average Monthly Demand (MMcfd) for PG&E in 2025

Climate	Month	Core	Industrial	Electric Gen	Off System	Total
Average	4	641	547	413	276	**1,876**
Average	5	446	500	346	236	**1,528**
Average	6	351	570	492	251	**1,664**
Average	7	335	704	871	309	**2,220**
Average	8	379	735	796	282	**2,192**
Average	9	370	705	709	350	**2,133**
Average	10	444	673	771	187	**2,076**
Cold/Dry	4	625	523	720	290	**2,158**

Climate	Month	Core	Industrial	Electric Gen	Off System	Total
Cold/Dry	5	439	485	585	236	**1,745**
Cold/Dry	6	336	536	898	246	**2,016**
Cold/Dry	7	323	674	1,451	292	**2,740**
Cold/Dry	8	368	702	1,321	270	**2,662**
Cold/Dry	9	362	680	1,186	325	**2,553**
Cold/Dry	10	431	651	1,234	186	**2,502**

Source: CEC Staff

Discussion and Conclusion

The Prophet forecasting models for gas demand effectively capture consumption patterns on peak days and monthly averages. These models account for additive and multiplicative seasonal effects while addressing daily and monthly demand fluctuations through Bayesian optimization, Fourier series, linear piecewise trends, and external regressors.

The models performed well with minimal residual errors, indicating their reliability in predicting peak day and monthly average demand. Cross-validation metrics show reasonable error margins, with a MAPE ranging from 5.5 percent to 7.8 percent for peak days and 3.3 percent to 5.4 percent for monthly averages. The variation in MAPE suggests that SoCalGas performs slightly better than PG&E in forecasting accuracy. Residual errors are normally distributed, confirming minimal bias and systematic inaccuracies.

Incorporating climate change projections significantly impacts demand fluctuations, including a gradual decline due to short-term climate variability and spikes during two climate scenarios: hot and dry conditions.

Core and electric generation customer classes show stronger correlations with temperature and seasonality. By using indirect forecasting, these customer profiles can enhance the consistency of projections for the less sensitive customer classes.

Dry conditions reduce hydroelectric output, heightening dependence on fossil gas and emphasizing the link between hydroelectricity availability and gas consumption. PG&E’s Northern California region is particularly susceptible to changes in the hydroelectric power supply.

In conclusion, the Prophet time series is an effective method for modeling and forecasting fossil gas demand. It incorporates trends, seasonal patterns, and historical and external regressor values, including climate projections, customer segmentation, and hydroelectric generation. Prophet provides accurate two-year forecasts for SoCalGas and PG&E with minimal bias. It effectively captures seasonal fluctuations and short-term trends in gas demand, making it easy to understand and adapt to changing climate and dry conditions.

To enhance the accuracy of demand forecasts, models should incorporate more detailed data on hydroelectric generation to adequately account for the effects of dry conditions and climate change.

APPENDIX C: Loss of Load Expectation

CEC consultant, Telos Energy, performed a probabilistic assessment of the reliability outlook from 2025 to 2040, under the supply forecast in the CPUC 2023 Preferred System Plan (PSP). The goal of this analysis was to determine if California is meeting the reliability criterion of 1 day in 10-year loss of load expectation (LOLE), or 0.1 days/year LOLE under a variety of scenarios related to the resource build and import uncertainty. Unlike previous assessments which focused on summer reliability risk, this analysis was conducted across the entire year to better understand the shifting of resource adequacy risk over the study horizon due to changes in the load and resource mix. Several resource adequacy risks are included in this analysis, combining uncertainty in resource availability, hourly demand, unexpected generator outages, lower than expected imports, and delays in resource builds. This Appendix provides expanded details to the analysis provided in Chapter 3.

The study finds that the California power system has sufficient resources to meet or exceed the 1 day in 10-year loss of load expectation (0.1 days/year LOLE) resource adequacy criterion and serve load under challenging demand and resource additions in 2025. Furthermore, if California's load serving entities successfully integrate new resources identified in the California Public Utilities Commission (CPUC) Preferred System Portfolio (PSP), the state will have sufficient resources to exceed the 0.1 days/year LOLE resource adequacy through 2035, even with projected increases in electricity demand.

However, the study did not evaluate all potential risk, and future work is being conducted to evaluate other aspects of power system reliability, including the impacts of transmission outages and alternative load scenarios, such as increased or different electric vehicle charging patterns. While the Base Case study results show that California is expected to meet or exceed its resource adequacy targets, higher than expected temperatures across the Western Interconnection, drought conditions, and/or transmission outages could lead to loss of load.

System reliability is expected to continue to significantly improve in the near term due to (1) significant new resource additions (including utility-scale solar, wind, and batteries, and distributed rooftop solar), (2) new energy efficiency and demand response programs, (3) the near-term retention of Diablo Canyon Power Plant (DCPP), and (4) projected reduction in summer peak demands relative to those that were used to design the generation mix used in this study (the 2023 PSP). Results of the scenarios and sensitivities are provided in Table 31.

Table 31: Resource Adequacy Results Across Scenarios

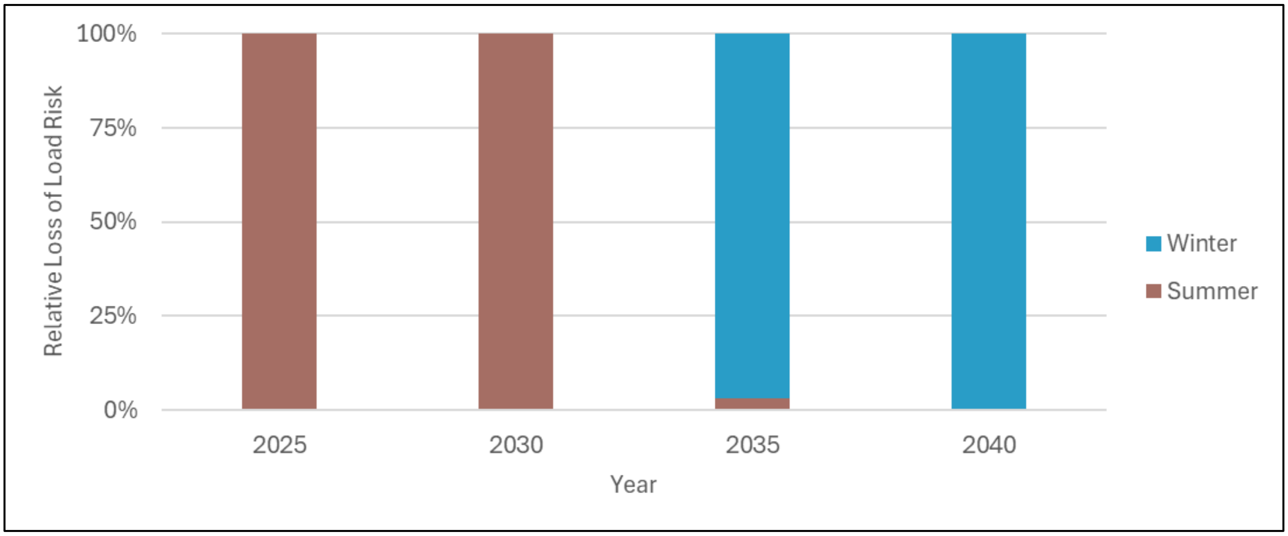
Scenario	Metric	2025	2030	2035	2040
Base Case LOLE	LOLE (days/year)	0.00	0.00	0.01	0.90
Base Case Effective Surplus / Deficit	GW	10+ GW Surplus	9-10 GW Surplus	4-5 GW Surplus	1-2 GW Deficit
Extend DCPP	LOLE (days/year)			0.00	0.57
Full PSP, No Imports	LOLE (days/year)	0.00	0.00	6.62	Greater than 10
40% Reduction in PSP	LOLE (days/year)	0.00	0.00	0.79	Greater than 10
40% Reduction in PSP + No Imports	LOLE (days/year)	0.003	0.17		

Source: Telos Energy

Over the study horizon, projected increases in electricity demand – notably from the increased adoption of electric vehicles and heat pumps – could significantly change the timing and season of California's resource adequacy risk. Historically, California's power system's greatest resource adequacy risk has been during hot summer afternoons. With the increased adoption of solar PV, resource adequacy risk has shifted to later in the evening. As demand from heating electrification increases, resource adequacy risk is projected to shift to overnight and early morning periods in the winter, when solar production is low or non-existent. This is a marked departure from California's longstanding challenges that focus on summer resource adequacy risk and will require evaluating whether system planning, maintenance scheduling, demand response programs, and other investments will need adjustments to address winter reliability risks.

Figure 46 below shows how the risk is distributed between summer and winter by study year. The near-term (through 2030) risk is dominated by summer reliability events, consistent with California's historical stress. As noted in the section titled *Characterizing System Risk*, 2035 represents either a winter-risk or a dual-risk year depending on the scenario under study. By 2040, the system is dominated by winter risk.

Figure 46: Relative Resource Adequacy Risk by Season Across the Study Horizon[156]



Source: Telos Energy

Model Development and Key Assumptions

To evaluate the RA of California's power system under a variety of scenarios, a probabilistic, hourly, chronological resource adequacy simulation was conducted in the PLEXOS modeling software. The software is utilized by other California entities for RA analysis, including the California ISO. This California 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.

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. On net these changes have increased the resource adequacy risk for California. The list below provides an overview of the major changes implemented in the model.

- **Demand Update** – The CEC issued a new Integrated Energy Policy Report California Energy Demand (IEPR CED, or simply "2024 CED"). This 2024 CED reworked major portions of the net load forecast, including reducing the behind the meter solar forecast, increasing the fuel substitution layer, and adding gigawatts of new data center load. The net peaks throughout the 2030s increased relative to the previous CED version, and the load forecast used to develop the PSP.
- **Inclusion of 2022 and 2023 weather years** – The weather years underpinning the analysis were expanded to include 2022 and 2023. This was done across load, wind, and

156 Each year is brought to a 0.1 LOLE criterion by either adding firm load or perfect generation. Results presented here are those closest to 0.1 days/year LOLE. The figure shows the share of unserved energy (MWh) occurring in each season.

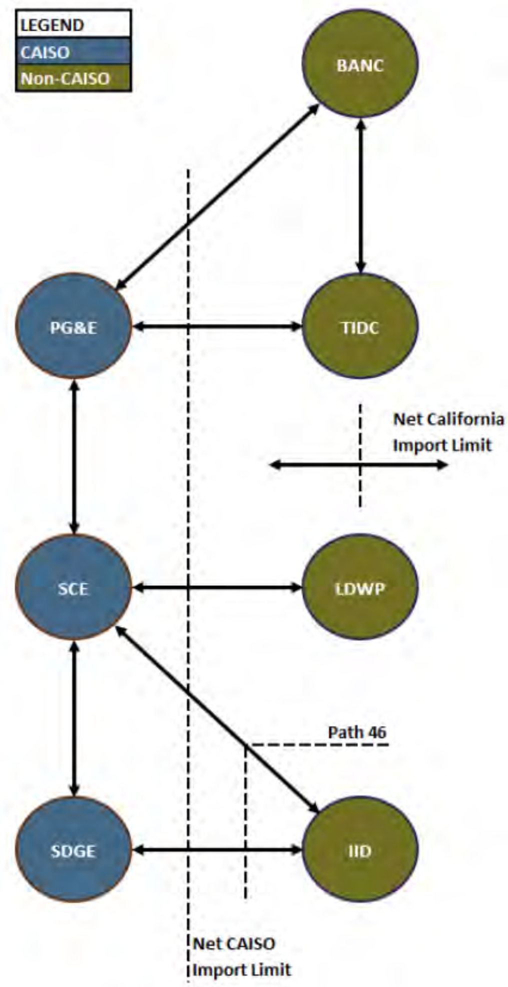
solar profiles. Notably, the addition of the 2022 weather year is expected to increase the observed LOLE as a heat wave in September of that year stressed the system.

