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California Energy Commission

COMMISSION REPORT

Final 2021 Integrated Energy Policy Report

Volume II: Ensuring Reliability in a Changing Climate

Gavin Newsom, Governor

February 2022 | CEC-100-2021-001-V2



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David Erne
Mark Kootstra
Tom Flynn
Christopher McLean
Angela Tanghetti
Stephanie Bailey
Primary Authors

Raquel Kravitz
Project Manager

Heather Raitt
IEPR Program Manager

Drew Bohan
Executive Director

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Denise Costa

Hannah Craig

Tom Flynn

Liz Gill

John Hingtgen

Elizabeth Huber

Erik Lyon

Rachel MacDonald

Joseph Merrill

Michael Nyberg

Hilary Poore

Harrison Reynolds

Carol Robinson

Lana Wong

ABSTRACT

The *2021 Integrated Energy Policy Report* provides the results of the California Energy Commission's assessments of a variety of energy issues facing California. Many of these issues will require action if the state is to meet its climate, energy, air quality, and other environmental goals while maintaining reliability and controlling costs.

The year 2021 has been unprecedented as the state continues to face the impacts and repercussions of challenging events, including the continued effects of the COVID-19 pandemic, extreme summer weather, and drought conditions. In addition to these events, the *2021 Integrated Energy Policy Report* covers a broad range of topics, including building decarbonization, energy efficiency, challenges with decarbonizing California's gas system, quantifying the benefits of the Clean Transportation Program, and the *California Energy Demand Forecast*.

Keywords: System reliability, electricity, Senate Bill 100, zero-carbon resources, stack analysis, midterm, summer, renewables, thermal resources, emergency proclamation

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EXECUTIVE SUMMARY

Introduction

The *2021 Integrated Energy Policy Report (IEPR)* provides information and policy recommendations on advancing a clean, reliable, and affordable energy system for all Californians. The *2021 IEPR* is presented in the following volumes:

- **Volume I** addresses actions needed to reduce the greenhouse gases (GHGs) related to the buildings in which Californians live and work, with an emphasis on energy efficiency. It also addresses reducing GHGs from the industrial and agricultural sectors.
- **Volume II** examines actions needed to increase the reliability and resiliency of California's energy system.
- **Volume III** looks at the evolving role of gas in California's energy system.
- **Volume IV** reports on California's energy demand outlook, including a forecast to 2035 and long-term energy demand scenarios to 2050. The analysis includes the electricity, gas, and transportation sectors.
- **Appendix** assesses the benefits of California's Clean Transportation Program.

Increased Focus on Ensuring Reliability

The summers of 2020 and 2021 have been pivotal in the management of the California electricity grid. The state experienced unprecedented extreme heat events, drought, and wildfires, attributable to California's changing climate. The heat — both in California and westwide at times — created unanticipated spikes in demand. Heat, drought, and wildfires also impacted supply, reducing hydropower generation, curtailing imports, and impacting generation and transmission performance.

At the same time, the state continues to add zero-carbon energy resources to replace fossil-fuel generation and support growing demand. Moving to zero-carbon resources is critical to reducing GHG emissions and addressing the long-term impacts of climate change. These sources do not operate on demand like traditional fossil-fuel generation, requiring more agile management of generation on the grid, greater coordination in the electricity market, and improved resource planning.

After the rotating electricity outages in August 2020, Governor Gavin Newsom directed the California Energy Commission (CEC), California Public Utilities Commission (CPUC), and California Independent System Operator (California ISO) to develop a root cause analysis. In response, the three energy institutions developed the *Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave* (Final Root Cause Analysis). The report identified three main causes of the outages:

1. The climate change-induced extreme heat wave across the western United States resulted in demand for electricity exceeding existing electricity supply and planning targets.
2. In transitioning to a reliable, clean, and affordable resource mix, planning targets have not kept pace to ensure sufficient resources to meet demand in the early evening hours. This situation made balancing demand and supply more challenging during the extreme heat wave.
3. Some practices in the day-ahead energy market exacerbated the supply challenges under highly stressed conditions.

In response, the three energy institutions took immediate actions to prepare for summer 2021 and improve electric reliability, particularly in the summer months. The extreme heat events of 2020 and 2021 made clear the vulnerabilities in the electric system. The efforts taken in 2021 and that are ongoing, with planning through 2026, will create a more reliable system for California, particularly to prepare for future extreme events.

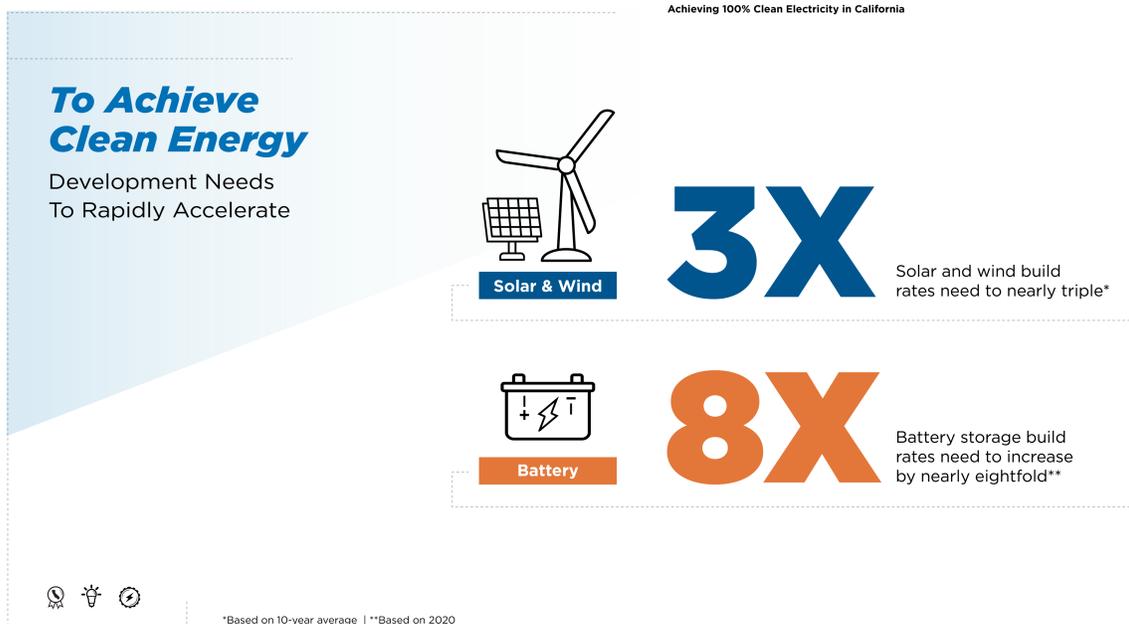
Transitioning to Zero-Carbon

The state is rapidly adding zero-carbon resources to support the ambitious targets of Senate Bill 100 (De León, Chapter 312, Statutes of 2018). SB 100 requires powering all retail electricity sold in California and state agency electricity needs with renewable and zero-carbon resources by 2045.

In the last decade, commercial solar photovoltaic (PV) in California has grown from 200 megawatts (MW) in 2011 to almost 13,000 MW in 2020, and wind capacity has grown from 4,000 MW in 2011 to 6,000 MW in 2020. At the same time, customer-sited solar has grown from 126 MW in 2005 to more than 11,000 MW in 2020.

While the growth in solar and wind has been unprecedented, record-setting additions of new zero-carbon resources are necessary to meet the state's climate goals. This finding was shown in the analysis that the CEC, CPUC, and California Air Resources Board (CARB) jointly submitted to the Legislature in March 2021 examining how the state's electricity system can become carbon-free by 2045 to meet the SB 100 targets. The analysis showed that California will need to sustain its expansion of clean electric generation capacity at a record-breaking rate for the next 25 years. On average, the state may need to annually build up its new renewable resources and storage at a rate that is threefold and eightfold faster than what it has achieved over the last 10 years. In total, the state may need to build 6 gigawatts (GW) of new renewable and storage resources annually (Figure ES-1). By comparison, over the last decade, the state has built on average 1 GW of utility solar, 300 MW of wind, and 250 MW of battery storage per year, with the vast majority of battery storage capacity having been added in 2021.

Figure ES-1: The State Needs to Build Renewable Resources and Storage at Unprecedented Rates to Achieve Climate Goals



Source: CEC

Future joint-agency SB 100 reports to the Legislature will need to build on the analysis in the first report. For example, the next report will explore how emerging zero-carbon technologies can support the transition to a zero-carbon future. The analysis also will need to assess how the buildout of new renewable and storage resources affects system reliability and provides non-energy benefits (such as air and water quality benefits) and reduces social impacts.

Feeling Climate Change Impacts

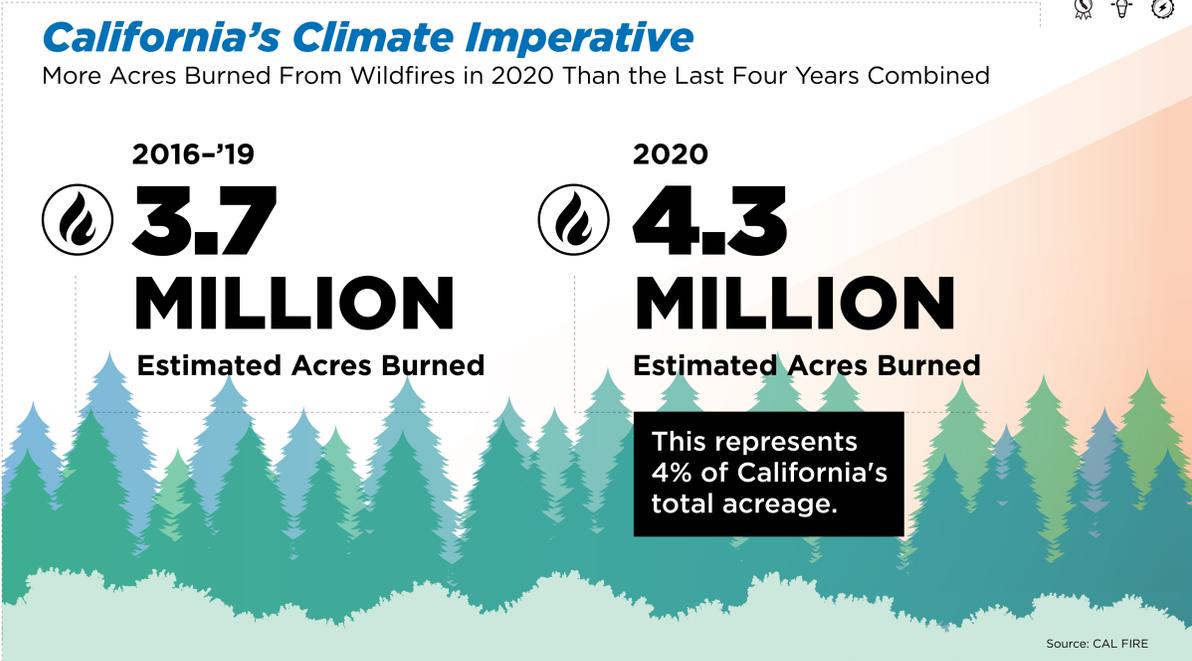
Extreme heat events and drought place increasing strain on the electric system reliability by increasing demand and reducing generation capacity. For example, the high temperatures on August 14–15, 2020, caused rotating blackouts in the California ISO territory. Westwide heat events and wildfires can reduce access to electricity from neighboring states because of greater competition for electricity in those states and because heat and wildfires may impact transmission lines that bring critical power into California or to load centers.

Drought conditions over the last decade have been somewhat cyclical, but the trend is toward more severe and longer droughts. These drought conditions impact the electricity sector in several ways and have the largest impact on reliability through hydroelectric supply. While less water means lower overall hydropower generation, it does not always impact reliability. This is because California uses hydropower strategically when it can best support electric reliability. However, the more severe the

drought, the greater potential for impacts to reliability. For example, water levels in Lake Oroville, which feeds California’s fourth-largest hydropower plant, dropped so low in 2021 that the plant was forced offline.

Droughts and extreme heat events also affect the grid by increasing wildfire risks. Recent years of dry and windy weather have resulted in California facing unprecedented wildfire risks (Figure ES-2). Although wildfire has been a part of California’s natural history for millennia, the size and intensity of wildfires have grown due to human activity and climate change. Wildfires are sometimes caused by electricity generation and transmission infrastructure and can threaten generation and infrastructure, compounding reliability concerns. For example, the Bootleg Fire in Oregon directly forced the main Pacific AC intertie path out of service July 9, 2021, because of impacts from the smoke. This outage triggered a California ISO Stage-1 Grid Emergency, with the California ISO requesting certain market participants to reduce energy use voluntarily and creating concerns of potential rotating blackouts. Further analysis is needed to better characterize the impacts of climate change on the electricity system and system reliability.

Figure ES-2: Climate Change Impacts Such as Wildfires Add Risks to California’s Energy Reliability



Source: CEC using data from CalFIRE

Summer Reliability

Traditionally, California prepares for the highest electricity demand in August and September, but the heat events of 2021 showed that the grid can also be strained in June and July. Recognizing the need to improve and update planning to account for

climate change, the Final Root Cause Analysis called on the CEC to develop and publish several statewide assessments, including an annual summer assessment of electricity reliability and a multiyear outlook (for example, an assessment of reliability for the next five years).

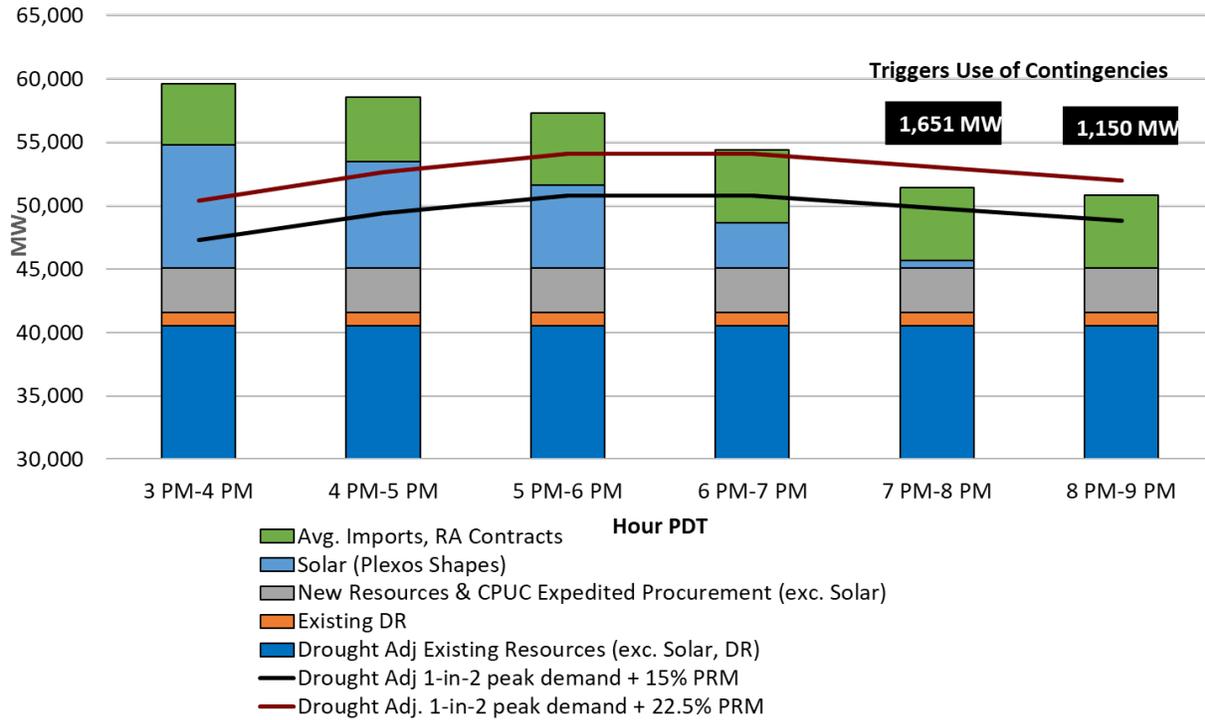
While a summer analysis could inform an emergency procurement (for example, requiring utilities to procure more generation or storage), the primary goal of a summer assessment is to understand the impact of an extreme heat event, like the one California experienced in 2020, and the contingency resources that could be needed to support grid reliability under those high-demand cases. In contrast, a multiyear reliability assessment can better inform future procurement. In 2021, the CEC began development of two reliability assessments: (1) a summer stack analysis to help support contingency planning the current year and (2) a multiyear analysis, referred to as the *California Reliability Outlook*.

Summer Stack Analysis

The stack analysis assesses supply and demand for average and extreme weather conditions. The stack analysis supplements traditional planning methods and is intended only to provide a snapshot of a potential worst-case scenario on the California ISO system to inform the need to prepare for adequate contingencies.

For example, the stack analysis for July 2022 (ES-3) shows snapshots of hourly electric supply and demand for hours when the grid may be strained. The “stacked” bars show the amount of capacity expected from imports, solar, new resources coming on-line by July, demand response (demand flexibility, as discussed further below), and existing resources. Overlaid on the stack is the potential electricity demand and required reserves for each hour. Embedded in the analysis are assumptions about planning reserves and factors such as drought impacts, unplanned generation outages, and weather variability. This analysis for July 2022 shows a need to plan for contingencies that can be drawn upon between 7:00 p.m. and 9:00 p.m. to avoid power outages.

Figure ES-3: Sample Stack Analysis for July 2022 15 Percent and 22.5 Percent Planning Reserve Margin



Source: CEC

Because it may not be possible to procure additional resources quickly enough to meet the needs of extreme heat events, the state can plan for contingency resources, as it did in 2020 and 2021. Contingency resources are typically called on in response to a California ISO warning when there is the potential for rotating outages, and some may only be called on under an emergency proclamation from the governor, such as those that would otherwise exceed air permit operational allowances. Contingency resources can include working with large customers to provide additional demand reductions or adding temporary generation. For example, managers of a large commercial or industrial plant may shift the timing of production schedules to reduce demand. Contingencies can also include use of backup generators to reduce demand on the grid. However, contingency resources that create air quality issues, such as diesel back-up generators, are resources of last resort. They are used only in extreme situations to prevent an outage and an emergency proclamation may be required to authorize the use of diesel back-up generators. The intent of a stack analysis is not to determine whether traditional procurement is needed; it is designed to inform the need for these types of contingency resources.

California Reliability Outlook

Whereas the stack analysis is a near-term look at reliability, the state also needs an analysis that looks at the midterm (for example, five years out) to help identify procurement targets to meet reliability. The CEC developed its first midterm analysis,

the *California Reliability Outlook*, to cover the period of 2022–2026. It was developed in close collaboration with CPUC staff and with stakeholder input. This first *California Reliability Outlook* included the five-year period of 2022–2026 and analyzed several key questions identified by the CEC and CPUC:

1. Is additional capacity needed beyond the current CPUC procurement orders to support reliability for the California ISO footprint?
2. Does incremental thermal capacity provide additional system reliability compared to a portfolio of new zero-emitting resources?
3. Is there sufficient energy at the systemwide level to charge battery energy storage systems under the expected resource build?
4. What are the potential reliability impacts of potential supply chain delays that impact battery storage?

The analysis showed that the CPUC’s resource procurement path for the state appears to be sufficient to support reliability, except for in 2022, which requires between 1,400 MW of net qualifying capacity (NQC) and 1,600 MW NQC from additional resources. *Net qualifying capacity* is the capacity assumed to be available at the peak hour within the resource adequacy (RA) program. It considers expected performance and ability of the resource to deliver at that level of performance. The resource adequacy program is managed by the CPUC with the purpose of ensuring sufficient generating capacity is available for reliability. In this program, load-serving entities (LSE) are assigned specific NQC contracting requirements and compliance with those targets is evaluated. An LSE is an entity, such as an investor-owned utility, that directly services retail electric customers.

The reliance on zero-carbon resources does not appear to adversely impact reliability compared to procuring thermal resources (such as gas-fired generation). As a result, the clean energy path for the state should not affect system reliability over the period of this study.

Further, it appears that increasing reliance on energy storage, such as utility-scale batteries, for systemwide energy needs at levels proposed does not appear to impact system reliability. While preliminary analysis suggests that modest supply chain impacts for battery storage do not appear to substantially impact system reliability, the state needs to continue to monitor and evaluate energy storage deployment and the related impact on reliability.

The CEC has committed to developing a summer stack analysis and a California reliability outlook annually. Staff will work with stakeholders to continually improve both analyses to evaluate different scenarios as the system evolves.

