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Joint Agency Reliability Planning Assessment

Covering the Requirements of SB 846 (Combined First and Second Quarterly Report for 2025) and SB 1020 (Annual Report)

Gavin Newsom, Governor
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ABSTRACT

The *Joint Agency Reliability Planning Assessment* addresses requirements for electricity reliability reporting in Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) and Senate Bill 1020 (Laird, Chapter 361, Statutes of 2022). The report provides the combined first and second quarterly review of 2025, including the demand forecast, supply forecast, and potential high, medium, and low risks to reliability in the California Independent System Operator territory from 2025 to 2035, as required by Senate Bill 846. As required by Senate Bill 1020, this report also provides a joint reliability progress report that reviews system and local reliability, with a particular focus on summer reliability, identifies challenges and gaps to achieving system and local reliability, and identifies the amount and cause of any delays to achieving compliance with all energy and capacity procurement requirements set by the California Public Utilities Commission.

Keywords: Reliability, Reliability Planning Assessment, SB 846, California ISO, CEC, CPUC, California, electricity, supply and demand, extreme weather, electricity system planning, stack analysis, summer reliability, resource procurement, extreme events

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Introduction

California continues to experience a substantial shift in conditions affecting the electric grid as it transitions to the state's clean energy future, while confronting the impacts of climate change. Senate Bill 100 (De León, Chapter 312, Statutes of 2018) set an ambitious target of powering all retail electricity sold in California and state agency electricity needs with renewable and zero-carbon resources by 2045 to reduce greenhouse gas emissions and help improve air quality and public health. The actions to achieve this target are resulting in the addition of unprecedented quantities of clean energy resources, primarily utility-scale solar and storage.

Since 2020, California's electric grid faced unprecedented challenges due to extreme weather and global economic pressures. Heat waves in 2020 and 2022 pushed electricity demand to record levels. A heat event in August 2020 resulted in rolling outages ranging from 8 – 90 minutes within the California Independent System Operator (California ISO) balancing area. In 2021, the Bootleg Fire in southern Oregon, which burned July 6 – August 15, 2021, resulted in 4 gigawatts of reduced import capacity to the state from the northwest.

Global supply chain disruptions compounded these challenges. Delays in obtaining materials for solar panels, battery storage, and other clean energy technologies slowed the state's progress toward expanding renewable energy and firm capacity. Furthermore, supply chain disruptions in network components, such as circuit breakers, dramatically increased project timelines. For example, high voltage circuit breakers, which typically have a lead time of up to 50 weeks, experienced a 200-week lead time because of supply chain issues.

Recognizing these challenges, Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) mandated the California Energy Commission (CEC) and California Public Utilities Commission (CPUC) to develop a quarterly joint agency reliability planning assessment. The assessment is required to include estimates of supply and demand for the next 10 years under different risk scenarios, information on existing and new resources and delays, and a description of barriers to timely deployment of resources. This report is the combined first and second quarterly report of 2025.

Senate Bill 1020 (Laird, Chapter 361, Statutes of 2022) requires the CEC, CPUC, and California Air Resources Board to issue a joint reliability progress report that reviews system and local reliability, with a particular focus on summer reliability; identifies challenges and gaps to achieving system and local reliability; and identifies the amount and cause of any delays to achieving compliance with all energy and capacity procurement requirements set by the CPUC. The request from Senate Bill 1020 is being incorporated into this joint agency assessment to fulfill the requirements of the annual Senate Bill 1020 report.

California's Reliability Situation

Climate change, which is resulting in greater weather variability and natural disasters, continues to create challenges for the expansion of clean energy resources in California, most of which are weather-variable themselves. This interaction has resulted in challenges related to timely and effective planning, securing sufficient scale and diversity of resources needed, and preparing for extreme weather events, including wildfires. State energy entities continue to take steps towards developing new strategies to address potential imbalances of electrical supply and demand.

Demand Forecast

As directed in Senate Bill 846, this reliability analysis uses the most recently available *Integrated Energy Policy Report (IEPR)* forecast. For the analysis, staff used the 2024 IEPR Update Planning Forecast from the *2024 IEPR Update*. The planning forecast is the forecast scenario that will be used by the CPUC for its Integrated Resource Planning efforts. In the planning forecast, the annual managed sales for the California ISO region increases from 196,000 gigawatt-hours in 2024 to 293,000 gigawatt-hours in 2034. The 1-in-2 summer peak increases from 46,000 megawatts (MW) in 2024 to 59,000 MW in 2034. The primary drivers for the increase in electricity demand are transportation and building electrification.

Supply Forecast

California has separate Integrated Resource Plan processes established by Senate Bill 350 (De León, 2015) for the load serving entities under jurisdiction of CPUC and the largest publicly owned utilities, respectively, to plan for mid- and long-term procurement of energy resources. Meeting increased load from economic and demographic growth and more extreme weather, replacing aging, retiring generation, and achieving greenhouse gas (GHG) emissions reductions translate into an enormous level of procurement in the mid- and long-term. CPUC-jurisdictional load serving entities and publicly owned utilities are procuring new energy resources to meet reliability and GHG emissions reduction targets, but they are facing a variety of barriers, including permitting, financing, and supply chain issues. This report contains information on new supply resources for both CPUC-jurisdictional entities and publicly owned utilities.

The CPUC Integrated Resource Plan process includes a "planning track" and a "procurement track." In the planning track, the CPUC adopts a Preferred System Plan and sets requirements for load serving entities to plan toward it. The Preferred System Plan is an optimal portfolio of resources for meeting state electric sector policy objectives at least cost to ratepayers. In 2019, the CPUC initiated the Integrated Resource Plan "procurement track" to explore possible actions it could take to address potential reliability or other procurement needs. On February 15, 2024, the CPUC adopted the 2023 Preferred System Plan and the 2024-25 Transmission Planning Process portfolios via Decision 24-02-047. Among other things, the decision:

- adopted an aggregated portfolio that reduces statewide yearly GHG emissions from the electric sector to 25 million metric tons by 2035, and
- provided an expected resource development portfolio for the California ISO to be utilized to plan transmission investments for their Transmission Planning Process.

Within the Integrated Resource Plan Proceeding's procurement track, the CPUC has approved three decisions:

- Decision 19-11-016 covering the near term (ending in 2023) reliability;
- Decision 21-06-035 covering the midterm (ending in 2028) reliability; and

- Decision 23-02-040 (supplemental midterm reliability) adding additional procurement to 2026 and 2027.

Across these decisions, the CPUC has ordered CPUC-jurisdictional load serving entities to procure a combined amount of 18,800 MW of net qualifying capacity of new electricity resources to come online between 2020 and 2028.

Publicly owned utilities are non-profit community owned utilities that provide electric service within their territories and are governed by locally elected governing boards. While many publicly owned utilities have used Integrated Resource Plans to guide their resource procurement for years, Senate Bill 350 (De León, Chapter 547, Statues of 2015) established the requirement for the 16 largest publicly owned utilities to adopt Integrated Resource Plans by January 1, 2019, and to submit them to the CEC for evaluation of consistency with Senate Bill 350 requirements, the state's GHG emissions reduction targets, Renewables Portfolio Standard procurement requirements, and other planning goals. The publicly owned utilities filed Integrated Resource Plans in 2018-2019, and the CEC found they were consistent with Senate Bill 350 and other requirements. The publicly owned utilities are directed to update their Integrated Resource Plans every five years and file an update with the CEC for a Senate Bill 350 consistency evaluation.

Tracking Project Development

Since 2020, California energy entities have taken steps to address the potential imbalances between the electrical supply and demand in California, in particular as the electric grid transforms to rely on a high penetration of renewables and zero-carbon resources. The Tracking Energy Development Task Force is an inter-agency working group to track new clean energy projects under contract to help overcome barriers to completion. It consists of the CEC, California ISO, CPUC and the Governor's Office of Business and Economic Development.

Large-scale renewable energy projects continue to face the challenges as previously reported: unclear or inconsistent permitting processes, supply chain problems that delay project timelines, and impediments to interconnecting to the grid. The Tracking Energy Development Task Force continues to gather information through outreach efforts with developers, governmental entities and other stakeholders that will help to inform our understanding of the issues and build on the current work progress to accelerate energy project deployment.

Recently, discussion among stakeholders is focused on fire safety concerns around utility-scale battery energy storage system projects. Recognizing this, the Tracking Energy Development Task Force is increasing outreach to local governments and assessing through cross-agency collaboration on how to best work with stakeholders to address the issues with evolving technology.

Senate Bill 1174 (Hertzberg, Chapter 229, Statues of 2022) requires electrical corporations that own electrical transmission facilities to annually report data on their portfolio of in-development transmission projects that are delayed, and the in-development generation and storage resources that depend on these transmission projects. Pacific Gas and Electric and Southern California Edison reported approximately 28.4 (gigawatts) GW of Renewables Portfolio Standard-eligible and storage resources that depend on delayed transmission projects and network upgrades. Of these 28.4 GW, CPUC staff determined that approximately 16 GW are projected to be delayed or are at risk of becoming delayed past their planned in-service date. The remainder are still forecast to meet their planned in-service date, despite their dependence on delayed transmission projects and network upgrades.

Reliability Assessments

This report employs both deterministic and probabilistic reliability assessment approaches to evaluate forecasted demand and supply for the 2025–2035 period. While Senate Bill 846 mandates analysis at the 5- and 10-year intervals, the CEC and CPUC continue to expand the scope to include annual results for greater detail. The preliminary summer 2025 analysis will not incorporate pre-summer updates such as hydroelectric conditions. This report also highlights near-term projects expected to come online within the next 1–2 years and provides a comprehensive probabilistic analysis extending to the 10-year horizon.

Near-Term Summer Reliability Assessment

The approach used for the near-term reliability assessment in this report remains consistent with the deterministic Summer Stack Analysis included in prior Senate Bill 846 Joint Reliability Quarterly reports, released in 2024. The analysis evaluates the hourly supply stack against projected demand for peak days in summer, accounting for resource availability and potential stress scenarios.

For summer 2025, California's grid is expected to meet demand under all modeled scenarios, including extreme conditions. The grid has benefited from enhanced battery storage and an expanding portfolio of solar and wind resources. Under average conditions, California is projected to maintain a surplus of more than 5,500 MW during peak demand. While under extreme conditions, a surplus of 1,368 MW is anticipated.

However, risks persist during wildfire events that can reduce import capacity by as much as 4,000 MW, as observed in previous incidents. The updated analysis highlights the need to continue developing clean energy, address delays from supply chain and permitting challenges, and implement proactive contingency measures to maintain reliability under extreme conditions.

Mid-Term Probabilistic Reliability Assessment (CPUC)

Using a list of baseline resources, which include existing resources and known planned resources expected to be online by June 1, 2026, CPUC staff performed a Loss of Load Expectation study for the 2026 Resource Adequacy compliance year to help in the CPUC’s consideration of establishing a Planning Reserve Margin for 2026. The results of the study were published in July 2024 and found the California ISO system to be reliable in all months of the year, surpassing the established standard (less than or equal to 0.1 Loss of Load Expectation). On an annual basis, CPUC staff were able to achieve Loss of Load Expectation of 0.1 with a surplus of 2,300 MW of capacity. The results of the study and their translation to the Slice-of-Day Framework are currently being considered in Track 3 of the CPUC’s Resource Adequacy proceeding with a Final Decision expected in June 2025. For the 2025 Resource Adequacy year, the Planning Reserve Margin remains at 17 percent.

Mid-Term Probabilistic Reliability Assessment (CEC)

The mid-term probabilistic reliability analysis uses the 2023 IEPR Planning Forecast from the *2023 IEPR*, adopted in February of 2024. The CEC performed a probabilistic assessment of the mid-term state-wide reliability outlook for California from 2025 to 2035, under the supply forecast in the CPUC 2023 Preferred System Plan. 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, or 0.1 days/year loss of load expectation under a variety of scenarios related to the resource build and import uncertainty. The study finds that the current resource mix and proposed PSP additions contain sufficient resources to exceed the 0.1 loss of load expectation reliability criterion and serve load under challenging demand and resource conditions. However, the study did not evaluate all potential risk, and future work is being conducted to evaluate winter reliability risks, the impacts of transmission outages, and drought conditions. Additionally, alternative load scenarios, such as increased or different electric vehicle charging patterns, may drive summer resource adequacy risks not captured here.

System reliability is expected to continue to significantly improve 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, 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 Preferred System Plan). Additional resources delays due to supply chain delays may reduce the improvement in system reliability, although the system is expected to be reliable even under resource delay scenarios, assuming typical weather conditions.

CHAPTER 1: Introduction

Energy reliability in California and nationally is increasingly impacted by highly variable and unusual weather events driven by climate change. California's energy system runs reliably without issue the vast majority of the time, and the state has backup assets in place to provide energy during extreme events and avoid outages. The state's greatest energy reliability concerns are driven by a small number of hours during increasingly historic heat events when demand for electricity skyrockets to unprecedented levels and available supply is constrained. If extreme heat events coincide with other climate-driven extreme events — like drought or fire, the state's energy system could be strained beyond the limits of historically planned reliability contingencies.

In 2020, a West-wide heat event resulted in rotating outages 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, 2022, and on September 6, 2022, the California ISO recorded a new record peak load at 52,061 MW, which was 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, California's mean temperature of 81.7 degrees Fahrenheit in July was ranked the warmest on record compared with a 75.2-degree Fahrenheit average over the previous 130 years. California was also impacted by the Park Fire in July and Pine Fire in October, which reduced the capacity of key transmission lines by more than 4,000 MW each time. On July 10, 2024, the Western Interconnection[1] reached a new all-time peak demand of 167,988 MW.[2]

Addressing Reliability Challenges

Since 2020 California energy entities have taken steps to address the potential imbalances between the electrical supply and demand in California as the electric grid transforms to a high penetration of renewables and zero-carbon resources. Even with programmatic changes, resource additions, and Strategic Reliability Reserve (SRR)[3] resources, there exists uncertainty in the supply-and-demand balance in the 5- and 10-year horizons.

Despite a boom in new project development, the state needs an even greater buildout of clean energy resources to meet near-term reliability and the long-term clean energy policy goals, embedded in Senate Bill 100 (De León, Chapter 312, Statutes of 2018) and in support of the

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1 The Western Interconnection extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between.

2 California ISO, *Summer Market Performance Report: July 2024*, available at: https://www.caiso.com/documents/summer-market-performance-report-july-2024.pdf

3 Developed as part of Assembly Bill 205 (Committee on Budget, Chapter 61, Statutes of 2022) to expand the resources capable of managing or reducing net-peak demand during extreme weather events such as heat and wildfires.

deep decarbonization strategy outlined in the 2022 Scoping Plan for Achieving Carbon Neutrality.[4] New strategies are needed to achieve the scale and diversity of resources necessary to accomplish the transition, especially considering continued supply chain disruptions for solar and storage.

Additionally, climate change and extreme heat and wildfire events are affecting the ability of existing models to assess energy reliability into the future due to increasing divergence from historical norms. Planning models and approaches need to continue to be enhanced to account for greater weather variability. The state will continue to benefit from updated planning strategies for bringing on new resources faster and at a larger scale, while engaging more closely with communities on solutions that meet their needs. The state could consider implementing additional programs to expand the resources capable of managing or reducing net-peak demand during extreme events.

California's energy reliability planning requires coordination among the CEC, CPUC, and California ISO. These entities collaborate to enhance forecasting accuracy, streamline resource planning, and assess system reliability for the near-, mid-, and long-term. Since 2020, the following actions have been taken to address these reliability challenges:

- **Increasing Coordination**
  - The Tracking Energy Development (TED) Task Force[5] continues to track the new clean energy projects under development to help overcome barriers to their completion.
  - The CEC, CPUC, and California ISO updated their 2010 Memorandum of Understanding in December 2022 to establish and reaffirm linkages among the planning activities at each entity to support the significant number of new resources and transmission needed to meet state goals.[6]
- **Establishing Contingency Resource Programs**
  - The SRR is comprised of three programs that provide funding to secure conventional generation resources, efficiency upgrades at existing natural gas plants, demand response (DR), distributed generation, and long-duration storage.
- **Increasing Transparency and Greater Analytics**
  - Quarterly reports such as this, provide frequent and ongoing reliability analysis to inform the legislature and energy policy.
  - The CEC revised the California Energy Demand (CED) forecast in the *IEPR* to account for climate change.
- **Increasing Supply Procurement**

4 2022 Scoping Plan Documents available at: https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents

5 Working group between the CEC, CPUC, California ISO, and Governor's Office

6 2022 Memorandum of Understanding Between The California Public Utilities Commission (CPUC) And The California Energy Commission (CEC) And The California Independent System Operator (ISO) Regarding Transmission and Resource Planning and Implementation via https://www.energy.ca.gov/sites/default/files/2023-01/MOU_Dec_2022_CPUC_CEC_ISO_signed_ada.pdf

- The CPUC ordered a total of 18,800 MW of net qualifying capacity to be procured by its jurisdictional load-serving entities from 2021-2028.
- The California ISO conducts the Transmission Planning Process (TPP), which helps assess and prioritize major transmission upgrades to add capacity and relieve grid limitations. The California ISO also continues to improve its interconnection queue through the Interconnection Process Enhancements Initiative with the goal of accelerating the deployment of generation projects.

Senate Bill 846

Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) requires the CEC and the CPUC to submit a Joint Reliability Planning Assessment to the Legislature quarterly. This assessment focuses on the California ISO's balancing area, specifically looking at the supply and demand balance for the forward 5- and 10-year periods under different levels of risk. This report is the combined first and second of the 2025 quarterly reports and provides information on the CED forecast, the supply forecast, a reliability assessment, and joint agency recommendations.

Senate Bill 1020

Senate Bill 1020 (Laird, Chapter 361, Statutes of 2022) requires the CPUC, CEC, and State Air Resources Board, on or before December 1, 2023, and annually thereafter, to issue a joint reliability progress report that reviews system and local reliability. These reports are to have a particular focus on summer reliability, identify challenges and gaps, if any, to achieving system and local reliability, and identify the amount and cause of any delays to achieving compliance with all energy and capacity procurement requirements set by the CPUC. This document is the 2025 annual report. The relevant content can be found in Chapter 7.

CHAPTER 2: Summer 2024 Reliability Summary

Compared to 2023, the reliability outlook improved going into the summer of 2024. Continued growth in battery energy storage and new clean generation resources strengthened the system's ability to handle net peak demand. Across summer 2024, California and the broader West incurred periods of prolonged and extreme heat. The Western Interconnection reached an all-time peak demand of 167,988 MW on July 10, 2024. While California experienced hot conditions, extreme temperatures elsewhere in the Western Interconnection and wildfire impacts presented challenges, such as reduced transfer capacity on key transmission lines. Despite this, California managed grid reliability without calling Flex Alerts and declaring just one Energy Emergency Alert (EEA) Watch in July due to the impacts of the Park Fire. The improvement in grid reliability is largely the results of improved resource adequacy (RA) planning, strategic coordination through reliability programs, and the effective use of DR initiatives.

Coordinated planning and a high degree of communication continue to factor into the success of response to challenging grid conditions. This includes maintaining and operationalizing the California ISO operational playbook, which fosters collaboration and communication with entities such as state agencies, load-serving entities, and other balancing authorities. In addition, the continued development and implementation of the SRR ensures that programs are available for addressing reliability risks during extreme events. The SRR includes two demand-side programs administered by the CEC and one supply-side program administered by the Department of Water Resources (DWR). The three programs administered under the SRR include the following:

- **Distributed Electricity Backup Assets Program –** This program was launched in October 2023 when the CEC adopted guidelines with funding to be made available through grants. The first Distributed Energy Backup Assets program grant funding opportunity was released in December 2023 for bulk grid efficiency upgrades and capacity additions at existing bulk grid power plants with a funding allocation of $150 million. In April 2024, the CEC released a Notice of Proposed Awards for nine projects requesting $123 million, which would add about 297 MW of new capacity by 2027 to increase California's grid reliability. Bulk grid efficiency projects are anticipated to be completed and come online throughout summer 2025 – summer 2027.
- **Demand Side Grid Support Program** - This program was launched in August 2022 with the adoption of initial program guidelines. Those guidelines were later revised in July 2023 to bring on more clean resources with expanded participation eligibility, additional incentive options for clean resources, including storage virtual power plant, and streamlined processes. In May 2024, the CEC adopted additional revisions to the guidelines for the 2024 summer season, continuing to streamline participation and allowing bi-directional electric vehicle chargers to participate in the storage virtual power plant. Currently, the CEC is pursuing potential revisions to program guidelines to further expand participation by additional clean resources in the 2025 season. The Demand Side Grid Support Program operates from May 1 through October 31 each year

and has three incentive options under which customers can participate, as captured in Table 1.