- **Stochastic Loads** – The CEC developed underlying stochastic load profiles aligned with historical weather patterns. These new profiles replaced previous implementations that relied upon other data sources. These new profiles ensure the simulated electricity demand follows similar chronological weather patterns as the simulated solar and wind profiles.
- **Renewable Availability Profiles** - In addition to adding 2022 and 2023 weather years across the utility-scale solar (UPV), distributed solar (DPV), and land-based wind (LBW) profiles, the underlying development of the profiles was updated for utility scale plants to capture increased granularity of project siting to better improve modeling accuracy. In addition, the LBW profiles make use of the new NREL dataset[157] for weather years 2015-2023, and incorporate a bias correction methodology to align simulated wind generation with observed performance in the California ISO.

157 Buster, Grant, Pavlo Pinchuk, Luke Lavin, Brandon Benton, and Nicola Bodini. 2025. *Bias Corrected NOAA HRRR Wind Resource Data for Grid Integration Applications*. National Renewable Energy Laboratory. https://data.openei.org/submissions/6218

- **Updated Outage Modeling** – Following a review of CAISO daily generation reports[158], the natural gas outage sampling in PLEXOS was updated to better align to the NERC GADS Forced Outage Factor. The net effect reduced the modeled forced outage rate, making the gas fleet more reliable and aligned with CAISO observations over the last 3 years (2021-2024).

Figure 47: Zonal Topology used in RA Analysis



Model Topology

The CEC's RA model is California-centric, meaning power plants for the state are modeled in detail, but areas 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), which are grouped together as CAISO when appropriate, as well as four publicly owned utility balancing authority areas (BANC, TID, LADWP, and IID). Transfer limits are assumed between the individual regions to represent the transmission network. In addition to the region-to-region transfers, the combined California ISO regions have a Total CAISO Import Limit of 11,665 MW, and 5,500 MW during resource adequacy risk hours (H16-22 during the summer months)[159]. Imports into California are limited to 12,450 MW in all hours of the day, subject to monthly energy limits. The statewide import constraint is the 95th percentile of historic imports reported on EIA Form 930.

LOLE results are reported for the entire state, though the California ISO regions experience most of the loss of load events. In other words, a loss of load hour is counted anytime one or more regions in California experiences unserved energy.

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158 California ISO staff. N.d. *Outage management*. California ISO. https://www.caiso.com/library/outage-management

159 The RA import limit during peak hours has been used in CAISO and CEC models for years. The 5500 MW listed here exceeds the 4000 MW that have been used in CAISO models due to the treatment of pseudo-tie resources, specifically Palo Verde and Hoover. Palo Verde and Hoover are treated as generic imports in the CEC RA model, but are modeled explicitly in the CAISO RA model. In the results section, we discuss a sensitivity performed on this assumption, extending the import constraint to morning (H6-9) and evening (H16-22) peaks across the year.

Generation from pseudo-tie units, such as Palo Verde, Hoover, and other jointly owned resources located outside of the state are modeled as generic imports and generation from these units counts against the import limits listed above.[160]

Demand Forecast

This analysis utilizes the 2024 Integrated Energy Policy Report California Energy Demand (IEPR CED) forecast. The model uses weather correlated demand and renewable shapes for 17 weather years representing 2007 to 2023. The underlying demand and behind-the-meter solar layers are assumed to be weather dependent and varied across weather years. All other load modifiers (i.e., electric vehicles, energy efficiency, etc.) do not vary in peak or energy by weather year, but the profiles are shifted to align with the historical calendar used in each weather year.

Of note, the 1-in-20 net peak[161] forecast modeled in this report is 1,600 MW lower in 2025 as compared to the 2022 CED used to develop the resource mix in the 2023 PSP.[162] This is attributed to a variety of factors, including reduced correlation between electricity and temperature, and a larger-than-anticipated adoption of behind-the-meter solar generation. However, when compared to previous versions of the CED demand forecast, load is projected to grow faster throughout the study horizon. By 2028, the 1-in-20 peak roughly aligned between the forecast vintages. However, the updated 2035 summer 1-in-20 net peak forecast exceeds the forecast used to develop the PSP supply mix by over 7,500 MW. [163] As a result of this demand forecast change, the PSP may have fewer resources than necessary to meet long-term reliability targets. The IRP is an iterative process, adapting to changes in economic outlook, policy and technology each cycle. The next PSP is anticipated to be adopted in 2026.

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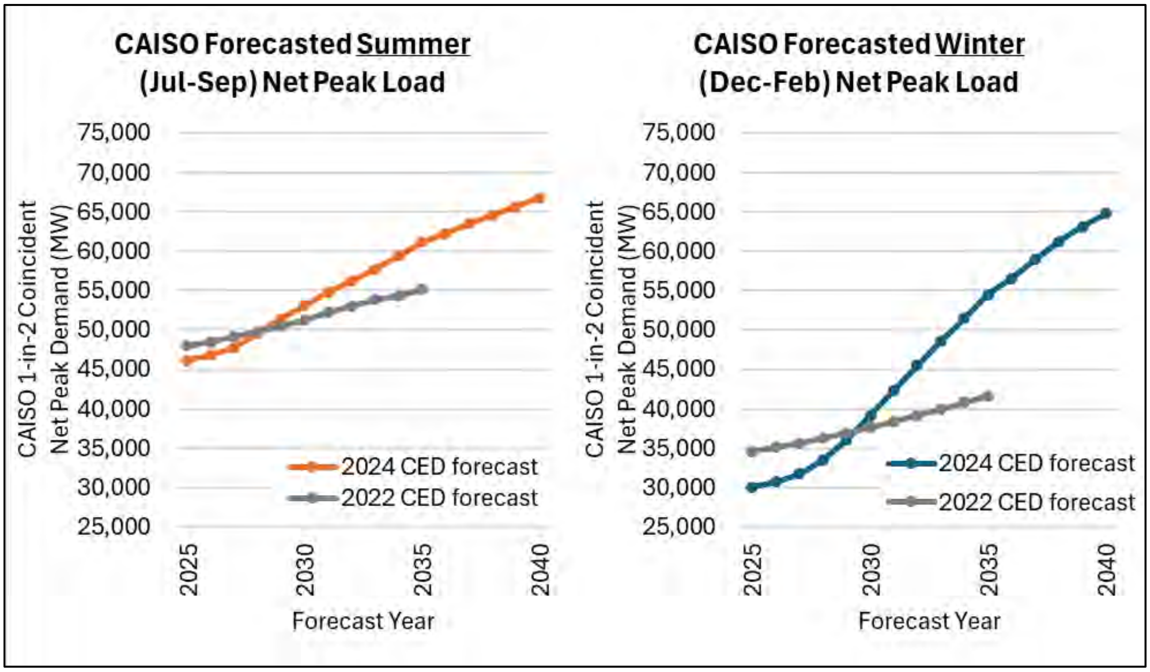
160 The exception to this is the new 840 MW Intermountain gas plant which is connected to LDWP via an HVDC line and represented as physically located in LDWP's service territory. In addition, consistent with the CPUC's preferred system plan, out-of-state resources available to California are modeled explicitly in each region. For example, the SunZia wind project is assumed to be physically located in SCE.

161 "Net peak" load throughout this report, consistent with the IEPR CED Forecast terminology, means the load that is expected to be served by utility-scale generation. Thus, it includes all load modifiers, and the effects of distributed solar generation.

162 The demand forecasts used across efforts are the latest that are available. In the case of the 2023 PSP effort, the CPUC team used the 2022 IEPR CED Forecast. For this modeling exercise, the team is using the 2024 IEPR CED, which was released in January 2025.

163 Note that even though the official 2022 IEPR CED forecast stops in 2035, the 2023 PSP includes resources built to serve load through 2045 based loads that were either defined through the 2021 IEPR High Electrification Interagency Working Group (HEIAWG) dataset or linearly extrapolated.

Figure 48: Statewide Coincident Peak Demand Forecast

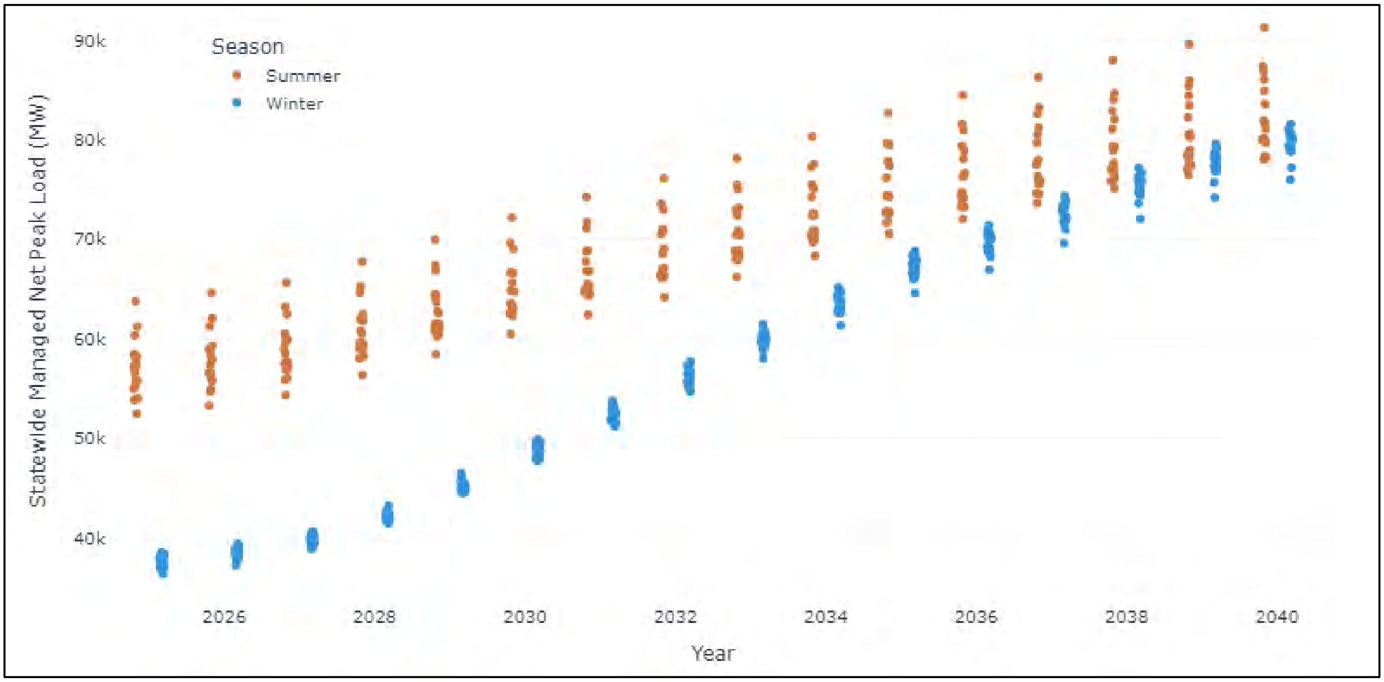


Source: Telos Energy

In addition to the growth in overall peak demand, the updated 2024 CED also includes higher load growth in winter months compared to previous iterations. This growth is most apparent in the 2030s, with the 2024 CED forecasting a California ISO net peak in February 2035 of 54,500 MW, compared to 41,600 MW forecasted in the 2022 iteration, a difference of nearly 13,000 MW. While all regions in California are forecast to be summer peaking throughout the horizon (2025-2040), the winter peak in the California ISO is only 2,000 MW below the summer peak in 2040. Coupled with decreased solar generation during winter months, the study shows that winter becomes the primary season of resource adequacy risk even if California remains a summer peaking system.

Peak demand fluctuates by weather year based on extreme heat and cold temperatures. The chart below shows the variation in peak demand by weather year for both the summer and winter seasons. It shows that the maximum peak demand observed across the 17 weather years is approximately 5 GW (10 percent) higher than the average peak demand. Also note that the variation in winter peak demand is minimal given the static weather inputs assumed for the fuel substitution load growth. See the section *Sensitivity Analysis: Weather Sensitive Fuel Substitution* for more information.

Figure 49: Managed Peak Load Observed by Weather Year and Season across the Study Horizon



Each dot represents a unique weather year and season.

Source: Telos Energy

Resource Additions

All resource additions and retirements for both California ISO and non-California ISO regions were sourced from the CPUC-adopted 2023 PSP released in February 2024.[164] Expansion resources include both in-development resources already under contract and generic resource additions generated from the CPUC's capacity expansion modeling using the RESOLVE modeling platform. Figure 50 shows the planned expansion resources projected to come online across California, including out of state resources intended for use by California.