Demand Response

Demand flexibility, or demand response (DR), is the practice of managing customer electricity usage in response to economic incentives. DR is increasingly important for

utilities and wholesale market operators to balance electricity supply and demand, especially under critical grid conditions. DR programs in California are largely directed by the CPUC and administered by California's three regulated investor-owned utilities: Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric.

At the request of the CPUC, the CEC has begun to analyze and propose improvements to how California plans and accounts for the contribution of DR capacity to reliability. As part of this effort, the CEC launched a working group process with utilities, the California ISO, demand response providers, and other stakeholders to develop solutions that unlock the promise of reliability benefits these programs hold for consumers and the grid. The CEC will provide its recommendations for a comprehensive supply-side demand response measurement and verification strategy including a new supply-side demand response capacity counting method in a report to be submitted to the CPUC in February 2022.

CHAPTER 1:

Introduction

The summers of 2020 and 2021 have been pivotal in the management of the California electricity grid. The state experienced unprecedented extreme heat events, drought, and wildfires in both years. The combination of these events had substantial impacts on the state's demand and supply of electricity. Extreme heat causes greater customer demand to keep cool and can reduce the ability of some generation resources to produce electricity. The efficiency of gas-fired power plants drops as temperatures rise. Drought can reduce hydropower generation when water levels in the state's dams and reservoirs reach a point called *deadpool*, where there is not sufficient water pressure to run the turbines. Westwide heat events and wildfires can reduce access to electricity from neighboring states, either because of greater competition for electricity in those states or because heat and wildfires impact transmission lines bringing critical power into California.

The extreme heat events, drought, and more frequent and larger wildfires are attributable to climate change, are predicted to be more frequent in the years ahead, and are already impacting the grid. On August 14–15, 2020, an extreme heat event resulted in rotating outages in the California Independent System Operator (California ISO) territory. Nearly 500,000 customers lost power for 15 to 150 minutes on August 14, and 321,000 customers lost power for 8 to 90 minutes on August 15. Outages, even those of short duration, can have substantial impacts, including health and safety threats to customers, especially those on medical devices, and to the broader state economy. The event revealed vulnerabilities in the reliability of the state's electricity supply, particularly during net peak hours. The net peak hours are those when solar generation is rapidly declining — and declining faster than demand does. This is after the highest demand of the day (gross peak), and it extends the period of concern for meeting load to the hours of 4:00 p.m. to 9:00 p.m.

The extreme heat was a 1-in-30-year weather event in California, when accounting for 35 years of weather data. Further, this extreme heat event extended across the western United States. The resulting demand for electricity exceeded the existing electricity resource planning targets, and resources in neighboring areas were also

strained.¹ The state experienced another extreme heat event September 6–7, 2020, that caused strained grid conditions but no rotating outages.

July through September have routinely been the months of greatest concern for high demand from heat waves; however, in 2021, the state experienced heat waves in May and June. The June 17–18, 2021, heat event broke temperature records across the West. The National Oceanic and Atmospheric Administration (NOAA) records that California, Idaho, Nevada, Oregon, and Utah experienced the warmest summer on record (June through August).²

In response to the August 2020 rotating outages, Governor Gavin Newsom requested that the California Energy Commission (CEC), California ISO, and the California Public Utilities Commission (CPUC) develop a root cause analysis to identify the issues causing the outages. The *Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave*³ (Final Root Cause Analysis) highlighted the importance of adequately planning for a changing generation mix, accounting for climate change impacts, and making sure that sufficient resources are available to serve load during the net peak period to ensure system reliability.⁴

The Final Root Cause Analysis provided recommendations for immediate, near-, and longer-term improvements to the state’s resource planning, procurement, and market practices, many of which are underway. The agencies and California ISO implemented actions to improve near-term system reliability. While not a comprehensive list, some key actions include:

1 California ISO, CEC, and CPUC. 2021. [Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave](http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf). <http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf>.

2 NOAA. September 9, 2021. ["Summer 2021 Neck and Neck With Dust Bowl Summer for Hottest on Record."](https://www.noaa.gov/news/summer-2021-neck-and-neck-with-dust-bowl-summer-for-hottest-on-record) <https://www.noaa.gov/news/summer-2021-neck-and-neck-with-dust-bowl-summer-for-hottest-on-record>.

3 California ISO, CEC, and CPUC. 2021. [Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave](http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf). <http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf>.

4 Ibid.

- The CPUC initiated significant procurements and program reforms under the resource adequacy (RA)⁵ and integrated resource planning (IRP)⁶ proceedings. An emergency reliability rulemaking expedited procurement for 2021 and a second phase in 2021 was opened to order additional procurement for 2022–2023. Through the IRP proceeding, the CPUC ordered additional resources for 2023–2026. The CPUC also initiated an effort to reevaluate several foundational planning elements, including the planning reserve margin, qualifying capacity method, and effective load-carrying capability by early 2023.
- The California ISO and CPUC worked to refresh and improve the Flex Alert program, which is a voluntary consumer energy conservation program.
- The California ISO made market enhancements, with approval of the Federal Energy Regulatory Commission, including (1) incentives for suppliers to submit import schedules in the hour-ahead scheduling process during tight market conditions, (2) reliability demand response resource dispatch and real-time pricing enhancements, (3) energy imbalance market coordination and resource sufficiency test modifications, (4) pricing enhancements during tight system conditions, and (5) targeted generation interconnection process improvement.
- The CEC initiated two new reliability-related assessments to support planning for the summers of 2021 and 2022 and for midterm planning (2023–2026). The summer analysis informs the state on the potential contingency resources that might be needed under extreme heat events, and the midterm analysis helps inform procurement for the midterm.
- The CEC, CPUC, and California ISO developed a contingency plan to improve coordination during emergencies. As well as clearly describing roles and responsibilities, the plan identified contingency resources that could be made available in the event of another extreme heat event. Contingency resources are

5 The resource adequacy proceeding is designed to ensure the reliability of electric service in California. RA obligations are assigned to each LSE within the CPUC’s jurisdiction for capacity procurement, and compliance with those obligations are enforced. For more [information](https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage), see <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage>.

6 The integrated resource plan proceeding is designed to consider all of the CPUC’s electric procurement policies and programs and ensure California has a safe, reliability, and cost-effective electricity supply. To evaluate needs, the proceeding looks ahead 10 years at the system, local, and flexibility needs. For more [information](https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning), see <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning>.

either further demand reduction or supply beyond currently planned resources that can be called on in an emergency, such as additional load reduction from large customers or mobile generation resources.

These actions provided immediate benefit to the state, which continued to experience record-breaking heat, impacts of a drought, and wildfires in 2021. This situation resulted in tight grid conditions during the summer of 2021 but no outages. By mid-July, the California ISO had issued six Flex Alerts, requiring the Governor's Office, agencies, and California ISO to call on additional resources, including large customer demand reduction, to support grid operations multiple times. This led to Governor Newsom issuing an emergency proclamation July 30, 2021, declaring an energy emergency and ordering several actions to enable additional capacity to support electric reliability. Actions included direction to the Department of Water Resources to secure additional energy supply, providing incentives for large energy users to reduce demand, and expediting the certification process amendments to existing facilities that would add capacity, temporary power generators, and battery storage.

The state is facing this growing impact of climate change as it takes a leadership position nationally and internationally to reduce the greenhouse gases that are driving climate change. The state passed Senate Bill 100 (De León, Chapter 312, Statutes of 2018), which sets an ambitious target of powering all retail electricity sold in California with renewable and zero-carbon resources by 2045. Moving toward 100 percent clean electricity will increase access to clean energy for Californians, reduce air pollution, improve public health, and support the emissions reductions in other sectors, such as transportation and buildings. However, it will continue to require deployment of a large amount of existing and new technologies and a close eye on grid reliability.

The next five years represent a critical transition period for California's electric grid. Nearly 6,000 megawatts (MW) of firm and dispatchable resources, or resources that can provide power on demand, are expected to be retired. These resources include the remaining once-through-cooling (OTC) plants⁷ and the Diablo Canyon Nuclear Power Plant. Analysis performed by the CEC and CPUC that looked at the impacts of retirements and increasing demand for the period of 2022–2026 shows the need for roughly 11,500 MW of new resources. The CPUC is addressing this procurement in its Integrated Resource Plan proceeding.

7 A once-through-cooling plant draws water from a nearby waterbody to provide a cooling fluid for the plant. The water is subsequently discharged back to the waterbody at a warmer temperature.

However, there continue to be challenges to address in the next five years to meet reliability goals, particularly during the net peak, to ensure sufficient resources are available. As well as the challenges described above, LSEs that participated in the July 8, 2021, IEPR workshop on reliability expressed concerns in the near and long term about the availability of quality imports, particularly during westwide heat events or wildfires.⁸ Further, energy storage, which is being deployed at a greater level, particularly to support the net peak, has supply chain and safety issues to overcome.

Addressing these challenges in the near term and midterm will be critical to ensuring grid reliability as the state's resource mix continues to evolve away from fossil-fueled resources to zero-carbon resources. Further, the shift toward electrification, which is discussed in more detail in Volumes I and III of the *2021 Integrated Energy Policy Report (IEPR)*, will put further stress on the system, and strategies will need to be developed to support the additional demand affordably.

⁸ July 8, 2021, IEPR workshop on Summer 2021 Electric and Natural Gas Reliability — Session 2. Workshop [transcript](https://efiling.energy.ca.gov/GetDocument.aspx?tn=240855&DocumentContentId=74690) is available at <https://efiling.energy.ca.gov/GetDocument.aspx?tn=240855&DocumentContentId=74690>.

CHAPTER 2:

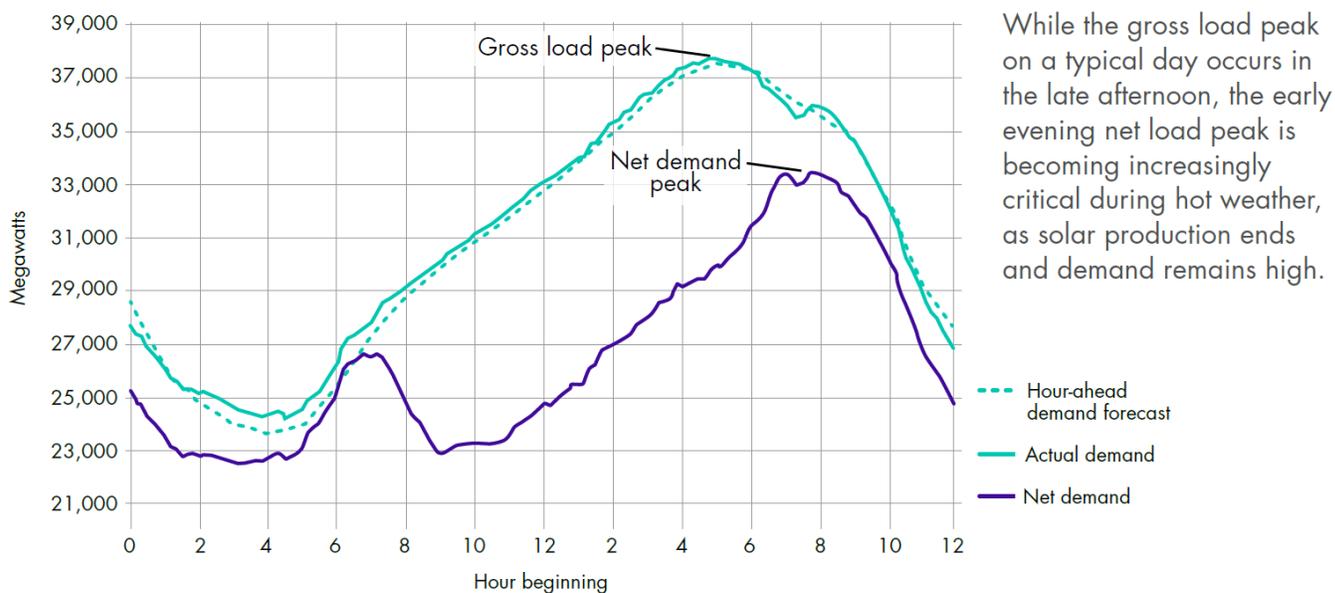
An Electric System Transitioning to Zero-Carbon

As noted in the introduction, the California grid is transitioning to a clean energy system while adapting to a changing climate. The growth of zero-carbon resources has changed the supply and demand throughout the day, making it harder to balance the electricity system. This change has required additional procurement of resources, particularly to support critical hours in the day. At the same time, there are greater opportunities to access resources statewide as the California Independent System Operator (California ISO) market expands.

Shifting to Net Peak

Historically, critical periods of system operations aligned with when the grid was most heavily loaded, and system demand approached annual system maximums. The growth of zero-carbon resources, especially solar resources, has shifted the reliability concerns from the peak hour (hour with the highest energy demand) to net peak hours (hours when energy demand minus wind and solar generation is largest). The changing resource mix is driving a change in the characteristics of the electricity system and requires consideration of the net demand curve, total electricity demand less the wind and solar generation, when planning how to operate traditional resources. This situation is referred to as the *duck curve*. The duck curve is characterized by more drastic increases in net demand in the evening hours as solar decreases, and a net peak that occurs later in the evening when solar generation is substantially diminished or nonexistent.

Figure 1: Peak and Net Peak Demand



Source: California ISO

The net peak period is presenting new challenges to forecasters, planners, and operators. These hours, usually between 4:00 p.m. and 9:00 p.m., carry dynamic uncertainties, and any shortcomings in forecasting loads and renewable resource production in these periods can lead to challenges in real-time operations. New solutions, including increased deployment of energy storage and reliance on flexible loads, can help, but they also introduce added uncertainty and complexity. As reliability concerns are driven more by the net peak hours, forecasters, planners, and operators will need to rapidly evaluate if and how the business-as-usual practices need to be adjusted to prepare California’s electricity system for the zero-carbon transition.

Resource Planning

High-demand conditions in 2020 and 2021 and predictions of potential shortfalls in 2022–2026 have resulted in the need to procure more resources for the California ISO territory. In response, the California Public Utilities Commission (CPUC) has taken actions to ensure more resources are available in 2021 and beyond. Further, the California Energy Commission (CEC), California ISO, and CPUC have worked to identify contingency resources — resources of last resort — when there are record-setting demands on the system, such as during extreme heat events.

To support system reliability after the rotating outages in August 2020, the CPUC established an Emergency Reliability Rulemaking (R.20-11-003) in November 2020. This proceeding was initiated to ensure reliable electric service in California in the event of an extreme weather event in 2021. In March 2021, the CPUC approved contracts from

the state's three large investor-owned utilities (IOUs) for roughly 564 megawatts (MW) by summer 2021. The CPUC also directed⁹ the IOUs to take actions to avert the potential need for rotating outages in the summers of 2021 and 2022, including:

- Launching a new statewide demand response program, the Emergency Load Reduction Program (ELRP) pilot.
- Modifying the IOUs' existing demand response and critical peak pricing programs.
- Funding a new statewide Flex Alert media campaign.
- Increasing the planning reserve margin — the buffer that accounts for extreme conditions and unexpected outages — by allowing the IOUs to procure to a target of 17.5 percent.

The CEC, CPUC, and California ISO also developed a 2021 Joint Agencies California ISO Balancing Authority Area Electric Reliability Contingency Plan (Contingency Plan) in August 2021,¹⁰ as identified in the *Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave*.¹¹ The Contingency Plan describes how those entities will coordinate in advance of and throughout an anticipated electricity supply shortfall in the California ISO balancing area. In doing so, the plan systematizes the measures that were enacted in 2020. It describes the roles and responsibilities of each institution to identify and pursue contingency resources, as well as the triggers for engaging each resource. Contingency resources are those beyond existing procured resources and can include load reduction from large customers, additional imports from other balancing authorities, generation from thermal plants beyond their permit limits/restrictions, and the CPUC's ELRP. Contingency resources are meant as a backstop against an extreme event and are not meant to be routinely called to support grid reliability. This is

9 CPUC. 2021. [Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022](https://docs.cpuc.ca.gov/publisheddocs/published/g000/m373/k745/373745051.pdf). Decision 21-03-056, Rulemaking 20-11-003. <https://docs.cpuc.ca.gov/publisheddocs/published/g000/m373/k745/373745051.pdf>.

10 CEC, CPUC, and California ISO. August 2021. [2021 Joint Agencies CAISO Balancing Authority Area Electric Reliability Contingency Plan](https://www.energy.ca.gov/sites/default/files/2021-11/August%202021%20Joint%20Agencies%20Contingency%20Plan_ADA.pdf). https://www.energy.ca.gov/sites/default/files/2021-11/August%202021%20Joint%20Agencies%20Contingency%20Plan_ADA.pdf.

11 California ISO, CEC, and CPUC. 2021. [Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave](http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf). <http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf>.

particularly true for contingencies that could result in air quality issues, such as backup generators.

The CEC and Governor's Office established a network of large customers that would be interested in reducing their load, either from changes in their operations or by relying on backup generators to take load off the grid during the net-peak period. The CPUC also established the ELRP to help reimburse large customers in the IOU territories for further demand reduction. The Governor's emergency proclamation established a similar program — the California State Emergency Program — that reimburses large customers for voluntary load reduction in the event of an emergency.

Analysis by the CPUC and CEC in 2021 showed that the state could continue to have tight supply conditions in 2022 through 2026. As a result of this analysis and in response to Governor Gavin Newsom's emergency proclamation, the CPUC released a scoping ruling (Rulemaking 20-11-003) August 10, 2021, focused on additional actions that the CPUC could take to secure reliability programs or procurement for summers 2022 and 2023. On October 29, 2021, the CPUC issued a proposed decision directing the IOUs to take multiple actions to prepare for potential extreme weather in the summers of 2022 and 2023. A final decision was issued December 6, 2021, with an effective date of December 2, 2021.¹²

The CPUC had already begun to order load-serving entities (LSEs) to procure 14,800 MW in its ongoing Integrated Resource Plan (IRP) Rulemaking (R.20-05-003). This procurement is needed to backfill capacity from retiring natural gas plants and the Diablo Canyon Power Plant and meet the electric sector greenhouse gas (GHG) emissions planning targets. The CPUC required procurement of 14,800 MW in two orders:

- In November 2019, the CPUC ordered LSEs to procure 3,300 MW net qualifying capacity¹³ (NQC) of new resources by 2023 (Decision 19-11-016). LSEs have reported procurement contracts for more than 1,600 MW NQC, and another

12 CPUC. 2021. [Decision 21-12-015](#).

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M428/K821/428821475.PDF>.

13 *Net qualifying capacity* is the maximum resource adequacy capacity that a resource may be eligible to provide, as determined by the California ISO, after accounting for applicable reductions due to resource limitations, performance criteria, and deliverability restrictions.

3,000 to 4,000 MW of nameplate capacity¹⁴ additions may be required to provide the remaining 1,700 MW NQC.

- In June 2021, the CPUC ordered the procurement of 11,500 MW of new NQC to come on-line in 2023–2026 (Decision 21-06-035), requiring all resources procured to be zero-emitting or otherwise Renewables Portfolio Standard-eligible.¹⁵ While the order specifies procurement of 11,500 MW of NQC, the total nameplate capacity of these resources is expected to exceed 23,000 MW, depending on the technologies implemented and whether the 2,000 MW NQC of long lead time resources must be procured by 2026. The June 2021 order will help ensure reliability in the mid-decade, keep California on track to achieve its climate goals, and spur the development of the clean, firm resources needed for deep decarbonization.

Resource planning is continuing to evolve to support Senate Bill 100 (De León, Chapter 312, Statutes of 2018) targets. The *2021 SB 100 Joint Agency Report (2021 SB 100 Report)*,¹⁶ submitted to the Legislature in March 2021, was developed with more than a year and a half of robust stakeholder engagement. The report evaluated potential resource pathways to meeting the 2045 policy through modeling different scenarios of resource buildout. The initial analysis concluded that the SB 100 targets are technically achievable with current technologies and that increasing the diversity of resources lowers overall costs. However, it also identified that it would require record-setting build rates of new resources to meet the targets. The report noted that this first analysis was preliminary, and that further analysis is necessary to evaluate how emerging resources, such as long-duration storage, green hydrogen, and gas with 100 percent carbon sequestration, would affect the results. It also noted that reliability was not evaluated, and that the reliability of buildout scenarios will need to be assessed in the next

¹⁴ *Nameplate capacity* is the value registered with authorities for classifying the power output of an electric generator usually expressed in megawatts (MW).