Table 1: Demand Side Grid Support Incentive Options and Summer 2024 Events

	Option 1 – Emergency Dispatch	Option 2 – Market Integrated Demand Response	Option 3 – Market Aware Storage Virtual Power Plant
Eligible Resources	Any load reduction resource	Market-integrated demand response	Storage (batteries + V2X)
Event Trigger	EEA issued by a balancing authority	California ISO energy market bidding & scheduling	California ISO day-ahead energy market locational marginal price ≥ $200 per MWh
Summer 2024 Events	July 24, 2024, EEA Watch	N/A	26 event hours over 16 days

Source: CEC

- **Electricity Supply Strategic Reliability Reserve Program** – This program was launched in July 2022 by DWR. In 2022, DWR managed 120 MW of temporary and emergency natural gas-powered resources, 82 MW of emergency backup diesel generators, and 3,349 MW of firm energy import contracts. For summer 2023, DWR closed the Backup Diesel Generation program early in favor of approximately 148 MW of lower-emitting temporary and emergency natural gas-powered resources and 3,391 MW of firm energy import contracts. For 2024, the portfolio of natural gas-powered resources increased to 3,150 MW, reflecting the inclusion of contracted resources that would have otherwise retired. Aside from necessary testing, these resources are off until a California-centric balancing authority (BA) issues an EEA or, for long-start resources in the California ISO footprint, ordered by the California ISO to turn on to address extreme events. DWR's portfolio of resources have been available and responsive to both EEAs and California ISO operator instruction.

Summer 2024 Balancing Authority Recaps

The following sections provide a recap of the reliability performance of multiple balancing authority areas (BAA) in California during summer 2024. These recaps highlight the unique challenges faced and the measures taken by each BAA to maintain grid stability throughout the season.

California Independent System Operator

This section is based on insights from the California ISO Summer Market Performance Reports for July 2024 and September 2024.[7] Overall, reliability conditions in summer 2024 were stable, with the California ISO territory better positioned on RA due to the continued addition of new

7 The California ISO Market Performance Report for July 2024 can be found at: https://www.caiso.com/content/monthly-market-performance/jul-2024/index.html

generation and storage resources. Additionally, the California ISO monitored and managed impacts of wildfires on grid infrastructure.

Despite periods of extreme heat and wildfire risks during summer 2024, the California ISO did not call any Flex Alerts and issued just one EEA Watch in July. The EEA Watch occurred on July 24, when the Park Fire caused a path capacity derate on the Malin intertie. This further highlights the improved conditions compared to previous years. For example, in 2022, the California ISO issued a record 10 consecutive days of Flex Alerts[8] between August 31 and September 9, 2022. Since then, the California ISO has not needed to call any Flex Alerts.

There were several factors that contributed to grid reliability across summer 2024. These include:

- Continued growth of new, clean generation on the California ISO system, notably a proliferation of battery storage resources that charge when solar is abundant and discharge across net peak periods when the sun starts to set.
- The Western Energy Imbalance Market continues to be effective to help balance supply and demand across the wider Western footprint.
- Strong planning and coordination between the California ISO and state agencies, load-serving entities, and regional partners in advance of and across summer.
- Strategic reliability reserves and demand-side programs provided grid support during extreme weather events.

Balancing Authority of Northern California

The Balancing Authority of Northern California (BANC) is a joint powers agency whose members include the Modesto Irrigation District, City of Redding, City of Roseville, Sacramento Municipal Utility District, City of Shasta Lake, and Trinity Public Utilities District. The BANC footprint also includes the Western Area Power Administration-Sierra Nevada Region and the 500 kV California Oregon Transmission Project intertie to the Pacific Northwest region.

In preparing for summer 2024, BANC performed a reliability analysis, updated its operating procedures, trained its operators, and engaged in joint training exercises with the California ISO and other adjacent BAAs. Similar to analyses conducted by the CEC and California ISO for the California ISO territory, BANC conducted reliability analyses that considered such factors as potential heat events, hydro derates, and potential impacts to imports resulting from wildfires. The assessment determined that BANC had sufficient resources to meet the 1-in-2 and 1-in-10 load for summer 2024 with sufficient operating margins. The assessment also showed sufficient resources for extreme events such as wildfire smoke and the California ISO reaching an EEA 3. However, BANC would have risks in the event of a West-wide heat event causing a 1-in-20 load and reduced import availability. In 2024, BANC reached the annual peak load of 4,776 MW on July 11, 2024, which was 120 MW higher than BANC's peak load in 2023 and 167 MW lower than BANC's all-time peak set in September 2022. BANC's resource supply

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8 Flex Alerts are voluntary calls for consumers to conserve electricity. A Flex alert is typically issued in the summer when extremely hot weather drives up electricity use, making the available power supply scarce. This usually happens in the evening hours when solar generation is going offline, and consumers are returning home and switching on air conditioners, lights, and appliances.

slightly increased in 2024 with the integration of 2 MW of net-metered solar generation and an increase in hydro power generation due to the above normal water year in 2023-2024. BANC managed through a hotter-than-normal summer, including two significant wildfires, without declaring any EEAs. The Park Fire in late July and the Pine Fire in early October both reduced the transfer capability of California Oregon Intertie by more than 4,000 MW. It should also be noted that the Western Energy Imbalance Market performed well during 2024, demonstrating the benefits of peak diversity.

Some of the other efforts to maintain reliability were:

- Increased communications with members and other BAAs.
- Appropriate use of EEAs to assist in initiating DR programs and deploying reserves**.**
- Increased energy procurement efforts by members as needed.

In preparation for 2025, BANC will continue to conduct detailed summer assessments of anticipated reliability under different scenarios and to evaluate RA policies in response to heat events. BANC will continue coordination with other BAAs, the state, and Department of Energy (DOE) to identify resources that may be underused, including backup generators.

Los Angeles Department of Water and Power

During the early September 2024 National Weather Service Excessive Heat Warning, the Los Angeles Department of Water and Power (LADWP) experienced four days where Net Power for Load (NPL) exceeded 5,000-MW (September 4, 5, 7, and 8) and two days where NPL exceeded 6,000-MW (September 6 and 9). LADWP's pre-Energy Imbalance Market record peak Net Power for Load is 6,502-MW (1-in-40 peak load), which occurred on August 31, 2017. On September 6, 2024, LADWP set a post-Energy Imbalance Market record peak of 6,237 MW. In all cases, LADWP was adequately resourced and did not require any Reliability Coordinator EEA declarations. The following factors contributed to this performance success.

1. Management and Dispatch of LADWP units: Despite significant performance challenges associated with LADWP's older, in-basin steam units, LADWP was able to dispatch units in a timely manner to ensure availability as hot weather pushed system loading upwards.
2. Energy Availability: On September 6, 2024, LADWP purchased 3,000 MW-hours in real time. Real time purchases were not required on the other days listed above.
3. DR: LADWP was able to call on available DR programs to reduce peak demand during hot weather.
4. Restricted Maintenance: LADWP Grid Operations declared Restricted Maintenance during the National Weather Service Excessive Heat Warning to minimize the probability of any maintenance-associated trips impacting system performance.

LADWP had sufficient resources to meet the 1-in-2 and 1-in-10 load for 2024 with sufficient operating margins. On the sub-transmission and distribution side of the LADWP power system, there were significant challenges during the September 2024 National Weather Service Excessive Heat Warning with regards to circuit and equipment overloads. These were mitigated to the best extent possible by managing power flow.

Conclusion

In summer 2024, the joint state agencies and BAAs successfully prepared the grid to manage high demand, extreme heat, and wildfire risks. The expansion of the SRR added critical resources, while favorable weather, and the continued growth of clean energy and battery storage contributed to grid stability. Collaboration among the BAAs, played a key role in minimizing emergency measures, such as Flex Alerts, and ensuring reliability. Looking forward, ongoing investments in clean energy, resource planning, and coordination will be essential for maintaining grid reliability in summer 2025 and beyond.

CHAPTER 3: California Energy Security Plan

The 2021 Infrastructure Investment and Jobs Act[9] (Act) outlined six elements in Section 40108 that are required to be included in State Energy Security Plans. The Act requires energy emergency plans to be reorganized to:

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

States are required to either submit an energy security plan for review or a Governor's letter affirming that the existing plan meets all Section 40108 provisions each year through 2025 to the U.S. Department of Energy (DOE).

State energy security plans represent an important part of energy security planning. The goals of these updated plans are to describe the state's energy landscape, people, processes, and the state's strategy to build energy resilience. Specifically, the goal of the updated plan is to detail how the state, working with energy partners, can secure their energy infrastructure against physical and cybersecurity threats; mitigate the risk of energy supply disruptions; enhance the response to, and recovery from, energy disruptions; and ensure that the state has secure, reliable, and resilient energy infrastructure. Recent California Energy Security Plan submission activities include the following:

- In September of 2023, a draft updated California Energy Security Plan was submitted to the DOE Office of Cybersecurity, Energy Security, and Emergency Response (CESER) for review.
    - In December of 2023, CESER sent a letter to the CEC team noting that the draft California Energy Security Plan met all content requirements.
    - The CESER letter also included recommendations on how the CEC team can further improve the draft plan.
- On September 24, 2024, the CEC resubmitted the California Energy Security Plan satisfying the requirements.

For 2025, the CEC can submit a revised plan with updated energy profile data, or a Governor's letter to satisfy the requirements. The CEC team is continuing to engage the CESER team and California agencies in preparation for the September 2025 submission.

9 2021. H.R.3684 - *Infrastructure Investment and Jobs Act*. https://www.congress.gov/bill/117th-congress/house-bill/3684.

CHAPTER 4: Demand Forecast

Demand Forecast Scenarios

As directed in SB 846, this reliability analysis uses the most recently available IEPR Forecast, which is the 2024 IEPR Update Planning Forecast, adopted in January of 2025 for the 2024 *IEPR Update*. The 2024 IEPR Update Forecast includes a baseline forecast, a planning forecast, and a local reliability forecast. The planning forecast considers the impacts of "additional achievable" scenarios for energy efficiency, fuel substitution and transportation electrification beyond the baseline forecast, and is typically used for planning resource procurement and transmission.

2024 IEPR Update Planning Forecast Inputs and Assumptions

The demand forecast relies on several data sources as inputs. The baseline economic projection is from a Moody's Analytics scenario that is described as a "50/50" likelihood. Demographic projections (for example, population and number of households) are derived from California Department of Finance analysis. Other drivers in energy consumption forecasts are the retail cost of energy, adoption of behind-the-meter self-generation and energy storage technologies, building electrification, and vehicle electrification. The electricity rate scenarios incorporate recent and pending utility rates and rate actions; projected costs of electric generation procurement, transmission, and distribution revenue requirements; and other costs. Key drivers of increasing electricity rates for the 2024 IEPR Update Forecast were the costs of wildfire mitigation, risk management, and other investment in the distribution grid to support state policy goals.

For planning areas within the California ISO balancing area, peak and hourly demand forecasts were developed using the CEC's top-down hourly load model. This model is at the system level and driven primarily by growth in annual consumption. The key functionality of the hourly load model is that it allows specific profiles for photovoltaic, electric vehicle charging, and other load-modifying resources to be layered onto the baseline consumption profile, ensuring that the resulting peak forecast accurately captures the contribution of these resources.

System reliability planning in the context of a changing climate requires the demand forecast to consider a broad range of likely or possible weather patterns, as electricity demand is highly sensitive to temperature. The CEC's peak forecast must consider demand under normal peak conditions, as well as for the types of extreme temperatures that would be expected only once in 5, 10, or 20 years.

The 2024 IEPR Update Forecast employs the same methodology as the 2023 IEPR Forecast, in which the CEC shifted away from its traditional practice of sampling only the historical record to define the range of possible weather patterns. Instead, it relies also on projected weather patterns from high-resolution projections derived from four global climate models[10] under the "Business as Usual" Shared Socio-Economic Pathway (SSP3-7.0)[11] scenario[12].

Staff is collaborating under Electric Program Investment Charge-funded agreements with Lumen Energy Strategy and Cal-Adapt: Analytics Engine team to improve climate considerations iteratively in the demand forecast and further validate approaches. This effort has identified further areas for improvement that will be taken up in future IEPR cycles.

For more information on the 2024 IEPR Update Forecast, see the *2024 IEPR Update*[13] and the December 12, 2024, IEPR workshop materials. [14]

2024 IEPR Update Planning Forecast Results

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*, both 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 gigawatt hours (GWh). This 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. These trends continue over the forecast period, and statewide planning scenario energy sales for 2040 are more than 411,000 GWh.

10 The four global climate models are CESM2, CNRM-ESM2-1, EC-Earth3-Veg, and FGOALS-g3.

11 Shared Socio-Economic Pathways represent different possible warming scenarios, as defined by the Intergovernmental Panel on Climate Change (IPCC), and explained in the IPCC Sixth Assessment Report found here: https://www.ipcc.ch/report/ar6/wg1/chapter/chapter-4/

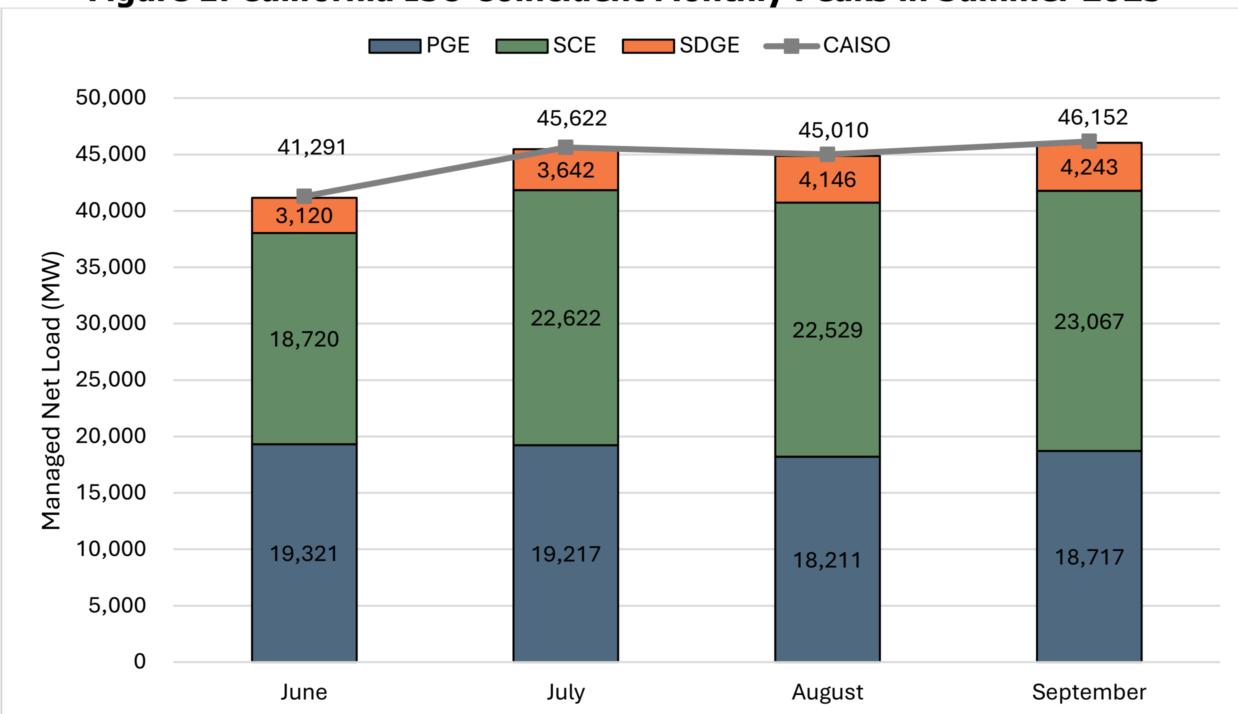
12 This effort is supported by multiple EPIC applied research efforts, including the Cal-Adapt Analytics Engine.

13 Bailey, Stephanie, Mathew Cooper, Quentin Gee, Heidi Javanbakht, Danielle Mullany. 2023. 2024 Integrated Energy Policy Report Update. California Energy Commission. Publication Number: CEC-100-2024-001. Available https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2024-integrated-energy-policy-report

14 IEPR Workshop presentations and event recordings are available at https://www.energy.ca.gov/event/workshop/2024-12/iepr-commissioner-workshop-draft-forecast-results.

Hourly electricity demand typically peaks in the summer months of July, August, or early September. The coincident peaks[15] forecast for the summer months of 2025 for the entire California ISO territory, composed primarily of the Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) Transmission Access Charge (TAC) areas, are shown in Figure 1. Note that the annual system peak[16] 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.

Figure 1: California ISO Coincident Monthly Peaks in Summer 2025



Source: CEC 2024 IEPR Update Planning Forecast

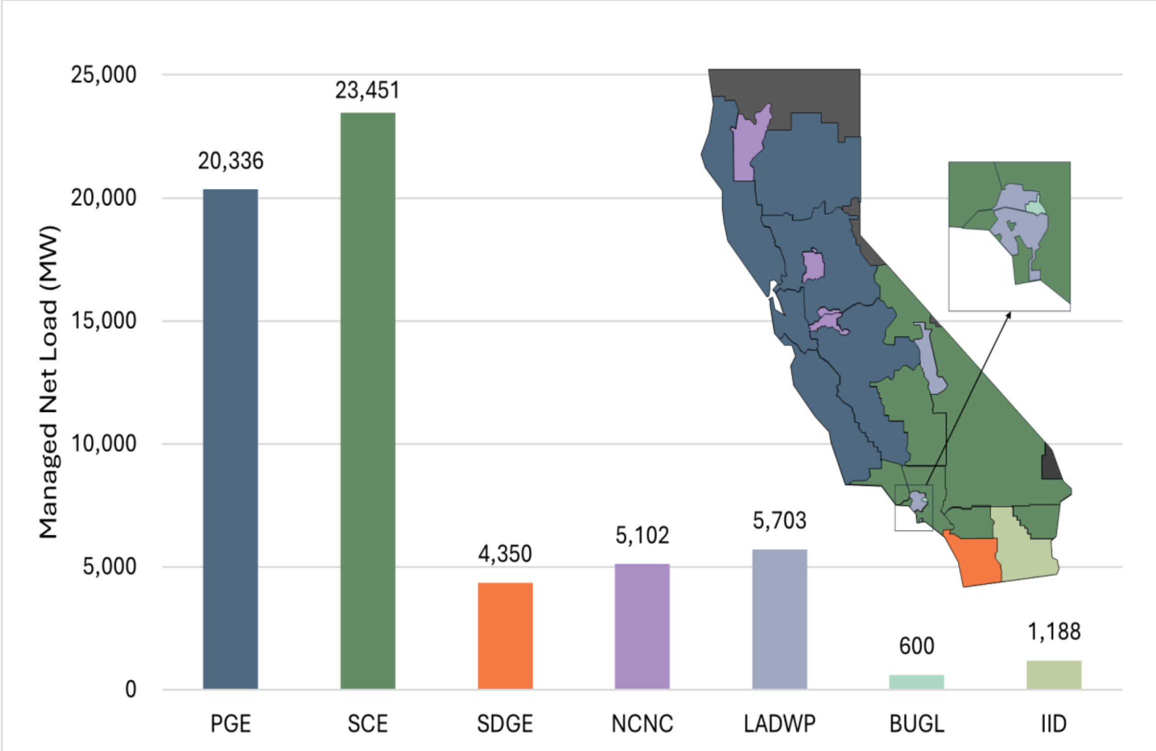
Note: SCE includes pumping load from the Metropolitan Water District (MWD) of Southern California. The California ISO total also includes a small amount of load supplied by the Valley Electric Association (VEA).

Figure 2 shows the annual non-coincident system peaks from the *2024 IEPR Update* Planning Forecast for the investor-owned utility (IOU) TAC areas within the California ISO control area as well as the four other main planning areas within California. The non-coincident 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. Additionally, the non-California ISO peaks sum to nearly 13,000 MW in 2025, for a statewide non-coincident total of nearly 61,000 MW.