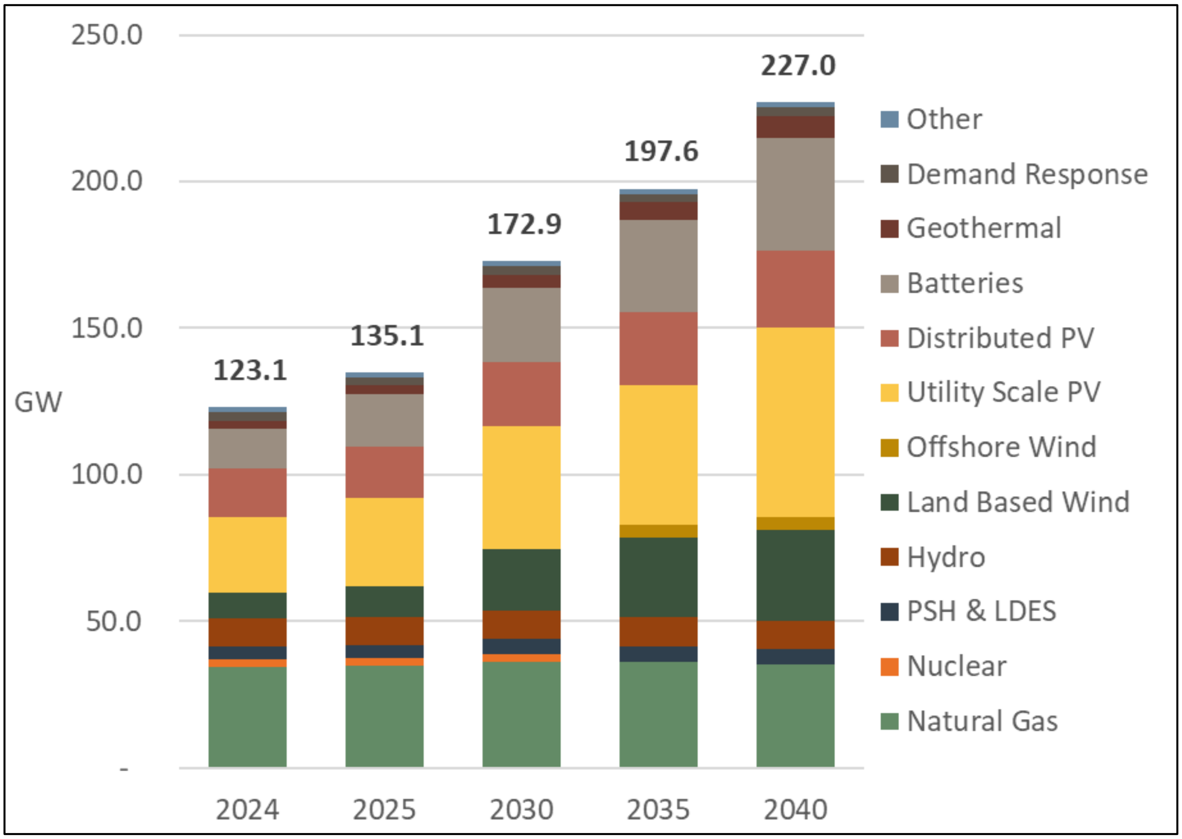
It should be noted that the planning reserve margin constraint in the PSP is often non-binding, meaning that the PSP resource build is driven primarily by the need for new zero-carbon and renewable resources to meet GHG reduction targets – and battery energy storage to shift production to high load periods - rather than resource adequacy needs. For that reason, it is expected that the PSP resource build will meet the 0.1 days/year LOLE criterion.

The projected retirements utilized in this analysis also align with the PSP. The once through cooling and generic gas retirements are balanced against the gas additions such that the gas amounts align with the PSP. Notably, this analysis includes Diablo Cayon as available through

164 California Public Utilities Commission staff. N.d. *2022-2023 IRP Cycle Events and Materials*. California Public Utilities Commission. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials.

2030/31, while the PSP assumed the nuclear power plant retired earlier as directed by state law in SB 846.

Figure 50: Total Installed Capacity Across California by Study Year



Source: Telos Energy

Table 32: Total Installed Capacity by Study Year – Nameplate (MW)

Category	2024	2025	2030	2035	2040
Peak Load	63,774	63,774	72,179	84,476	91,257
Natural Gas (Total)	34,527	35,058	36,326	36,231	35,236
Baseline	34,527	34,527	34,527	34,527	34,527
Additions	-	940	3,840	4,840	4,940
OTC Retirements	-	(326)	(1,661)	(1,661)	(1,661)
Generic PSP Gas Retirements	-	(83)	(380)	(1,475)	(2,570)
Utility Scale PV	25,673	30,279	41,984	47,371	64,548
Distributed PV	16,417	17,544	21,660	25,076	26,450
Batteries	13,462	17,586	25,421	31,420	38,392
Pumped Storage & Long Duration Storage	4,380	4,380	5,165	5,365	5,365
Hydro	9,693	9,693	9,693	9,693	9,693
Land Based Wind	9,003	10,371	21,067	27,227	30,797

Category	2024	2025	2030	2035	2040
Offshore Wind	-	-	-	4,531	4,531
Geothermal	2,970	3,180	4,508	6,028	7,415
Demand Response	2,769	2,793	2,885	2,885	2,885
Nuclear (Total)	2,393	2,393	2,393	-	-
Baseline	2,393	2,393	2,393	2,393	2,393
Diablo Canyon Retirement	-	-	-	(2,393)	(2,393)
Other	1,780	1,780	1,780	1,748	1,716
Total Installed Capacity	**123,068**	**135,057**	**172,883**	**197,576**	**227,029**

Source: Telos, recreated by CEC Staff

Table 33: Incremental Resource Additions by Study Year relative to a 2024 Baseline – Nameplate (MW)

Resource Type	2024	2025	2030	2035	2040
Natural Gas	-	940	3,840	4,840	4,940
Utility Scale PV	-	4,606	16,312	21,699	38,876
Distributed PV	-	1,127	5,243	8,659	10,033
Batteries	-	4,123	11,958	17,957	24,930
Pumped Storage Hydro & Long Duration Storage	-	-	785	985	985
Hydro	-	-	-	-	-
Land Based Wind	-	1,367	12,063	18,223	21,793
Offshore Wind	-	-	-	4,531	4,531
Geothermal	-	210	1,538	3,058	4,445
Demand Response	-	24	116	116	116
Nuclear	-	-	-	-	-
Other	-	-	-	-	-
Total Incremental Additions	**-**	**12,398**	**51,855**	**80,068**	**110,649**

Source: Telos, recreated by CEC Staff

Additional Inputs and Assumptions

Additional inputs and assumptions are provided in Table 34.

Table 34: Additional Inputs and Assumptions

Model Input	Data Source	Description
Demand Profiles	CEC IEPR Forecasting team	Shapes based on 2022 CPUC shapes. Energy and peaks scaled to 2023 IEPR CED revision. Load modifiers from 2023 CED
Outage Rates	NERC Generating Availability Data System (GADS)	Forced outage rates and maintenance rates are based on U.S. averages, which vary by plant size and fuel type.
Plant Capacities	QFER	QFER Data reported in 2024
Expansion Resources	CPUC 2023 PSP	PSP Core Scenario (25 MMT by 2035), February 2024 release. Note that the PSP Core Scenario includes resource builds beyond 2035, ultimately achieving the 2045 state carbon goals.
Solar Shapes 2007-2023	NREL National Solar Radiation Database (NSRDB)	Unique solar profiles developed using the NREL System Advisor Model (SAM) for each significant existing solar plant with capacity-weighted aggregation to regional profiles.
Wind Shapes, 2007-2023	NREL WindToolkit (2007-2014) NREL BC HRRR (2015-2023)	Simulated wind production profiles were calibrated to align with actual generation data from California ISO subpoena data, aggregated by wind resource area, and checked against monthly generation totals reported to EIA via Form 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 EIA 930	Hydro resources are limited in their 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 Monthly Energy Budget	Monthly hydro generation reported in EIA 923, CEC QFER	Maximum hydro generation within a month based on historic generation patterns.
Operating Reserves	6% of Load	Assumes operating reserves of 6% of net load (after reductions for BTM-PV) are held during loss of load events. All other reserves (regulation, load following, etc.) are assumed to be curtailed prior to load shed.

Source: Telos Energy

Results

Base Case Results

With all new PSP resources successfully deployed, the modeling results project that California will exceed the reliability criterion, beginning in summer 2025, and extending through the early 2030s. The results indicate that the California system is expected to have sufficient resources – under normal hydro and transmission conditions – to meet the 0.1 days/year LOLE criterion in these future study years provided that the PSP resources are added as expected. The resulting resource adequacy metrics are provided below.

- 2025 Base Case: No shortfall events
- 2030 Base Case: No shortfall events
- 2035 Base Case: No shortfall events
- 2040 Base Case: 0.9 days/year LOLE

The 2025, 2030, and 2035 Base Case results are largely consistent with recent reports from the CEC, including the 2025 SB 846 Combined Q1 and Q2 report[165], 2024 Q1 report[166] the 2024 California Energy Resource and Reliability Outlook[167] released in August 2024.

With this report, we are now able to model the future 2040 calendar year. Under base case assumptions, 2040 sees a LOLE of 0.9 days/year, which is 9x higher than the LOLE criterion. As noted in the section *Notable Updates from Previous CEC Reliability Reports* above, the updated demand forecast includes significant winter load growth in the 2030s primarily due to heat pump adoption. This load growth forecast was not an input into the design of the PSP, and once reflected will likely drive resource plans in subsequent resource planning cycles.

These results indicate that the probability of resource shortfalls is very low in the near term, provided that the PSP additions are brought online as planned and under normal hydro and transmission conditions. However, California could face a variety of additional challenges that could lead to resource adequacy deficits. Additional sensitivities were evaluated to test system reliability if things do not go according to plan, including a reduction in future generator build out, removing California's ability to import power from neighbors, modifying the California ISO's import ability during periods of high system stress in future years, and varying

165 Yee Yang, Chie Hong, and Brendan Burns (CPUC). April 2025. *Joint Agency Reliability Planning Assessment*. California Energy Commission. Publication Number: CEC-200-2025-004, https://www.energy.ca.gov/publications/2025/joint-agency-reliability-planning-assessment-covering-requirements-sb-846.

166 Yee Yang, Chie Hong, and Sarah Goldmuntz (CPUC). May 2024. *Joint Agency Reliability Planning Assessment*. California Energy Commission. Publication Number: CEC-200- 2024-006. https://www.energy.ca.gov/publications/2024/joint-agency-reliability-planning-assessment-covering-requirements-sb-846-first.

167 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.

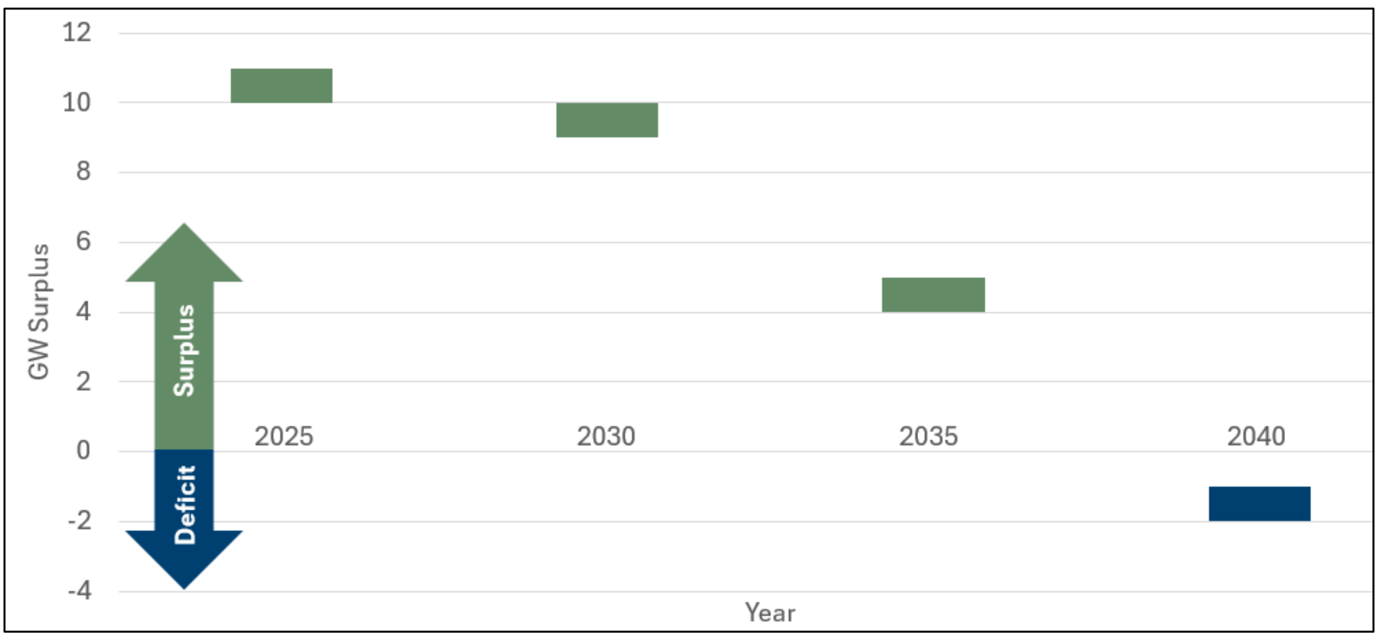
hydroelectric generation availability. Widespread western drought and/or wildfires could also pose a resource adequacy risk but were not explicitly considered in this analysis.