¹⁵ The Renewables Portfolio Standard (RPS) is one of California’s key programs for advancing renewable energy which sets continuously escalating renewable energy procurement requirements for the state’s load-serving entities whereby generation must be procured from RPS-certified facilities.

¹⁶ CEC, CPUC, and California Air Resources Board. 2021. [*2021 SB 100 Joint Agency Report Achieving 100 Percent Clean Electricity in California: An Initial Assessment*](#).

file:///C:/Users/hraitt/Downloads/TN237167_20210315T110256_2021%20SB%20100%20Joint%20Agency%20Report.pdf. Publication Number: CEC-200-2021-001.

iteration of the report. These analyses help inform future resource planning to meet the SB 100 goals.

Following the release of the *2021 SB 100 Report*, the CEC, CPUC, and California ISO initiated a collaborative process to focus on the resource build requirements needed to achieve the SB 100 goals.¹⁷ This ongoing collaboration includes a public stakeholder process. One of the priorities of the SB 100 resource build collaborative process is to inform the California ISO's 20-year transmission outlook ("20-year outlook"),¹⁸ a process to explore longer-term grid requirements and options for meeting the state's GHG reduction goals. In September 2021, the CEC posted a *starting point* scenario document,¹⁹ based on the *2021 SB 100 Report*, for the California ISO's use in its 20-year outlook process. The starting point scenario includes the allocation of resources in the scenario and, as applicable, the location of those resources. The starting point scenario is designed to provide information for a wide range of potential transmission needs driven by a combination of potential resource opportunities.

Expanding the Western Energy Imbalance Market (EIM)

The Western EIM is a real-time wholesale energy trading market that enables participants in the West to buy and sell energy when needed. Launched in 2014, it is operated by the California ISO, and its footprint includes portions of Arizona, California, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming. By 2023, the Western EIM will have 22 participants covering about 85 percent of the load on the Western Interconnection.²⁰

The addition of new participants reflects just one mode of growth. The California ISO also plans to expand the Western EIM in its features and capabilities. Recent stakeholder initiatives have helped promote more granular participation by establishing

17 On May 21, 2021, the CEC opened a new [docket, 21-SIT-01](https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-SIT-01), for SB 100 Implementation Planning for SB 100 Resource Build. <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-SIT-01>. Workshop materials and public and stakeholder comments are available in the docket.

18 California ISO. "[20-Year Transmission Outlook](https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/20-Year-transmission-outlook)." <https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/20-Year-transmission-outlook>.

19 CEC staff. 2021. Docket Number 21-SIT-01, [TN # 239685](https://efiling.energy.ca.gov/GetDocument.aspx?tn=239685&DocumentContentId=73101). <https://efiling.energy.ca.gov/GetDocument.aspx?tn=239685&DocumentContentId=73101>.

20 California ISO, Western EIM. News Release 2021. "[WAPA Desert Southwest Region Announces It Plans to Join the EIM](https://www.westerneim.com/Documents/WAPA-Desert-Southwest-Region-Announces-it-Plans-to-Join-the-EIM.pdf)." <https://www.westerneim.com/Documents/WAPA-Desert-Southwest-Region-Announces-it-Plans-to-Join-the-EIM.pdf>.

a Western EIM subentity role in support of more customized scheduling. The newest initiative aims to deliver improvements from day-ahead market enhancements to Western EIM participants, extending operations from the real-time market, currently, to the day-ahead market by 2024. This growing market will provide continued opportunities for California renewable resources to support the transition to a clean grid.²¹

Solar and Wind

Renewables, such as solar and wind, have grown substantially on the grid in the last decade. As of 2020, solar accounts for 15.4 percent of in-state generation (up from 7.7 percent five years ago), and wind accounts for 7.2 percent (up from 6.2 percent in 2015). The California ISO system continues to set records ever closer to the goal of meeting all load with renewable, or zero-emission, resources. In 2021, the California ISO grid served 94.5 percent of system demand with renewable resources instantaneously at 2:28 p.m. on Saturday, April 24.²² While this record represents a momentary success, reaching these goals, and eventually the 100 percent goal, provides key demonstrations of system operating capabilities under a renewable resource paradigm. The following sections provide some additional perspective on trends for solar and wind.

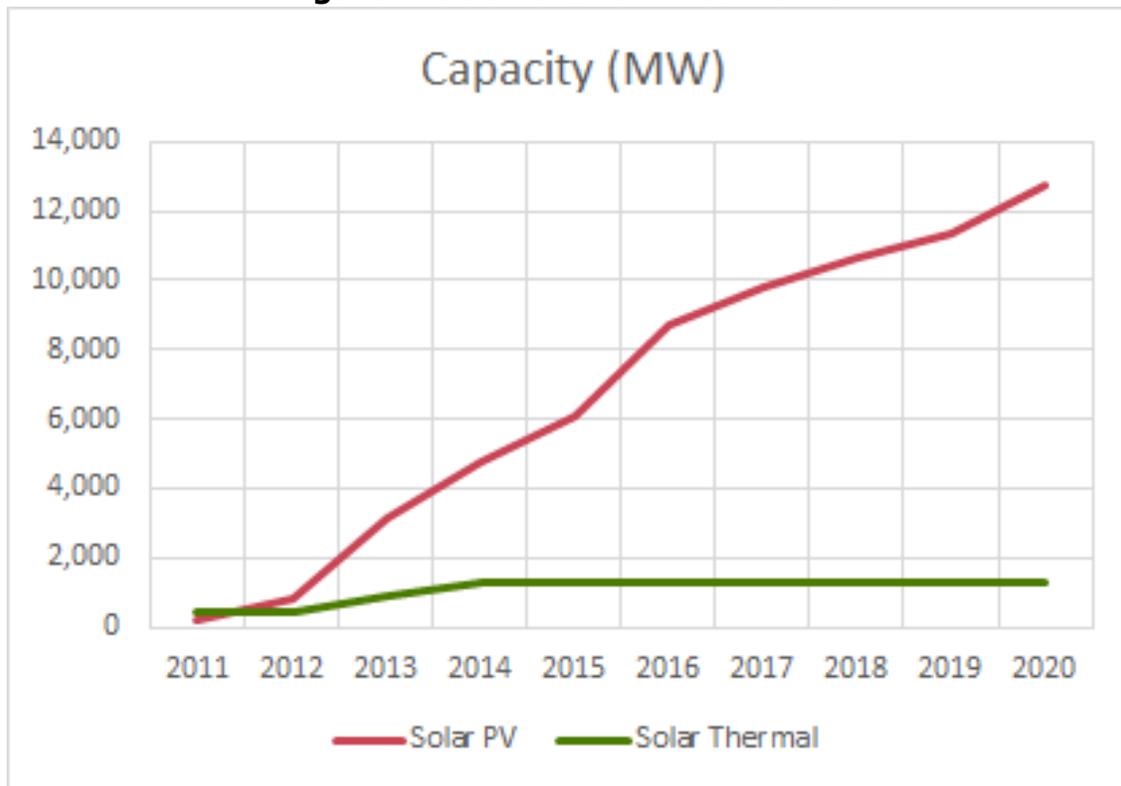
Solar Growth

As shown in Figure 2, commercial solar capacity and generation grew substantially over the last decade. Solar includes both photovoltaic (PV) and thermal generators. CEC data reflect operating power plants rated at least 1 MW in capacity that are considered commercial. Commercial solar PV grew from 200 MW in 2011 to almost 13,000 MW in 2020. Additions were slower in 2011 and 2012 and then accelerated. Solar thermal grew from 400 MW in 2011 to 1,200 MW in 2020, and growth leveled off starting in 2014.

21 California ISO. "[Initiative: Extended Day-Ahead Market](https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market)." <https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market>.

22 California ISO. "[Key Statistics for September 2021](http://www.caiso.com/Documents/Key-Statistics-Sep-2021.pdf)." <http://www.caiso.com/Documents/Key-Statistics-Sep-2021.pdf>.

Figure 2: Solar Growth in California



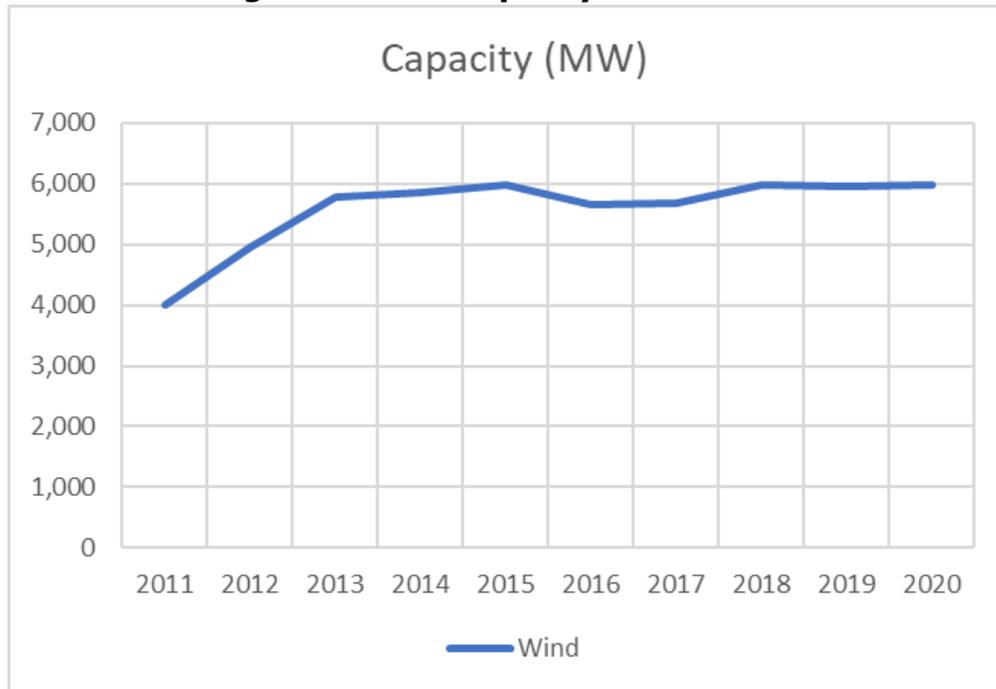
Source: CEC

Net energy generation from commercial systems followed similar trends. Solar PV energy grew from 200 gigawatt-hours (GWh) in 2011 to 27,000 GWh in 2020. The steepest increases were from 2014 through 2018. Solar thermal grew from 900 GWh in 2011 to more than 2,000 GWh in 2020. Larger annual increases were in 2014 and 2015. A temporary dip occurred in 2012 and 2013, which may have been the result of generation fluctuations that can occur during the commissioning phase of new power plants. Energy generation stabilizes as operators fine-tune the power plant for optimum performance.

Wind Growth

As shown in Figure 3, commercial wind generation grew over the last decade. As with solar, CEC data on wind capture operating power plants rated at least 1 MW in capacity, which are considered commercial size.

Figure 3: Wind Capacity in California



Source: CEC

Wind capacity grew from 4,000 MW in 2011 to 6,000 MW in 2020. The fastest growth was from 2011 through 2013. Net energy generation followed similar trends as capacity. Wind grew from 8,000 GWh in 2011 to almost 14,000 GWh in 2020, with steeper growth through 2014. Wind generation reflects weather variations from year to year.

The growth in wind capacity of 2,000 MW over the period is smaller than the growth of solar PV capacity over the same time. Steep solar PV cost reductions resulting from worldwide competition have allowed PV to become more attractive at many sites. Cost reductions in wind equipment have been more modest, leading to smaller changes in project economics.

The growth in wind capacity was accompanied by a shift in turbine sizes. While the number of turbines in the state decreased, turbine capacities increased, and the average turbine surpassed 1 MW. Larger turbines often take advantages of economies of scale at all phases, from design through operation. Modern turbines also offer modern communication systems that allow project operators and grid operators to control and optimize generation in real time. These capabilities allow higher productivity and better integration with the grid.

Older turbines are replaced in repowering projects, where equipment on a site is replaced with modern technology. Because of stringent land-use requirements in most areas of the state, it is often more feasible to repower an existing site than to develop a new site.

Wind plants in California tend to peak in the evening, providing a complementary resource to solar generation — solar peaks at midday and declines in the evening as wind generation increases. All wind plants in California are on land, but the state is planning for offshore wind. The CEC is working with the Bureau of Ocean Energy Management, the United States Department of Defense, and other federal and state agencies to plan for offshore wind off California’s coast. Initial estimates suggest that generation from offshore wind may peak earlier in the day than onshore wind. Although there is some variation in the time profile of onshore plants, offshore plants might generate closer to the net peak than most onshore wind plants.

Solar and Wind Variability

Managing a growing portfolio of solar and wind presents challenges to balancing authorities like the California ISO. To describe the variations in solar and wind generation, CEC staff used 2017–2018 data on energy generation from the California ISO, supplemented by data from the Quarterly Fuel and Energy Reports and Wind Performance Reporting System to show three time frames: monthly variations, daily variations over selected months, and hourly variations over selected days. Solar PV and thermal are combined in the analyses, as solar thermal is usually a small percentage of total solar. To evaluate variations, staff calculated capacity factors (CF).²³ CF is the ratio of the energy generated in a period to what could have been generated if the generator produced energy at maximum capacity during the same period. CF can be expressed as either a percentage or a decimal fraction.

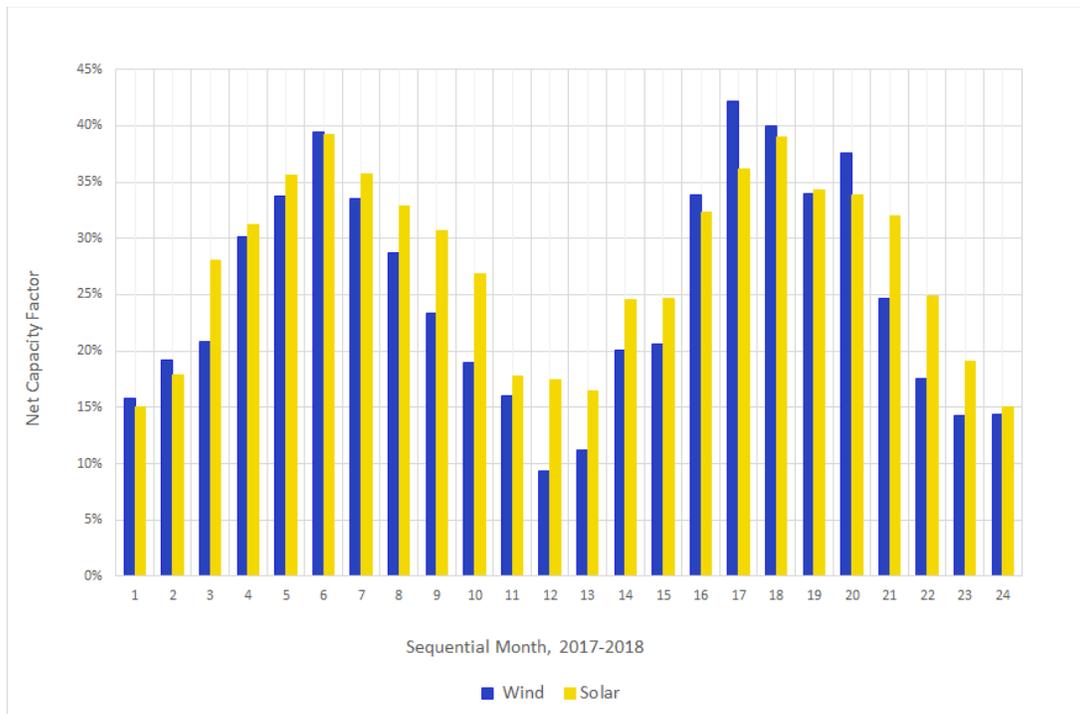
Variations Over a Year

To show how solar and wind can vary over a year, staff looked at performance by month. Figure 4 shows the CF profiles by month during 2017 and 2018 for wind and solar resources. The wind and solar profiles had roughly the same shape, with peaks in the summer and lows in the winter. Over the two-year period, the highest monthly CF for wind was in May 2018 at more than 42 percent, and the lowest was in December 2017 at 9 percent. The solar CF was highest in June 2017 at 39 percent and lowest in January 2017 at 15 percent. From 2017 to 2018, all monthly CFs for the same source

²³ Generation and capacity data to calculate capacity factor come from data sets of the California ISO and the Wind Performance Reporting System and Quarterly Fuel and Energy Reports data sets of the CEC.

varied only by 9 percentage points or fewer, showing consistency in generation from year to year.

Figure 4: Capacity Factors by Month During 2017 and 2018



Source: California ISO data analyzed by CEC staff

Variations Over a Month

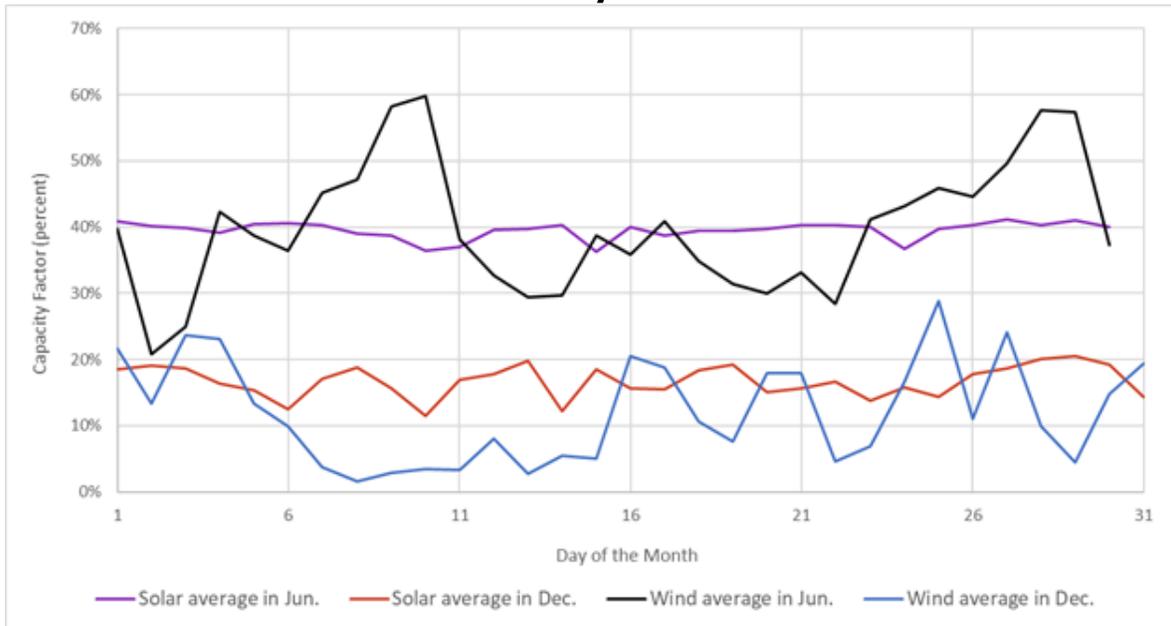
To analyze data over shorter periods, staff examined the variation using selected days, choosing four midmonth weekdays in March, June, September, and December and the peak day in each year. The four dates were selected to represent the generation in each season. The analysis accounts for the change in the number of hours per day due to the shift to daylight saving time but does not adjust the hours for the difference between solar noon and clock noon, (when the sun reaches maximum height in the sky and when the clock shows noon) during daylight saving time. The selected days were:

- In 2017: March 15, June 15, September 15, and December 15.
- In 2018: March 15, June 15, September 14, and December 14.

The dates when system demand peaked were September 1, 2017, and July 25, 2018. Both were weekdays, when demand is typically higher than on weekends. Staff examined the daily variation during the months by averaging the factors on selected days for 2017 and 2018. Figure 5 and Figure 6 show the months when solar radiation is highest and lowest (June and December).

The differences in variation by day are depicted in Figure 5. CFs were higher in June than December throughout the month for wind and solar. The highest and the lowest CFs were reached by the wind plants. The CFs in June for each source were about twice those in December. The graph illustrates that wind and solar output both vary daily.