15 Coincident peaks are the amount of demand that the individual TAC areas contribute at the time of the overall California ISO system peak. Non-coincident peaks are the maximum peaks of each individual TAC areas, which do not necessarily occur at the same time.

16 The annual system peak is the point of highest demand experienced by the entire CAISO transmission system for a given year.

Figure 2: California Non-Coincident System Peaks by Planning Area in 2025



Source: CEC 2024 IEPR Update Planning Forecast

According to the 2024 IEPR Update Planning Forecast, the annual system peak for the California ISO territory in 2040 will be more than 66,000 MW. The annual non-coincident peaks for the IOU TAC areas within the California ISO control area will sum to more than 68,000 MW in 2040, and the annual non-coincident peaks for all California territories will sum to a total of nearly 85,000 MW.

Future Uncertainties

There are many uncertainties in forecasting electricity demand, the largest being climate change impacts, the adoption rates of transportation and building electrification, and large loads such as data centers.

Electrification of buildings and transportation will change energy-use patterns and uncertainties will need to be considered and monitored as electrification becomes more prevalent. These uncertainties include the rate of adoption of electric vehicles and heat pumps, battery storage and electric vehicle charging patterns, and load flexibility and DR. At the same time, utilities are considering rate strategies, such as real-time pricing, that encourage electrification and load shifting while ensuring grid reliability. As part of SB 846, the CEC set a load shift goal for the state. *The Senate Bill 846 Load-Shift Goal Report*[17] examines the potential for reducing load during peak demand hours. Future work will explore how that load can potentially be redistributed to best match supply.

17 *Senate Bill 846 Load-Shift Goal Report* available at https://www.energy.ca.gov/publications/2023/senate-bill-846-load-shift-goal-report.

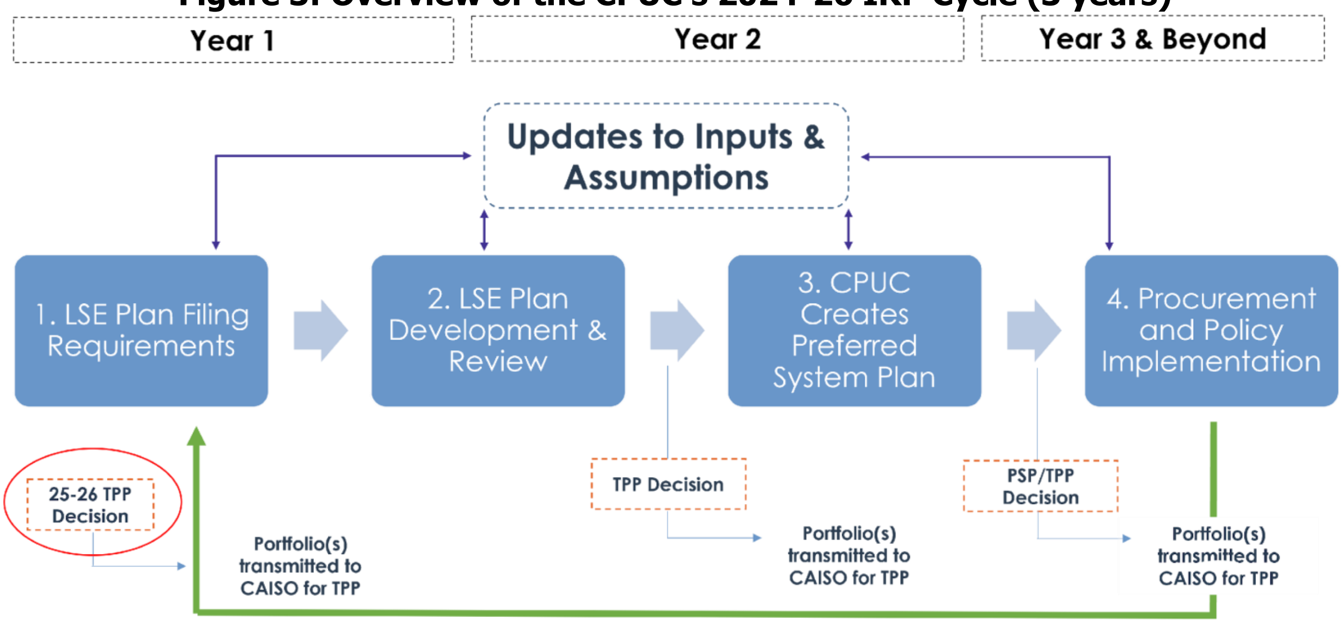
CHAPTER 5: Supply Forecast

Background

California has an Integrated Resource Planning (IRP) process that was established by Senate Bill 350 (De León, Chapter 547, Statutes of 2015) to plan for mid- and long-term procurement of energy resources. The process differs for CPUC-jurisdictional entities and non-CPUC-jurisdictional entities. The IRP process for CPUC-jurisdictional load serving entities (LSEs) succeeded the CPUC's longstanding Long-Term Procurement Planning process, established by Assembly Bill 57 (Wright, Chapter 835, Statutes of 2001). The CPUC IRP process aims to reduce the cost of achieving GHG reductions and other policy goals by looking across LSE boundaries and resource types to identify solutions to reliability, cost, or other concerns that might not otherwise be found. Separately from the CPUC IRP process, the 16 largest publicly owned utilities submit IRPs to the CEC every five years and are reviewed by CEC staff for consistency with Senate Bill 350 requirements.

The CPUC's IRP is a multi-step process, the major steps of which are laid out in Figure 3 below. The first half of an IRP cycle typically builds on the findings of the previous cycle. It is designed to provide analysis and guidance for those who provide power to the grid (LSEs) to plan for meeting their GHG, reliability, and cost objectives. The second half of the IRP cycle is designed to consider the portfolios and actions that each LSE proposes for meeting these objectives, and to allow the CPUC to review each LSE plan and aggregate their portfolios to develop a Preferred System Plan (PSP) portfolio, and to consider further related actions. The development and adoption of a PSP represents the final step of an IRP cycle.

Figure 3: Overview of the CPUC's 2024-26 IRP Cycle (3 years)



Source: CPUC Staff

CPUC IRP Planning Track

The CPUC is currently running the 2024-26 IRP Cycle. At this point in the planning cycle, it manages two related workstreams. First, to support development of a PSP with targeted adoption in 2027, the CPUC has initiated Step 1 of 4. CPUC staff are working to produce filing requirements for LSEs that meet statutory requirements for reliability and emissions reduction at lowest cost. As part of this IRP Cycle, the CPUC began a stakeholder process for updating its modeling inputs and assumptions in the first quarter of 2025. This inputs and assumptions development process will help the CPUC finalize the inputs and assumptions that underlie IRP modeling, including the modeling necessary to develop LSE filing requirements. Second, the CPUC also developed and vetted portfolios for study in California ISO's 2025-26 TPP, described in the following section.

2025-26 TPP Cycle

On February 20, 2025, the CPUC adopted the 2025-26 TPP portfolio in D.25-02-026.[18] This cycle's 2025-2026 TPP base case portfolio builds off the 2024-2025 TPP base case portfolio that the Commission adopted in D.24-02-047. If adopted, the base case will continue to facilitate the analysis of the transmission needed to bring over 60 gigawatts of new generation and storage resources online to cost-effectively achieve a 25 million metric ton greenhouse gas emissions level by 2035, while maintaining system reliability. By 2035, the 2025-2026 TPP base case portfolio is modeled to reduce greenhouse gas emissions by over 45 percent compared to the 2026's modeled 47 million metric ton target and surpasses the Senate Bill 1020 (Laird, Chapter 361, Statutes of 2022) target of 90 percent clean energy retail sales. This 2025-2026 portfolio continues to model decreased use of natural gas plants in the California ISO-system throughout the modeling timeframe, with a projected 71 percent decline in annual natural gas generation in terawatt-hours by 2035 as compared to the first modeled year, 2026. By 2040, modeled natural gas usage would be reduced by 80 percent from modeled 2026 usage. The decision also recommends that the California ISO study a sensitivity portfolio with a high upper bound for resources that require longer lead times to develop and come online, such as geothermal and offshore wind.

CPUC IRP Procurement Track

Overview of IRP Procurement Orders (D.19-11-016, D.21-06-035, and D.23-02-040)

Through three decisions in the IRP proceeding, the CPUC has ordered 18,800 MW net qualifying capacity (NQC) of procurement from CPUC-jurisdictional LSEs from 2021-2028.[19]

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18 California Public Utilities Commission. Decision Transmitting Electricity Resource Portfolios to the California Independent System Operator For 2025 2026 Transmission Planning Process. Rulemaking 20-05-003. February 20, 2025. Available at: https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=557879249

19 The IRP procurement order decisions, D.19-11-016, D.21-06-035, and D.23-02-040, are available on the IRP Procurement track website here: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track

The 3 decisions ordering procurement, D.19-11-016, D.21-06-035 Mid Term Reliability (MTR), and D.23-02-040 (Supplemental MTR), are summarized in Table 2.

Table 2: IRP Procurement Orders (MW NQC)

CPUC Orders	Total	2021	2022	2023	2024	2025	2026	2027	2028
D.19-11-016 Applies to 25 LSEs since 18/43 LSEs opted out	3,300	1,650	825	825	n/a	n/a	n/a	n/a	n/a
D.21-06-035[20] (MTR) Applies to all CPUC-jurisdictional LSEs. No opt-outs allowed	11,500	n/a	n/a	2,000	6,000	1,500	n/a	n/a	2,000
D.23-02-040 (Supplemental MTR) Applies to all CPUC-jurisdictional LSEs. No opt-outs allowed	4,000	n/a	n/a	n/a	n/a	n/a	2,000	2,000	n/a
Cumulative Procurement Ordered	18,800	1,650	2,475	5,300	11,300	12,800	14,800	16,800	18,800

Source: CPUC Decision 19-11-016, Decision 21-06-035, Decision 23-02-040, Decision 24-02-047

Compliance with CPUC 2019 Procurement Order (D.19.11-016) Near Term Reliability and (D.21-06-035) Mid Term Reliability

CPUC staff released the Summary of Compliance with IRP Order D.19-11-016 and Mid-Term Reliability (D.21-06-035) Procurement using the December 2023 Data Filing.[21] CPUC staff are

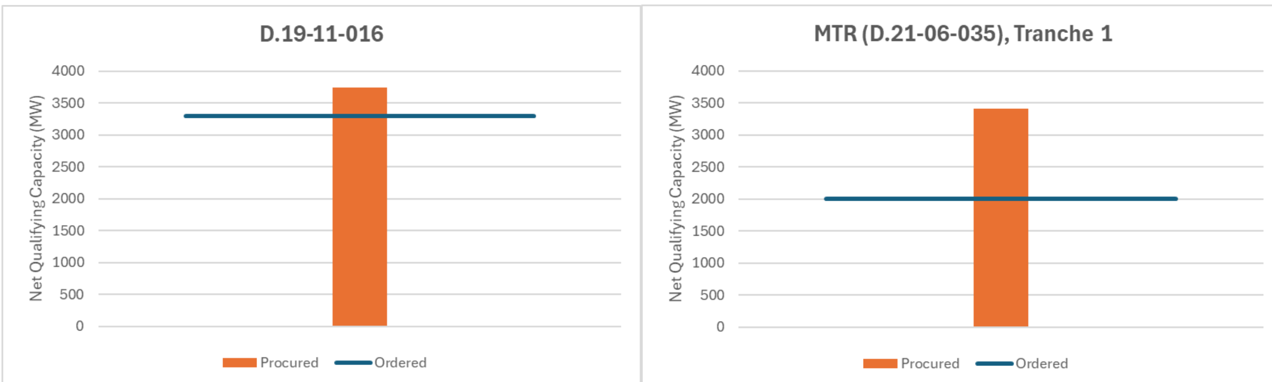
20 (1) D.21-06-035 required 2,500 of the 9,000 MW required between 2023-2025 be zero-emitting generation, generation paired with storage, or demand response resources for Diablo Canyon Replacement Firm Zero Emitting (DCR Firm ZE). (2) D.21-06-035 required 2,000 MW of Long-Lead Time Procurement by 2026, with an option to extend to 2028: 1,000 MW of long-duration storage and 1,000 MW of firm zero-emitting. D.23-02-040 automatically extends the procurement obligation to 2028. D.24-02-047 provides additional options to extend those deadlines until 2031 on a project-by-project basis.

21 California Public Utilities Commission. Summary of Compliance with Integrated Resource Planning (IRP) Order D.19-11-016 and Mid Term Reliability (MTR) D.21-06-035 Procurement, December 2023 Data Filings. Rulemaking 20-05-003. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/irp12123compliancereport.pdf.

monitoring LSE Procurement Progress with IRP Procurement Orders. As of the December 1, 2023, IRP Compliance Filings, LSEs are reporting:

- 3,747 MW NQC of total procurement toward D.19-11-016, 447 MW NQC above the 3,300 MW NQC obligation (left graph of Figure 4)
- 3,407 MW NQC of procurement towards MTR that is verified online, 1,407 MW NQC above the 2,000 MW NQC obligation for Tranche 1 (2023) (right graph of Figure 4)
- 10,845 MW NQC of forecasted procurement towards MTR by 2027
- 1,074 MW NQC of forecasted long-lead time procurement by 2028.

Figure 4: Ordered D.19-11-016 and D.21-06-035 Procurement Compared to Verified LSE Procurement as of December 2023



Source: CPUC

More comprehensive information about compliance with IRP procurement orders can be found in the CPUC Summary of Compliance with Integrated Resource Planning (IRP) Order D.19-11-016 and MTR D.21-06-035 Procurement.[22]

Estimates of Resources Under Contract to CPUC-Jurisdictional LSEs

This section updates the estimated capacity under contract to CPUC-jurisdictional LSEs through 2028. Table 3 through Table 8 include resources being developed for compliance with IRP procurement orders as well as procurement for LSE compliance with Renewables Portfolio Standard (RPS) and procurement the CPUC approved in the Emergency Reliability proceeding.

All totals provided below represent the cumulative LSE-reported September NQC under contract to CPUC-jurisdictional LSEs. Developers often aim to bring projects online in advance of contractual obligations. The data underlying the expected projects can be challenging to track. A new resource can have several expected on-line date changes, multiple off-takers, several on-line dates for different tranches of a project, multiple technologies in various configurations, changes to project sizing, changes to project naming, and multiple California ISO resource identification numbers, once they come online.

Furthermore, LSE procurement activity is still ongoing to meet existing CPUC IRP procurement orders; some of the existing contracts will be delayed, and other contracts will be added,

22 Ibid.

which is consistent with the cycle of energy project development. Table 3 to Table 8 do not include all known resources in development in California, nor in all of California ISO's footprint, and represent only resources known to be under contract to CPUC-jurisdictional LSEs between 2025 and 2028, as of November 2024. These totals are subject to change as the CPUC receives new data from LSEs, conducts field calls with developers and IOUs interconnection departments, and continues to evaluate the data. For each TAC area,[23] the following tables describe MW of capacity — measured in terms of NQC for the month of September — that are forecast to come online each quarter through the end of 2028.

Procurement by TAC Area

Table 3: Estimated September NQC (MW) by TAC Area 2025 through 2026

TAC Area	2025 Q1	2025 Q2	2025 Q3	2025 Q4	2026 Q1	2026 Q2	2026 Q3	2026 Q4
East Central	687	1,116	1,275	1,825	1,961	2,979	3,012	3,221
North	384	613	1,144	1,330	1,336	1,642	1,675	1,993
South	36	588	751	751	751	892	892	999
Other	16	1,113	1,228	1,341	1,613	2,247	2,494	2,724
Total	**1,123**	**3,430**	**4,399**	**5,247**	**5,662**	**7,759**	**8,074**	**8,937**

Source: CPUC Staff Aggregation of January 2025 LSEs' Procurement Status Reports

Table 4: Estimated September NQC (MW) by TAC Area 2027 through 2028

TAC Area	2027 Q1	2027 Q2	2027 Q3	2027 Q4	2028 Q1	2028 Q2	2028 Q3	2028 Q4
East Central	3,611	5,358	5,358	5,358	5,376	5,929	5,929	5,929
North	2,009	2,977	2,977	3,720	3,720	3,826	3,826	3,826
South	999	1,074	1,074	1,148	1,148	1,198	1,198	1,198
Other	2,913	3,239	3,689	3,722	3,727	3,982	3,982	4,001
Total	**9,532**	**12,648**	**13,098**	**13,948**	**13,972**	**14,935**	**14,935**	**14,955**

Source: CPUC Staff Aggregation of January 2025LSEs' Procurement Status Reports

23 A Transmission Charge Access area is a designated geographical region where a single Participating Transmission Operator (PTO) - an entity that manages transmission infrastructure - operates. Major examples of PTOs with their own TAC areas include, but are not limited to: PG&E, SCE, and SDG&E.

Procurement by LSE Type

Table 5: Estimated September NQC (MW) by LSE Type 2025 through 2026

LSE Type	2025 Q1	2025 Q2	2025 Q3	2025 Q4	2026 Q1	2026 Q2	2026 Q3	2026 Q4
IOU[24]	717	2,278	2,835	3,418	3,749	4,722	4,817	4,887
Non-IOU	406	1,152	1,565	1,830	1,913	3,037	3,257	4,050
Total	**1,123**	**3,430**	**4,399**	**5,247**	**5,662**	**7,759**	**8,074**	**8,937**

Source: CPUC Staff Aggregation of January 2025LSEs' Procurement Status Reports

Table 6: Estimated September NQC (MW) by LSE Type 2027 through 2028

LSE Type	2027 Q1	2027 Q2	2027 Q3	2027 Q4	2028 Q1	2028 Q2	2028 Q3	2028 Q4
IOU	5,277	6,665	7,115	7,115	7,115	7,765	7,765	7,765
Non-IOU	4,255	5,982	5,982	6,832	6,856	7,170	7,170	7,189
Total	**9,532**	**12,648**	**13,098**	**13,948**	**13,972**	**14,935**	**14,935**	**14,955**

Source: CPUC Staff Aggregation of January 2025LSEs' Procurement Status Reports

Procurement by Resource Type

Table 7: Estimated September NQC (MW) by Resource Type 2025 through 2026

Resource Type	2025 Q1	2025 Q2	2025 Q3	2025 Q4	2026 Q1	2026 Q2	2026 Q3	2026 Q4
Solar	343	795	933	1,013	1,225	1,225	1,230	1,230
Battery	746	2,437	2,982	3,614	3,743	5,501	5,652	5,917
Paired/hybrid	16	171	451	574	574	857	857	1,226
Wind	16	16	16	16	66	95	253	413
Geothermal	-	6	6	16	40	68	68	138
Biomass/biogas	2	5	10	13	13	13	13	13
Total	**1,123**	**3,430**	**4,399**	**5,247**	**5,662**	**7,759**	**8,074**	**8,937**

Source: CPUC Staff Aggregation of January 2025LSEs' Procurement Status Reports

24 Investor-owned utility

Table 8: Estimated September NQC (MW) by Resource Type 2027 through 2028

Resource Type	2027 Q1	2027 Q2	2027 Q3	2027 Q4	2028 Q1	2028 Q2	2028 Q3	2028 Q4
Solar	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Battery	6,157	8,610	9,060	9,803	9,803	10,446	10,446	10,446
Paired/ hybrid	1,308	1,871	1,871	1,945	1,945	1,978	1,978	1,978
Wind	498	498	498	498	498	498	498	498
Geothermal	176	276	276	309	333	621	621	640
Biomass/ biogas	13	13	13	13	13	13	13	13
Total	**9,532**	**12,648**	**13,098**	**13,948**	**13,972**	**14,935**	**14,935**	**14,955**

Source: CPUC Staff Aggregation of January 2025LSEs' Procurement Status Reports

CHAPTER 6:
Tracking Project Development

Since 2020, California energy entities have taken steps to address the potential imbalances between the electrical supply and demand in California, in particular as the electric grid transforms to rely on a high penetration of renewables and zero-carbon resources. The CEC, CPUC, and California ISO substantially increased coordination and developed the TED Task Force with the Governor's Office of Business and Economic Development (GO-Biz) to track new clean energy projects under development to help overcome barriers to their completion. Table 9 shows a list of resource tracking efforts and their frequency. The priority focus for the TED Task Force is near-term projects, defined as those that can come online in the next one to three years.