Surplus Calculations

To provide additional information, the CEC quantified the amount of that 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 51 below. This analysis indicates that California's statewide surplus is expected to diminish across the study horizon, from 10-11 GW in 2025, to 9-10 GW in 2030, 4-5 GW of surplus in 2035, and ultimately a deficit of 1-2 GW is expected in 2040. Note that these surpluses assume the full PSP resource build is successful, assumes normal hydro conditions and transmission capability, including the California ISO Total Import Constraint is at 11,655 MW in all hours except for summer evenings. Again, this level of near-term reliability is driven by resource additions built for greenhouse gas emissions reductions, a reduced near-term load forecast relative to the one used to design the resource mix, and the retention of Diablo Canyon through 2030/31.

Figure 51: Expected surplus capacity across California (Full PSP, Full Imports)



Source: Telos Energy

The 10+ GW surplus in 2025 is well higher than the 2,550 MW surplus reported by the California ISO (2024)[168] and the 1,500 MW reported by CPUC (2026)[169] due to the following:

- The updated stochastic load forecast includes lower net peaks than were used in previous analyses. The official 1-in-20 2024 CED forecast for 2025 is roughly aligned with the forecast from 2023, but this analysis includes peaks that are roughly 1 GW lower than the 1-in-20 forecast due to weather normalization effects.
- This analysis reports a Statewide surplus rather than the California ISO-only surplus reported by CPUC and the California ISO. For each gigawatt of firm load / perfect generation added, only 82 percent (820 MW) is added into California ISO regions; the other 18 percent is distributed to LADWP, BANC, TIDC, and IID commensurate with each region's contribution to forecasted coincident peak statewide load.
- The DCPP extension, which contributed 2,300 MW of nuclear power to California, was not included in CPUC or California ISO analyses.
- The California ISO includes incremental operating reserves that are kept during unserved energy events amounting to roughly 1000 MW of additional generation requirement. CEC assumes a simple operating reserve to be 6 percent of net load, while the California ISO formulation includes regulation and load following reserves that are also held during loss of load events.

Characterizing System Risk

Shifting Nature of Risk

California's power system risk has historically been defined by periods of high temperature, low solar 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 RA events are relatively short in nature.

As California's power system increasingly electrifies buildings via fuel substitution, these historically significant events will be replaced by a new set of challenges. Rather than heat waves driving shortfalls, a combination of cold snaps and cloudy conditions will likely be the largest source of grid stress. Importantly, this analysis reveals that by 2035 California's system likely becomes either winter risk or dual-risk across the winter and summer months depending on the scenario. By 2040, the risk is primarily observed in the winter, regardless of the scenarios considered.

The Figures below show the percentage of unserved energy from across the year that occurs within any given hour. These are shown for study years with LOLE close to 0.1 days/year,

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168 California ISO staff. 2024. *2024 Summer Loads and Resources Assessment*. California ISO. https://www.caiso.com/Documents/2024-Summer-Loads-and-Resources-Assessment.pdf.

169 California Public Utilities Commission staff. 2024. *Loss of Load Expectation Study for 2026: Including Slice of Day Tool Analysis*. California Public Utilities Commission. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/2026_lole_final_report_07192024.pdf.

achieved by adding either firm load or perfect generation to the system until the LOLE criteria is achieved. The percentages in each table add up to 100 percent within any study year and provide an indication of when resource adequacy risk occurs.

While each case is calibrated to roughly 0.1 days/year, the underlying nature of the resource adequacy risk shifts across the study horizon as the resource mix and load profiles evolve. Figure 52 shows how unserved energy is distributed throughout the day and year. It shows that resource adequacy risk shifts later in the day, from early evening in 2025 to overnight periods and winter periods in 2035 and 2040. In 2025, resource adequacy risk is predominately driven by capacity deficits, when there is insufficient available capacity to serve load. As nearly 20 GW of battery storage is added to the system, the resource adequacy risk shifts to overnight periods. In rare instances, the battery storage discharges all available energy and has insufficient state of charge to continue discharging in overnight periods.

Figure 52: Distribution of Unserved Energy (MWh) Across the Year for each Study Year.

2025 No Imports / 40% Reduction in PSP												
Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	0%	25%	0%	0%	0%
19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%	57%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	18%	0%	0%	0%

2035 + 4GW Fixed Load												
Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	6%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
5	0%	0%	0%	0%	0%	0%	0%	0%	2%	0%	0%	2%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	8%
7	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	21%
8	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	14%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%
21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	7%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	9%

Source: Telos Energy

While the chart above shows 2035 as primarily a winter risk season, the dual-risk nature of 2035 is revealed when examining additional scenarios. For example, when another gigawatt of firm load is added to the system for a total of 5 GW, the risk profile shifts dramatically as shown in Figure 53 below. To ensure that this is not just a function of distorted load profiles due to large amounts of fixed load, an additional scenario is shown that captures 2035 with a

Full Year California ISO Constraint and 40 percent Reduction in PSP resources, with these sensitivities discussed more in the sections that follow. The relative ratio of summer vs winter risk varies depending on the scenario, but loss of load risk is consistently observed in both summer and winter months in 2035.

Figure 53: Distribution of Unserved Energy (MWh) Across the Year for additional 2035 scenarios.

2025 No Imports / 40% Reduction in PSP

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	0%	25%	0%	0%	0%
19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%	57%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	18%	0%	0%	0%

2030 + 9GW Fixed Load

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0%	0%	0%	0%	0%	0%	0%	0%	14%	0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%
19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%	7%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	78%	0%	0%	0%

2035 + 4GW Fixed Load

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	6%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
5	0%	0%	0%	0%	0%	0%	0%	0%	2%	0%	0%	2%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	8%
7	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	21%
8	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	14%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%
21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	7%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	9%

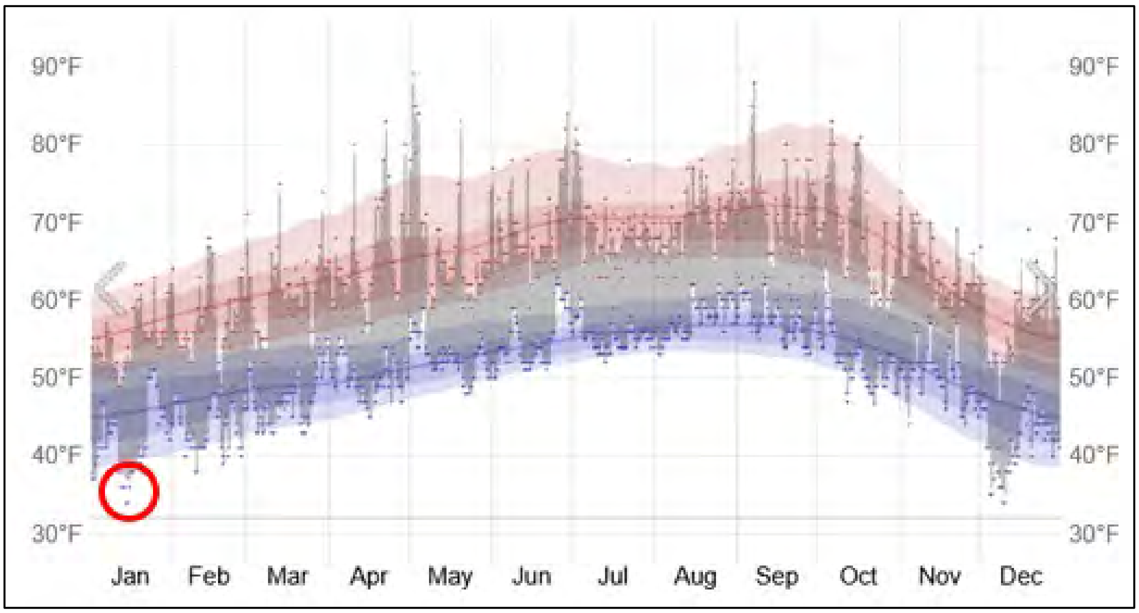
2040 + 1.5GW Perfect Generation

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	4%
1	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%
2	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
3	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
5	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
6	6%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	6%
7	16%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	14%
8	14%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	8%
9	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
22	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
23	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%

Source: Telos Energy

To further validate this point, we examine two weather years that drive the largest deficits in the 2040 base case.[170] Periods throughout the year with high loss of load probability in the 2040 simulations were inspected further. One such event occurred when simulating January of the 2013 weather year. This event posed no resource adequacy risk in 2013, nor when performing simulations of the years 2025 and 2030. However, significant resource adequacy risk appeared when simulating January 2013 weather in 2040. The primary difference in the resulting resource adequacy risk in 20240 and prior years is large amount of electricity demand from heating via fuel substitution. The cold snap in January 2013, shown below, was much colder than typical but does not represent a significant outlier given that similar temperatures were observed in San Francisco and Los Angeles in December of that same year, when the simulated loss of load probability was very low. As shown Figure 54, the January weather year 2013 event is notable because the cold temperatures coincided with relatively low solar output.

Figure 54: Temperature History in 2013 in San Francisco

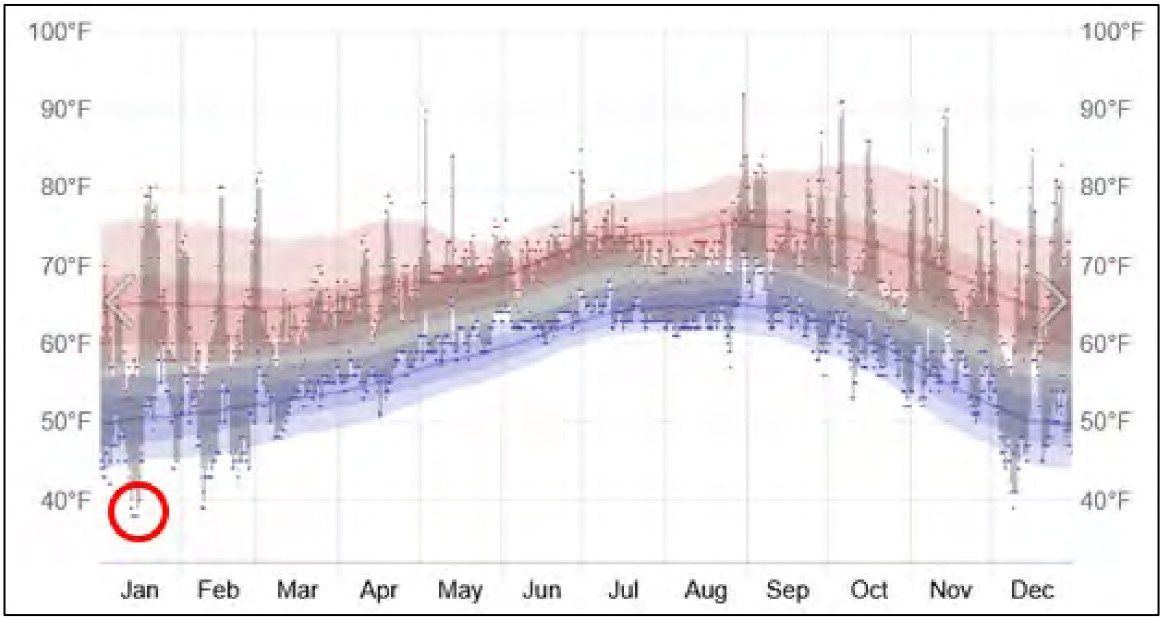


Source: WeatherSpark.com[171]

170 The cases and load discussed here include fuel substitution that is aligned with the 2020 weather year, consistent with the profiles provided in the 2024 CED. The CEC intends to evaluate weather-sensitive fuel substitution impacts as part of a separate, future analysis.