Figure 5: Wind and Solar Variations Within Month for June and December Days



Source: CEC

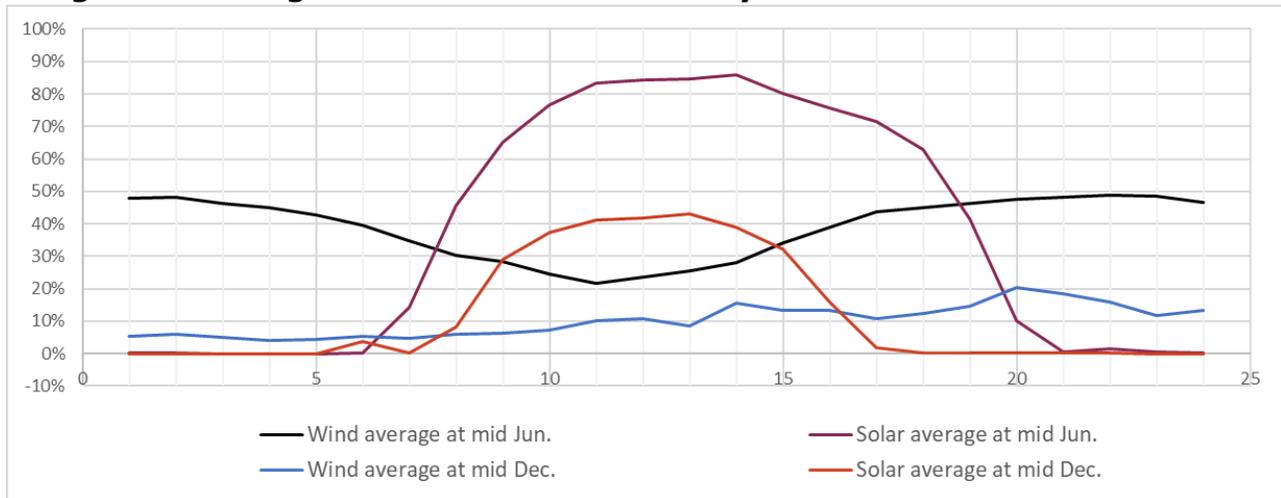
Variations Over a Day

Daily solar generation profiles vary by hour according to received solar radiation. During periods of no solar generation at night, station load continues to consume energy from the grid, and the net solar generation becomes negative in some hours. Station load is typically a small fraction of gross generation.

Wind generation varies with wind speed, and wind speed is affected by many factors, including seasonal and daily patterns, microclimates, local topography, and land cover. Generation profiles vary by hour, as local and regional weather systems move and affect airflow at the generator site. Wind speeds can be low, but are usually not zero, and are not directly dependent on daylight.

To illustrate these patterns, staff calculated the CFs for the wind and solar projects in California ISO for 2017 and 2018 and then averaged the years for each hour of the midmonth days. The factors by hour during midmonth days in June and December are shown in Figure 6.

Figure 6: Average Wind and Solar Profiles by Hour in June and December



Source: CEC

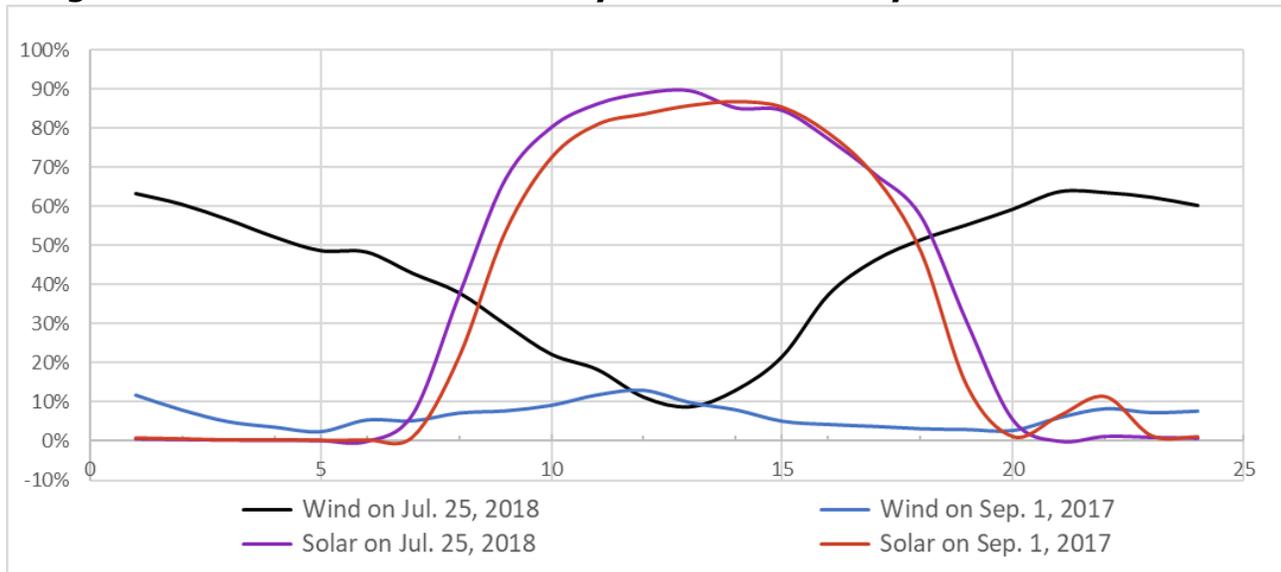
Profiles for March and September fall between the June and December profiles. In June, the average wind profile reached a daily low at midday and a daily high at night, but in December, the average did not follow that trend. The average solar profile showed a peak after midday in both June and December. Both solar and wind showed higher CFs in June than in December. In December, wind factors were higher than solar until early morning and then higher from late afternoon to the end of the day. In June, solar factors rose slightly above wind factors earlier in the morning and stayed higher until early evening. This finding reflects the dependency of the solar peak breadth on the daylight hours.

Peak demand times require dispatching generation plants with different fuels, and generation resources in the state are diverse. Wind and solar generation are part of the supply on most days. During the peak days — September 1, 2017, and July 25, 2018 — wind and solar profiles were as depicted in Figure 7.

Solar generation peaked near midday on both days. Wind generation showed a less pronounced peak at midday in 2017 and an inverse profile to solar in 2018. The profiles for solar between the two years were more similar than the profiles for wind in these years.

The curves reinforce the fact that there can be significant variation in generation output from year to year. This variation is a result of many factors leading to the energy production from a renewable energy resource. Mitigation for natural variation includes energy storage systems and more sophisticated control technology designed into generators.

Figure 7: Wind and Solar Profiles by Hour on Peak Days in 2017 and 2018



Source: CEC

Combination of Hourly Wind and Solar Profiles

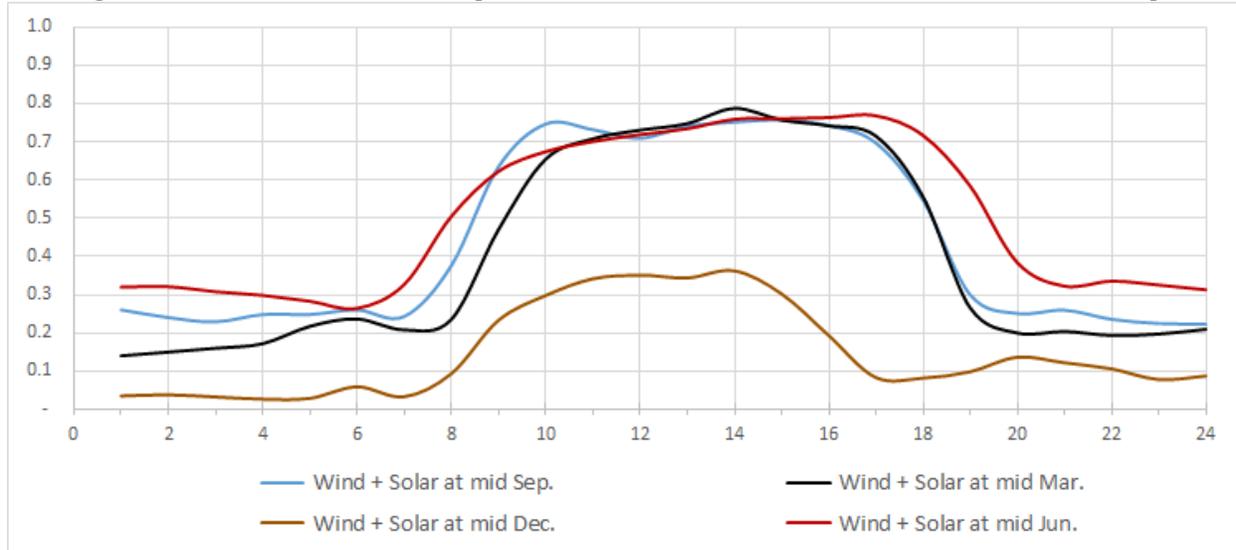
In practice, grid operators dispatch available generation resources to meet demand, accommodating must-take wind and solar energy along with other thermal resources. To illustrate the combination of wind and solar generation, the CFs of the two years for each of wind and solar are averaged for each midmonth day. Then the average wind and the average solar factors are added, and the results are shown in Figure 8. The Y-axis is dimensionless. Combining the two sources this way removes the effect of different capacities to focus on the time profiles. A combined CF could theoretically reach 1.5, made up of a maximum of 1.0 from wind and 0.5 from solar over a year. (Wind can generate day and night, but solar can generate only during the day.) In practice, total CF would not reach 1.5 because that would require ideal generating conditions.

The curves represent the combinations on a same-capacity basis of wind and solar generators on midmonth days in 2017 and 2018. Solar generation raises the combined profile during the daylight hours, and wind generation raises it during the night hours. The plateau was centered later after noon in mid-June compared to mid-December. The time lag in June may reflect the influence of thermal inertia and more heat in the atmosphere, leading to a delay in when wind speeds peak. Winds speeds were not examined.

A combination of wind and solar generators on an equal-capacity basis would have an extended generating plateau from morning through evening in March, June, and September. The profile in December has a shorter plateau from later morning to earlier evening hours. Of the four times of the year, mid-December days provided the least combined generation. Solar radiation is low at that time of year, reducing both solar

and wind generation. Lower radiation directly affects the solar generation and indirectly affects the wind generation. The combined profile in mid-September was higher than in mid-March during most hours.

Figure 8: Combined Hourly Wind and Solar Profiles on Midmonth Days



Source: CEC

At the beginning and end of the day, the grid operator manages the load by ramping hydropower or nonrenewable generators up or down. As solar capacity has grown in recent years, net peak has shifted to later in the day. Wind generation late in the day aids in meeting the shift to a later net peak. The graph in Figure 8 depicts the combined CFs later in the day. In mid-June, the combined factor stays above 40 percent during the night hours.

Energy Storage

Deployment of battery energy storage systems (BESS) on the California grid has substantially increased in recent years, including 2021, during which growth has been unprecedented. California ISO reports that BESS capacity on the system was roughly 550 MW at the end of 2020, 1,500 MW as of September 2021, and is expected to grow

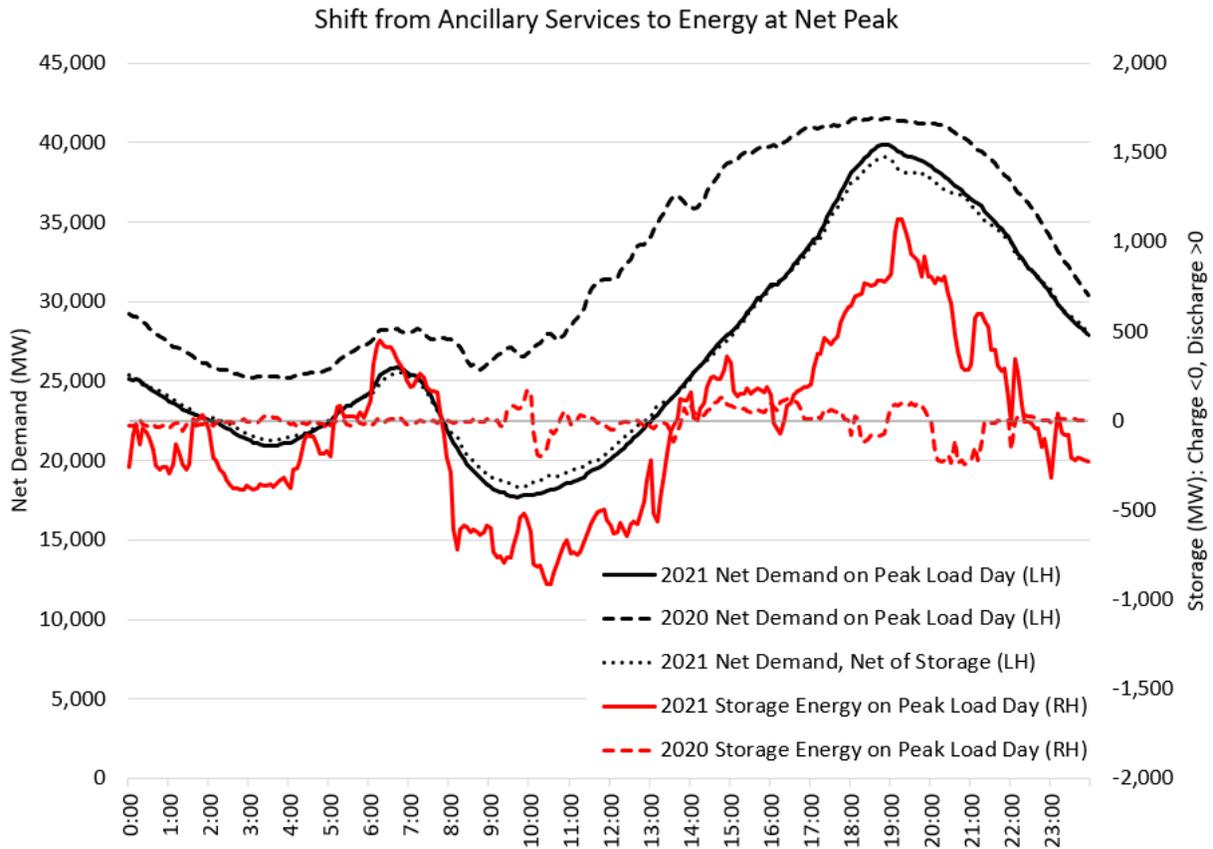
to 3,000 MW by the end of 2021.²⁴ BESS offers the opportunity to take advantage of clean energy during the day by storing it for use during resource-limited conditions, such as the net peak. The CPUC has begun to call for more storage procurement to provide greater grid reliability during net peak. The CPUC's recent 11,500 MW of NQC procurement order will likely result in more than 10,000 MW of new BESS nameplate capacity by the end of 2026.

BESS operation on the grid, in total, has begun to reflect the growth in capacity. Before 2021, when installed capacity only totaled in the hundreds of megawatts, the BESS charging and discharging profiles depicted a resource dedicated to providing ancillary services, especially regulating reserves. By the summer of 2021, the BESS resources on the grid grew to nearly 1,500 MW, and the operating profiles began to demonstrate the shift from ancillary services to a resource consistently providing energy during the net peak period.

Figure 9 plots the net demand and BESS operations for the annual peak days in 2021 and 2020. Net demand is the demand minus the renewable production. Notably, the 2020 storage energy on peak load day (day with high the highest peak load) remains within 250 MW of the x-axis and does not exhibit strong correlation with the 2020 net demand on peak load day. These data represent an operating profile more consistent with provision of regulation reserves. The 2021 storage energy on peak load day and 2021 net demand on peak load day exhibit a more pronounced relationship consistent with charging in low net demand periods and discharging in higher net demand periods, acting as a critical grid resource during net peak. This marks a clear transition in the operating mode of BESS resources from an early history of ancillary services provision to an expected future of energy shifting across operating hours. This is shown by the 2021 net demand, net of storage, which shows how energy storage might create a trend that moves toward flattening the duck curve. The difference between net demand and storage operation defines net demand, net of storage. In particular, when storage resources are charging, the measure increases relative to net demand. And when storage resources are discharging, the measure decreases relative to net demand.

24 Murtaugh, Gabe. 2021. "[Storage: An Intersection Between Reliability Today and Climate Goals of Tomorrow](http://www.caiso.com/about/Pages/Blog/Posts/Storage-An-intersection-between-reliability-today-and-climate-goals-of-tomorrow.aspx)." California ISO. <http://www.caiso.com/about/Pages/Blog/Posts/Storage-An-intersection-between-reliability-today-and-climate-goals-of-tomorrow.aspx>.

Figure 9: BESS Grid Performance for 2020 and 2021



Source: CEC staff

Further, as of August 2021, 30 BESS resources were participating in the California ISO markets. Of these 30 resources, 28 BESS resources participated in both the energy and ancillary service markets.²⁵ The remaining two resources participated only in the ancillary service market providing regulation.

As BESS resources grow to represent a greater proportion of the operational resource fleet, the increase in interconnected BESS capacity, combined with the small and relatively fixed market sizes for ancillary services, especially for regulation service, drive the apparent shift to delivering energy across the net peak period. With saturated

²⁵ *Ancillary services* are the services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system in accordance with good utility practice. (Based on FERC order 888-A.)

markets for ancillary services, BESS is well-suited to store energy from periods with significant solar production and corresponding low energy prices for use during the net peak period and higher energy prices.

The California ISO resource interconnection queue has seen tremendous growth in BESS resource capacity; roughly 60 percent of the nearly 250 GW in the queue are BESS projects. Of these, half of the proposed capacity would interconnect as stand-alone resources and the other half as an element of a hybrid or colocated resource. More than 100 GW of this BESS queue capacity represents new requests in the latest group of interconnection requests, Cluster 14, also known as the *super cluster*. The sheer size of the commercial interest in BESS projects has forced significant changes to the California ISO interconnection processes.

The expansion of BESS deployment has highlighted the evolving challenges with BESS installations, including permitting and emergency response. Both require technical expertise in BESS operation. The CEC has overseen the construction of BESS installations on CEC-licensed natural gas sites and has identified specific needs as California continues to expand BESS deployment. For example, outreach to the local fire departments, which is part of the CEC process, is paramount since fire departments are the first to respond to a system fire. Through these collaborative efforts, the CEC has observed that the expertise of local permitting and fire department personnel in BESS installation and operation varies greatly. The local permitting authorities and fire departments engaged are aware of the hazards associated with lithium-ion BESS, but the technical expertise to ensure that the fire and explosion hazards are addressed remains uneven. In general, urban permitting authorities and fire departments have had a greater level of expertise in using the current codes to ensure proper mitigations are put in place for potential hazards. However, rural permitting authorities and fire departments have not had the same level of expertise, and staff has directed them to reach out to the California State Fire Marshal's office for additional resources. To address the current and growing deployment of BESS, a consistent, statewide approach to permitting and emergency response capabilities should be adopted to ensure that every jurisdiction is consistent and expert in siting BESS and responding to BESS operational issues.

There is also value in having an inventory of BESS resources. To support further tracking and evaluation of BESS resources, the CEC has begun identifying and mapping

California's large-scale BESS.²⁶ Since there is no centralized database, the CEC is compiling data by filtering through 23 datasets, including the United States Energy Information Administration's EIA-860 database and the United States Department of Energy's global energy storage database. For cross-referencing, the CEC also refers to the storage resources represented in the California ISO master control area generating capability list,²⁷ which is limited to only California ISO balancing authority territories and lacks location. The CEC will be engaging with stakeholders to supplement these resources to build a better accounting of location, size, type, and use of grid-scale BESS. However, more data collection would be valuable, including information on operational and safety performance.

Recognizing the need to better understand the optimal mix of energy storage to meet system and local reliability needs, the CEC is funding research under the Electric Program Investment Charge (EPIC) to assess long-duration storage needs. The research will model different scenarios of energy storage deployment to identify optimal location and duration of energy storage, including seasonal storage, to support grid reliability. Two research projects were funded and will be complete in early 2024.

Gas Fleet

Just under half of California's in-state electricity generation comes from gas combustion capacity.²⁸ A key value of these resources is that they can provide stable generation capacity throughout the day. They are also able to start up quickly, in some cases within 10 minutes, and can ramp up and down quickly to enable the balancing authorities to meet changing demand throughout the day. These systems have

26 The scope does not include BESS designated for use in *black start*. For a power plant to provide power via the combustion turbine to the grid, the plant takes power from the grid to start up the turbines. However, if grid power is unavailable due to a blackout or the grid being down, the power is provided by either diesel generators or batteries onsite. This is referred to as a *black start*. So, if the grid is down, the power plant can start itself up without the grid.

27 Link to California ISO Open Access Same-Time Information System [data](http://oasis.caiso.com/oasisapi/SingleZip?resultformat=6&queryname=ATL_GEN_CAP_LST&version=4&startdatetime=20210915T07:00-0000&enddatetime=20210916T07:00-0000&resource_id=ALL&agge_type=ALL&resource_type=ALL).
http://oasis.caiso.com/oasisapi/SingleZip?resultformat=6&queryname=ATL_GEN_CAP_LST&version=4&startdatetime=20210915T07:00-0000&enddatetime=20210916T07:00-0000&resource_id=ALL&agge_type=ALL&resource_type=ALL.