Tracking Energy Development Task Force

Currently, the TED Task Force is tracking more than 150 projects expected to come online over the next several years. The TED Task Force members are conducting an increased number of meetings with IOUs, increasing availability for direct discussions with local permitting agencies and developers, and engaging with other state and federal agencies with regulatory oversight of permitting and project siting. The TED Task Force continues to assist as needed when issues arise and collect as much information as possible that will help us better understand the problems and enable us to find global solutions.

Table 9: Resource Tracking Efforts

Frequency	Action
Ongoing	TED Task Force conducts outreach to developers with a large number of projects under development to review status of projects and issues, if any.
Ongoing	Ad-hoc meetings with developers and others about specific project challenges.
Weekly	TED Task Force meets weekly to review issues/developer requests for assistance and provide updates.
Monthly	CPUC receives and compiles submitted data from LSEs on resources under contract for the near-term.
Monthly	CPUC compiles data on new MW online.
Monthly	CPUC holds calls with IOU interconnection teams to review projects, pinpoint discrepancies, and identify operational areas for improvement.
Quarterly	TED Task Force provides progress update to SB 846 Joint Agency Reliability Report.
Biannual	California ISO, in conjunction with CPUC, hosts the Transmission Development Forum to discuss delays to transmission projects including network upgrades.

Source: GO-Biz

Renewable Energy Project Development Challenges in 2024

Renewable energy project deployment continues to face many of the same challenges as previously reported. These challenges include supply chain shortages for critical equipment, interconnection delays, and permitting and siting approval delays. A project may encounter multiple issues over the course of deployment. Table 10 lists the most cited issues/problems facing developers.

Table 10: Challenges to Renewable Energy Project Deployment

Permitting Delays	Supply Chain Issues	Interconnection Delays
• Local, state and/or federal reviews • Staffing capacity/turnover • Community opposition	• Global competition including from other industries for same technology (i.e. battery) • Longer lead time for circuit breakers and transformers	• Network upgrades (sometimes linked to supply chain issues) • Inverter problems • Deliverability • Grid testing and synchronization • Obtaining easements to the point of connection to substation

Source: GO-Biz

Battery energy storage system projects continue to be a topic of concern to local jurisdictions due to fire safety risks, even as these projects become more critical to helping California maintain grid stability. Recognizing that battery energy storage technology is evolving, as well as California's experience in deploying these projects, it is critical that developers, local jurisdictions and other stakeholders work collaboratively to develop a better and common understanding of how battery energy storage system technology can be designed and installed properly to operate safely and reliably. The TED Task Force has engaged with several industry associations to increase availability of educational and safety resources as well as deepening engagement with local governments, including those seeking to update and/or create renewable energy ordinances for their jurisdiction. Most recently, TED Task Force worked with the Rural County Representatives of California, California State Association of Counties, and the League of California Cities to host a battery energy storage system permitting webinar.

Additionally, the Governor convened the Battery Storage Collaborative, an inter-agency working group to review the battery storage landscape for opportunities to improve battery safety, including technology development and best practices for outreach and education, permitting and installation of battery projects, inspection and monitoring practices, and first responder training and safety. The collaborative enhances coordination among state agencies, many of which are already working on these areas. The collaborative brings together multiple state agencies and departments with regulatory and industry expertise, including the California Air Resources Board, CEC, CPUC, California Department of Forestry and Fire Protection – Office of the State Fire Marshal, Governor's Office of Emergency Services, and GO-Biz.

Renewable Energy Projects Deployed in 2024

Despite the challenges to deployment, new projects continue to come online and are providing power to millions of Californians. There were 110 projects totaling 7,052 MW that came online in 2024. Figure 5 shows a map, as well as a list, of the top 10 counties by MW, of where these projects were deployed. Additional information on energy projects online and operating can be found on the state's infrastructure website.[25]

Figure 5: 2024 Top 10 Counties by MWs Deployed

2024 | Top Counties

County	Deployed MWs	Deployed Projects
Riverside	2,549	21
Fresno	740	11
Kern	703	13
San Bernardino	550	9
Imperial	399	3
Stanislaus	387	7
Los Angeles	352	12
Solano	230	1
Tulare	86	3
San Diego	76	10

Source: GO-Biz

New resources span a range of technology types. Table 11 summarizes MW and projects added in 2024 by technology. It summarizes the same data points for cumulative additions from 2020 to 2024.

25 Building California. https://build.ca.gov/.

Table 11: Cumulative New Resource Additions, in 2024 and for January 2020 through December 9, 2024

Technology Type	Nameplate Capacity (MW)	Estimated Sept. NQC MW	Number of Projects	Nameplate Capacity (MW)	Estimated Sept. Net Qualifying Capacity (NQC) MW	Number of Projects
	2024	2024	2024	2020-2024	2020-2024	2020-2024
Storage	3,678	3,180	55	9,499	8,983	136
Solar	2,227	331	40	7,338	2,176	116
Hybrid (Storage/ Solar)	503	286	4	1,839	1,253	24
Wind	260	63	2	1,118	265	22
Geothermal	41	31	1	41	31	1
Biomass, Biogas, Hydro	1	-	1	39	0	11
Subtotal, New SB 100 Resources, California ISO	**6,709**	**3,892**	**103**	**19,874**	**12,708**	**310**
Natural Gas Capacity Additions**	63	13	5	1,735	1,474	17
Total New Resources, California ISO	**6,772**	**3,905**	**108**	**21,609**	**14,182**	**327**
New Imports, Pseudo-Tie or Dynamically Scheduled	280	201	2	1,751	927	14
Total New Resources, including Imports	**7,052**	**4,105**	**110**	**23,360**	**15,109**	**341**

Source: California ISO Master Control Area Generating Capability Lists and CPUC NQC Lists, January 1, 2024, to December 31, 2024
* Some new projects have not yet made it onto the CPUC NQC Lists and have not yet been assigned NQC. Future reports will include updated NQC amounts for these resources.
** MW in this row come from increases in the maximum power output of existing units, not entirely new resources.

Assessment of Transmission System Delays

The unprecedented number of renewable and storage resources seeking to interconnect to California's transmission system, coupled with the long timelines for transmission development, have led to an urgent need to assess and resolve bottlenecks in the transmission development process, and to prioritize the transmission projects that have the highest impact on reliability and are preventing the largest amounts of generation and storage from coming online on time.

Senate Bill 1174 Requirement

Senate Bill 1174 (Hertzberg, Chapter 229, Statutes of 2022) requires each electrical corporation that owns electrical transmission facilities to annually prepare and submit to the CPUC a report on any changes to previously reported in-service dates of transmission and interconnection facilities necessary to provide transmission deliverability to eligible renewable energy resources or energy storage resources that have executed interconnection agreements. The collected data via the SB 1174 requirement provides the public more information about delays to generation and storage project development that may affect future electric system reliability.

Data Request & Narrative Statements

The IOUs, including SDG&E, PG&E, and SCE, reported data on their portfolio of in-development transmission projects that are delayed and the in-development generation and storage resources that depend on these transmission projects. IOUs also provided narrative statements on the impact of transmission development delays on RPS compliance obligations, including a discussion of the general magnitude and causes of delays, challenges to overcoming them, and potential solutions. Analysis of this data and narrative statements was incorporated into the 2024 RPS report to the Legislature and will be included in each annual RPS report going forward. Some of the conclusions of this analysis are summarized below.

Analysis Objectives

The objectives of CPUC staff's analysis include:

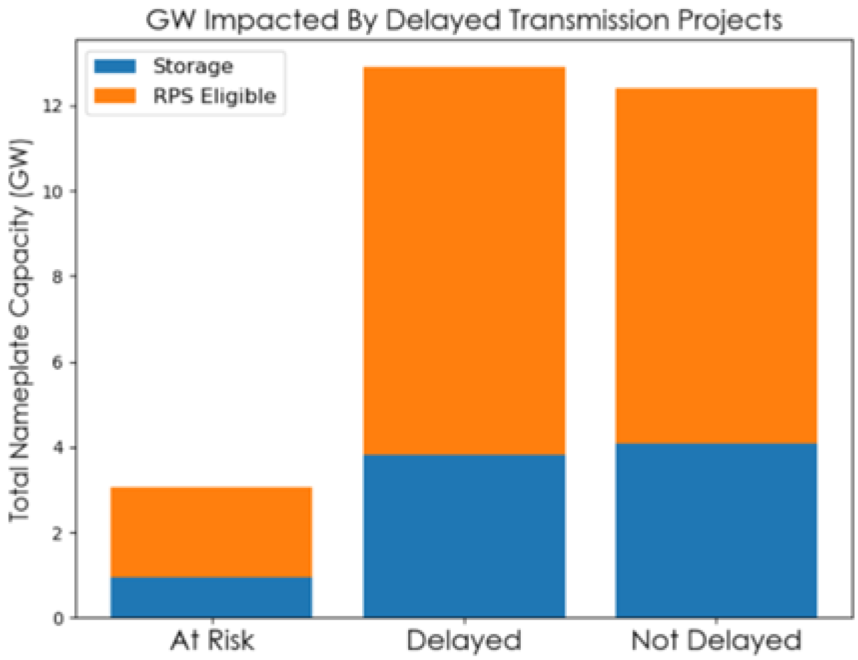
- Identifying how many gigawatts of generation and storage resources are projected to be delayed or at risk of becoming delayed by the delayed transmission projects that these resources depend on.
- Identifying specific transmission projects of concern (that are holding up the largest number of GW of resources).
- Understanding the median delay time for each delay reason.

Conclusions

Data from the SB 1174 reporting requirements revealed the following insights:

- PG&E and SCE reported approximately 28.4 GW of RPS-eligible and storage resources that are dependent on delayed transmission projects and network upgrades in their portfolios. Of these 28.4 GW, CPUC staff determined that approximately 16 GW are projected to be delayed or are at risk of becoming delayed due to the delayed transmission projects that these resources depend on. Figure 6 shows the breakdown of the affected 28.4 MW classified as at risk, delayed, and not delayed, for storage and RPS-eligible projects, respectively.

Figure 6: Renewable Generation and Storage Resources (28.4 GW) as of September 2024 Dependent on Delayed Transmission Projects.



Source: 2024 RPS Report, Figure 13.

- SDG&E reported no delayed transmission projects.
- The longest reported transmission project delays are associated with permitting (federal, state, and local), but the delays impacting the largest number of GW of generators are associated with scope and design changes, and reprioritization (for SCE), and land rights and materials (for PG&E).
- Certain specific delayed transmission projects have a large number of GW of resources behind them. For SCE, a large number of resources are projected to be delayed behind delayed Centralized Remedial Action Schemes,[26] while for PG&E the biggest impacts come

26 A CRAS is a centralized transmission element monitoring and control system, which can lower or trip off generation/load when needed to maintain reliable operation when faults occur. CRAS can often be used in place of larger reliability upgrades, such as new substations and lines.

from transmission projects delayed due to materials procurement problems, and trouble obtaining land rights to reroute lines.

Actions

Utility-reported data via the SB 1174 requirement informs state agency work to reduce bottlenecks to project development.

- The SB 1174 transmission system assessment identifies the reasons for transmission delays that have the highest impact on generation and storage resources and that are associated with the largest changes in in-service dates.
- This information will be used by the CPUC, California ISO, TED Task Force, developers, utilities, and law makers to focus their attention on specific problem projects, and general areas where transmission system process improvements are needed.

CHAPTER 7:
Near-Term Reliability Assessment and SB 1020

CEC staff conducted the Near-Term Reliability Assessment used for this chapter, which is consistent with the same assessment used in past SB 846 quarterly reports.[27] Chapters 8 and 9 provide two probabilistic analyses for the mid- and long-term horizons. The analysis in this chapter compares an hourly evaluation of anticipated supply against the projected hourly demand for the peak day of each month, July through September. The comparison stacks the resources expected to be available in each hour and compares the total against the projected demand plus a 17 percent reserve margin (referred to as the current RA planning standard, or planning standard), equivalent events to 2020 and 2022 peaks, and those situations under high fire risk. This assessment identifies the max hourly shortfall by year for each scenario. The stack analysis is used primarily for understanding the extent of contingency resources that might be needed to support grid reliability in extreme events.

Stack Analysis

The following is a summary of the key input assumptions used in this analysis.

- **Demand**: The hourly demand scenario used for this analysis is the Final 2024 CED Planning Forecast.[28] Additional information on this can be found in CHAPTER 4: Demand Forecast.
- **Conditions Relative to the 1-in-2 Forecast**: This analysis explores 3 system conditions (Table 12).
- **Current RA Planning Standard**: Assumes a 17 percent reserve margin, effective beginning in 2024.
- **2020 Equivalent Event**: Includes 50 percent higher forced outages and demand variability, requiring a 22.5 percent reserve margin above the forecasted peak demand.
- **2022 Equivalent Event**: Increases demand variability to 12.5 percent, aligning with the September 2022 event, and requires a 26 percent reserve margin above the forecasted peak demand.

All these conditions were also evaluated under a coincidental fire risk that reduces the total import capacity by 4,000 MW, similar to what the state experienced in 2021 during the Bootleg Fire in Oregon.

27 California Energy Commission, " Summer Reliability" is available at https://www.energy.ca.gov/data-reports/california-energy-planning-library/reliability/summer-reliability

28 California Energy Commission, "2023 CED Planning Scenario," is available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=253682&DocumentContentId=88934.

Table 12: System Conditions Defined

Condition Relative to 1-in-2 Forecast	Operating Reserves	Outages	Demand Variability	Coincidental Fire Risk (MW)	Notes
Current RA Planning Standard – 17%	6%	5%	6%		17% beginning 2024
2020 Equivalent Event: Additional capacity needed to weather heat event like 2020	6%	7.5%	9%	4,000	9% higher demand over median, and 2.5% higher levels of outages
2022 Equivalent Event: Additional capacity needed to weather heat event like 2022	6%	7.5%	12.5%	4,000	12.5% higher demand over median, and 2.5% higher levels of outages

Source: CEC Staff – 1/20/2023 Lead Commissioner Workshop

- **California ISO 2025 NQC List:**[29] Used for existing resources in the 2025 summer stack analysis.
- **Resource Updates**: Two resource builds are used in this analysis. The first is based on mid-term reliability procurement with additional resource builds. The second is based on California ISO interconnection queue data.[30] For the purposes of the stack analysis, the mid-term reliability procurement is used for the 10-year outlook for years 2026 to 2035 while the near-term 2025 summer outlook used the California ISO queue data.
- **Demand Response:** The IOU DR monthly projections are published by the CPUC in their Load Impact Protocol Reports.[31] These numbers are used in addition to the CPUC's 2024 NQC list for the baseline DR. The DR numbers in Table 13 are assumed to be fixed to 2035 because the IOUs do not forecast or report DR numbers to a 10-year horizon. Future studies will continue to make improvements on the representation of DR and improve alignment between the CPUC and CEC characterization of DR in their analyses.

29 California ISO. *Final Net Qualifying Capacity Report for Compliance Year 2025*. https://www.caiso.com/documents/final-net-qualifying-capacity-report-for-compliance-year-2025.xlsx

30 California ISO. *Generator Interconnection Resource ID Report*. https://www.caiso.com/Documents/Generator-Interconnection-Resource-ID-Report.xlsx

31 California Public Utilities Commission, *Load Impact Protocol ReportsResource Adequacy Compliance Materials*, available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials

Table 13: 2025 Aggregated DR Numbers Reported by IOUs

	July	August	September
Demand Response (MW)	1028	1047	1033

Source: CEC Staff with Load Impact Protocol Report data

- **RA Imports:** Standard imports are set to 5,500 MW in every hour. The 5,500 MW of fixed RA imports was set in consultation with California ISO and CPUC. The value is consistent with modeling approaches used by both entities. In addition to the 5,500 MW of RA imports, the stack analysis includes contributions from new out-of-state wind resources on new transmission interconnected directly into the California ISO above this total RA import number, consistent with CPUC modeling for the PSP.
- **Wind and Solar:** The CEC uses hourly shapes to estimate generation from onshore wind and solar located within the California ISO BA footprint. These are based on historic generation on high-load days between 2014 and 2024. Out-of-state wind resources are included in the stack based on the expected effective load carrying capability values for those resources.[32]
- **Battery Storage**: Battery storage is limited to 4 hours of total discharge within a 24-hour stack. Storage is optimized so that the shortfall in any given hour is equal or less than the capacity shortfall at net peak. The full nameplate capacity for battery storage is included in the stack, rather than the expected effective load carrying capability values because discharge limits are directly incorporated. See Hourly Wind, Solar, and Battery Shapes, below for additional information.
- **Contingency Resources and Retirements**: The stack analysis reflects that the Once-Through-Cooling (OTC) plants have been removed from the supply stack and considered as contingency resources under the SRR and that DCPP retires based on new retirement dates of October 31, 2029 (Unit 1) and October 31, 2030 (Unit 2). DCPP Units 1 and 2 are assumed to be offline by end of 2030, resulting in 2,280 MW of net qualifying capacity reduction to the supply stack.

Supply Delay Scenarios

Given that there are uncertainties in when new clean energy resources may come online (for example, supply chain, construction, interconnection, and permitting), the analysis looks at different scenarios that might affect timely online dates. The delay scenarios assume that each year a percentage of resources will be delayed in the current summer but will be available in the next summer. Scenarios were ran for a 0 percent delay, 20 percent delay and a 40 percent delay.

MTR Procurement Order and Additional Resource Builds

The CPUC provided information on the projected new resources based on the total resource build for the 25 MMT core portfolio based on the proposed 2023 PSP portfolio from the

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32 California Public Utilities Commission, *2023 CPUC IRP PSP – Resolve Public Release v1.0.2*, available at: https://files.cpuc.ca.gov/energy/modeling/LTPP/2023%20CPUC%20IRP%20PSP%20-%20Resolve%20Public%20Release%20v1.0.2.zip

October 2023 Administrative Law Judge Ruling.[33] This resource build portfolio includes resources counting towards MTR targets and additional resource builds beyond the MTR. The total nameplate capacity added for this scenario is provided in Table 14.

Table 14: Total Builds in 25 MMT Core Portfolio (Nameplate MW)

Resource Type	2026*	2027*	2028*
Coal	0	0	0
Combined Cycle Gas Turbine	0	0	0
Peaker	0	0	0
Reciprocating Engine	0	0	0
Steam	0	0	0
Combined Heat and Power	0	0	0
Nuclear	0	0	0
Geothermal	765	941	1118
Biomass/Biogas	0	168	336
Hydro	0	0	0
In-State Wind	512	711	909
Out-of-State Wind	250	1053	1856
Solar	1582	3032	4481
Battery storage (4-hr)	2784	3630	4476
Battery storage (8-hr)	526	797	1069
Pumped Hydro Storage	0	239	477
Advanced Compressed Air Energy Storage	0	0	0
Shed Demand Response	0	0	0
Total	**6,419**	**10,570**	**14,722**

*Values are cumulative and in nameplate capacity.

Source: CPUC Data

The resource needs established by the CPUC's procurement orders were developed using the 2020 CED Mid-Electricity Demand update[34] and only include procurement through 2028. The option to delay procurement of the long lead time resources, which are assumed to be geothermal and 8-hour batteries, from 2026 to 2028 is assumed to be taken. Thus, in this scenario, the long lead time resources that are not already under contract arrive in 2028.

Hourly Wind, Solar, and Battery Shapes

Hourly wind shapes and solar shapes were developed from California ISO-wide aggregated generation profiles, normalized to installed capacity, for each hour from 2014-2024. Using

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33 California Public Utilities Commission, *2023 CPUC IRP PSP – Resolve Public Release v1.0.2*, available at: https://files.cpuc.ca.gov/energy/modeling/LTPP/2023%20CPUC%20IRP%20PSP%20-%20Resolve%20Public%20Release%20v1.0.2.zip

34 Bailey, Stephanie, Nicholas Fugate, and Heidi Javanbakht. 2021. *Final 2020 Integrated Energy Policy Report Update, Volume III: California Energy Demand Forecast Update*. California Energy Commission. Publication Number: CEC-100-2020-001-V3-CMF.

historic hourly demand data from the California ISO OASIS portal, the median wind generation value for each hour of the day was calculated based on the five highest-load days of each month for each year 2014-2024. The 20th percentile for the wind generation value is calculated similarly. The profiles are a weighted average of the median and the 20th percentile, with 80 percent of the weight going to the median and 20 percent to the 20th percentile. This weighting method is similar to the NQC approach for projecting non-dispatchable hydro capacity.

$$\text{Hourly Profile} = (0.2 \times 20^{th} \text{ Percentile}) + (0.8 \times \text{Median})$$

Battery storage and long duration storage are optimized so that the energy shortfall does not result in numbers higher than the capacity shortfall. The profile is created in five steps:

- First, find the capacity shortfall. This is the highest shortfall in any hour with the batteries discharging at full capacity.
- Then, spread the battery discharge out so that in any hour that has a shortfall without battery discharge, the shortfall in that hour is less than or equal to the capacity shortfall.
- If there is battery capacity remaining after step 2, the battery discharge is used to eliminate the smallest hourly shortfall or reduce it as much as the capacity and power of the batteries allows.
- Step 3 is repeated until the battery discharge reaches 4 total hours.
- If every hour has either no shortfall or the maximum hourly battery discharge before total discharge reaches 4 hours, the remaining discharge is split evenly between the 4 and 10 PM hours that have not reached maximum hourly discharge.