171 Weather Spark staff. N.d. *2013 Weather History in San Francisco*. Weather Spark. https://weatherspark.com/h/y/557/2013/Historical-Weather-during-2013-in-San-Francisco-California-United-States#Figures-Temperature.

Figure 55: Temperature History in 2013 in Los Angeles

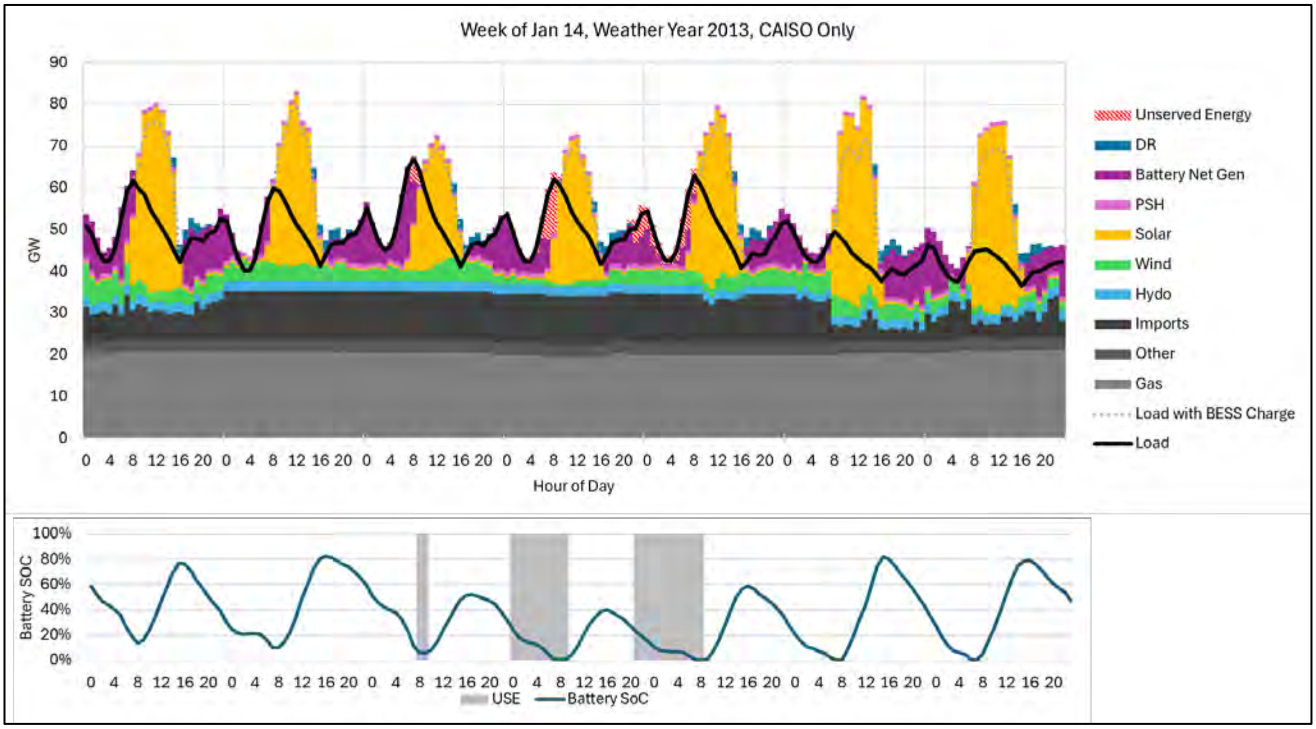


Source: WeatherSpark.com[172]

As can be seen in the charts below, the resource adequacy risk (unserved energy) stems from a combination of increased load, low solar, and 4-hour batteries being unable to contribute once their state of charge is depleted. This occurs even though the California ISO is importing at its maximum limit of 11,655 MW across the three days of the event. The *Sensitivity Analysis: Adjusting Import Levels* section of this report outlines how the reliability outlook deteriorates with modified import levels in the winter, similar to levels currently observed in the summer months. The batteries lagging state of charge (SoC) creates a cascading effect where the system stress lasts for multiple days in a row; we see unserved energy on 3 consecutive mornings.

172 Weather Spark staff. N.d. *2013 Weather History in Los Angeles*. Weather Spark. https://weatherspark.com/h/y/1705/2013/Historical-Weather-during-2013-in-Los-Angeles-California-United-States.173 Smith, Hayley, and James Rainey. December 31, 2021. *California's very dry year ends with some chaos, some relief in heavy rain and snow*. Los Angeles Times. https://www.latimes.com/california/story/2021-12-31/powerful-storm-pounds-california-after-year-of-drought.

Figure 56: Week of Jan 14, Weather Year 2013 Dispatch Chart in the 2040 Forecast Year



Source: Telos Energy

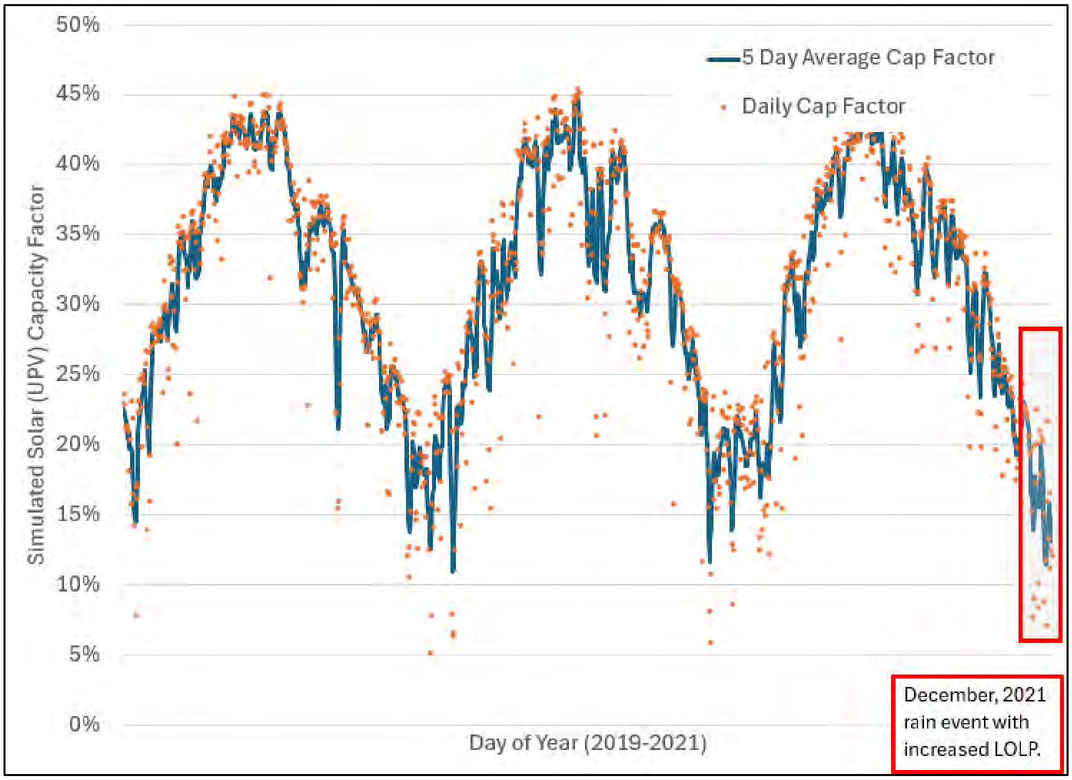
Another day with high LOLP in the simulation of 2040 occurred in the weather year 2021. The weather data reflected a significant rainfall event causing a decrease in solar output. The LA Times characterized the weather as follows: "Back-to-back storms dumped about 7 inches of rain in downtown Los Angeles in December, more than tripling the month's normal rainfall of 2.03 inches and placing it in the 10 wettest Decembers on record, the National Weather Service said. The National Weather Service measured a record 2.34 inches of rain in downtown L.A., which blew away the previous Dec. 30 record of 1.85 inches from 1936."[173] While this event did not materially impact resource adequacy in 2021, a similar weather event in the future could lead to challenges for the power system due to changes in load and increased reliance on solar and storage resources.

Figure 57 below shows the daily capacity factors of solar generation for the simulated fleet in 2040 across a range of weather years. The 2021 event had low solar generation (7 percent daily capacity factor), but not the lowest across the weather years (a 5 percent capacity factor is simulated on multiple occasions). Other days with lower solar production were able to avoid loss of load. These results indicate that a combination of low temperatures, consecutive days

173 Smith, Hayley, and James Rainey. December 31, 2021. *California's very dry year ends with some chaos, some relief in heavy rain and snow.* Los Angeles Times. https://www.latimes.com/california/story/2021-12-31/powerful-storm-pounds-california-after-year-of-drought.

with low solar and wind production yield high power system risk associated with December 2021 weather.

Figure 57: Daily Solar Capacity Factors for 2019-2021.



Source: Telos Energy

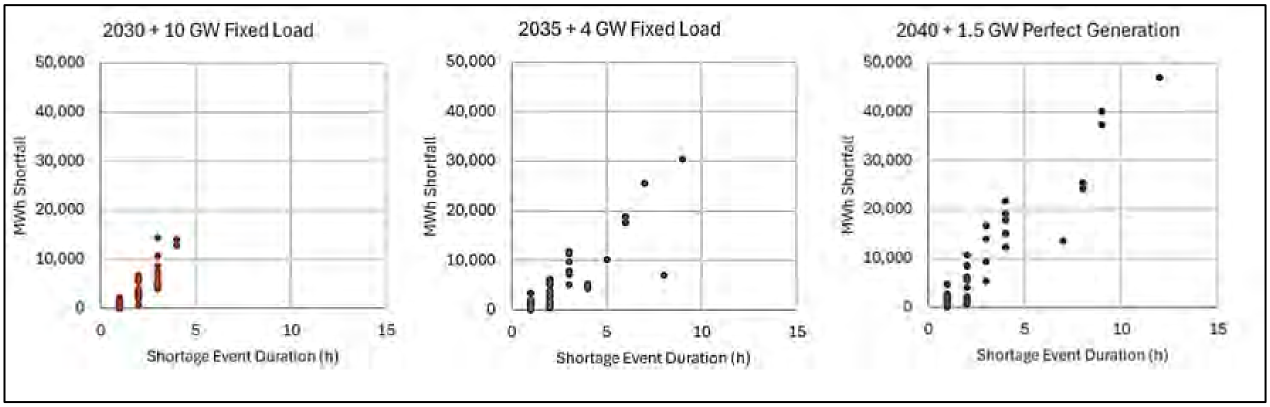
Moving into the 2030s, California planners can no longer just consider heat waves when assessing power system risk. Grid stress conditions are a function of weather conditions, and the resource mix designed to serve load. As state processes such as the PSP consider a resource mix designed for this updated demand forecast, a different mix of resources may be designed that reveal different historical weather patterns as the primary drivers of power system risk. Planners must increasingly consider a broad set of conditions that are likely to challenge resource adequacy.

Size, Frequency and Duration of Shortfall Events

The 2030, 2035, and 2040 cases that most closely aligned with 0.1 days/year LOLE utilizing the approach described in the previous section were further assessed to characterize system risk. This analysis provides directional insights on the size, frequency, duration, and timing of resource adequacy risk. However, 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 generator) applied equally to all hours. For that reason, the demand profile is not necessarily representative of the current or future demand. While this is standard practice in resource adequacy modeling, actual risk periods may be different as load grows and resources retire.