28 CEC. "2020 Total System Electric Generation." <https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2020-total-system-electric-generation>.

provided baseload power for the state for many years and have proven necessary to fill in when renewable resources are not available.

However, gas plants have their own reliability issues. Like other generation resources, gas plants often operate at less-than-rated maximum capability during extreme heat events, when demand is high. And like any mechanical equipment, they can have system failures, causing them to shut down for maintenance. Operators work to keep them maintained during lower-demand periods of the year, but systems can break down during prolonged and heavy heat events. The extreme heat events in 2020 heightened the need to identify options to make the greatest use of these resources to support the state, particularly in extreme heat events.

One such system failure occurred on May 27, 2021, when a steam turbine generator exploded and caught fire at Russell City Energy Center in the San Francisco Bay Area. This failure brought the 600 MW combined-cycle facility to a complete stop. On June 3, the project owner submitted a petition to the CEC for a temporary modification of their license to allow the facility to operate in simple-cycle mode, bypassing the steam turbine generator and generating 350 MW of electric power. Recognizing the need for electric reliability in the event of climate-induced heat events and the need to protect public health, CEC Commissioners approved a temporarily modified license for Russell City Energy Center until the fall of 2021.

On December 2, 2020, the CEC hosted a workshop titled "Incremental Efficiency Improvements to the Natural Gas Powerplant Fleet for Electric System Reliability and Resiliency."²⁹ The workshop explored technology options to increase the efficiency and flexibility of the existing gas-fired fleet to increase California electric system reliability and provide insurance against extreme weather, fire, or climate-related events. The workshop identified the potential for increased generation through project change improvements to increase peak output and reduce start times from existing equipment and software technology upgrades to improve ramp rate, turndown, and overall efficiency of the combustion turbines. This workshop helped position the state to prepare for 2021.

²⁹ December 2, 2020, IEPR Workshop on Incremental Efficiency Improvements to the Natural Gas Powerplant Fleet for Electric System Reliability and Resiliency. Workshop [documents](https://www.energy.ca.gov/event/workshop/2020-12/afternoon-session-finance-and-governance-lead-commissioner-workshop) are available at <https://www.energy.ca.gov/event/workshop/2020-12/afternoon-session-finance-and-governance-lead-commissioner-workshop>.

Supplemental Gas Generation to Support 2021 Grid Needs

In February 2021, the CPUC's Rulemaking Order 20-11-003 directed California's three large electric IOUs to seek contracts for additional supply-side capacity. In response, the IOUs filed advice letters seeking contract approval for 564 MW of additional generation for summer 2021. As a result, owners and operators of more than a dozen CEC-jurisdictional power plants (plants with capacity of 50 MW or greater) submitted project change petitions to the CEC to modify their conditions of certification in anticipation of securing procurement contracts.

CEC staff reviewed and were able to approve eight projects totaling an additional 136 MW to support electric grid reliability for summer 2021. The projects include:

- Palomar Energy Project (San Diego Gas & Electric) — 22 MW increased output.
- Roseville Energy Park (City of Roseville) — 5 MW increased output.
- Pastoria Energy Facility (Calpine) — 10 MW increased output.
- Otay Mesa Energy Center (Calpine) — 10 MW increased output.
- Metcalf Energy Center (Calpine) — 30 MW increased output.
- Walnut Creek Energy Park Units 1–5 (Clearway/NRG) — 17.4 MW increased output.
- El Segundo Energy Center (Clearway/NRG) — 30 MW increased output.
- Marsh Landing Generating Station (Marsh Landing LLC) — BESS capacity improvement of 11.5 MW.

The location of these projects is shown in Figure 10. Each project has been docketed through CEC regular docketing procedures and the CEC has created a public web page accessible from the CEC's home page to provide transparency of the reviews.³⁰ All projects submitted, approved, or denied are listed.

³⁰ CEC Temporary and Emergency Generation Program [webpage](https://www.energy.ca.gov/programs-and-topics/programs/temporary-and-emergency-generation-program), <https://www.energy.ca.gov/programs-and-topics/programs/temporary-and-emergency-generation-program>. Accessed January 11, 2022.

Figure 10: Jurisdictional Facility MW Upgrades for Summer 2021



Source: CEC

Thermal Resources Over the Next Five Years

In the next five years, more than 6,000 MW of thermal capacity in California is expected to retire. These retiring resources include the remaining OTC plants and Diablo Canyon Nuclear Power Plant.

In 2010, the State Water Resources Control Board (SWRCB) adopted a policy on the use of coastal and estuarine waters for OTC power plants to reduce harmful effects on

marine life associated with cooling intake structures.³¹ To comply with the OTC policy, coastal power plant owners could either install closed-cycle evaporative cooling systems or replace, repower, or retire existing coastal power plants. Most opted to retire OTC power plants,³² which impacted more than 20,000 MW of electric generation resources.³³ Recognizing the need to maintain reliability and allow for effective long-term planning of transmission and generation resources, the SWRCB adopted a compliance schedule with input from the State Advisory Committee on Cooling Water Intake Structures (SACCWIS). The SACCWIS is composed of representatives from several state agencies, including the CEC and CPUC.³⁴ The SACCWIS provides SWRCB with annual reports on the status of compliance and includes recommendations to ensure the compliance schedule considers the reliability of California's electricity supply, including local area reliability, statewide grid reliability, and permitting constraints.³⁵

To date, 12,985 MW of OTC capacity has complied with OTC policy requirements, largely by retirement. The remaining 5,303 MW is expected to retire by 2029, with most retiring by 2023. The Los Angeles Department of Water and Power's Harbor, Haynes, and Scattergood OTC plants are planned to retire by 2029.³⁶ The Diablo Canyon Nuclear Power Plant Units 1 and 2, roughly 2,200 MW of capacity, are expected to comply with

31 SWRCB. "[Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling](https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/)." Effective November 30, 2020. https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/.

32 To comply with the OTC policy, coastal power plant owners could either install closed-cycle evaporative cooling systems or replace, repower, or retire existing coastal power plants.

33 Once-through cooling technologies take in 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.

34 SACCWIS is composed of the CEC, CPUC, California ISO, California Coastal Commission, California State Lands Commission, the California Air Resources Board, and the SWRCB.

35 Section 3.B(4) of the OTC Policy provides that the SACCWIS will report to the State Water Board with recommendations on modifications to the compliance schedule each year.

36 [Final SACCWIS Report to SWRCB](https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/saccwis_report.pdf). March 26, 2021.

https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/saccwis_report.pdf

the OTC policy by November 2, 2024, and August 25, 2025, respectively, consistent with the respective Nuclear Regulatory Commission licensing expiration dates.³⁷

On September 1, 2020, the SWRCB amended the OTC Policy under Resolution No. 2020-0029, which extended the compliance dates of four power plants to address systemwide grid reliability in the California ISO balancing authority and the timing of new resources coming on-line.³⁸ This OTC policy amendment was approved by the Office of Administrative Law (OAL) on November 30, 2020. The amendment extended the compliance dates for:³⁹

- Alamos Generating Station Units 3, 4, and 5 for three years until December 31, 2023.
- Huntington Beach Generating Station Unit 2 for three years until December 31, 2023.
- Ormond Beach Generating Station Units 1 and 2 for three years until December 31, 2023.
- Redondo Beach Generating Station Units 5, 6, and 8 for one year until December 31, 2021.

Based on additional analysis and recommendations from the 2021 SACCWIS report,⁴⁰ the SWRCB considered an OTC policy amendment to extend the compliance date for Redondo Beach Generating Station Units 5, 6, and 8 for two additional years through December 31, 2023, to address systemwide grid reliability concerns.⁴¹ On October 19,

37 SWRCB. September 1, 2020. [Final Staff Report](#).

https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_policy_2020/final_sr.pdf.

38 Ibid.

39 [SWRCB Notice of Decision](#).

https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/nod.pdf.

40 SACCWIS. [Final 2021 Report of the Statewide Advisory Committee on Cooling Water Intake Structures](#). March 26, 2021.

https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/sacccwis/docs/sacccwis_report.pdf

41 SWRCB. September 17, 2021. [Proposed Final Amendment to the Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling to Extend the Compliance Schedule for the Redondo Beach Generating Station](#).

https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_policy_2021/otc_amd_mt_2021.docx.

2021, at a public SWRCB hearing,⁴² the amendment was adopted. The amendment was approved by the Office of Administrative Law on December 23, 2021.

To replace these resources and address the resource and load uncertainties discussed in this volume, the CPUC ordered the procurement of 11,500 MW of NQC to come on-line from 2023 to 2026 in its June 30, 2021, decision.⁴³ In that proceeding and the subsequent proceeding on the CPUC's preferred system plan, the CPUC evaluated whether there was a need to call out a requirement for a certain amount of the procurement to be thermal resources, such as from gas plants. To support this decision, the CEC analyzed whether there was the potential for additional gas capacity, if needed. The CEC identified 1,200 MW that it had approved that could be built at several existing CEC jurisdictional facilities. The additional units have not been constructed, as the owners of the plants do not have contracts for the additional capacity. Figure 11 shows these facilities and locations.

42 SWRCB. Posted [Notice](#) of October 19, 2021, meeting.
https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_policy_2021/notice_2021otcamend.pdf.

43 CPUC. June 30, 2021. [Decision 21-06-035: Decision Requiring Procurement to Address Mid-Term Reliability \(2023–2026\)](#).
<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF>.

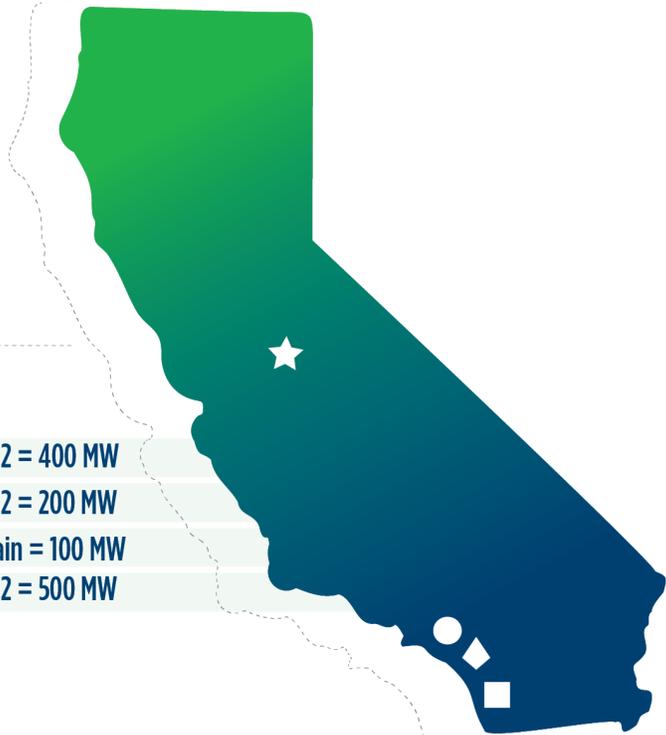
Figure 11: Additional Capacity Approved by CEC but Not Constructed

POWER PLANT PROJECTS PERMITTED BUT NOT BUILT

CEC Permitted Projects at Existing Facilities Could Bring Online an Additional

1200 MWs

- Alamos Energy Center
 - ◆ Huntington Beach Generating Station
 - Carlsbad Energy Center Project
 - ★ Cosumnes Power Plant
- ⚡ Phase 2 = 400 MW
 - ⚡ Phase 2 = 200 MW
 - ⚡ 6th Train = 100 MW
 - ⚡ Phase 2 = 500 MW



Source: CEC

Transmission

California’s transmission system continues to serve a critical role in meeting demand. On the California ISO system, net imports represented 21 percent of supply resources, with the majority from the Pacific Northwest.⁴⁴ Import and export volumes tend to track with prices in the wholesale markets. When prices rise with demand in California, imports generally increase. When prices are low in periods of low demand and increased production from renewable resources, exports generally increase. While pricing in the wholesale markets can drive import and export flows, the system has limitations in the designed capabilities. These limitations become painfully apparent when contingency events materialize. For example, the Bootleg Fire in southern Oregon

44 California ISO. August 2021. [2020 Annual Report on Market Issues and Performance](http://www.aiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf).
<http://www.aiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf>.

forced reduced operating limits on the Pacific AC Intertie, severely impacted California ISO imports, and very nearly prevented operators from balancing system load.

The state agencies and the California balancing authorities continue to identify opportunities to coordinate through SB 100 planning efforts, including the California ISO transmission planning processes. The Western Interconnection has attracted a great deal of transmission project planning interest to accompany renewable resource projects throughout the West. Increasingly, these integrated planning processes drive the energy transition toward shared efficiencies and expanded grid capabilities.

CHAPTER 3:

Feeling the Impact of Climate Change

Growing Impacts of Climate Change in California

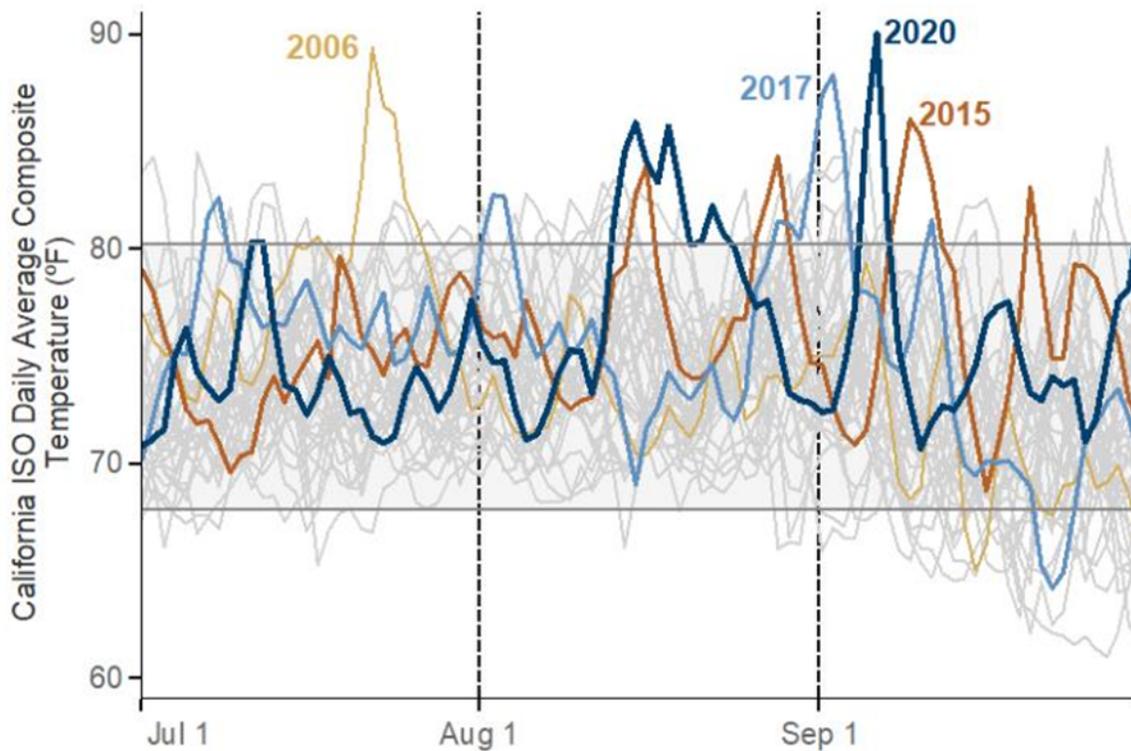
Extreme heat events and drought are becoming a greater risk to the state as a result of climate change. These events place increasing strain on the electric system by increasing demand and reducing generation capacity. Further, they are major contributing factors to the more frequent and larger wildfires the state has experienced in recent years. Collectively, these climate change impacts require the state to plan differently to ensure a reliable electric grid.

Heat Events

Average California summer temperatures are increasing over time, and extreme events are generally hotter, as shown in Figure 12. The gray shaded region of the figure represents the middle 90 percent of temperatures from July 1 to October 1 between 1985 and 2020. (It excludes the highest and lowest temperatures.) August 2020 (dark blue) is distinguished from the year with the next-hottest days, 2015 (orange), by the magnitude and duration of the extreme heat wave.

The hottest day in 2020 was a full degree and a half higher than that of 2015 — averaged over all hours of the day and across different parts of California. Further, the six hottest days of 2020 came in succession, compared with two distinct heat waves in 2015 that each lasted just a day or two. Also, as mentioned previously, the extreme heat wave spanned the western United States, which California typically relies on for electricity imports.

Figure 12: July, August, and September Temperatures (1985–2020)



Source: CEC staff

The extreme heat in August 2020 was a 1-in-30-year weather event in California, when considering 35 years of weather data and extended across the western United States. The resulting demand for electricity exceeded the existing electricity resource planning targets, and resources in neighboring areas were strained.⁴⁵ The Western Interconnection loads set a new record high of 162,017 megawatts (MW), while the gas fleet in the California Independent System Operator (California ISO) experienced a 5 percent decline in efficiency because of ambient temperature impacts on efficiency and operations. The state experienced another extreme heat event September 6–7, 2020, that caused strained grid conditions but no rotating outages.

45 California ISO, CPUC, and CEC. 2021. [Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave](http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf). 2021. <http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf>.

July through September have routinely been the months of greatest concern for high demand from heat waves; however, in 2021, the state experienced heat events in May and June as well, with a record-setting westwide heat event across the West occurring June 17–18, 2021. The National Oceanic and Atmospheric Administration (NOAA) records that California, Idaho, Nevada, Oregon, and Utah experienced the warmest summer on record (June through August).⁴⁶

Continuing impacts of climate change on temperatures in California are projected to increase demand in the summer months and decrease demand in the winter months because of increased cooling and decreased heating, respectively.

Drought

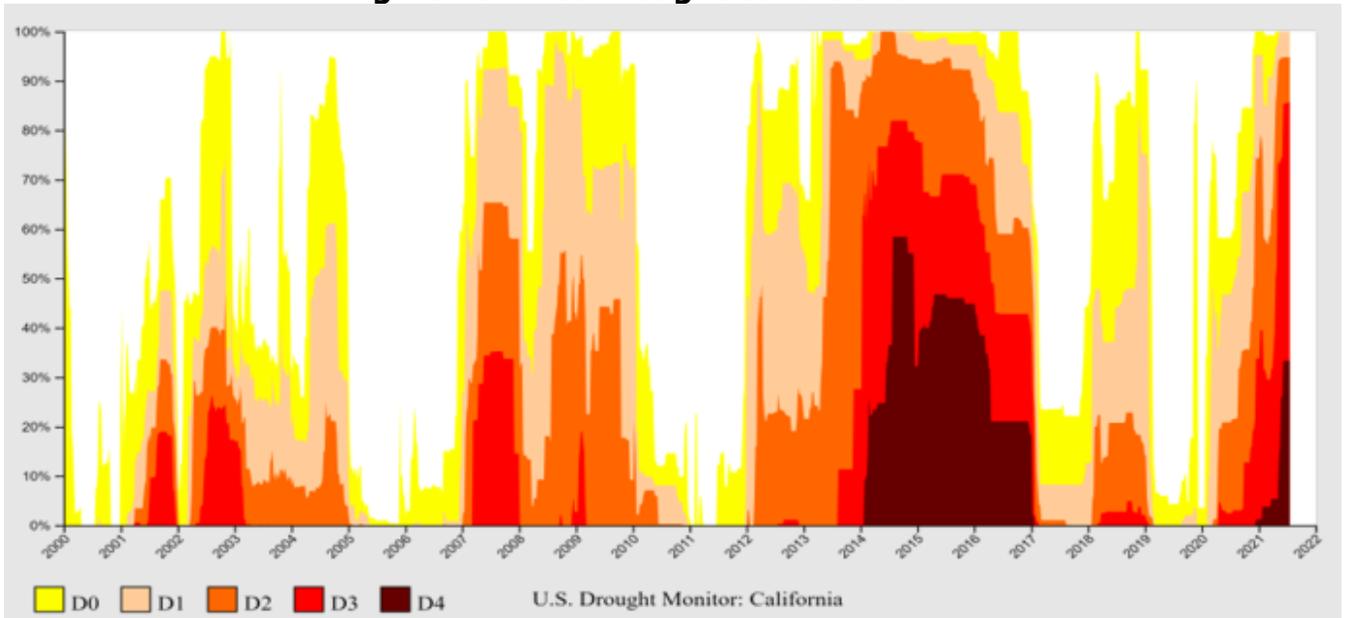
Drought conditions over the last decade in California have been somewhat cyclical, but the trend is for more severe and longer droughts when they occur. Figure 13 shows that the state reached the severest level of drought earlier than in past cycles.