Table 15 shows the hourly profile used for solar, wind and battery resources. While the solar and wind profiles remain unchanged throughout the analysis, the battery profile changes to reduce the shortfalls. Therefore, the battery profile in Table 15 is for 2024 September peak hours, which was created using the California ISO supply case with a 40 percent delay. The California ISO supply scenario with a 40 percent delay is the extreme case in 2024; thus, the battery profile is optimized to reduce the shortfalls as much as possible across all critical hours.

Table 15: Wind, Solar, and Battery Hourly Profiles

Time (PDT)	Jul - Wind	Aug - Wind	Sep - Wind	Jul - Solar	Aug – Solar	Sep - Solar	Jul - Battery	Aug - Battery	Sep - Battery
4PM-5PM	0.46	0.35	0.18	0.56	0.55	0.41	0.39	0.48	0.35
5PM-6PM	0.49	0.40	0.21	0.32	0.25	0.10	0.42	0.51	0.66
6PM-7PM	0.51	0.42	0.25	0.07	0.03	0.00	0.77	0.85	1.00
7PM-8PM	0.54	0.47	0.27	0.00	0.00	0.00	1.00	0.98	1.00
8PM-9PM	0.55	0.49	0.28	0.00	0.00	0.00	0.84	0.71	0.64
9PM-10PM	0.56	0.50	0.28	0.00	0.00	0.00	0.58	0.48	0.35

Source: CEC staff with California ISO data

Summer Resource Stack Analysis Annual Results

This assessment compares an hourly projection of anticipated supply against the projected hourly demand, plus the reserve margin, for the peak day of each month (July through September). The 17 percent planning reserve margin (current resource adequacy planning standard) represents average conditions, while 22.5 and 26 percent planning reserve margins are comparable to elevated conditions experienced during the 2020 and 2022 heat events, respectively. The annual results discussed are the maximum capacity shortfalls found in each of the deterministic scenarios introduced above, within each reliability year (defined as year ending September 30). It should be noted that the deterministic scenarios are not directly tied to any particular probability; however, insights can be drawn from the results relative to one another.

2025 Expected New Resources

This report introduces a change in the new resource counting conventions. Due to the uncertainty in new resource development, staff modified the counting conventions to use a more conservative approach by excluding new resources that show no indication of getting close to the commercial operations date. In this report, the expected new resources consist of resources with testing status (SYNC), partially online status, Active queue resources that have an NQC value assigned, and resources that achieved online operations but not shown for resource adequacy. The stack analysis in this report was conducted using a conservative new resource forecast as shown in Table 16. The conservative forecast adds more than 2,100 MW of new capacity by September.

Table 16: Expected New Resource Additions – 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**	**2,115**

Source: California ISO New Resource Implementation. Accessed 3/27/2025.

California ISO Area: Updated Resource Stack for Summer 2025

As shown in Table 17, 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 and/or scheduling coordinator modifications of NQC values for existing resources since the last report. Additionally, new battery capacity projections increased by more than 300 MW, while solar capacity grew by over 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 17: 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**[35]	**46,152**[36]	▲**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**

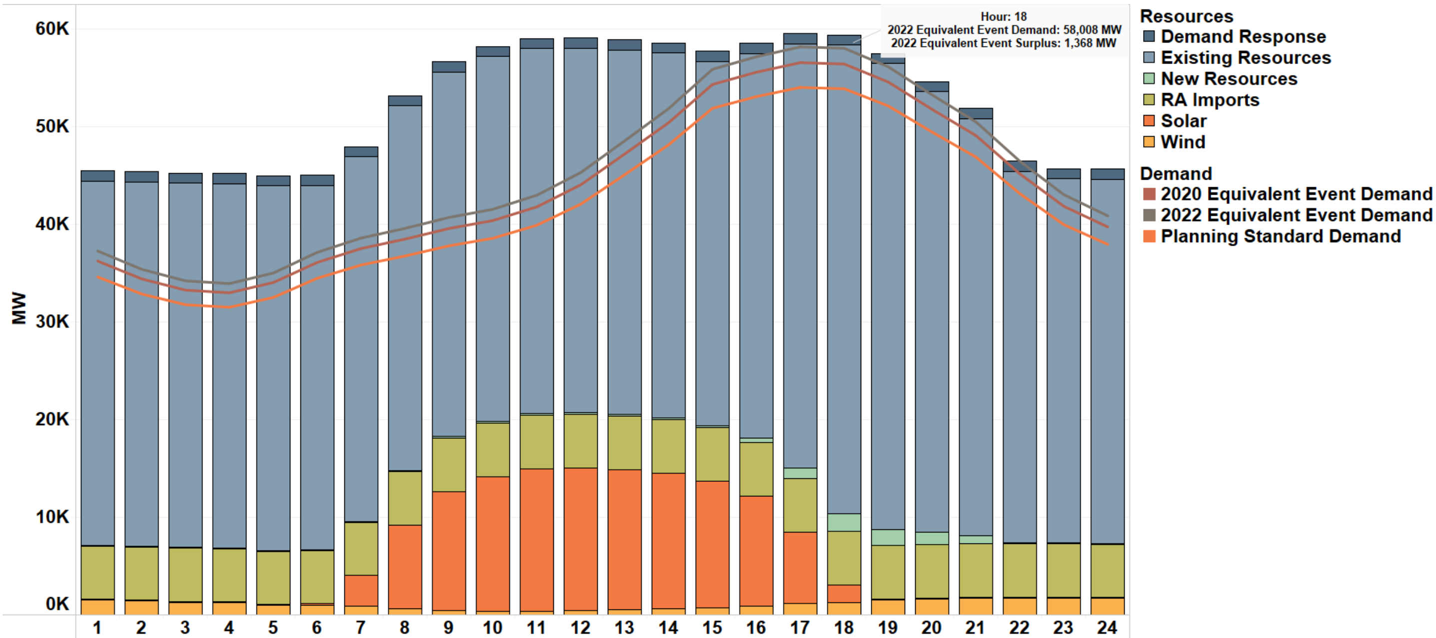
Source: CEC staff with California ISO data

Using data sourced in March 2025 for the summer 2025 stack analysis, Figure 7 to Figure 9 shows that there is enough supply to meet demand under all conditions, including extreme weather events similar to 2022. The analysis shows that, under the most severe heat event scenario, a 2022-equivalent heat event in September, there is an estimated surplus of 1,300 MW during the peak demand hour. With a 40% delay in resource development, the system still maintains a surplus of more than 700 MW during the same peak hour as shown on Figure 9. This is a big improvement compared to previous years, where shortages were expected under extreme conditions. The results highlight the progress made with new resource development and state-procured backup measures to ensure reliability during peak demand. This does not account for coincident wildfire risk to transmission, which is discussed in the next section.

35 For 2024 summer using 2023 California Energy Demand Data

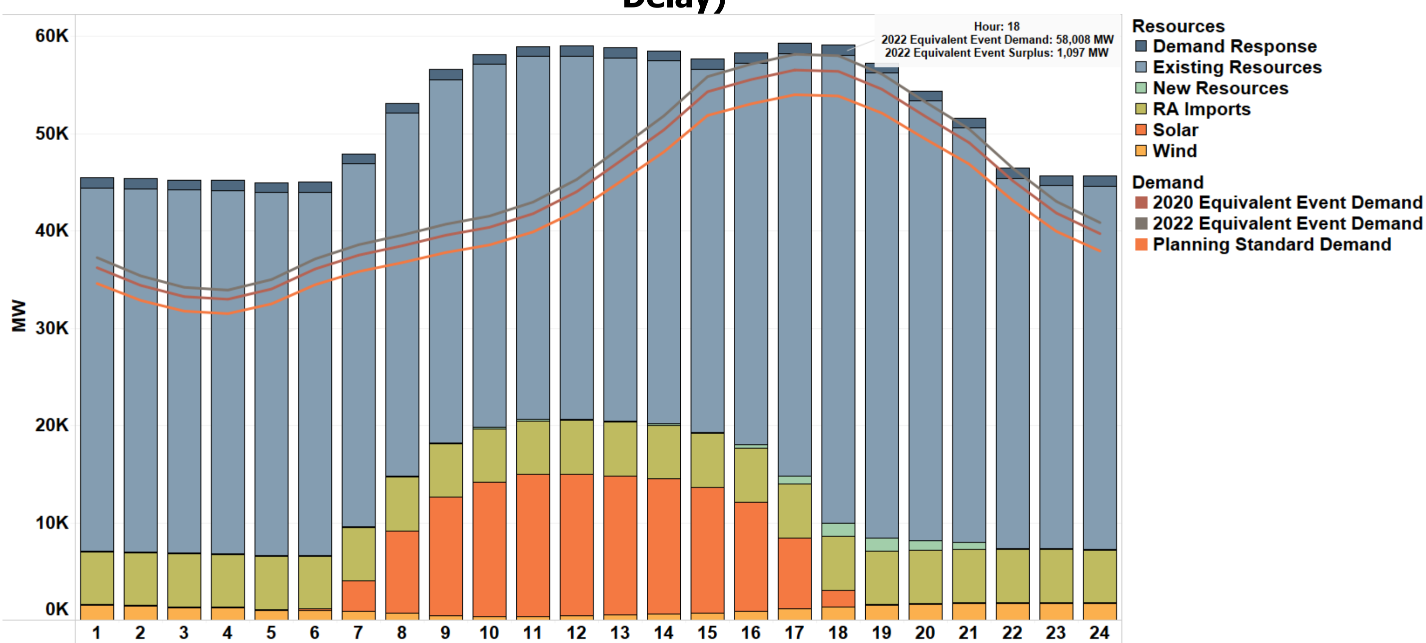
36 2024 California Energy Demand Data. Note: There is an error in the demand forecast that does not significantly impact the results of the stack analysis in this report. The overall conclusions and forecasted conditions remain the same, despite the error. The data will be updated with the revised demand forecast in the next quarterly report.

Figure 7: 2025 September Hourly Stack Comparison (0 percent New Supply Delay)



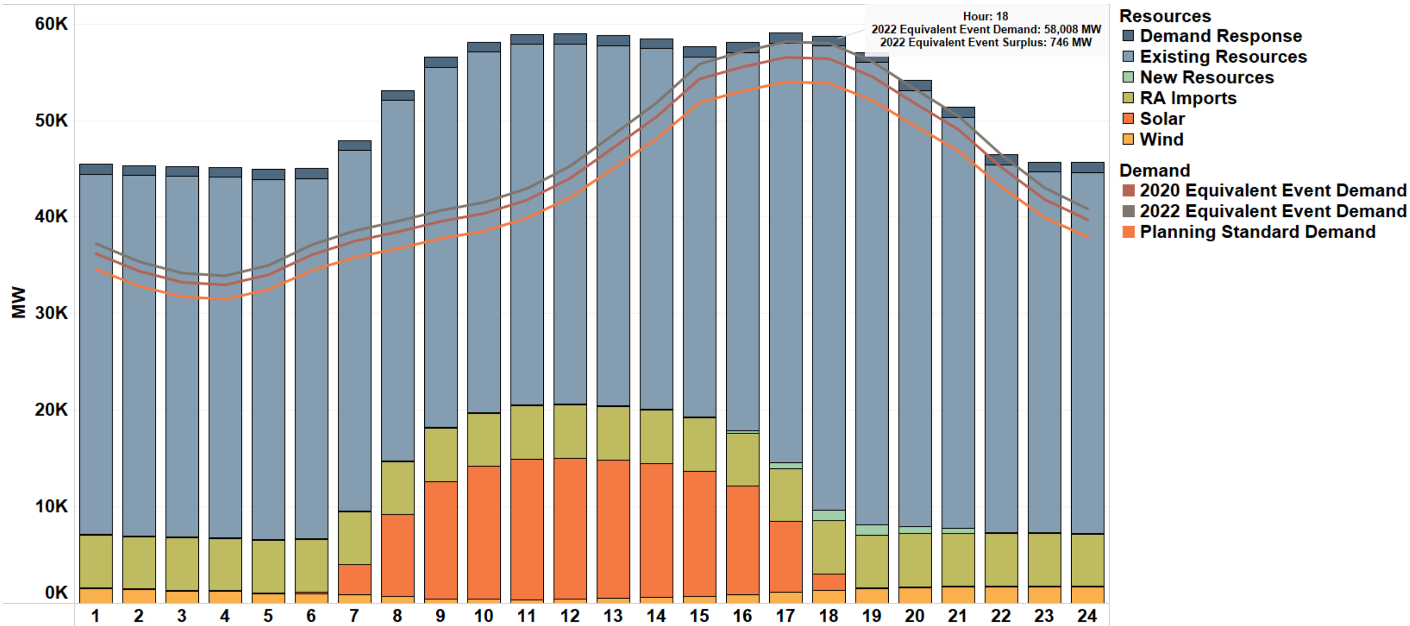
Source: CEC staff with California ISO data

Figure 8: 2025 September Hourly Stack Comparison (20 percent New Supply Delay)



Source: CEC staff with California ISO data

Figure 9: 2025 September Hourly Stack Comparison (40 percent New Supply Delay)



Source: CEC staff with California ISO data

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 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 18 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 18: 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

5-Year Overview (2026 to 2030):

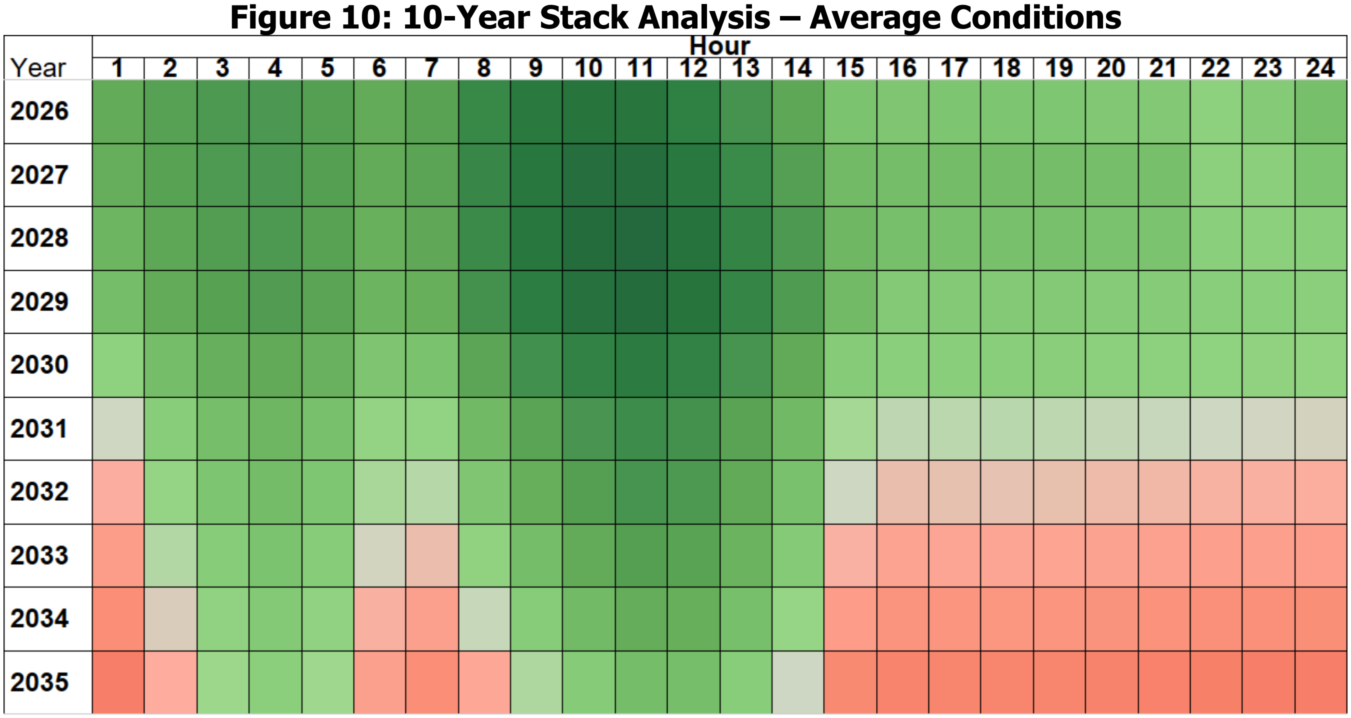
Within the 5-year horizon, the planning standard resulted in surplus in all delay scenarios. Similar to last year's stack analysis, the analysis projects surplus capacity until 2031, under average conditions. This is due in part to the extension of DCPP, which is included in the supply stack through 2030. Other contributing factors include the addition of new resources coming online, supplemental procurement order, and lower projected demand forecast in the 2023/24 Final CED. However, using the latest 2024 Final CED, the stack analysis shows that there may be a need for additional contingency resources as soon as 2030, under conditions similar to the 2022 heat event.

10-Year Overview:

This section explores the supply and demand balance in the 10-year horizon using 0, 20, and 40 percent delay adjustments to the PSP supply in each year. The annual supply was compared to a planning standard of a 17 percent reserve margin (average conditions). Then, the annual supply was compared to more extreme events, which were defined as a 2020 equivalent event and a 2022 equivalent event.

Under average conditions, the PSP resulted in surplus for all delay scenarios until 2032, which is due to no new supply being ordered after 2028 and the gradual demand increase year to year. The max shortfall observed, in average conditions, was 7,400 MW in 2035 (Figure 10). The shortfalls observed, starting in 2032, could indicate that there is a potential need for additional resources.