In addition to a shift towards winter LOLE risk discussed above, Figure 58 shows that the nature of these shortfall events shifts across the study horizon. While near-term shortage events extend from 1 hour to up to 4 hours in length before the system can recover when the net load decreases, future shortage events can be more prolonged (up to 10 hours in duration for a single event). These prolonged events are driven by deficiencies in storage state of charge unable to recover overnight. With prolonged events, the total energy shortfall also rises.

Figure 58: Shortage Event Duration and Total Shortfall for Select Cases



Source: Telos Energy

The frequency of loss of load events (measured in LOLE days/year), is similar across all three study years, but the size (GWh) and duration (hours) of deficit increases. This indicates a shift from risk driven by insufficient capacity to risk driven, at times, by insufficient energy.

Sensitivity Analysis: 40 Percent Reduction in Future Resources

Additionally, California's resource adequacy was evaluated with a 40 percent reduction in future resource additions assumed in the PSP to assess whether the system can maintain resource adequacy if procurement delays, or project cancellations occur. This represents a hypothetical risk assessment and does not imply that a 40 percent reduction in the PSP is likely or expected. For the 40 Percent Reduction scenario, CEC Staff and their consultant Telos Energy evaluated resources reductions for future generating resource additions in both the CAISO regions (PSP) and non-CAISO regions. This 40 percent reduction was applied across all resource types, from utility scale solar to new firm resources, such as natural gas and geothermal.

The 40 percent Reduction scenario shows minimal reliability risk in 2025 and 2030 (0 LOLE in either year). This indicates that even if some new resources additions are delayed, resource adequacy can still be maintained. However, when PSP additions are reduced by 40 percent and retirements of Diablo Canyon and other gas generators are assumed by 2035 as is in the base case, the system shows increased LOLE risk (0.79 days/year), exceeding the reliability criterion. This trend is further exacerbated in 2040, where LOLE risk exceeds the 0.1 days/year reliability criterion by more than 100x in a scenario where the PSP resource build is reduced by

40 percent. This shows the dependence of the future system on achieving the resource additions identified in the PSP as the system undergoes evolution.

Sensitivity Analysis: Adjusting Import Levels

No California Imports

As an additional extreme scenario, both the full PSP and the 40 percent reduction scenario were evaluated with California treated as an electrical island. Regions within California are still able to transfer power with each other, subject to transfer limits and the CAISO Import constraint. The results from this analysis are presented in Table 35. [174]

Table 35: Loss of load expectation (days/year) across scenarios and sensitivities

#	PSP	California Imports	CAISO Import Limit	2025	2030	2035	2040
1	Full PSP (Base Case)	Yes	Summer Only	0	0	0	0.9
2	Full PSP	No	Summer Only	0	0	6.62	Over 10
3	40% Reductions in PSP	Yes	Summer Only	0	0	0.79	Over 10
4	40% Reductions in PSP	No	Summer Only	0.003	0.17		

Source: Telos Energy

In the near term, California continues to meet its LOLE criterion of 0.1 days/year even without relying on imports from neighboring systems. When the system is further constrained by reducing future resource additions by 40 percent and simultaneously removing California imports, the system falls below the resource adequacy criterion in 2030.

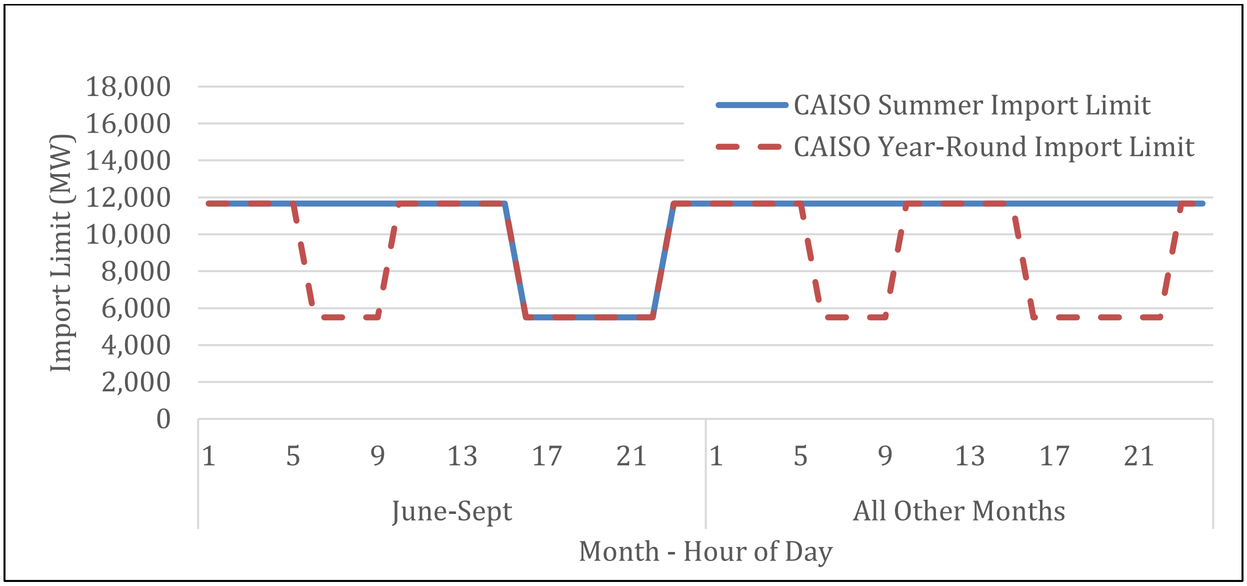
The outlook beyond 2030 shows that the reliability of the California system can be quite sensitive to a reduction in the resource build or a reduction in import availability. The 2035 study year shows the system is still dependent on its neighbors for resource adequacy even if California adds all PSP resources between now and 2035. A 40 percent reduction in the PSP would exceed the reliability criterion in 2035. The 2040 system is less reliable than the 0.1 days/year LOLE criterion under base conditions. This 2040 reliability deficiency is exacerbated by reductions in import levels or in PSP resource buildout, with both scenarios showing reliability risk several times higher than the 0.1 days/year LOLE criterion.

174 Given the very high LOLE observed in Case 2 in 2035 and 2040, reducing the resource mix, as described in sensitivity #4, would produce results that are extremely unreliable.

Modified California ISO Import and Energy Constraints

In addition to the *No California Imports* sensitivities that were run above, the analysis also included a possible future constraint on the California ISO system. In this scenario, the California ISO import limit is extended from H16-22 in the summer months to include the morning (H6-9) and evening peaks (H16-22) across all months as shown in Figure 59 below. This modified import constraint is intended to capture potential future conditions across the West when the California ISO is unable to import significant amounts of electricity from its neighbors. Given that other regions are experiencing similar resource changes, increased heating electrification, and shift to winter risk, it is important that adequacy assessments reflect tightening supplies during new periods of system risk.

Figure 59: California ISO Import Limit Scenarios



Source: Telos Energy

The results from this analysis are shown in Table 36 below. Note that the LOLE in the 2040 case rises from 0.9 days/year to 4.29 days/year depending on the CAISO Import limit scenario.

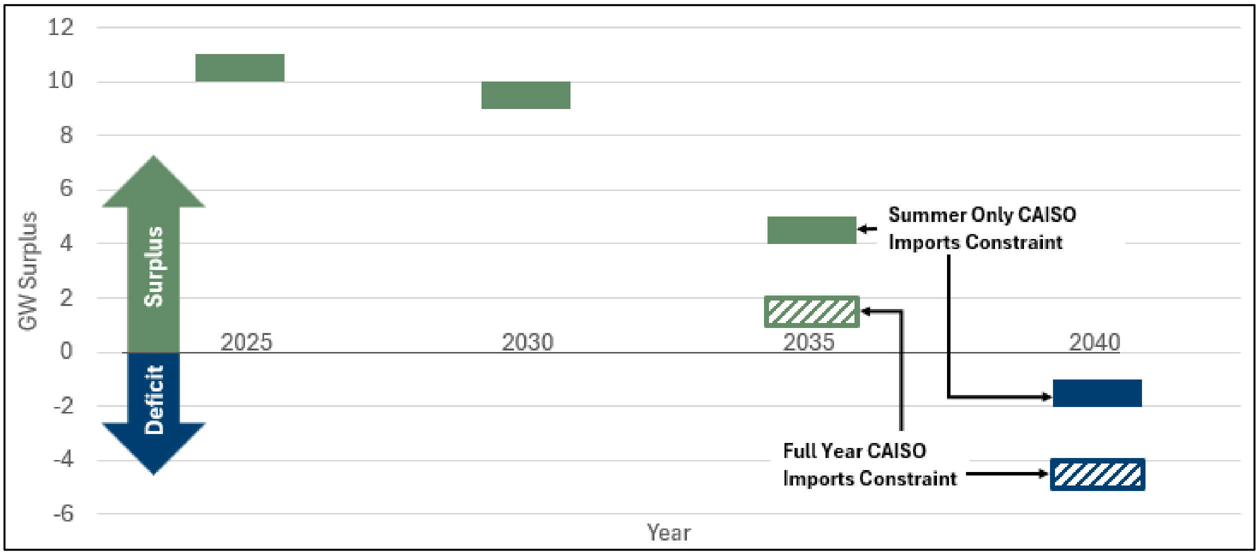
Table 36: LOLE (days/year) given import limits for possible future constraints.

#	PSP	California Imports	CAISO Import Limit	2025	2030	2035	2040
5	Full PSP	Yes	Year-Round	0	0	0	4.29
6	Full PSP	No	Year-Round	0	0	10.21	Over 10
7	40% Reductions in PSP	Yes	Year-Round	0	0	2.64	Over 10

Source: Telos Energy

The California ISO Import limit impacts the LOLE results, and the surplus calculations identified above. With the more restrictive year-round import limit, 2035's surplus is reduced from 4-5 GW to 1-2 GW, and 2040's deficit is increased from 1-2 GW to 4-5 GW. These findings are shown in Figure 60 below.

Figure 60: California Surplus Calculations given different CAISO Import Constraint Scenarios



Source: Telos Energy

As a final sensitivity on this topic, we removed the monthly import energy constraints into California, which are based on historical flows. The relevance of historical imports will diminish as the system shifts to winter risk. It is unknown whether neighbors will be able to import at these high levels year-round to meet California's winter risk period. However, the impact of the monthly import energy amounts could be a factor in future resource adequacy evaluations. By removing the constraint, the LOLE of the 2040 system with the year-round CAISO import limit was reduced from 4.29 to 4.05 days/year.

Sensitivity Analysis: Hydroelectric Availability - Stochastic and Low Hydro

This sensitivity analysis examined the impact of hydroelectric generation availability on the future system. Outside of this section, all analyses presented within this report are consistent with the hydroelectric description provided in Table 34.

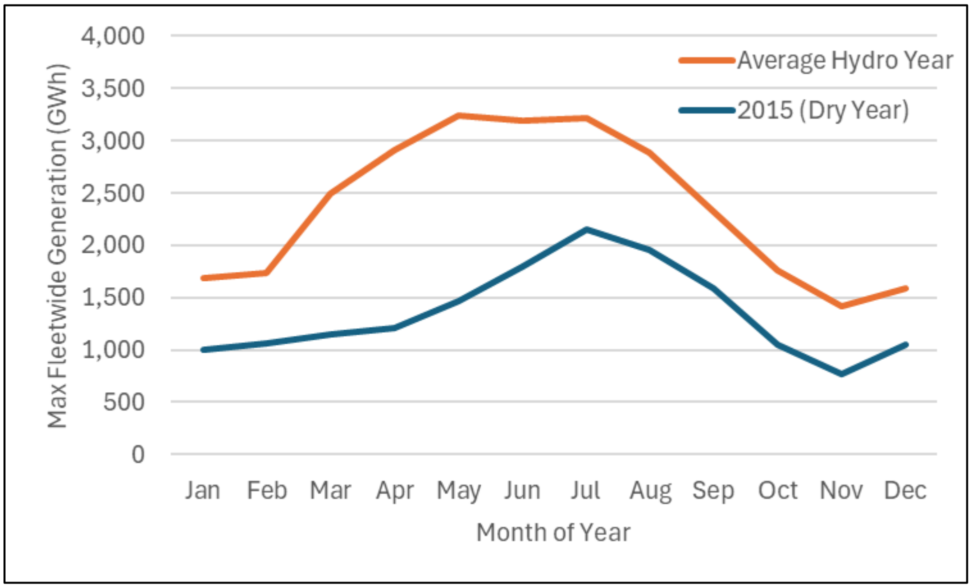
Hydro resources maximum output (MW) remains consistent across these simulations, based on historical observations, wherein monthly fleetwide maximum generation is well below fleetwide installed capacity[175]. Similarly, hydro minimum output (MW) is held consistent across the simulations. Furthermore, this analysis does not assume any changes to statewide pumping

175 There is correlation between the 97.5th percentile maximum California-wide hydroelectric generation (MW) and the monthly generation (MWh) of these plants between 2019-2023. However, there is convergence on a maximum MW across the historically risky months of August and September regardless of the monthly generation (MWh).

loads. During drought years electricity demand from pumping and irrigation is also lower, offsetting a portion of the decreased generation availability. However, the allowable monthly energy generation (MWh) varies in one of the following two ways.