Going into the 2021 summer, about 10 percent of California was considered to be in exceptional drought conditions. California has at times had nearly two-thirds of the state in exceptional drought conditions. NOAA projects similar drought conditions to persist in the West in 2022 (Figure 14).

These drought conditions impact the electricity sector in several ways but has the largest impact on reliability through the hydroelectric supply.

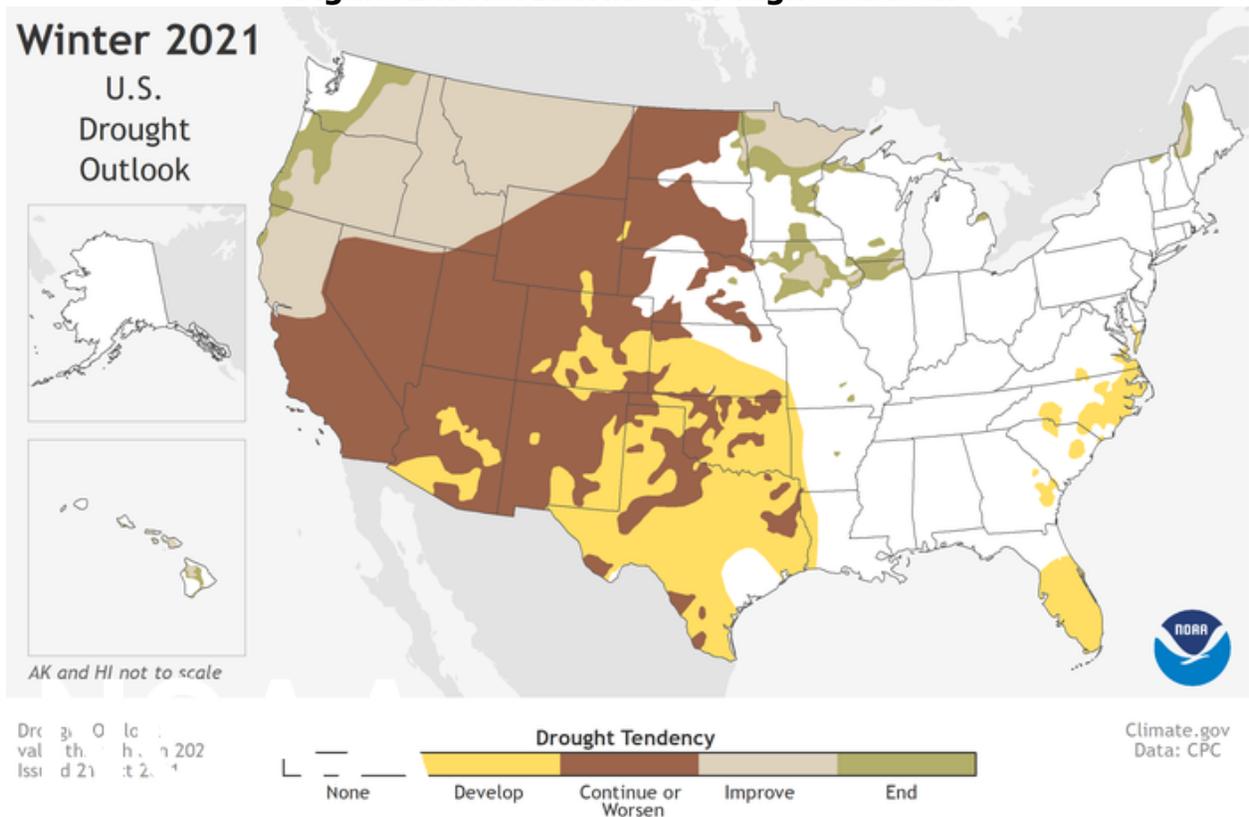
46 NOAA. September 9, 2021. "[Summer 2021 Neck and Neck With Dust Bowl Summer for Hottest on Record](https://www.noaa.gov/news/summer-2021-neck-and-neck-with-dust-bowl-summer-for-hottest-on-record)." <https://www.noaa.gov/news/summer-2021-neck-and-neck-with-dust-bowl-summer-for-hottest-on-record>.

Figure 13: Past Drought Conditions



Source: U.S Drought Monitor

Figure 14: NOAA Winter Drought Outlook

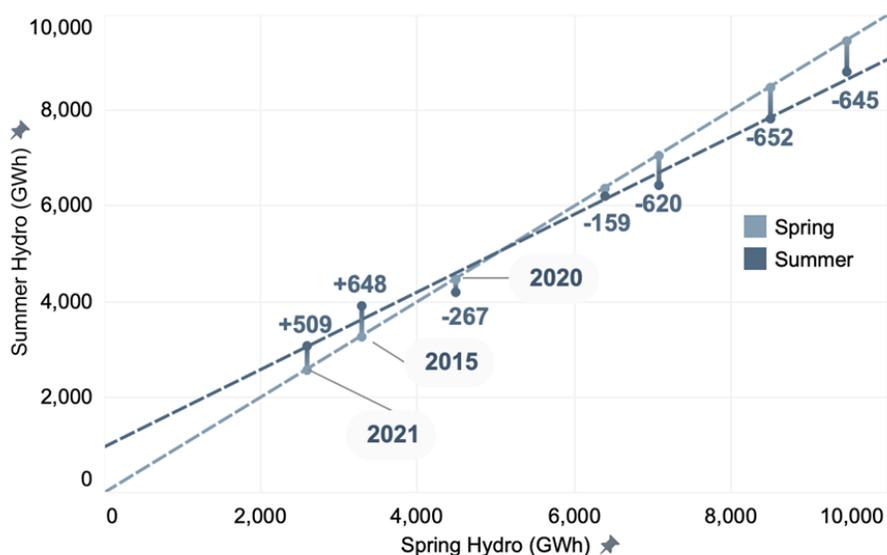


Source: NOAA

California Reserves Water for Hydropower in Summer During Drought Years

Less water means low hydro availability, which can substantially decrease the amount of electricity generated from hydropower. However, when water is low, California uses hydro strategically to ensure it can best support the electric grid and reduce reliance on greenhouse gas-emitting resources such as fossil gas. In the spring (April through June) and summer (July through September) of 2021, California⁴⁷ generated less hydropower than in any of the six previous years. Figure 15 shows that when water is scarce, California reserves hydro for use during the summer. For example, Pacific Gas and Electric “reduced springtime generation to maximize reservoir storage and [use] flexible generation on higher demand months [and] highest demand hours.”⁴⁸

Figure 15: Total Summer (July–September) Hydroelectric Generation Relative to Spring (April–June)



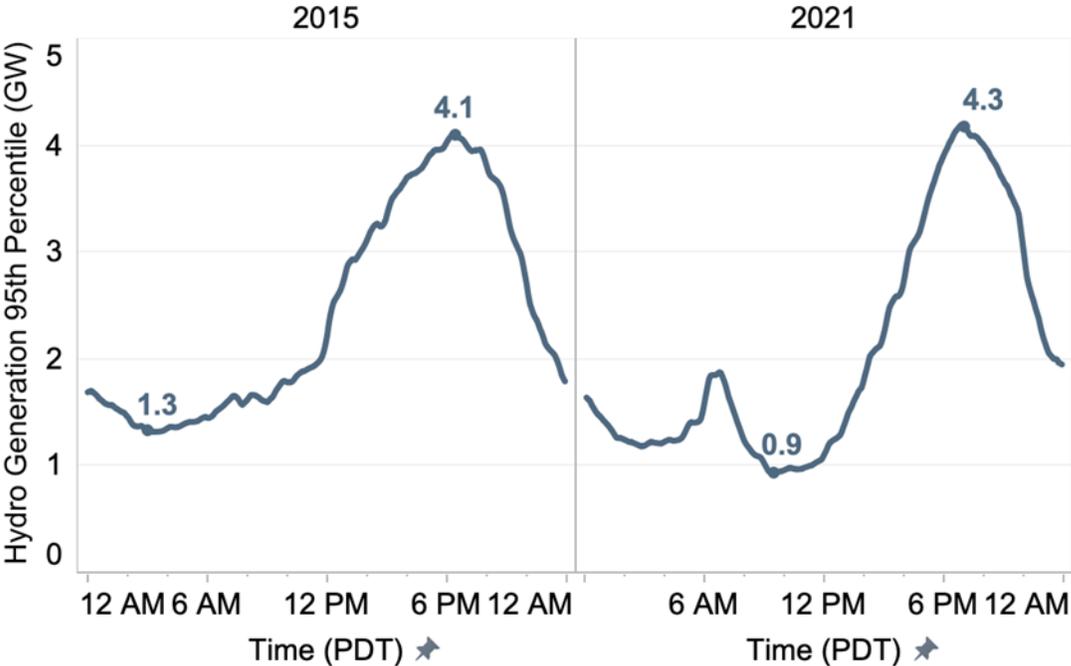
Source: California Energy Commission (CEC) analysis of California Independent System Operator (ISO) data. See Table 1 for details.

47 In the following analyses, “California” refers to the electric grid managed by the California ISO, which represents roughly 80 percent of California’s total electricity consumption.

48 Presentation by Eric Van Deuren, “[IEPR Join Agency Workshop on Summer 2021 Electric and Natural Gas Reliability](#).” July 8, 2021, IEPR workshop on Summer 2021 Electric and Natural Gas Reliability, p.8. <https://efiling.energy.ca.gov/getdocument.aspx?tn=238754>.

The rollout of renewable energy has also allowed hydro to act as a peaking resource under drought conditions, as seen in the graph below. Hydro is used most during the morning and evening peaks in net demand. On the high-demand days of summer 2015 (left), hydropower increased throughout the day and peaked in the evening at 4.1 gigawatts (GW). By 2021 (right), grid-scale renewables, particularly solar, allowed hydro to reduce midday generation and generate more power around the net demand peak. Hydro generation on the highest demand days of 2021 surpassed 4.3 GW — an increase from 2015 despite a 20 percent reduction in overall hydro production.

Figure 16: As Renewable Penetration Increases, Hydropower Is Used as a Peaking Generation Resource (Summers 2015 and 2021)



Source: CEC analysis of California ISO data

Based on these data, droughts do not necessitate reliability concerns from decreased hydroelectric generation. However, the depth of the current drought presents additional risks. Lake Oroville, which feeds California’s fourth-largest hydro plant, has dropped so low that it has forced the plant off-line. Across the state, dropping reservoirs and requirements to maintain downstream temperatures for vulnerable fish populations and flows for recreation, among others, have reduced the California ISO’s late summer hydro capacity by about 22 percent or 1,500 MW.

Fire

After an extended drought, worsening fuel conditions, and recent years of dry and windy weather, California is facing unprecedented wildfire and heat risks. Although

wildfire has been a part of California’s natural history for millennia, the size and intensity of wildfires have grown because of human activity and climate change effects. Prolonged droughts and extreme heat events, coupled with greater vulnerability to insect infestation, have contributed to the death of millions of trees in California. Fire control policies have limited the extent of fires over the past century but also led to the buildup of significant quantities of vegetation to fuel fire. Since 1950, the area burned by California wildfires each year has been increasing, as spring and summer temperatures have warmed, and spring snowmelt has occurred earlier.

Of the 20 largest wildfires ever recorded in California, 18 have occurred since 2000, and 12 occurred in the last five years, including the 8 largest wildfires in California history.⁴⁹ The severity of wildfires has been accelerating during this period, with 2017 including extreme wind-driven fire events in several communities, 2018 being by far the most destructive wildfire season in California history at the time, and 2020 and 2021 both exceeding the 2018 acreage total by a large margin. Rising surface temperatures due to climate change means wildfires will plausibly get worse on average, with some years expected to exceed the extreme scenarios observed in 2017, 2018, 2020, and 2021.⁵⁰

Grid infrastructure has been identified as the cause of multiple fires in the last several years. The California Department of Forestry and Fire Protection (CAL FIRE) identified grid infrastructure failure as the cause of multiple fires in 2017 and 2018. Much less has been discussed about the impacts of fire on grid infrastructure, particularly transmission and generation equipment.

Risks to Generation

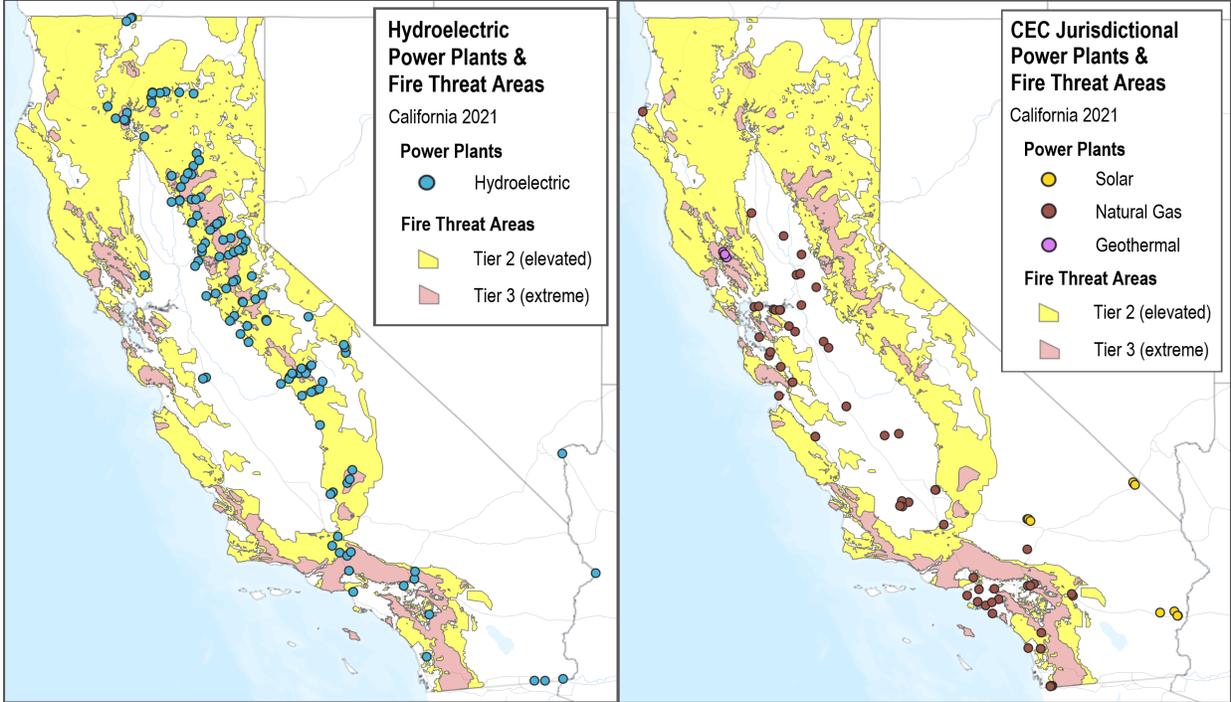
California Energy Commission (CEC) staff reviewed data for generation resources greater than 10 MW and compared the locations to the California Public Utilities Commission’s (CPUC’s) Fire Threat Map to assess those facilities that could be at most risk to fire. Staff found that most in-state hydro and geothermal generation are in high fire-threat areas. Some of the in-state pipeline gas power plant fleet is in high fire-threat areas, but much of the gas fleet occurs in relatively fire-safe urban pockets. The large solar facilities tend to be outside high-fire threat areas. A fire may cause

49 CAL FIRE list of [Top 20 California Wildfires](https://www.fire.ca.gov/media/4jandlhh/top20_acres.pdf). https://www.fire.ca.gov/media/4jandlhh/top20_acres.pdf.

50 [California’s Fourth Climate Change Assessment Key Findings](https://www.climateassessment.ca.gov/state/overview/). <https://www.climateassessment.ca.gov/state/overview/>.

generation to go out of service directly or pose unacceptable risk to operating personnel.

Figure 17: Generation Resources and Fire Risk



Source: CEC

Risks to Transmission Facilities

California features some of the largest electric load centers on the Western Interconnection and relies on imported power to meet about one-third of its load. Imported electricity is delivered primarily on high-voltage transmission lines from the Pacific Northwest and the Desert Southwest. All of California's import paths cross many miles of high fire-risk areas both inside and outside state boundaries to connect in-state loads to out-of-state resources.

Transmission is inherently more exposed to fire compared to generation facilities due to the great linear distances of transmission and proximity to combustible material in remote areas. High-voltage transmission facilities are relatively fire-resistant, with most tower structures built from steel and lines often made of steel. The structures and line clearances are relatively tall and sized based on voltage level and terrain.

Fires often occur near high-voltage transmission lines. The most likely impact of fire on transmission lines is the need to temporarily reduce flows on lines to avoid exceeding equipment thermal limits. The most likely damage to a transmission facility is heat damage to the line(s). However, major fires can permanently damage high-voltage transmission tower structures, such as happened in the destructive 2018 Carr Fire near Redding. While the Carr Fire is historically significant in size and tragic consequences,

fires of this order have not been uncommon in California in recent years, including several fires larger and more destructive than the Carr Fire.

A fire on or near transmission may also temporarily force a line out of service because of impacts from smoke, by request of a fire department for safety, or to manage overall electricity system risks. Risk of disruption or safety hazard from smoke is mainly due to electrical short circuits traveling in the air through the smoke, potentially causing faults on the system or electrocuting people or equipment nearby.

When impacts occur on one line, direct and in-direct effects may occur in other parts of the system as well. The Bootleg Fire in Oregon directly forced the main Pacific AC intertie path into an extremely limited operating level on July 9, 2021, because of anticipated and realized impacts from the smoke. The path was partially derated midday to secure system reliability in advance of potential impacts. Actual transmission events occurred later that day, further derating the path. To ensure reliability following the transmission events, the Pacific DC intertie path was derated as well, illustrating that fire impacts can extend beyond direct effects on the lines. The path deratings caused the California ISO to issue a Stage-1 Grid Emergency and worries of potential rolling blackouts. Ultimately, grid conditions were eased within a few hours, and no rolling blackouts occurred.

The CEC published a study in August 2018 commissioned for the Fourth Climate Change Assessment called *Assessing the Impact of Wildfires on the Electric Utility Grid*.⁵¹ The study assesses historical incidence of fires along 40 major in-state transmission paths and seven urban fringe areas. The results estimated total incidence and density of incidence of fire along the full paths and conducted production cost modeling to estimate potential changes in power flows.

California ISO reviewed their actions taken during fire events from 2003 to 2016 to assess the impacts of historical fires on the bulk electricity system. The results were also translated into estimates for future climate change scenarios. During the period studied, fires rarely caused significant damage to transmission assets but often forced the California ISO to reduce flows on transmission lines to maintain security of the bulk

51 Dale, Larry, Michael Carnall, Gary Fitts, Sarah Lewis McDonald, and Max Wei. (Lawrence Berkeley National Laboratory). 2018. [Assessing the Impact of Wildfires on the California Electricity Grid](https://www.energy.ca.gov/sites/default/files/2019-11/Energy_CCCA4-CEC-2018-002_ADA.pdf). California's Fourth Climate Change Assessment, California Energy Commission. Publication Number: CCCA4-CEC-2018-002, https://www.energy.ca.gov/sites/default/files/2019-11/Energy_CCCA4-CEC-2018-002_ADA.pdf.

electric system, causing economic impacts. The fires were more likely to damage distribution equipment compared to transmission. Individually, the fires were unlikely to cause major damage to either transmission or distribution equipment; most damages occurred in a few major incidents.