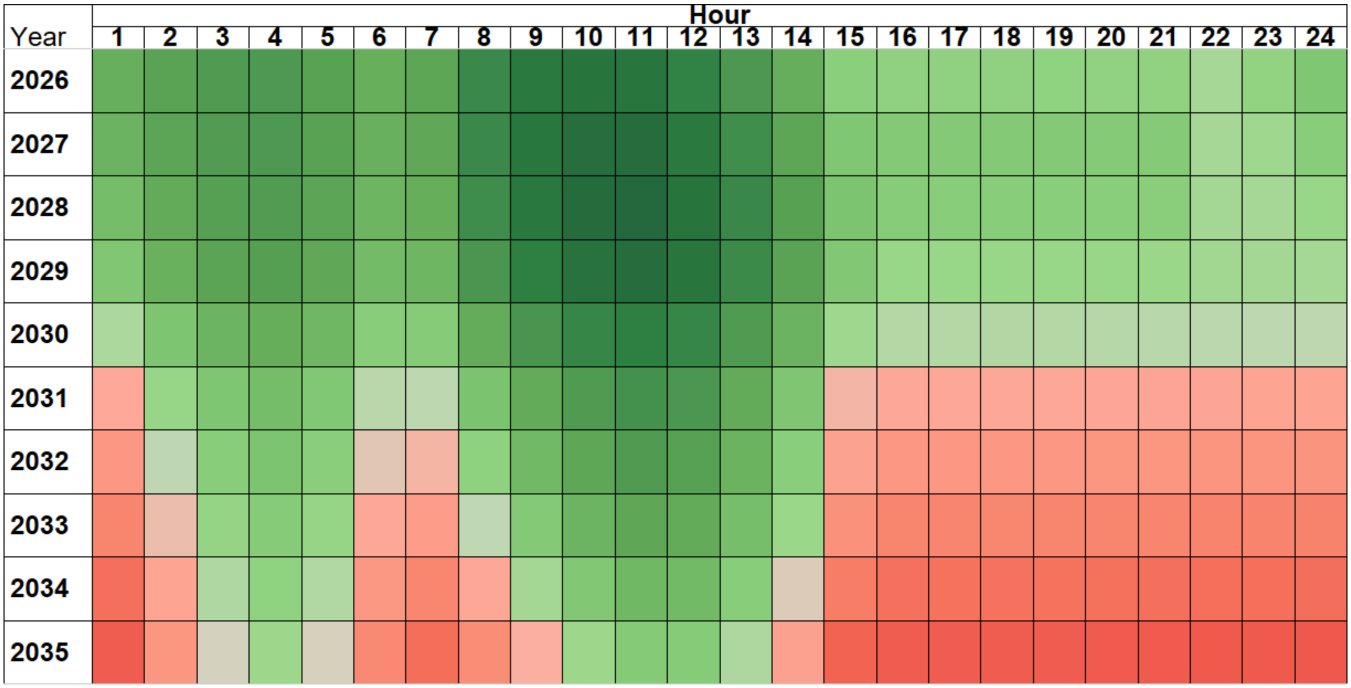
Figure 10: 10-Year Stack Analysis – Average Conditions



Red - Shortfall
Green - Surplus

Source: CEC staff with CPUC data

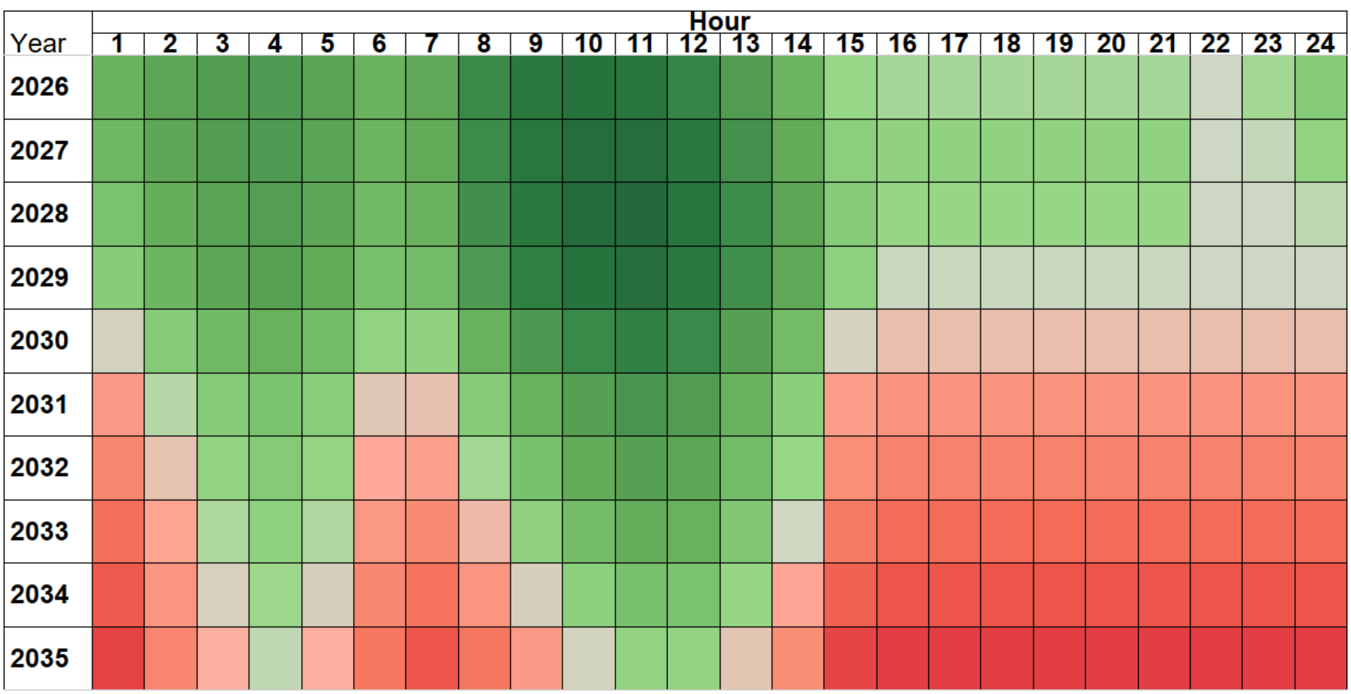
Figure 11: 10-Year Stack Analysis – 2020 Equivalent Event



Red - Shortfall
Green - Surplus

Source: CEC staff with CPUC data

Figure 12: 10-Year Stack Analysis – 2022 Equivalent Event



Red - Shortfall
Green - Surplus

Source: CEC staff with CPUC data

When considering the impacts of extreme events, the outlook becomes worse with 2035 having a 12,000 MW shortfall, in a 2022 equivalent event (Figure 12). It is important to note that DCPP Units are currently planned to be fully retired beginning in 2031, with one unit retiring in 2029 and the second unit retiring in 2030. However, the extreme event shortfalls are driven more by increasing demand in the forecast and resource deficiency in the later years of the analysis, rather than DCPP retirements.

Another element to consider in addition to extreme events, which can worsen an already strained power grid, is loss of transmission. The effects of losing 4,000 MW in the 10-year horizon leads to shortfalls in most years, including shortfalls under traditional planning standards starting in 2030 and greatly increase the shortfalls in the most extreme events, up to 16,000 MW.

Contingency Resources

The agencies and the California ISO are continuing to track contingency resources, which are resources outside of the resources considered in the stack analysis and provide support during an extreme event. The updated contingency list for 2025 includes the addition of 2,859 MW of once-through cooling resources that were added to the Electricity Supply Strategic Reliability Reserve Program in May 2024. Contingency resources, identified in Table 19 are expected to provide between 4,700 MW and 5,000 MW during extreme events and may be called upon to cover contingency needs identified in real time grid operations.

Table 19: Contingency Resources for Summer 2025

Type	Contingency Resource	Available MW July	Available MW August	Available MW September
SRR [37]	DWR Electricity Supply Strategic Reliability Reserve Program	3,079	3,079	3,079
SRR	Demand Side Grid Support (DSGS)	530	540	545
SRR	Distributed Electricity Backup Assets (DEBA) (under development)	0	0	0
CPUC	Ratepayer Programs (Emergency Load Reduction Program, Smart Thermostats, etc.)*	247	238	233
CPUC	Imports Beyond Stack*	25	25	25
CPUC	Capacity at Co-gen or Gas Units Above Resource Adequacy *	794	364	474
Non-Program	Balancing Authority Emergency Transfers	300	300	300
Non-Program	Thermal Resources Beyond Limits: Gen Limits	40	40	40
Non-Program	Thermal Resources Beyond Limits: Gen Limits Needing 202c	25	25	25
	Total	5,040	4,611	4,721

*Estimates based on IOU excess procurement reports from 2024.

Comparison to Past Stack Analyses

The Stack Analysis began in early 2021 in response to the August 2020 rotating outages as a way to quickly assess near-term, worst-case reliability scenarios. The first few iterations assessed summer 2021 and 2022 and focused on the implications of solar dropping off in the late evening and hydroelectric resources losing effectiveness during drought conditions. In 2022, the CEC extended the time horizon for the stack analysis to assess planning priorities out to 2026. The analysis was expanded in part to evaluate the impacts of OTC retirements. Hourly shapes for wind, solar, and other new resources were introduced to better represent the limitations of resources the state will rely on in the future.

For summer 2025, the stack analysis incorporates updated hourly shapes for wind and solar, while battery shapes remain unchanged. Initial projections for 2025 are based on California ISO New Resource Implementation Queue data, enabling the CEC stack analysis to more

37 Strategic Reliability Reserve

accurately evaluate the need for contingency resources based on resources coming online beyond what has already been ordered and contracted.

Table 20 below shows the progression of the stack analysis during 7-8 PM from September 2021 to March 2025, which is the maximum shortfall hour in each of these analyses. Table 20 includes the average and elevated reserve margins and shortfall numbers at the same hour. Assuming that all projected resources come online by the start of summer, this will be the first time no shortfalls were observed under extreme scenarios.

Table 20: Summer Stack Releases from September 2021 to March 2025

Publication Date	Summer Assessed	Average Reserve Margin	Average Shortfall (MW)	Elevated Reserve Margin	Extreme Shortfall (MW)*
Sep 2021	2021	15%	60	17.5%	1,180
Sep 2021	2022	15%	980	22.5%	4,350
May 2022	2022	15%	40	22.5%	3,500
May 2022	2023	15%	0	22.5%	600
Jan 2023	2023	16%	0	26%	2,700
May 2024	2024	17%	0	26%	90
March 2025	2025	17%	0	26%	0

*Extreme shortfall definition: 26% elevated reserve margin is equivalent to a 2022 September heat event and 22.5% elevated reserve margin is equivalent to a 2020 August heat event.

Source: CEC Staff

SB 1020

Senate Bill 1020 sets interim targets to SB 100 of 90 percent by 2035 and 95 percent by 2040, and requires the CPUC, CEC, and State Air Resources Board, to annually issue a joint reliability progress report that:

- reviews system and local reliability within the context of the SB 100 and SB 1020 interim targets, with a particular focus on summer reliability
- identifies challenges and gaps, if any, to achieving system and local reliability
- identifies the amount and cause of any delays to achieving compliance with all energy and capacity procurement requirements set by the CPUC.

California ISO 2025 Local Capacity Area Technical Study

To satisfy the requirements of SB 1020, this report draws on insights from the California ISO 2025 Local Capacity Area study.[38] The technical study focuses on addressing the minimum capacity necessary in identified transmission-constrained "load pockets" or Local Capacity Areas to ensure compliance with mandatory reliability standards.

The concept of Local Capacity Requirements (LCR) predates the 1998 restructuring of the California electric system. Before restructuring, investor-owned utilities made deliberate trade-offs between investing in transmission and generation, relying on local generation to supplement transmission capacity in certain areas. While electric restructuring did not alter the physical need for local generation, it changed the means of accessing such resources. Following restructuring, the California ISO entered contracts with Reliability Must-Run generation to meet local reliability needs. The state's adoption of RA requirements has shifted the procurement of resources to LSEs, aligning with the technical study to ensure sufficient local generation for reliability standards.

The assumptions and processes employed in the 2025 Local Capacity Technical (LCT) Study align closely with those utilized in the 2007-2024 LCT Studies, ensuring consistency and comparability. However, the 2025 LCT study used the CEC's 2023 IEPR demand forecast.[39] Since the release of the 2025 LCT study, a new CEC IEPR demand forecast has been released. Overall, the capacity required for LCR has seen an increase from 2024 to 2025 of approximately 702 MW, or 3.2 percent.

The specific areas with decreased LCR needs include North Coast/North Bay, Los Angeles Basin and San Diego/Imperial Valley due to load forecast decrease, and Kern due to small increase in capacity rating for the limiting component. Conversely, LCR needs have increased in Humboldt, Bay Area, Sierra, Stockton, Fresno and Big Creek/Ventura due to load forecast increase.

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38 California ISO. 2024. 2025 LOCAL CAPACITY TECHNICAL STUDY. https://stakeholdercenter.caiso.com/InitiativeDocuments/Final2025LocalCapacityTechnicalReport.pdf

39 *CED 2023 Planning Forecast LSE and BAA Tables*. https://efiling.energy.ca.gov/GetDocument.aspx?tn=255151

Table 21: 2025 Final LCR Needs (MW)

	August Qualifying Capacity (AQC)	AQC	AQC	AQC	Capacity Available at Peak	2024 LCR Need	2025 LCR Need
Local Area Name	**QF/ Muni**	**Non-Solar**	**Solar**	**Total**	**Total**	**Capacity Needed**	**Capacity Needed**
Humboldt	0	175	0	175	175	133	164
North Coast/ North Bay	136	849	0	985	985	983	967
Sierra	1,221	704	0	1,925	1,925	1,212	1,532
Stockton	125	608	7	740	733	750	735
Greater Bay	604	7,781	4	8,389	8,385	7,329	7,441
Greater Fresno	229	2,839	199	3,267	3,068	2,028	2,532
Kern	9	397	43	449	406	427	434
Big Creek/ Ventura	399	3,702	249	4,350	4,350	1,971	2,145
LA Basin	1,157	9,129	10	10,296	10,296	4,413	4,123
San Diego/ Imperial Valley	3	5,297	169	5,469	5,469	2,834	2,709
Total	**3,883**	**31,481**	**681**	**36,045**	**35,792**	**22,080**	**22,782**

Source: California ISO

The results of the 2025 LCT Study are forwarded to the CPUC for consideration in its 2025 RA requirements program. These results will be utilized by the California ISO as "Local Capacity Requirements" to determine the minimum local capacity necessary to meet the LCR criteria. Additionally, the results assist in allocating costs for any California ISO procurement of capacity required to achieve Reliability Standards, independent of the RA procurement by LSEs. California ISO will finalize a 2026 LCT study in May 2025.

CHAPTER 8: 2026 CPUC Resource Adequacy Planning Reserve Margin Study

CPUC staff conduct probabilistic reliability studies of the California ISO system on an annual cadence for the purpose of supporting the CPUC to transmit portfolios for the Transmission Planning Process. In conjunction with these annual studies, staff also conduct studies for other purposes in the IRP and RA proceedings. Probabilistic studies conducted by CPUC staff generally focus on CPUC-jurisdictional load-serving entities within the California ISO system.

For CPUC staff's contribution to this *Joint Reliability Assessment Report*, staff drew on work performed in the RA Proceeding for use in setting a RA Planning Reserve Margin (PRM). In D.22-06-050, the CPUC adopted a minimum 17 percent PRM for the 2024 RA year. In D.23-06-029, the CPUC adopted a 17 percent PRM and extended the effective PRM for 2025, stating that "[g]iven the realities of available RA supply and persistent delays in development projects, it is prudent to retain the status quo 17 percent PRM for the 2024 and 2025 RA years. Increasing the PRM without greater certainty about installed RA resources for 2024 and 2025 is not appropriate at this time." The decision further stated that "[t]he Commission will continue to monitor market conditions and impacts of the adopted PRM framework and will reevaluate the PRM requirements for the 2026 RA year in 2024."

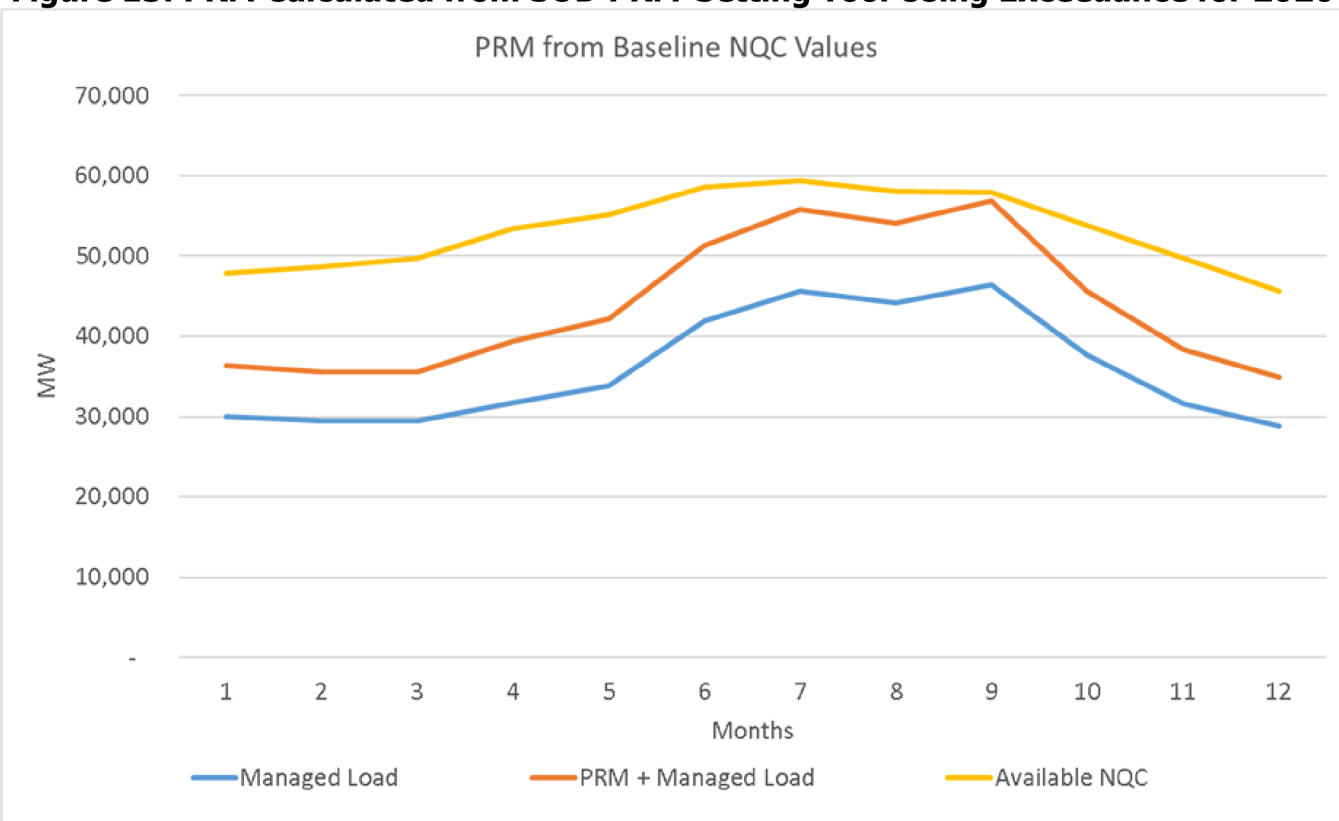
As part of the recent Track 2 RA Proceeding, CPUC staff published a 2026 RA Loss of Load Expectation (LOLE) study in July of 2024. The study was done using the existing baseline fleet of resources plus the known planned resources expected to be online by June 1, 2026. In order to surface LOLE to the 0.1 standard, staff constrained the import assumption. The results of this analysis reflect that a LOLE of 0.1 is achieved with a sizable surplus. Focusing on the peak month of September, staff found that the baseline resource fleet was over-reliable, allowing for a decrease in the evening California ISO simultaneous import constraint from 4,000 MW to 1,700 MW. The 2026 study also included a monthly stress test to ensure the 0.1 LOLE criteria was ensured across all months of the year. The LOLE Study results, after accounting for the stress test, reflect that existing and in-development resources plus a simultaneous import constraint of 2,500 MW satisfy reliability needs for the 2026 RA compliance year.

Translating the PRM from the current RA construct to the Slice-of-Day (SOD) Framework has proven a complex analytical task. To implement the SOD Framework, staff must perform a LOLE study and translate the results using the SOD PRM tool, to produce a PRM for all 12 months that ensures meeting the 0.1 LOLE target. After publishing the initial 2026 RA LOLE study results, which included the translation of these results to a 2026 PRM level, parties identified several rounds of errors with the results in the SOD calibration tool that have led to further vetting of the 2026 PRM results. The most recent Track 2 Decision D.24-12-003 noted that a broad range of parties recommend further analysis and vetting of Energy Division's revised analysis and recommend deferring adoption of the 2026 PRM to Track 3 of this proceeding. The CPUC agreed with parties that further correction was needed to the study results and directed that further correction and consideration be undertaken in Track 3 of the proceeding.

On December 20, 2024, an updated SOD calibration tool and results were published for party consideration. It should be noted that while the PRM levels have slightly changed from prior versions, the results of the LOLE study are still the same, reflecting a surplus of capacity to meet forecasted 2026 needs.

Figure 13 shows modeled PRM requirements versus available resources during the most constrained hours in each month of the year. The yellow line is available NQC based on existing and planned capacity, including 2,500 MW of imports and a DCPP extension through 2030. In off-peak months, the orange line reflects what the modeled PRM requirements would require if adopted as the RA program requirements. In other words, the modeled PRM requires from LSEs a volume of resources which is lower than available installed resources (reflected in the yellow line).

Figure 13: PRM Calculated from SOD PRM-Setting Tool Using Exceedance for 2026



Source: CPUC staff

CHAPTER 9: Mid-Term Probabilistic Reliability Assessment (CEC)

Demand Forecast Vintage

The mid-term probabilistic reliability analysis uses the 2023 IEPR Planning Forecast from the *2023 IEPR*, adopted in February of 2024. The 2023 IEPR Forecast includes a baseline forecast, a planning forecast, and a local reliability forecast. The planning forecast considers the impacts of "additional achievable" scenarios for energy efficiency, fuel substitution and transportation electrification beyond the baseline forecast, and is typically used for planning resource procurement and transmission.