For the Low Hydro sensitivity, the California hydro generators' maximum monthly energy is limited to their output pattern in 2015, which was the lowest annual output across the last decade (2013-2023).

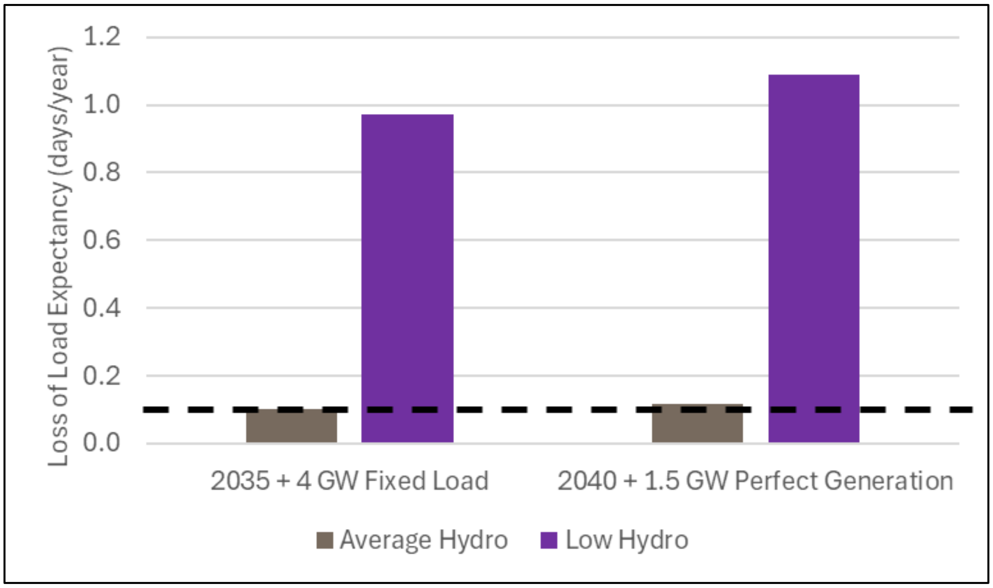
Figure 61: Monthly Hydroelectric Generation Budgets



Source: Telos

Given the high surpluses modeled in 2025 and 2030, the modeling team analyzed scenarios in 2035 and 2040 for hydroelectric generation sensitivity. Figure 62 below shows the increase in LOLE expected for a low hydro year relative to an average year, even when allowing hydroelectric to generate at the same maximum output for any given hour across the simulations. This further underscores that the future system becomes energy limited under certain conditions. Note that the 2035 and 2040 systems modeled here are over dominated by winter risk, with only a handful of events in 2035 in each hydro scenario occurring in the summer months.

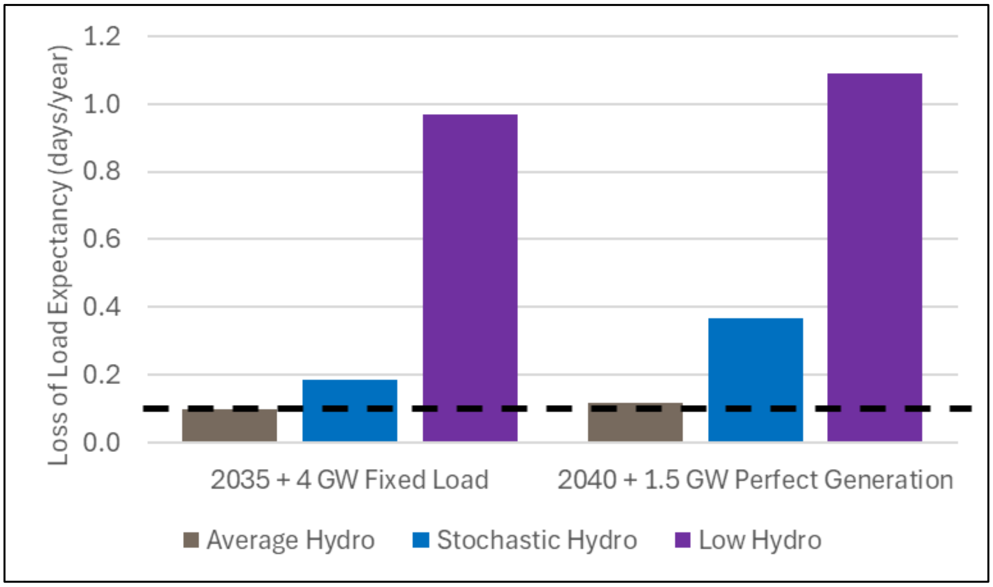
Figure 62: Loss of Load Expectancy for Average and Low Hydro Conditions



Source: Telos Energy

For the *Stochastic Hydro* sensitivity, hydro monthly energy limits were randomly selected from the weather years 2007-2023. These hydro years are not correlated with the rest of the weather year variables (load and renewable profiles) given the difference in the horizon across which the underlying weather drivers influence the power system. Incorporating stochastic hydro into the analysis resulted in higher LOLEs relative to the average hydro case in both 2035 and 2040. The impact is less pronounced relative to the low hydro sensitivity which was a bookend case.

Figure 63: Loss of Load Expectancy for Average, Stochastic and Low Hydro Conditions



Source: Telos Energy

These hydro sensitivities show the importance of accurately incorporating monthly hydro energy variability when assessing system reliability. More research is needed to determine how changes in hydro max output across weather years could influence these results. Further study is also needed to assess how California's RA may be more significantly influenced by external hydro resources in the Pacific Northwest (PNW) and Desert Southwest (DSW), which could impact assumptions regarding California ISO RA import availability.

As winter risk increases, electric system planners need to re-evaluate how to model hydro availability in RA studies. Basing hydro resource availability solely on historical generation profiles may not be accurate, as some hydro reservoirs could be used in other seasons.

In the future, CEC hopes to embed the stochastic hydro modeling approach across model runs to capture the variable nature of hydro availability on the future system. Additional advancements are also needed to capture the correlated impact of hydro availability and pumping loads. While wet years improve the availability of hydroelectric generation, pumping loads across the State also rise. The inverse is also true: dry years reduce both hydroelectric generation and pumping loads. Prior to the broad implementation of stochastic hydro approaches, the CEC plans to capture this phenomenon.

Future Work

While this analysis provides an evaluation of resource adequacy risks for California, it is not exhaustive. The CEC intends to continue evaluating the current and future power system to better understand and quantify potential resource adequacy risk in the state. Future work is intended to improve system modeling, and help inform policy decisions related to resource procurement, retirements, demand-side 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 2035, California's primary reliability risk period could be winter due to the resource mix, and widespread heat pump adoption and electrification. Additionally, 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 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 that changes, 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 extreme 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. This includes diversifying winter energy sources and enhancing grid flexibility to respond to unanticipated resource shortfalls.

Drought Conditions and Wildfire Risks

The results presented in this analysis assume normal hydro conditions and do not assess potential impacts of wildfires, including both loss of transmission and reduced solar production from smoke. Potential drought conditions and impacts of climate change will need to be better assessed in future studies to help prepare the state, and its power system, for potential challenges.

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 future 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 electric vehicles, 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

APPENDIX D: Abbreviations

AB - Assembly Bill

BAA - Balancing Authority Area

BA - Balancing Authority

BANC - Balancing Authority of Northern California

BCF – Billion Cubic Feet

CalGEM - California Department of Conservation’s Geologic Energy Management Division

CARB – California Air Resources Board

CARBOB - California Reformulated Gasoline Blendstock for Oxygenate Blending

CCA - Community Choice Aggregators

CEC - California Energy Commission

CED – California Energy Demand

CERRO – California Energy Resource and Reliability Outlook

CESP - California Energy Security Plan

CGR – California Gas Report

CPC - Climate Prediction Center

CPUC - California Public Utilities Commission

CREPC - Committee on Regional Electric Power Cooperation

CREPC TC - Committee on Regional Electric Power Cooperation Transmission Collaborative

DMM - Department of Market Monitoring

DSGS - Demand-Side Grid Support

EEA – Energy Emergency Alert

EIA - Energy Information Administration

ESSRRP - Electricity Supply Strategic Reliability Reserve Program

EDAM – Extended Day-Ahead Market

FERC - Federal Energy Regulatory Commission

GHG - Greenhouse Gas

GW - Gigawatt

GWh - Gigawatt-hour

IEPR - Integrated Energy Policy Report

IID – Imperial Irrigation District

IOU - Investor-Owned Utility

IRP - Integrated Resource Planning

ISO - Independent System Operator

kWh – Kilowatt Hour

kV - Kilovolt

LADWP - Los Angeles Department of Water and Power

LOLE - Loss of Load Expectation

LSE - Load-Serving Entity

MAPE - Mean absolute percentage error

MMbtu – Million British thermal unit

MMcfd - Million Cubic Feet per Day

MW - Megawatts

MWh - Megawatt-hour

NERC - North American Electric Reliability Corporation

NQC – Net Qualifying Capacity

OTC – Once-Through Cooling

PACW - PacifiCorp-West

Pathways – Pathways Initiative

PG&E – Pacific Gas and Electric

PIIRA – Petroleum Industry Information Reporting Act

POU - Publicly Owned Utility

PUC - Public Utility Code

PRM - Planning Reserve Margin

PV - Photovoltaic

RA - Resource Adequacy

RMO - Restricted Maintenance Operations

RO – Regional organization

RPS - Renewable Portfolio Standard

SDG&E – San Diego Gas and Electric

SB – Senate Bill

SCE – Southern California Edison

SoCalGas – Southern California Gas

SMUD - Sacramento Municipal Utility District

SRR – Strategic Reliability Reserve

TAC – Transmission Access Charge

TID - Turlock Irrigation District

WECC - Western Electricity Coordinating Council

WEIM - Western Energy Imbalance Market

WI - Western Interconnection

WIEB – Western Interstate Energy Board

APPENDIX E: Glossary

For additional information on commonly used energy terminology, see the following industry glossary links:

- California Air Resources Board Glossary, available at California Energy Commission Energy Glossary, available at https://ww2.arb.ca.gov/glossary
- California Independent System Operator Glossary of Terms and Acronyms, available at: https://www.caiso.com/glossary
- California Public Utilities Commission Glossary of Acronyms and Other Frequently Used Terms, available at https://www.cpuc.ca.gov/glossary/
- Federal Energy Regulatory Commission Glossary, available at https://www.ferc.gov/about/what-ferc/about/glossary
- North American Electric Reliability Corporation Glossary of Terms Used in NERC Reliability Standards, available at: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.
- US Energy Information Administration Glossary, available at: https://www.eia.gov/tools/glossary/

Balancing authority

A balancing authority is the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time. Balancing authorities in California include BANC, California ISO, Imperial Irrigation District, TID, and LADWP. The California ISO is the largest of about 38 balancing authorities in the WI, handling an estimated 35 percent of the electric load in the West.

Balancing Authority of Northern California (BANC)

The Balancing Authority of Northern California is a joint powers authority consisting of the SMUD, Modesto Irrigation District, Roseville Electric, Redding Electric Utility, Trinity Public Utility District, and the City of Shasta Lake. The BANC is a partnership between public and government entities and provides an alternative platform to other balancing authorities like the California ISO.

Billion Cubic Feet
Standard unit of measurement for natural gas supply/demand - 1,000,000 MMBtu = 1 Bcf.