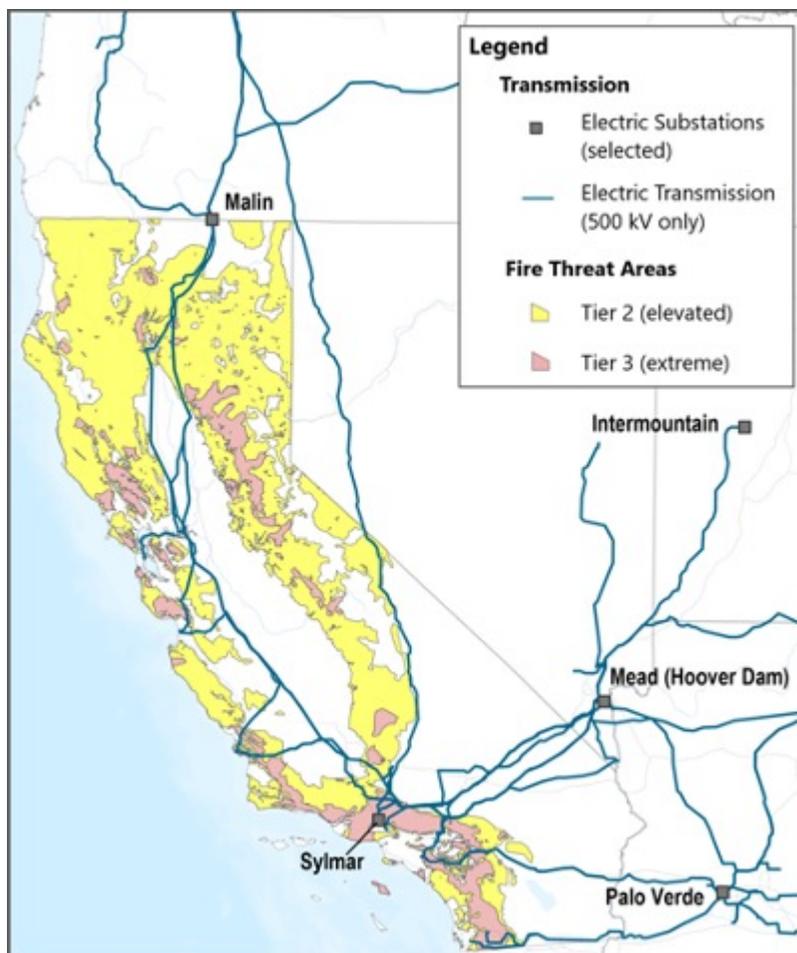
The study noted the large extent and damage of 2017 fires, like the Ventura County Thomas Fire, were not easily predictable based on previous historical data because it exceeded previous events. The study concluded major wildfires are difficult to fight or predict. This notion is further supported by the extreme events that followed in the November 2018 Camp Fire; extreme weather events in late 2019, 2020, the worst fire season on record; and 2021, which is on track to be the new worst season on record.

Risks on In-State Transmission Paths

Fires can occur in any part of the state, and most transmission outside urban areas pass through high fire-risk areas. In fact, the CPUC and CAL FIRE identified fire-threat area spans contiguously from the northernmost to the southernmost areas of the state without a break, meaning no conceivable import paths to the major load centers exist that avoid elevated or extreme fire risk area. As California's electricity system

increasingly leverages transmission infrastructure, expanding transmission capacity must proceed with careful consideration of the risks from wildfire.

Figure 18: California-Serving 500 kV Transmission and In-State Fire Risk



Source: CEC

Risks on Out-of-State Import Transmission Paths

Transmission connections to external service areas are called “interties.” The Pacific AC intertie connects historically plentiful hydro resources in the Pacific Northwest with load centers up and down the California coast. The interconnection is called the California-Oregon Intertie. The Pacific DC intertie (PDCI) connects these resources directly to Southern California load centers. A total of 50 percent of the PDCI capacity serves Southern California Edison, 40 percent serves Los Angeles Department of Water and Power, and the remaining 10 percent serves other local municipals. These paths travel through hundreds of miles of Oregon and Nevada, including elevated fire threat areas, notably in densely forested areas of Oregon. The previous Bootleg Fire example was a timber fire in Oregon.

Most of the interties supporting Southern California loads are high-voltage AC lines delivering power from Desert Southwest resources like the Palo Verde Nuclear Generating Station in Arizona, the largest generator on the Western Interconnection system. The Desert Southwest imports enjoy the flexibility of hydroelectric generating resources by virtue of the Hoover Dam power station, which has been a key supplier of ancillary services in California ISO markets. The LADWP system is also directly connected via high-voltage DC transmission lines to Intermountain Power Plant in Utah. Fires occur along these paths.

As fire risks rise in the state, there will continue to be threats to the electric system reliability, with likely greatest impact on reliability from impacts to transmission lines within and beyond the state. While this infrastructure has been designed to reduce the potential for impact, the risks of imports remain a concern and can have substantial impacts on reliability because of the need the state has for imports, which are critical during the net peak.

CHAPTER 4:

The Challenges of Summer Reliability

Energy demand in the state has traditionally been highest in August and September, but the heat events of 2021 showed that extreme temperatures can also strain the electrical grid in June and July. Recognizing the need to improve planning for such events, the *Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave*⁵² (Final Root Cause Analysis) called on the California Energy Commission (CEC) to develop several statewide energy assessments, including an annual summer assessment. While a summer analysis may inform a call for emergency procurement, the primary goal of a summer assessment is to understand what the impact could be of an extreme heat event, like the one California experienced in 2020, and the contingency resources that could be needed to support grid reliability under those high demand cases.

In response to the Final Root Cause Analysis, the CEC began development of two reliability assessments:

- 1) The *2022 Summer Stack Analysis*⁵³ to help support contingency planning as discussed below.
- 2) Loss-of-load-expectation (LOLE) analysis to help support midterm procurement planning and policy development as discussed in Chapter 5.

The *2022 Summer Stack Analysis* assesses supply and demand in average and extreme weather conditions for scenarios with varying levels of planning reserve margins (PRMs). PRM is a metric designed to ensure adequate supply to meet demand and consider potential issues ranging from common strains on the grid (for example, a generating plant mechanical failure causes it to go offline) to those that are more extreme (for example, extreme weather). The stack analysis supplements traditional planning methods and is intended only to provide a snapshot of a potential worst-case scenario on the California Independent System Operator (California ISO) system to

52 California ISO, CEC, and CPUC. 2021. [Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave](http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf). <http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf>.

53 Tanghetti, Angela, Liz Gill, and Lana Wong. 2021. [2022 Summer Stack Analysis](https://www.energy.ca.gov/publications/2021/2022-summer-stack-analysis-update). California Energy Commission. Publication Number: CEC-200-2021-006, <https://www.energy.ca.gov/publications/2021/2022-summer-stack-analysis-update>.

inform preparation for adequate contingencies. Contingency resources may include working with large customers to reduce demand (such as by shifting production schedules at a large industrial plant), using backup generators to reduce the draw on the grid of a facility, or procuring and deploying temporary mobile generators.

Because it may not be possible to procure additional resources quickly enough to meet the needs of extreme heat events within a year, the state can plan for contingency resources, as it did in 2020 and 2021. While decision makers may conclude that portions of a shortfall identified in a stack analysis for an extreme weather scenario need to be addressed through additional procurement, the intention of a stack analysis is not to determine whether traditional procurement is needed. As noted above, it is a snapshot to estimate the grid impact of extreme weather events.

2021 and 2022 Reliability

The hourly stack analysis tool (tool) draws data from varied sources that provide projections of hourly demand and supply. The hourly demand projections are consistent with the latest adopted California Energy Demand forecast and updated with recent projections to changes in water agency pumping loads caused by the 2021 drought. (Volume IV of the *2021 IEPR* discusses the energy demand forecast.)

The supply resource portfolio projections used in the tool are developed from the California ISO's publicly available, net qualifying capacity (NQC)⁵⁴ list. To provide a more detailed snapshot for the days with peak energy demand in each month, staff refined the NQC list to capture the hourly solar profiles, instead of the single monthly solar NQC value. The hourly capacity projections for solar resources are calculated from historical hourly generation profiles. The tool does not use an hourly profile for wind resources; however, the next iteration will do so. Another adjustment to the NQC existing resource portfolio is consideration of the impact of drought on hydro resources. Colleagues at the California Department of Water Resources (CDWR) provided drought adjusted NQC values for their hydro resources that staff incorporated into the analysis. Staff also developed a drought derate (expected loss of hydroelectric power due to drought conditions) for hydro resources beyond those provided by CDWR. Staff assumed that the 2021 California drought conditions would persist into 2022.

54 California ISO's [webpage](http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx) on Reliability Requirements.
<http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx>.

Only announced retirements of the existing resource portfolio are included in the tool. The Redondo Beach generating facility was assumed to retire in 2022 since the State Water Resources Control Board (SWRCB) had not yet met to decide on an extension. On October 19, 2021, after the analysis was completed, the SWRCB voted to extend the Redondo Beach Generation Station to operate through December 2023.

The new resource portfolio projections are provided by California Public Utilities Commission (CPUC) staff and are based on recent multiyear emergency procurement decisions and newly developed Emergency Load Reduction Program and Demand Response Program participation. CPUC staff also provides periodic updates to the CEC if there are any changes to these projections.

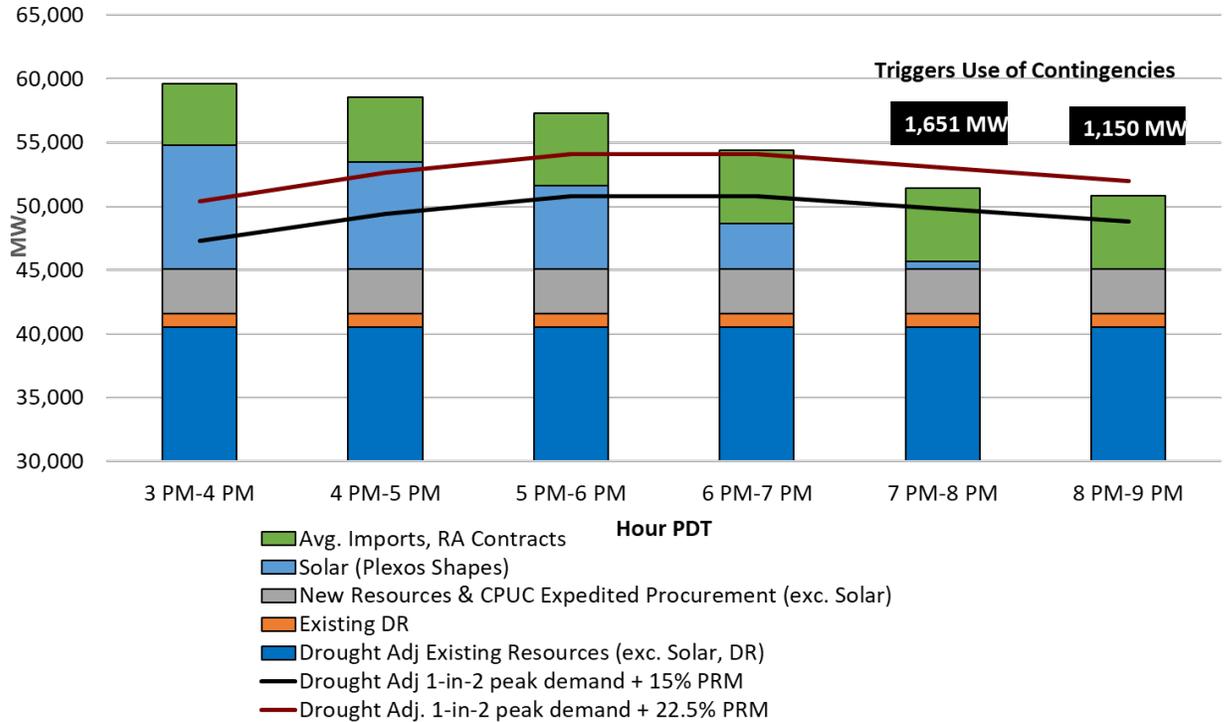
The import projections are provided by the California ISO and based on the average of the 2015–2020 resource adequacy (RA) showings for imports. Actual economic imports during peak and net peak hours often exceed the average RA showing for imports and are dependent on actual demand and real time supply. Thus, using an average of RA showing for imports presents a conservative approach to imports in the stack.

The tool projects hourly snapshots of electricity supply and demand for traditional and extreme weather PRMs. In California electric system planning, 15 percent PRM is considered the traditional target level for grid reliability. The 15 percent PRM is the sum of the 6 percent operational reserve requirement,⁵⁵ 5 percent to account for unplanned generation outages, and 4 percent to account for weather variability. The tool also accounts for an extreme weather PRM of 22.5 percent, assuming 6 percent operational reserves, 7.5 percent unplanned generation outages, and 9 percent for weather variability. The extreme weather PRM represents the potential impact that an extreme weather event, fire, and smoke may add to not only the demand forecast, but outages in the supply fleet. Factors such as climate change and the greater levels of variable generation resources impact elements of the PRM, warranting a need to reassess the PRM for electric system planning in the state.

⁵⁵ Operational reserves in the tool are made of up 3 percent to account for spinning reserves (generation available instantaneously) and 3 percent to account for non-spinning reserves (generation available within 10 minutes).

The following *2022 Summer Stack Analysis*⁵⁶ results, adopted by the CEC⁵⁷ are shown in Figures 19, 20, and 21.

Figure 19: July 2022 Considering 15 Percent and 22.5 Percent PRM

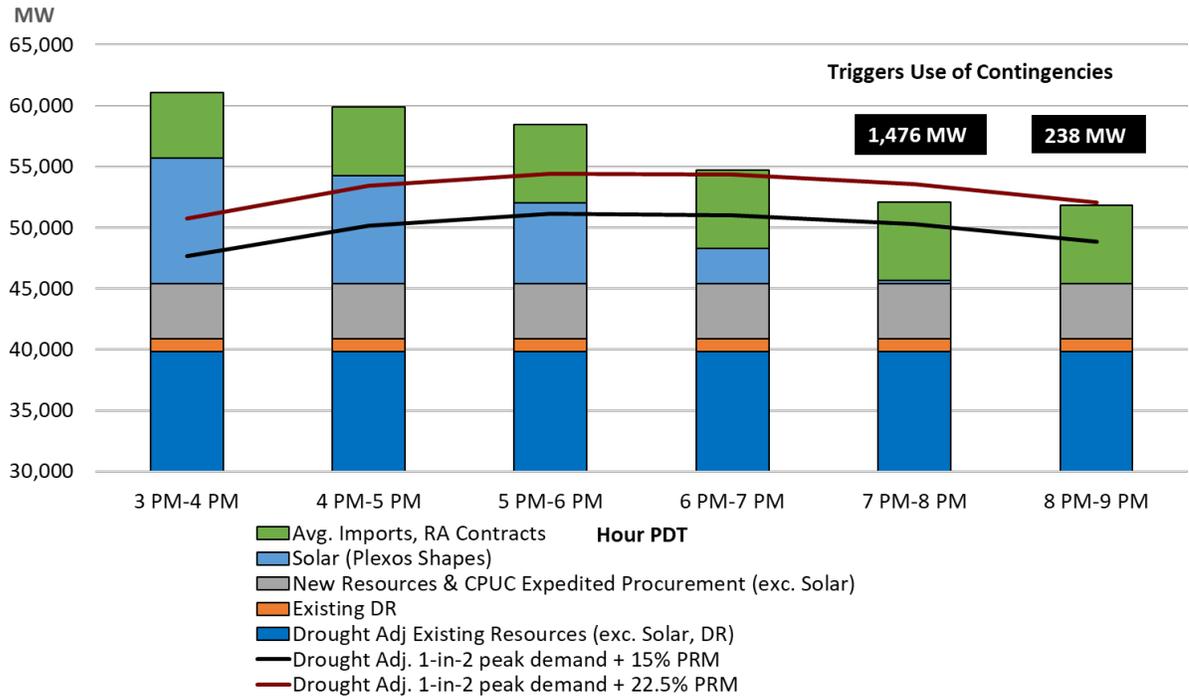


Source: California Energy Commission. Publication Number: CEC-200-2021-006

56 Tanghetti, Angela, Liz Gill, and Lana Wong. 2021. *2022 Summer Stack Analysis*. California Energy Commission. Publication Number: CEC-200-2021-006.

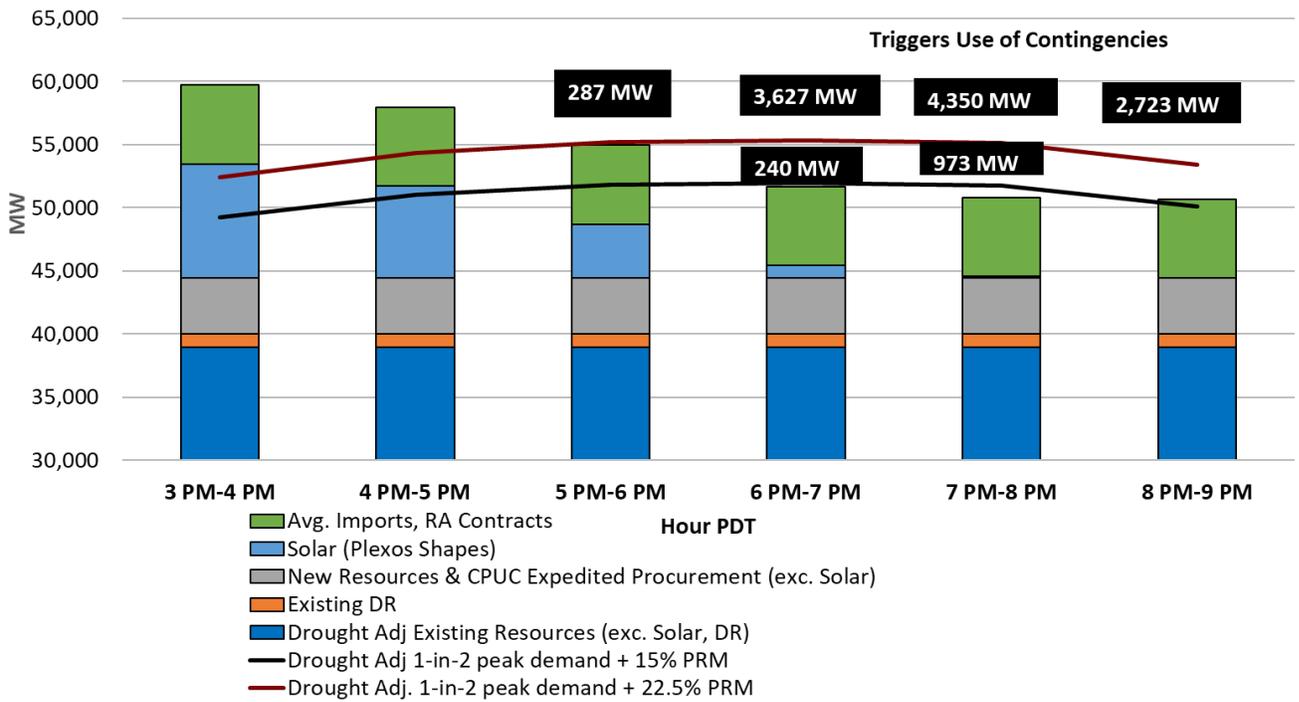
57 CEC. 2021. Resolution No: 21-0908-8.

Figure 20: August 2022 Considering 15 Percent and 22.5 Percent PRM



Source: California Energy Commission. Publication Number: CEC-200-2021-006

Figure 21: September 2022 Considering 15 Percent and 22.5 Percent PRM



Source: CEC. Publication Number: CEC-200-2021-006

Based on this analysis, under average weather conditions, the resource portfolio is largely adequate to meet demand plus a 15 percent PRM. With the extension of Redondo Beach (834 MW NQC) through 2023, the shortfall in September of 2022 is reduced to less than 150 MW in the 7:00 p.m. to 8:00 p.m. hour. While still a capacity shortfall, a 150 MW shortfall is a limited cause for concern given the conservative assumptions used in the analysis. Extreme weather and persisting drought, however, may spur a need for further contingencies.

Import Challenges

California has enjoyed a long history as a net importer of electric power, serving about 30 percent of its annual load with out-of-state generation. This long-standing operational reality has begun to face several economic challenges. As populations expand in the West and new demands increase the total system load, competition for the energy from resources needed to balance the system also increases. An aging thermal fleet and the industry pivot away from coal-fired power serve to make this competition more intense.

Compounding these factors, the growth of renewable resources has led to persistent and consistently low pricing for wholesale power across many operating hours in California's power markets. This situation reduces the likelihood that power for import into California will prove economically viable.

CHAPTER 5:

Reliability Outlook for the Midterm: 2022–2026

California Energy Commission (CEC) Analysis of 2022–2026

While the stack analysis is a valuable tool in planning for contingency resource needs in the near term, a reliability outlook spans a longer period to inform decisions about whether additional resources (for example, renewables and storage) need to be procured to address system reliability. The CEC’s *California Reliability Outlook (CRO)*⁵⁸ seeks to address this midterm need as identified in the recommendations in the *Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave*⁵⁹ (Final Root Cause Analysis).