A correction to the hourly demand forecast results of the *2023 IEPR* was published on May 30, 2024. The correction was limited to the Additional Achievable Fuel Substitution impacts, and consequently the Managed Net Load projections for both the Planning Scenario and Local Reliability Scenario.

Mid-Term Probabilistic Reliability Analysis

The CEC performed a probabilistic assessment of the mid-term statewide reliability outlook for California from 2025 to 2035, under the supply forecast in the CPUC 2023 PSP. The goal of this analysis was to determine if California is meeting the reliability criterion of 1 day in 10-year LOLE, or 0.1 days/year LOLE under a variety of scenarios related to the resource build and import uncertainty. This analysis was conducted only on the summer season (July – September), when current reliability risk is highest.[40] Several reliability 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.

The study finds that the current resource mix and proposed PSP additions for CPUC-jurisdictional LSEs and supply form additions for POUs contain sufficient resources to exceed the 0.1 LOLE reliability criterion and serve load under challenging demand and resource conditions. However, the study did not evaluate all potential risk, and future work is being conducted to evaluate winter reliability risks, the impacts of transmission outages, and hydro drought conditions. A greater than 0.1 LOLE indicates risk of loss of load more than one day in 10 years. Additionally, alternative load scenarios, such as increased or different electric vehicle charging patterns, may drive summer reliability risks not captured here. While the Base Case study results show that California is expected to meet or exceed its reliability targets, higher than expected temperatures across the Western Interconnection, combined with drought and transmission outages could lead to loss of load.

System reliability is expected to continue to significantly improve 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

40 Note: recent revisions to the CED demand forecast assume large growth in electrified heating demand that may occur in future years. When combined with underlying risk factors in the changing resource mix, reliability risk may shift in later years to winter seasons. This will be explored in future work, discussed later in this report.

of 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 22.

Table 22: Resource Adequacy Results Across Scenarios

Results	Units	2025	2030	2035
Base Case LOLE	LOLE (days/year)	0.00	0.00	0.00
Base Case Effective Surplus	GW	4-5	9-10	6-7
Extend DCPP	LOLE (days/year)	N/A	N/A	0.00
Full PSP, No Imports	LOLE (days/year)	0.08	0.00	0.003
40% Reduction in PSP	LOLE (days/year)	0.02	0.00	0.15
40% Reduction in PSP + No Imports	LOLE (days/year)	0.27	0.01	0.79

Source: CEC staff

Model Development and Key Assumptions

To evaluate the RA of California's power system under a variety of scenarios, a probabilistic, hourly, chronological RA simulation was conducted in the PLEXOS modeling software. The software is also utilized by other California entities for RA, 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 RA Study and the California ISO Summer Reliability Assessments.

Notable Updates from Previous SB 846 Joint Agency Reliability Planning Assessment 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 improved the reliability outlook for California. The list below provides an overview of the major changes implemented in the model.

- **Demand Update** – The CEC issued a revision to the 2023 CED, which affected the fuel substitution layer, and lowered forecasted peak loads. The 2035 net peak reduced by approximately 3 GW from the original 2023 CED Forecast.
- **Intermountain Power Plant** – The new gas generator was placed directly in LADWP territory, due to its high voltage direct current connection. Coupled with the California import limits, this had a net increase in capacity available to the state.
- **California ISO Import Constraint** – Consistent with California ISO analysis, the maximum import constraint was shifted back one hour to include Hour Beginning 21 (9-10 PM).

- **Incremental retirements** – The natural gas generation capacity was balanced to more closely align with the PSP in 2035, resulting in a net increase in gas retirements. Previous balancing efforts aligned with 2045 PSP gas capacity quantities.

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, Turlock Irrigation District, LADWP, and Imperial Irrigation District). Transmission is represented between the regions. The California ISO regions have a total California ISO Import Limit of 11,665 MW, and 5,500 MW during reliability risk hours (H16-22 in July-September).[41] Imports into California are limited at 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 Energy Information Administration (EIA) Form 930.

LOLE results are reported for the state as a whole, though the California ISO regions experience most of the loss of load events.

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.[42]

Demand Forecast

This analysis utilizes the revised 2023 IEPR CED forecast. The underlying demand and behind-the-meter solar layers are assumed to be weather dependent and varied across weather years. The model uses weather correlated demand and renewable shapes for 15 weather years representing 2007 to 2021. The demand profiles are modified from those used for the probabilistic analysis in the PSP by scaling the 2022 CED load forecast utilized in the PSP to the updated 2023 CED 1-in-2 energy forecast and the 1-in-20 peak demands for each forecast year. All other load modifiers (ie.gl., electric vehicles, energy efficiency) do not vary by weather year.

Of note, the 1-in-20 peak forecast modeled in this report ranges from 750 to 2,000 MW lower between 2025 and 2033, as compared to the 2022 CED used to develop the resource mix in

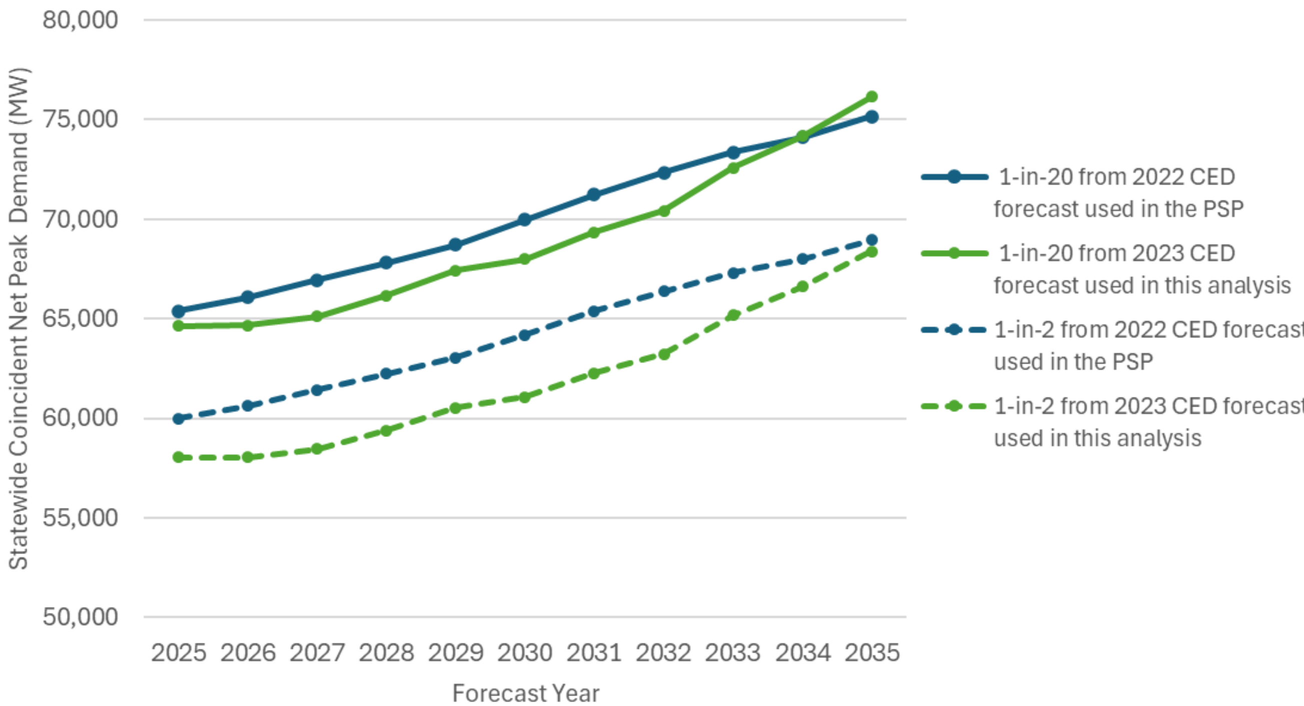
41 The 5500 MW figure exceeds the 4000 MW that have been used in California ISO models due to the treatment of pseudo-tie resources, specifically Palo Verde and Hoover. Palo Verde and Hoover are treated as generic imports in the CEC RA model but are modeled explicitly in the California ISO RA model.

42 The exception to this is the new 840 MW Intermountain gas plant which is connected to LADWP via a high-voltage direct current line and represented as physically located in LADWP'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.

the 2023 PSP, shown in Figure 14.[43] The 2034 peak is roughly aligned, and the 2035 summer 1-in-20 net peak forecast exceeds the forecast used to develop the PSP supply mix. As a result, the revision downward in the demand forecast may mean that the PSP has more resources than necessary to meet reliability targets.

The 2024 IEPR CED will be incorporated into the CEC's RA analysis for the California Energy Resource and Reliability Outlook report in the spring. Compared to the 2023 CED, the 1 in 2 peak forecast for the 2024 IEPR is similar out to 2026 and then grows much more quickly, rising to a difference of about 4,000 MW in 2030.

Figure 14: 2022 and 2023 California Energy Demand Forecasts



Source: CEC staff

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.[44] Resource additions 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. Table 23 shows the expansion resources slated to come online across California.

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

44 CPUC. *2022-2023 IRP Cycle Events and Materials*. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials.

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 rather than reliability needs. For that reason, it is expected that the PSP resource build will exceed the 0.1 days/year LOLE criterion.

The retirements utilized in this analysis align with the PSP. The OTC and generic gas retirements are balanced against the gas additions such that the gas amounts align with the PSP. Notably, this analysis includes DCPP as available through 2030, while the PSP had the nuclear power plant retiring earlier.

Table 23: PSP Cumulative Resource Additions (MW)

	2024 Baseline	2025 Additions	2030 Additions	2035 Additions
Peak Load[45]	64,649	64,643	67,994	76,141
Natural Gas	34,527	940	3,840	4,840
Utility Scale PV	25,673	4,606	16,312	21,699
Distributed PV	16,615	1,529	10,708	17,263
Batteries	13,462	4,123	11,958	17,957
Pumped Storage Hydro & Long Duration Storage	4,380	-	785	985
Hydro	9,693	-	-	-
Land Based Wind	9,003	1,367	12,063	18,223
Offshore Wind	-	-	-	4,531
Geothermal	2,970	210	1,538	3,058
Demand Response	2,769	-	-	-
Nuclear	2,393	-	-	-
Other	1,780	-	-	-
Total Incremental Additions	**0**	**12,776**	**56,419**	**87,771**
Total Resources	**123,266**			

Source: CEC staff

Table 24: PSP Resource Retirements (MW)

	2025	2030	2035
Once Through Cooling	326	1,661	1,661
Generic PSP California ISO Gas Retirements	83	380	1,475
Nuclear Retirements	-	-	2,393

45 Represents 1-in-20 coincident peak load for California used in this study

Source: CEC staff

Additional Inputs and Assumptions

Additional inputs and assumptions are provided in Table 25.

Table 25: Additional Inputs and Assumptions

Model Input	Data Source	Description
Demand Profiles	CPUC Weather-Sensitive Load	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	Forced outage rates and maintenance rates are based on U.S. averages, which vary by plant size and fuel type.
Plant Capacities	Quarterly Fuel and Energy Report (QFER)	QFER Data reported in 2024
Expansion Resources	CPUC 2023 PSP	PSP Core Scenario (25 MMT by 2035), February 2024 release
Solar Shapes **2007-2021**	National Renewable Energy Laboratory (NREL) National Solar Radiation Database	Unique solar profiles developed using the NREL System Advisor Model for each significant existing solar plant with capacity-weighted aggregation to regional profiles.
Wind Shapes, 2007-2014	NREL Wind Toolkit	Simulated wind production profiles were calibrated to align with actual monthly generation totals reported to EIA 923
Wind Shapes 2015-2021	Actual Generation Data from California ISO Subpoena	Hourly wind production data, inclusive of curtailment, aggregated by Wind Resource Area
Transmission Line Ratings	Western Electricity Coordinating Council (WECC) Path Limits	Applied to imports from WECC regions as well as Path 46
Hydroelectric Monthly Maximum Ratings	Hourly hydro generation reported in EIA 960	Hydro resources are limited in maximum output based on historical observations, wherein fleetwide maximum generation is well below fleetwide installed capacity. The 2019 hydro year, a relatively average hydro year, is used across simulations.
Hydroelectric Energy Budget	Monthly hydro generation reported in EIA 923, 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 are assumed to be curtailed prior to load shed.

Source: CEC staff

Results

Base Case Results

The Base Case assumed full achievement of the PSP with standard import assumptions. With all new PSP resources successfully deployed, the modeling results project that California will have surplus resources, exceeding the reliability criterion, beginning in summer 2025, and extending through 2035. 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 future study years provided that the PSP resources are added as expected. The resulting RA metrics are provided below.

- 2025 Base Case: 1 event in 300 samples, affecting 1 hour with a shortfall of 193 MW
- 2030 Base Case: No shortfall events
- 2035 Base Case: No shortfall events

These Base Case results are largely consistent with the Q1 report[46] from last year and the 2024 California Energy Resource and Reliability Outlook[47] released in August. As noted in the section *Notable Updates from Previous SB 846 Joint Agency Reliability Planning Assessment Reports* above, a variety of modeling updates were made that were expected to improve the reliability outlook. Every year modeled resulted in a 0.00 days/year LOLE in the Base Case within the study horizons. This result is driven by the following:

- The peak demand forecast has been revised down, lower than the one used in previous studies and in the PSP.
- DCPP is available through 2030 but is not included in the portfolio used to build the PSP.
- The PSP resources are predominately added to meet emissions reductions goals and RPS constraints, not the planning reserve margin constraint.
- Significant additions of solar and storage in recent years, with limited plant retirements, has pushed capacity reserves higher.

These results indicate that the probability of resource shortfalls is very low, 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 reliability deficits. Additional sensitivities were evaluated to test system reliability if things do

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46 Yee Yang, Chie Hong, Sarah Goldmuntz. 2024. *Joint Agency Reliability Planning Assessment: Covering the Requirements of SB 846 (First Quarterly Report for 2024) and SB 1020 (Annual Report).* California Energy Commission. Publication Number: CEC-200-2024-006. Available at https://www.energy.ca.gov/publications/2024/joint-agency-reliability-planning-assessment-covering-requirements-sb-846-first.

47 Yee Yang, Chie Hong, Kristen Widdifield, Liz Gill, Hannah Craig, Angela Tanghetti, Grace Anderson, Christopher McLean et al. 2024*. California Energy Resource and Reliability Outlook, 2024*. California Energy Commission. Publication Number: CEC-200-2024-016. Available at https://www.energy.ca.gov/publications/2024/california-energy-resource-and-reliability-outlook-2024.

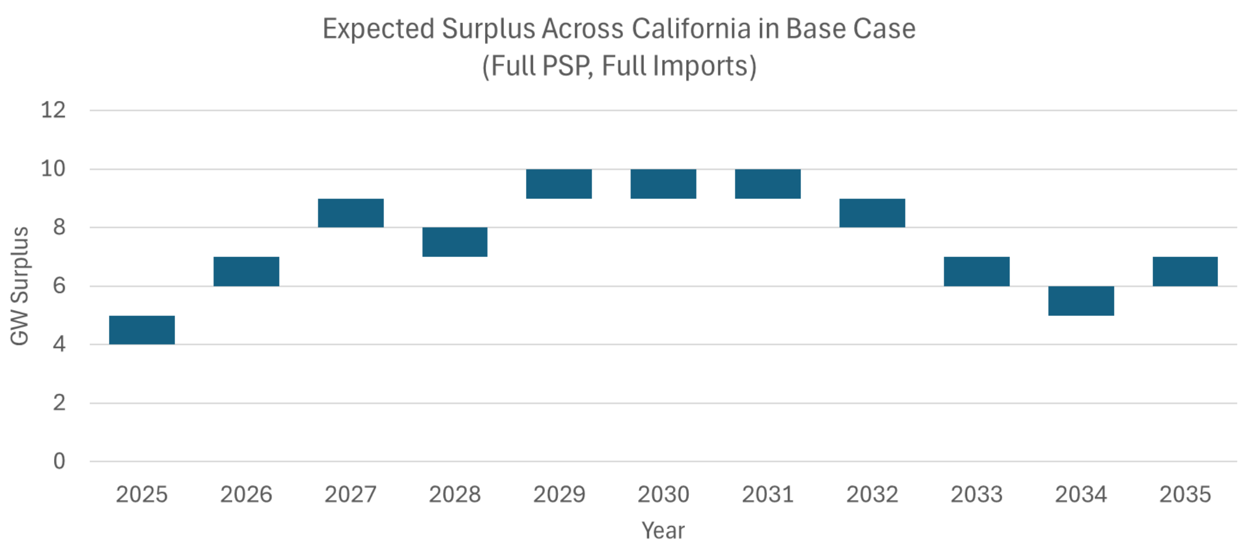
not go according to plan, including with a reduction in future generator build out and removing California's ability to import power from neighbors during periods of high system stress. Furthermore, widespread Western drought and/or wildfires could also challenge reliability but were not explicitly considered in this analysis.

Surplus Calculations

To provide additional information, the CEC quantified the amount of that surplus capacity beyond the 0.1 days/year LOLE reliability criterion for each study year. This effective capacity surplus is calculated by adding firm load, applied as a constant MW addition in all hours, until 0.1 days/year LOLE is reached. The firm load added approximates how much perfect capacity, or capacity that is always dispatchable without any outages or derates, could be removed from the resource mix and still be reliable. If the system were in a supply deficit, firm resources would be added until a 0.1 days/year LOLE is reached. Firm load is allocated to each region based on the region's contribution to forecasted coincident peak statewide load.

The results of this analysis are presented in Figure 15 below. This analysis indicates that California's statewide surplus is expected to be 4-5 GW in 2025, rising to 9-10 GW in 2029 before returning to 7-8 GW of surplus in 2035, assuming the full PSP resource build and normal hydro conditions and transmission capability. Again, this level of reliability is driven by resource additions built for greenhouse gas emissions reductions, a reduced load forecast relative to the one used to design the resource mix, and the retention of DCPP in the near term.

Figure 15: Expected Surplus Across California in Base Case (Full PSP, Full Imports)



Source: CEC staff

The 4-5 GW surplus in 2025 is higher than the 2,550 MW surplus reported by California ISO (2024)[48] and the 1,500 MW reported by CPUC (2026)[49] due to the following:

- This analysis reports a statewide surplus rather than the California ISO-only surplus reported by CPUC and California ISO.
- The California ISO characterizes reserves differently and the total quantity of reserves that must be retained before a loss of load event is triggered is different than the CEC's model and may be higher or lower depending on system conditions.
- The California ISO 2024 study was based on existing and expected resources for 2024 which did not include all of the resources that come online in 2024 as part of the PSP. The CPUC also used an update baseline resource list from January 2024.
- The California ISO 2024 study also used an earlier release of the 2023 CED and manipulated it in a slightly different way, which resulted in higher peaks but less variation in which month and day those peaks occur in.
- CPUC and California ISO analyses include the 2022 weather year, which has a higher-than-normal peak demand.

Characterizing System Risk

To further characterize system risk, the 2025, 2030, and 2035 cases were calibrated to meet approximately 0.1 days/year LOLE utilizing the approach described in the previous section. Note that all events occur within the California ISO, which is subject to the California ISO maximum import constraint. This analysis provides directional insights on the size, frequency, duration, and timing of reliability risk. 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 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 reliability modeling, actual risk periods may be different as load grows and resources retire.