British thermal unit

The standard measure of heat energy. Quantity of heat required to raise the temperature of one pound of water 1 degree Fahrenheit at sea level. One Btu is equivalent to 252 calories, 778 foot-pounds, 1055 joules, and 0.293 watt-hours. Note: In the abbreviation, only the B is capitalized.

Climate change

Climate change refers to a change in the state of the climate that can be identified (for example, by using statistical tests) by changes in the mean and/or the variability of its properties and that persists for an extended period, typically decades or longer. Climate change may be due to natural internal processes or external forces such as modulations of the solar cycles, volcanic eruptions, and persistent anthropogenic changes in the composition of the atmosphere or in land use. **Anthropogenic** climate change is defined by the human impact on Earth's climate while **natural** climate change are the natural climate cycles that have been and continue to occur throughout Earth's history. Anthropogenic (human-induced) climate change is directly linked to the amount of fossil fuels burned, aerosol releases, and land alteration from agriculture and deforestation.

Community Choice Aggregation (CCA)

Community Choice Aggregation (CCA) is a program that allows cities, counties, and other qualifying governmental entities available within the service areas of IOUs, to purchase and/or generate electricity for their residents and businesses. The IOU continues to deliver the electricity through its transmission and distribution system and provide meter reading, billing, and maintenance services for CCA customers.

Core Load

A **core load** is that of residential and small business natural gas customers.

Demand response (DR)

Demand response refers to providing wholesale and retail electricity customers with the ability to choose to respond to time-based prices and other incentives by reducing or shifting electricity use (“shift DR”), particularly during peak demand periods, so that changes in customer demand become a viable option for addressing pricing, system operations and reliability, infrastructure planning, operation and deferral, and other issues. It has been used traditionally to shed load in emergencies (“shed DR”). It also has the potential to be used as a low-greenhouse gas, low-cost, price-responsive option to help integrate renewable energy and provide grid-stabilizing services, especially when multiple distributed energy resources are used in combination and opportunities to earn income make the investment worthwhile.

For more information, see the [CPUC Demand Response Web page].

Distributed energy resources (DER)

Distributed energy resources are any resource with a first point of interconnection of a utility distribution company or metered subsystem. Distributed energy resources include:

Demand response, which has the potential to be used as a low-greenhouse gas, low-cost, price-responsive option to help integrate renewable energy and provide grid-stabilizing services, especially when multiple distributed energy resources are used in combination and opportunities to earn income make the investment worthwhile.

Distributed renewable energy generation, primarily rooftop PV energy systems.

Vehicle-Grid Integration, or all the ways plug-in electric vehicles can provide services to the grid, including coordinating the timing of vehicle charging with grid conditions.

Energy storage in the electric power sector to capture electricity or heat for use later to help manage fluctuations in supply and demand.

Effective load carrying capability (ELCC)

Effective load carrying capability (ELCC) is the increment of load that could met by the resource while maintaining the same level of reliability. The ELCC of a variable renewable energy resource is based on both the capacity coincident with peak load and the profile and quantity of existing variable renewable energy resources. For a detailed description of ELCC implementation in RESOLVE, see page 87 of the Inputs & Assumptions: CEC SB 100 Joint Agency Report.

Electric Program Investment Charge (EPIC)

A public purpose program established by the California Public Utilities Commission to fund clean energy research, development, and demonstration projects. EPIC supports advancements that promote safe, reliable, and affordable electricity, while helping California meet its energy and climate goals.

Extreme event

An extreme event is an event that is rare at a particular place and time of year. Definitions of rare vary, but an extreme weather event would normally be as rare as or rarer than the 10th or 90th percentile of a probability density function estimated from observations. By definition, the characteristics of what is called extreme may vary from place to place in an absolute sense. Examples of extreme events can include drought, extreme heat, and wildfires.

Extreme weather event

An extreme weather event is an event that is rare at a particular place and time of year. Definitions of rare vary, but an extreme weather event would normally be as rare as or rarer than the 10th or 90th percentile of a probability density function estimated from observations. By definition, the characteristics of what is called extreme weather may vary from place to place in an absolute sense. When a pattern of extreme weather persists for some time, such as a season, it may be classed as an extreme climate event, especially if it yields an average or total that is itself extreme (e.g., drought or heavy rainfall over a season).

Federal Energy Regulatory Commission

Regulates natural gas transportation in interstate commerce and construction of gas pipeline, storage, and liquefied natural gas facilities.

Fossil Gas

A fossil energy source also known as "natural gas." Fossil gas is an energy source that formed deep beneath the earth's surface that contains many different compounds. The largest component of fossil gas is methane (CH4).

Henry Hub

A natural gas pipeline located in Erath, Louisiana, that serves as the official delivery location for futures contracts on the New York Mercantile Exchange.

Integrated Energy Policy Report (IEPR)

SB 1389 (Bowen and Sher, Chapter 568, Statutes of 2002) requires the CEC to prepare a biennial integrated energy report. The report, which is crafted in collaboration with a range of stakeholders, contains an integrated assessment of major energy trends and issues facing California's electricity, natural gas, and transportation fuel sectors. The report provides policy recommendations to conserve resources, protect the environment, ensure reliable, secure, and diverse energy supplies, enhance the state's economy, and protect public health and safety. For more information, see the CEC Integrated Energy Policy Report Web page.

Integrated Resource Planning (IRP)

The CPUC's Integrated Resource Planning (IRP) process is an "umbrella" planning proceeding to consider all of its electric procurement policies and programs and ensure California has a safe, reliable, and cost-effective electricity supply. The proceeding is also the Commission's primary venue for implementation of the SB 350 (De León, Chapter 547, Statutes of 2015) requirements related to IRP (Public Utilities Code Sections 454.51 and 454.52). The process ensures that load serving entities meet targets that allow the electricity sector to contribute to California's economy-wide greenhouse gas emissions reductions goals. For more information see the CPUC Integrated Resource Plan and Long-Term Procurement Plan (IRP-LTPP) Web page.

Interties

Interties are transmission connections between two or more electric power systems or regions. They allow the transfer of electricity across boundaries, such as between states, utilities, or countries.

Investor-owned utility (IOU)

Investor-owned utilities (IOUs) provide transmission and distribution services to all electric customers in their service territory. The utilities also provide generation service for "bundled" customers, while "unbundled" customers receive electric generation service from an alternate provider, such as CCAs. California has three large IOUs offering electricity service: Pacific Gas and Electric, Southern California Edison (SCE), and San Diego Gas & Electric.

Liquified Natural Gas

Natural gas that has been cooled to a liquid state, at about -260° Fahrenheit, for shipping and storage.

Load-serving entity (LSE)

A load-serving entity is defined by the California ISO as an entity that has been "granted authority by state or local law, regulation or franchise to serve [their] own load directly through wholesale energy purchases."

Loss of load expectation (LOLE)

The expected number of days per year for which the available generation capacity is insufficient to serve the demand at least once in that day. California has a planning target of expecting no more than one day with an outage every 10 years. Assessments of the LOLE for a system use hundreds or thousands of potential combinations of various system, weather, and resource supply conditions for a single year. The LOLE is then determined by dividing the total number of days with an outage by the total number of simulated years. If the result is not greater than 0.1, the planning target has been met even if all the days with an outage occurred in a single simulated year.

Million British Thermal Unit

A thermal unit of measurement for Natural Gas. See British thermal unit definition.

Million Cubic Feet Per Day (MMcfd)

A unit of measurement used to express the amount of fluid (gas, water etc.) that is consumed, produced or traversed in a pipeline on any given day.

Natural Gas

A hydrocarbon gas found in the earth, composed of methane, ethane, butane, propane and other gases.

Net qualifying capacity (NQC)

The amount of capacity that can be counted towards meeting RA requirements in the CPUC's RA program. It is a combination of the CPUC's qualifying capacity counting rules and the methodologies for implementing them for each resource type, and the deliverability of power from that resource to the California ISO system.

Noncore Load

Electric generators, industrial customers, commercial, and all other noncore customers.

Once-through cooling (OTC)

Water that is withdrawn from a source, circulated through the heat exchangers, and then returned to a water body at a higher temperature.

Petroleum Industry Information Reporting Act (PIIRA)

Legislation enacted in 1980 that enables a complete response to possible shortages of fuel or other disruptions. The information also helps develop and administer energy policies in the interest of the state's economy and the public's well-being.

Planning reserve margin (PRM)

Planning reserve margin (PRM) is used in resource planning to estimate the generation capacity needed to maintain reliability given uncertainty in demand and unexpected capacity outages. A typical PRM is 15 percent above the forecasted 1-in-2 weather year peak load, although it can vary by planning area. The CPUC's RA program is increasing the PRM requirement to 16 percent minimum for 2023, and 17 percent minimum for 2024 and beyond.

Publicly owned utility (POU)

Publicly owned utilities (POUs), or Municipal Utilities, are controlled by a citizen-elected governing board and utilizes public financing. These municipal utilities own generation, transmission and distribution assets. Examples include the LADWP and the SMUD. Municipal utilities serve about 27 percent of California's total electricity demand.

Renewables Portfolio Standard (RPS)

The Renewables Portfolio Standard, also referred to as RPS, is a program that sets continuously escalating renewable energy procurement requirements for California's load-serving entities. The generation must be procured from RPS-certified facilities (which include solar, wind, geothermal, biomass, biomethane derived from landfill and/or digester, small hydroelectric, and fuel cells using renewable fuel and/or qualifying hydrogen gas). More information can be found at the CEC Renewables Portfolio Standard web page and the CPUC RPS Web page.

Resource adequacy (RA)

The program that ensures that adequate physical generating capacity dedicated to serving all load requirements is available to meet peak demand and planning and operating reserves, at or deliverable to locations and at times as may be necessary to ensure local area reliability and system reliability. For more information, see the CPUC Resource Adequacy Web page.

Scenario

A plausible description of how the future may develop based on a coherent and internally consistent set of assumptions about key driving forces (for example, rate of technological change, prices) and relationships. Note that scenarios are neither predictions nor forecasts but are used to provide a view of the implications of developments and actions.

Southern California Gas Company

A utility company and primary provider of natural gas to Los Angeles and Southern California.

Synergi Gas

The long-time industry standard for hydraulic modeling of large, complex distribution and transmission systems.

Time-dependent electricity rates

Time-dependent electricity rates vary depending on the time periods in which the energy is consumed. In a time-of-use rate structure, the most common type of time-dependent rate, higher prices are charged during utility peak-load times. Such rates can provide an incentive for consumers to curb power use during peak times.

Transmission Planning Process (TPP)

The California ISO's annual transmission plan, which serves as the formal roadmap for infrastructure requirements. This process includes stakeholder and public input and uses the best analysis possible (including the CEC's annual demand forecast) to assess short- and long-term transmission infrastructure needs. For more information, see the California ISO Transmission Planning Web page.

Western Electricity Coordinating Council (WECC)

The Western Electricity Coordinating Council (WECC) operates as a non-profit corporation ensuring a reliable Bulk Electric System in the geographic area known as the Western Interconnection. WECC has been approved by the Federal Energy Regulatory Commission (FERC) as the Regional Entity for the Western Interconnection. The North American Electric Reliability Corporation (NERC) has delegated authority to create, monitor, and enforce reliability standards to WECC (and other Regional Entities in North America) through a Delegation Agreement.

Western Interconnection (WI)

The physical infrastructure comprising the Bulk Electric System in the geographic area encompassing all or parts of:

- 14 states situated west of, yet including, Montana, South Dakota, Colorado, New Mexico and Texas
- the Canadian provinces of Alberta and British Columbia
- the state of Baja California, Mexico

Generally, transmission lines at or above 100 kV, and the generation and storage resources interconnected to them in the above geographic area make up the Western Interconnection.

Western States Transmission Initiative (WSTI)

A collaboration of western states' regulators and policy leaders focused on developing new approaches to transmission planning and cost allocation in the western interconnection. WSTI proceedings are led by the Gridworks facilitation group for the benefit of members of the Committee on Regional Electric Power Cooperation (CREPC). A primary goal of WSTI is to address energy transition challenges by building a shared understanding of transmission issues among western regulators and state energy policy leaders, surfacing strategies for CREPC to address both opportunities for transmission development across a regional footprint and supporting regulatory and policy foundations. For more information, see the WSTI web page.