While each case is calibrated to roughly 0.1 days/year, the underlying nature of the reliability risk shifts across the study horizon as the resource mix and load profiles evolve. Figure 16 shows how unserved energy is distributed throughout the day for select scenarios in calibrated study years 2025, 2030, and 2035. While the reliability risk for the full PSP build out is within acceptable bounds, this analysis shows that reliability risk within those bounds shifts later in the day, from early evening in 2025 to overnight periods in 2035. In 2025, relative reliability risk is predominately driven by capacity deficits, meaning there are times where there are insufficient MW of available capacity to serve load. As nearly 20 GW of battery storage is added to the system, the risk shifts to overnight periods. In rare instances, the battery storage

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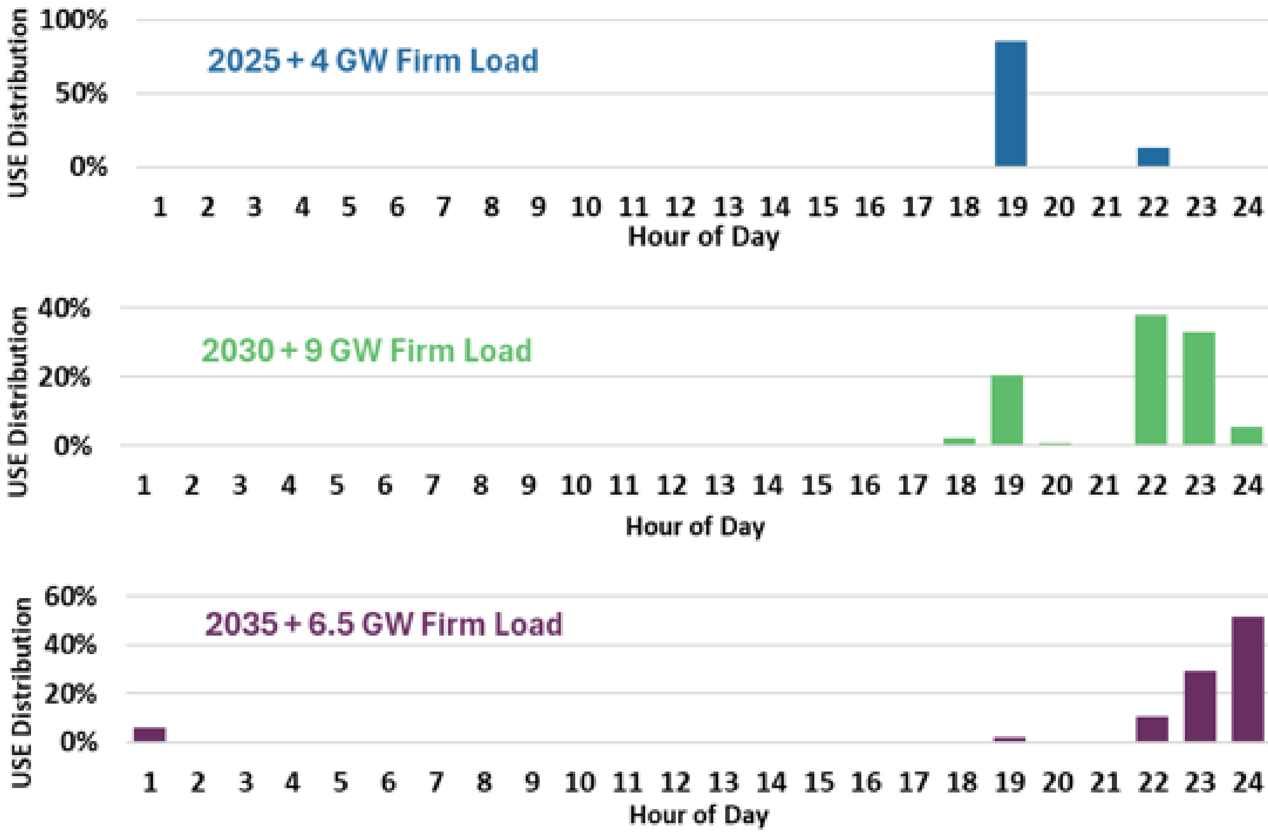
48 California ISO. May 2024. *[2024 Summer Loads and Resources Assessment](https://www.caiso.com/Documents/2024-Summer-Loads-and-Resources-Assessment.pdf)*. https://www.caiso.com/Documents/2024-Summer-Loads-and-Resources-Assessment.pdf.

49 CPUC. July 2024. *Loss of Load Expectation Study for 2026 Including Slide of Day Tool Analysis*. 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.

discharges all available energy and has insufficient state of charge to continue discharging in overnight periods.

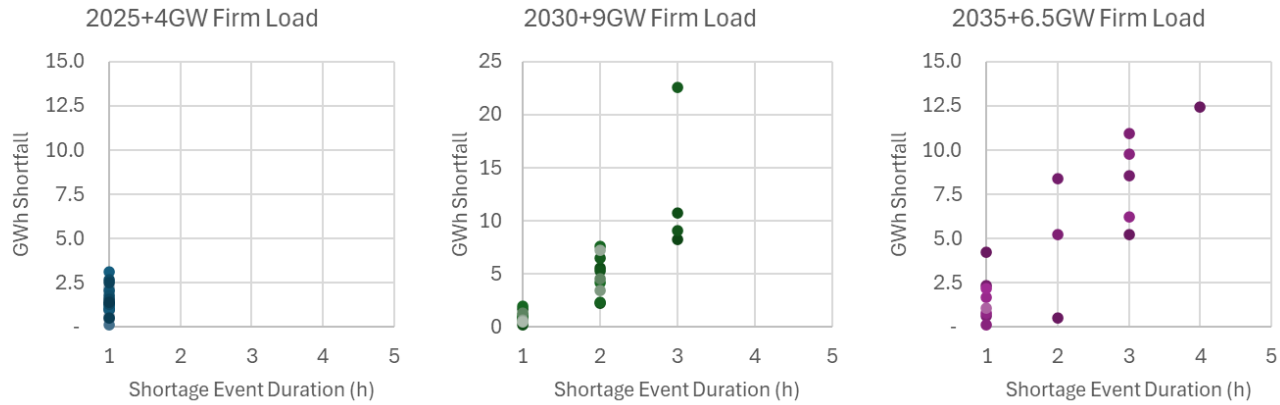
Figure 16: Unserved Energy Distribution throughout the Day for Select Cases (% Unserved Energy)



Source: CEC staff

As shown in Figure 17, the nature of these events means that unserved energy events extend from 1 hour to up to 4 hours in length before the system can recover, usually because the net load decreases. With these prolonged events, the total energy shortfall also rises. It should be noted that 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 in the evening to risk driven, at times, by insufficient energy to charge energy storage.

Figure 17: Shortage Event Duration and Total Shortfall for Select Cases



Source: CEC staff

Sensitivity Analysis: 40 Percent Reduction in Future Resources

Additionally, California's reliability was evaluated with a 40 percent reduction in future resource additions assumed in the PSP to assess whether the system can maintain reliability 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 evaluated resource reductions for future generating resource additions in both the California ISO regions (PSP) and non-California ISO regions (derived from CEC Supply Forms). 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 (0.02 LOLE) and 2030 (0 LOLE). However, when incremental retirements of firm generation including at DCPP and in the gas fleet occur by 2035, the system shows increased LOLE risk (0.15 LOLE), exceeding the LOLE criterion. This shows the importance of continuing to build out the resource additions identified in the PSP, as system conditions change.

Sensitivity Analysis: 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 to each other, subject to transfer limits and the California ISO peak constraint. The results from this analysis are presented in Table 26.

Table 26: Loss of Load Expectation (Days/Year) Across Scenarios and Sensitivities

Scenario	2025	2030	2035
Base Case	0.003	0.00	0.000
Full PSP, No Imports	0.077	0.00	0.003
40% Reductions in PSP, Full Imports	0.020	0.00	0.150
40% Reductions in PSP, No Imports	0.267	0.01	0.790

Source: CEC staff

With the full PSP buildout assumed, California continues to meet its LOLE criterion of 0.1 days/year. When the system is further constrained by reducing future resource additions by 40 percent and simultaneously removing California imports, the system falls below the RA criterion in both 2025 and 2035.

The 2025 study year shows that if California does not add the full PSP resources in 2025, the system is still dependent on its neighbors for reliability. The 2030 system appears to be resource adequate across all scenarios evaluated. However, the 2035 system is dependent upon the procurement of the PSP resources to offset retirements occurring between 2030 and 2035. Lastly, it should be noted that the 40 percent reduction scenario with no imports shows reliability risk several times higher than the 0.1 days/year LOLE criterion.

Discussion

It is fundamental to electricity system planning that planned resource portfolios meet the 0.1 days/year LOLE criterion. The primary reliability risks arise when things do not goas planned: demand is higher than expected, imports are lower than expected, or resources do not come online as expected. CEC staff analysis suggests that the state will be reliable even if resources come in 40 percent below the resource additions of the proposed 2023 PSP, but the state will continue to depend on imports for the next few years. Provided that PSP resource additions come online as expected, the reliability risk is mitigated without DCPP in the 2030s.

Future Work

While this analysis provides an evaluation of reliability 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 reliability risk in the state. Future work is intended to improve system modeling and CEC’s quantitative rigor 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 focused exclusively on summer LOLE risks, it is crucial to consider the shifting dynamics that are expected to redefine seasonal reliability challenges. By 2040, California is projected to transition into a winter peak demand region due to widespread heat pump adoption and electrification. Even before California becomes a winter peaking system, reliability risks will increasingly manifest in the winter season due to the seasonal availability of renewable resources and the potential for fuel supply disruptions. This winter risk is already observed in other parts of the WECC, such as the Pacific Northwest, portions of the Rocky Mountains, and Western Canada. Additionally, other regions in WECC – even those in warmer climates - are on a similar trajectory due to changes in resource mixes and electrification patterns. Notably, this analysis utilized the 2023 CED. The 2024 CED incorporates increased levels of heat pump adoption and may result in winter risk materializing earlier than 2040.

The urgency of addressing winter reliability risks will evolve over time, based on the expected demand forecasts:

- Short Term (Next 5-7 years): Winter risks are expected to remain low but should be monitored as electrification accelerates and resource mixes change.
- Medium Term (7-15 years from today): A more detailed evaluation of winter reliability risks is warranted as California's energy system approaches a transitional phase. Planning for this period should begin today to allow for sufficient testing, validation, and resource planning efforts to adapt to the changing risk profile.
- Long Term (15+ years): California is likely to become predominantly winter risk focused. Comprehensive planning efforts should be in place to address this new paradigm.

Weather-Dependent Loads and Heat Pump Performance

The transition to winter reliability risk necessitates a deeper understanding of weather-dependent load patterns, particularly the performance of heat pumps during extreme cold events. Heat pump efficiency can degrade under extreme temperatures, leading to higher electricity consumption and amplifying peak demand. Additional effort is required to refine load profiles that reflect these dynamics, especially under prolonged cold spells.

Addressing Fuel Supply Disruptions

Fuel supply disruptions pose a compounding risk to California's winter reliability, particularly as natural gas continues to support reliability. 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.

Chapter 10: Conclusion

The grid remains stable with a projected surplus of resources coming online as summer approaches. Pending any extraordinary or extreme events, the outlook is cautiously optimistic.

Summer 2025 Outlook

The following are key takeaways for the Summer 2025 Outlook:

- 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.
- California Energy Demand Forecast: California's energy demand continues to rise and peak in summer. The 2024 *IEPR Update* forecasts a coincident peak of more than 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.

Recent and Upcoming Activities

The following activities occurred recently or are projected for the next quarter:

- Recommended portfolios for 2025-26 TPP:
  - Every year, CPUC staff develop a recommended set of portfolios for the California ISO to use in its annual TPP.[50] The California ISO evaluates a reliability and/or policy-driven "base case" portfolio. Under the California ISO tariff adopted by the Federal Energy Regulatory Commission, if the results of the base case analysis show the need for additional transmission development, California ISO brings the transmission projects to its board for approval in the spring of the second year of the TPP. If approved by the California ISO Board, under the Federal Energy Regulatory Commission tariff, the project would receive cost recovery through the transmission access charge. Along with the base case analysis that leads directly to transmission project approval, the California ISO can analyze one or more "sensitivity" portfolios. Policy-driven sensitivity portfolio analyses are designed either to support a "least regrets" approach that provides a reasonable range of future scenarios that can be linked to the base case or to gather additional transmission information to support future portfolios' development. Identified transmission solutions in policy-driven sensitivities do not directly go to the California ISO Board for approval, but they can help inform base case solutions.

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50 During years that the CPUC adopts a PSP (once per IRP cycle, or every two to three years), its adopted TPP base case portfolio is identical to the PSP portfolio. In the other years, the TPP portfolios use an updated set of model assumptions compared to the most recently adopted PSP.

  - On February 20, 2025, the CPUC adopted the recommended 2025-26 TPP portfolios in D.25-02-026.[51] This cycle's 2025-2026 TPP base case portfolio builds off the 2024-2025 TPP base case portfolio that the CPUC adopted in D.24-02-047. The base continues to facilitate the analysis of the transmission needed to bring more than 60 gigawatts of new generation and storage resources online to cost-effectively achieve a 25 million metric ton greenhouse gas emissions level by 2035, while maintaining system reliability. By 2035, the 2025-2026 TPP base case portfolio is modeled to reduce greenhouse gas emissions by over 45 percent compared to 2026's modeled 47 million metric ton target and surpasses the SB 1020 target of 90 percent clean energy retail sales. This 2025-2026 portfolio continues to model decreased use of natural gas plants in the California ISO system throughout the modeling timeframe, with a projected 71 percent decline in annual natural gas generation in terawatt-hours by 2035 as compared to the first modeled year, 2026. By 2040, modeled natural gas usage would be reduced by 80 percent from modeled 2026 usage. The decision also recommends that the California ISO study a sensitivity portfolio with a high upper bound for resources that require longer lead times to develop and come online, such as geothermal and offshore wind.
- Summer Reliability
  - On May 2, 2025, the CEC will host their annual Summer Reliability Workshop. Presentations will include panels on anticipated summer conditions, emerging trends, and energy reliability assessments
- DEBA
  - On August 14, 2024, the CEC approved the first of nine grant agreements under a Notice of Proposed Awards issued for DEBA Program grant funding opportunity for bulk grid efficiency upgrades and capacity additions at existing power plants. Two additional agreements were approved at the September 11, 2024, and March 17, 2025, business meetings. Staff expect to present the remaining six agreements for approval throughout 2025.
- DSGS
  - On April 10, 2025, the CEC adopted the Fourth Edition of the guidelines for its DSGS program for the 2025 summer season to improve program effectiveness and continue to grow participation from clean resources. Major modifications include a new emergency load flexibility virtual power plant participation option, adding energy emergency alert triggers for the storage virtual power plant participation option, and monthly performance reporting.
- Emergency Program and Energy Security Plan:
  - Between October of 2024 and February of 2025, CEC staff supported multiple State Operations Center activations and California Office of Emergency Services efforts responding to the Los Angeles fires, Southern California fire weather conditions, Public Safety Power Shutoffs, and atmospheric river events.

51 California Public Utilities Commission. *Decision Transmitting Electricity Resource Portfolios to the California Independent System Operator For 2025 2026 Transmission Planning Process*. Rulemaking 20-05-003. February 20, 2025. Available at: https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=557879249

  - CEC staff continue to support monthly energy security calls and regional activities related to energy security planning and preparedness.
  - CEC staff are updating and developing energy emergency resources and guidance documents.
  - During quarter one of 2025, staff finalized updates and edits to the California Energy Security Plan.
  - Through quarter two of 2025, staff will coordinate state agency and external briefings on the California Energy Security Plan.
- Demand Activities:
  - The 2024 *IEPR Update* Forecast was adopted at the CEC Business Meeting on January 21, 2025.
  - An *IEPR* Staff Workshop on Gas Demand and Rate Forecasting Information Forms and Instructions was held on February 13, 2025.
  - A 2025 *IEPR* Forecast Workshop on the Economic and Demographic Outlook for California was held February 26, 2025.
  - A Demand Analysis Working Group Meeting on the Demand Flexibility Tool was held February 28, 2025. The Demand Flexibility Tool ("D-Flex Tool") is used to determine potential capacity that could be shifted away from demand for each hour of a given year or series of years.
  - Preliminary work for the 2025 *IEPR* Forecast is ongoing.

APPENDIX A: Acronyms and Abbreviations

BA – balancing authority

BAA – balancing authority area

BANC – Balancing Authority of Northern California

California ISO – California Independent System Operator

CEC – California Energy Commission

CED – California Energy Demand

CESER - Cybersecurity, Energy Security, and Emergency Response

CPUC – California Public Utilities Commission

D. – Decision

DCISC - Diablo Canyon Independent Safety Committee

DCPP – Diablo Canyon Power Plant

DWR - Department of Water Resources

DOE - Department of Energy

DR – demand response

EEA - Energy Emergency Alert

EIA – Energy Information Administration

GHG – greenhouse gas

GO-Biz – Governor's Office of Business and Economic Development

GW – gigawatts

GWh – gigawatt-hours

IEPR – Integrated Energy Policy Report

IOU – investor-owned utility

IRP – integrated resource plan

LADWP – Los Angeles Department of Water and Power

LCR – Load capacity requirements

LCT – Local capacity technical

LOLE – Loss of Load Expectation

LSE – load-serving entity

MMT – million metric ton

MTR – mid-term reliability

MW – megawatt

MWh - megawatt-hour

NQC – net qualifying capacity

OASIS – Open Access Same-time Information System

OTC – Once-through cooling

PG&E – Pacific Gas and Electric

POU – publicly owned utility

PSP – Preferred System Plan

PST – Pacific Standard Time

R. – Rulemaking

RA – resource adequacy

RPS – Renewables Portfolio Standard

SB – Senate Bill

SCE – Southern California Edison

SDG&E – San Diego Gas & Electric

SOD – Slice-of-Day

SRR – Strategic Reliability Reserve

TAC – Transmission Access Charge

TED – Tracking Energy Development

TPP – Transmission Planning Process

VPF - Volumetric Performance Fees

APPENDIX B: 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://www.energy.ca.gov/resources/energy-glossary.
- California Energy Commission Renewables Portfolio Standard Eligibility Guidebook, Ninth Edition Revised, available at: https://efiling.energy.ca.gov/getdocument.aspx?tn=217317.
- 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 the Balancing Authority of Northern California (BANC), California ISO, Imperial Irrigation District, Turlock Irrigation District, and Los Angeles Department of Water and Power (LADWP). The California ISO is the largest of about 38 balancing authorities in the Western Interconnection, handling an estimated 35 percent of the electric load in the West. For more information, see the WECC Overview of System Operations: Balancing Authority and Regulation Overview Web page.

Balancing Authority of Northern California (BANC)

BANC is a joint powers authority consisting of the Sacramento Municipal Utility District, 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 Independent System Operator.

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. For more information, see the Energy Education Natural vs Anthropogenic Climate Change Web page.

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.

Demand Side Grid Support (DSGS) Program creates incentives for utility customers anywhere in the state to reduce load and dispatch backup generation with existing resources on an on-call basis.

Distributed Electricity Backup Assets (DEBA) Program provides incentives for the construction of clean and efficient distributed energy resources. The CEC adopted program guidelines on October 18, 2023, with basic program parameters. Funding will be issued through grant funding opportunities.

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 photovoltaic 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)

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 SB100 Joint Agency Report.

Electricity Supply Strategic Reliability Reserve Program (ESSRRP)

ESSRRP is being implemented by the DWR via the Electricity Supply Reliability Reserve Fund to provide additional generation capacity to support grid reliability. 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.

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).

Integrated Energy Policy Report (IEPR)

Senate Bill 1389 (Bowen, 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 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 Senate Bill 350 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.

Investor-owned utility (IOU)

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 CCA. California has three large IOUs offering electricity service: Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric.

Load serving entity (LSE)

A load serving entity is defined by the California Independent System Operator 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." For more information see the California Independent System Operator's Web page.

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 day with an outage occurred in a single simulated year.

Net qualifying capacity (NQC)

The amount of capacity that can be counted towards meeting Resource Adequacy 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.

Once-through cooling (OTC)

OTC technologies intake ocean water to cool the steam that is used to spin turbines for electricity generation. The technologies allow the steam to be reused, and the ocean water that was used for cooling becomes warmer and is then discharged back into the ocean. The intake and discharge have negative impacts on marine and estuarine environments. For more information on the phase-out of power plants in California using once-through cooling, see the Statewide Advisory Committee on Cooling Water Intake Structures Web page and the CEC Once-Through Cooling Phaseout Tracking Progress Report.

Planning reserve margin (PRM)

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 resource adequacy program is increasing the PRM requirement to 16 percent minimum for 2023, and 17 percent minimum for 2024 and beyond.

Publicly owned utility (POU)

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. In contrast to ds, all utility functions are handled by these utilities. Examples include the Los

Angeles Department of Water and Power and the Sacramento Municipal Utility District. Municipal utilities serve about 27 percent of California's total electricity demand.

Renewables Portfolio Standard (RPS)

The 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.

Transmission Planning Process (TPP)

The California Independent System Operator'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 Energy Commission's annual demand forecast) to assess short- and long-term transmission infrastructure needs. For more information, see the California ISO Transmission Planning Web page.