The scope for this first CRO was designed in collaboration with the California Public Utilities Commission (CPUC) to support the CPUC’s Integrated Resource Planning (IRP) proceeding. In Decision 21–06-035 of the IRP proceeding, the CPUC called for 11,500 megawatts (MW) to be procured by load-serving entities by 2026 to support system reliability. The CEC’s CRO was intended to provide an alternative to the CPUC’s analyses, evaluate the reliability of the proposed procurement, and answer several related questions that could further inform CPUC decisions in the proceeding:

1. Is additional capacity needed beyond the CPUC’s procurement orders in Decision 21-06-035 to meet the system reliability for the California Independent System Operator (California ISO) footprint?
2. Does incremental thermal capacity (such as gas-fired power plants) provide additional system reliability compared to a portfolio of new zero-emitting resources (such as wind and solar)?

58 Gill, Liz, Mark Kootstra, Elizabeth Huber, Brett Fooks, Chris McLean. 2021. [Midterm Reliability Analysis](https://www.energy.ca.gov/sites/default/files/2021-09/CEC-200-2021-009.pdf). California Energy Commission. Publication Number: CEC-200-2021-009. <https://www.energy.ca.gov/sites/default/files/2021-09/CEC-200-2021-009.pdf>.

59 California ISO, CEC, and CPUC. 2021. [Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave](http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf). <http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf>.

3. Is there sufficient energy at the system-wide level to charge battery energy storage systems (BESS) under the expected resource build?
4. What is the potential for reliability impacts if there are BESS supply chain delays?

This chapter summarizes the method and results of the CEC’s first CRO and provides an overview of the CEC’s work on demand response in support of the CPUC’s resource adequacy proceeding.

Approach

The CEC’s analysis relied on the well-established loss-of-load-expectation (LOLE) analytical framework that is used widely in the industry to evaluate reliability. The LOLE target used in this study is 1 day with unserved energy every 10 years, or a LOLE of 0.1 days per year. The LOLE approach considers the probability of a wide range of key variables and relies on thousands of simulations drawing randomly from different combinations of demand, solar, and wind profiles, as well as unexpected plant outages. However, like any other modeling effort, the modeling used in this analysis approximates conditions and includes many reasonable simplifying assumptions to reduce computation time and increase the number of scenarios modeled. One important simplifying assumption is the transmission representation, which does not consider local area constraints.

Loss-of-Load-Expectation

Reliability analysis is an essential component of electric sector planning. For long-term planning, reliability is typically assessed through LOLE studies. These studies draw on a distribution of future demand profiles, historic wind and solar profiles, and randomized resource outages to estimate the probability of a supply shortfall. The typical reliability standard is to ensure no more than one day with unserved energy (a power outage) every 10 years. A day with unserved energy means a single day with any length of outage.

The study includes resources eligible to participate in the CPUC’s resource adequacy (RA) program. These are resources that have been assigned a qualifying capacity (QC) by the CPUC and a subsequent net qualifying capacity (NQC) value, which reflect the ability of the resource to deliver capacity to the system for the purposes of meeting RA requirements. Scenarios based on three resource builds were studied:

1. **No Build Scenario** — No new resources beyond the baseline in the CPUC’s Reliability Need Assessment and the summer 2021 procurement (D.21-02-028) that will be on-line for the modeled years. This scenario identifies the baseline need if no new procurement had occurred.
2. **Procurement Order Scenarios** — Resource build based on the procurement orders for 2021–2023 (D.19-11-016) and 2023–2026 (D.21-06-035). (See Table 1.)

3. **Preferred System Plan (PSP)** — Resource builds that include the proposed PSP based resources incremental to the baseline resources in the no build scenario.

Table 1: Cumulative Procurement Order Assumptions

Resource (megawatts [MW] NQC)	2022	2023	2024	2025	2026	2026+
D.19-11-016 NQC Remaining	1,070	1,505	-	-	-	-
D.21-06-035 NQC Remaining	-	2,000	8,000	9,500	-	11,500
Total	1,070	3,505	9,505	11,005	11,005	13,005

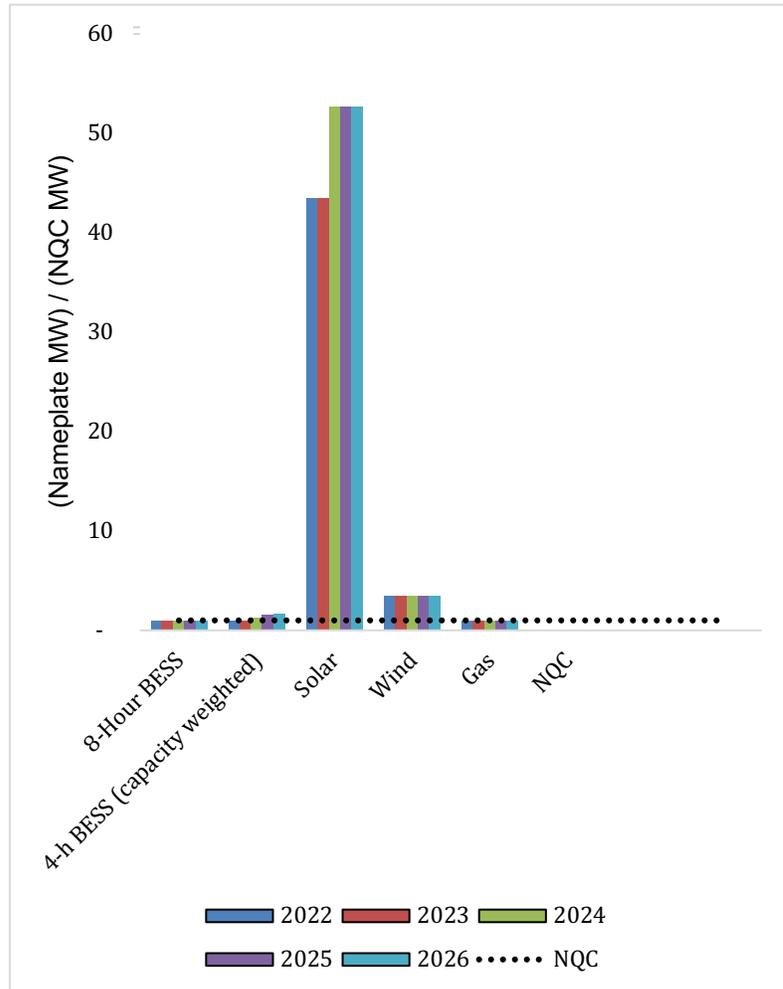
Note: Remaining procurement for D.19-11-016 listed in the table are the modeling assumptions used. Since the analysis was performed, the remaining procurement numbers have changed. As of November 24, 2021, an additional 825 NQC MW of additional procurement for 2022 and 1,650 MW NQC cumulative procurement for 2022 and 2023. These updated numbers do not reflect any delayed procurement from 2021.

Source: CEC Staff Analysis of D.19-11-016, D.21-06-035, and the CPUC’s Reliability Need Determination Model

When estimating the nameplate capacity build required to meet the procurement orders, staff applied the CPUC’s published technology factors and effective load-carrying capability (ELCC) values to the mix of resources selected. The new capacity build in the model was then adjusted until the NQC equaled the procurement orders. For scenarios that analyzed the reliability of the system with gas capacity in place of the zero-emitting resources, the total NQC of the portfolio was replaced with gas capacity at a one-for-one basis using the NQC values. A similar process, but in reverse, was used to determine the NQC value of the portfolio, which was then converted into gas capacity.

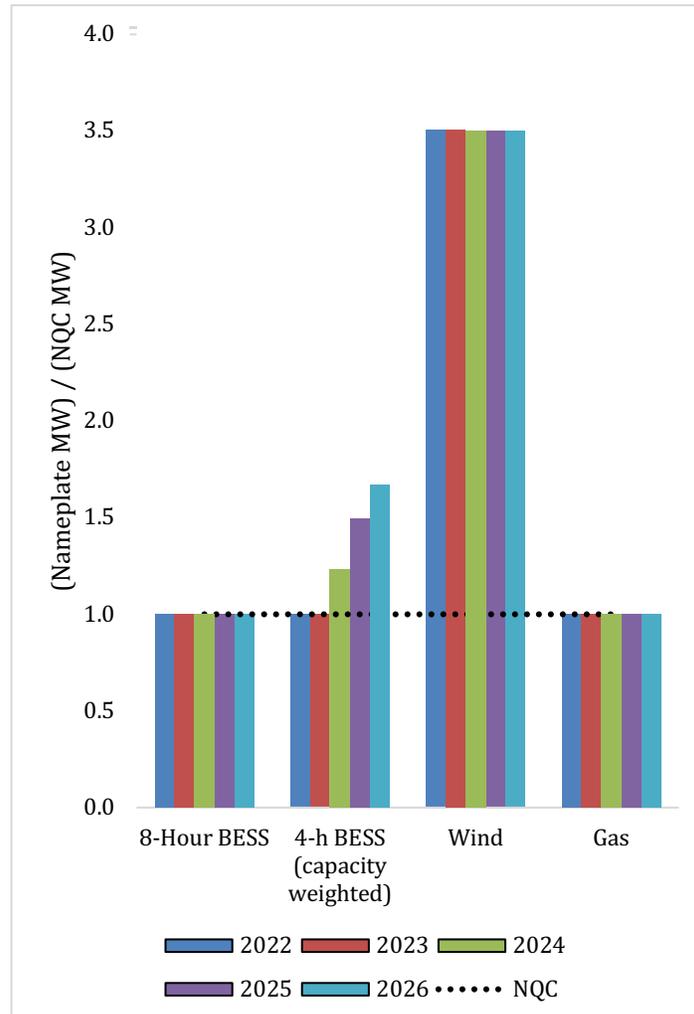
Figures 22 and 23 illustrate how nameplate capacity is converted to NQC values. Gas resources and long-duration storage, modeled as 8-hour BESS, were assumed to have an NQC equal to nameplate capacity. In 2022 and 2023, a 4-hour BESS also is assumed to require 1 MW nameplate to provide 1 MW NQC. As a result of a declining ELCC, by 2026 a 4-hour BESS is assumed to require 1.7 MW nameplate to provide 1 MW NQC. Solar requires roughly 43 MW nameplate capacity to provide 1 MW NQC in 2022, growing to 53 MW nameplate by 2026. Wind consistently requires about 3.5 MW nameplate capacity to provide 1 MW NQC across all years.

Figure 22: Comparison of the Nameplate Capacity Necessary to Provide 1 MW NQC



Source: CEC staff

Figure 23: Comparison of the Nameplate Capacity Necessary to Provide 1 MW NQC of BESS, Wind, and Gas



Source: CEC staff

Using these capacity values, a model was created in PLEXOS, a commercial production cost model software used by the CEC. This model represented all the California ISO footprint, along with specified and unspecified imports, within a single zone. Transmission constraints that hinder the delivery of electricity supply to demand were not included. Generation capacity was modeled by resource type with a simple characterization, focused on what power capacity could be delivered in each hour. The model included four variables that were randomly selected for each of the more than 10,000 samples simulated for each scenario. These variables include seven solar profiles, seven wind profiles, 140 demand distributions, and randomized unplanned outages.

Results from these scenarios were then processed to determine the LOLE and the shortfall capacity, if any. The unserved demand for each event is defined as the hour

with the highest unserved energy in a day. The LOLE is the number of unserved demand events divided by the number of samples. To determine the shortfall, the events were ordered from highest to lowest unserved demand. The scenario shortfall capacity is the capacity that would need to be fully available in all hours of the year (perfect capacity) to reduce the LOLE to below 1 day in 10 years. The shortfall capacity for a simulation with 100 samples would be the eleventh highest unserved demand event.

Results

The following section summarizes the results from the LOLE analysis of the three categories of scenarios studied: no build scenario, PSP scenarios, and new procurement scenarios.

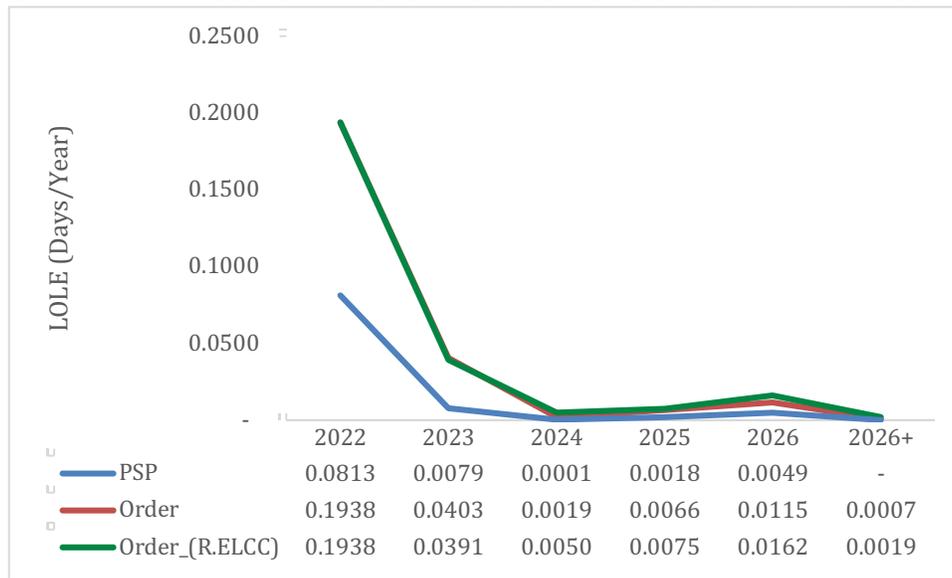
On Need for Additional Capacity

CEC modeling suggests that the current CPUC's PSP would result in a reliable system, with a loss of load expectation at, or below, one outage event in every 10 years. Similarly, the CPUC's procurement orders result in a reliable system over the CPUC's midterm reliability procurement period — beginning 2023 through 2026. However, the LOLE for 2022 exceeds the desired one event in 10 years reliability metric. (See Figure 24.) For 2022, the ordered procurement results in a capacity shortfall of about 1,300 MW.

The 2026 year is for modeling results without the 2,000 MW NQC of long lead time resources, while the 2026+ year includes that additional capacity.⁶⁰

⁶⁰ D.21-06-035 allows for the long lead-time resources to be delayed up to two years to 2028.

Figure 24: LOLE Results for the Procurement Order and PSP Scenarios



Source: CEC staff

CEC modeling suggests that an estimated 1,400–1,600 MW NQC of additional capacity is needed in 2022 to reduce the LOLE to 0.1 day per year and eliminate the shortfall. This amount is consistent with the NQC additions associated with the PSP scenarios. Table 2 illustrates the anticipated shortfall, had no procurement been ordered, compared to anticipated procurement and the proposed PSP. A capacity shortfall is the need for perfect operating capacity and cannot be directly translated into NQC need. It does, however, provide valuable information on the magnitude of the need and facilitated the analysis to identify the need for the additional 1,400–1,600 MW NQC in 2022 to reduce the LOLE to below 0.1 day per year.

Table 2: No Build Shortfall Capacity Compared to NQC Additions (MW)

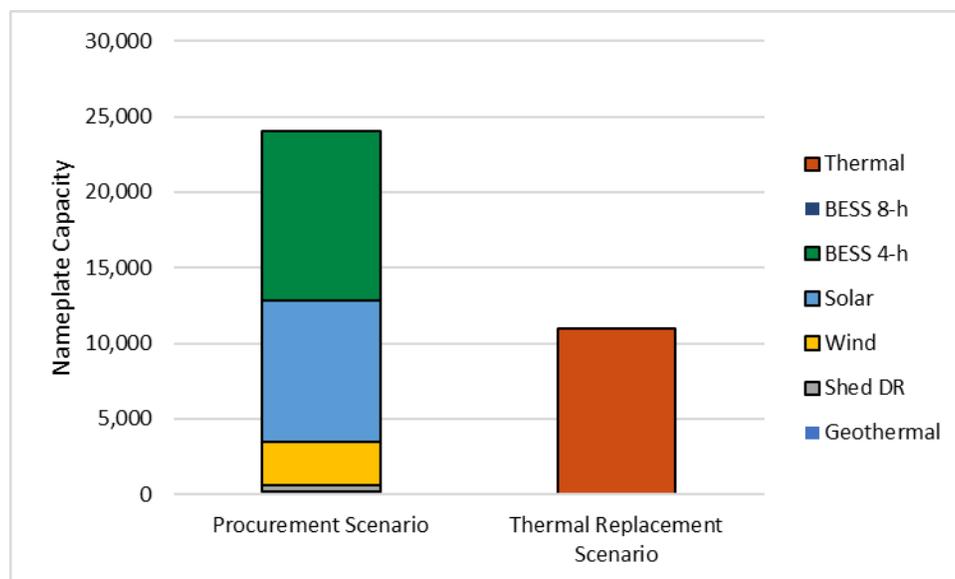
	2022	2023	2024	2025	2026	2026+
No Build Shortfall	2,372	2,391	6,711	11,540	12,022	12,022
Cumulative Ordered NQC	1,070	3,505	9,505	11,005	11,005	13,005
PSP NQC	2,753	4,916	9,907	11,712	12,012	14,012
PSP NQC, with September 2021 ELCC Values	2,603	4,970	10,778	12,879	13,128	15,128

Source: CEC staff

On Reliability Impacts of Incremental Thermal Capacity

To determine if incremental thermal capacity provides additional system reliability compared to zero-emitting resources of equivalent NQC, staff replaced the entire incremental resource build with gas capacity, 1 megawatt of gas for each megawatt of NQC added by the resource build. This method to compare portfolios was selected to align with the CPUC's Resource Adequacy Qualifying Capacity method, which is used to assign system reliability value to resources. The total nameplate capacity for new zero-emitting resources is roughly 24,000 MW, compared to about 11,000 MW for thermal capacity to provide equivalent NQC in 2026.

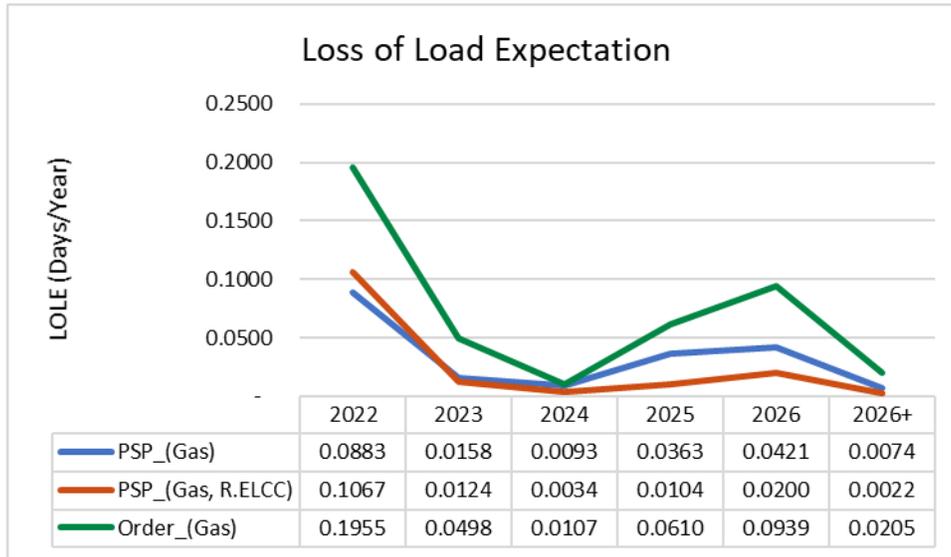
Figure 25: Comparison of the Procurement Order Scenario and Thermal Replacement Portfolio



Source: CEC staff

Figure 26 shows the LOLE does not increase above an LOLE of 0.1 day per year.

Figure 26: LOLE Results for the Procurement Order and PSP Build Replaced With Thermal Capacity



Source: CEC staff

The reliability of thermal capacity in place of the portfolio of preferred resources is not meaningfully different. Reliability issues still only arise in 2022, though issues arise for both the gas in place of the ordered procurement, Order_(Gas), and the gas in place of the PSP when the September 2021 ELCC values are used, PSP_(Gas, R.ELCC). These scenarios illuminate that many technology types can support system reliability if enough capacity is procured. These results do not indicate that a portfolio consisting of zero-emitting or thermal resources are inherently less reliable, though the amount of nameplate capacity that would need to be procured can vary significantly to get the same NQC.

It is important to recognize the accounting method differences for determining the NQC of different resource technologies. Additional work⁶¹ is needed determine if this performance difference is attributable to the specific technologies or the qualifying

61 For example, the California ISO has conducted analyses studying the ability to integrate battery storage resources in local capacity areas given their charging limitations. See [Section 2.4](http://www.caiso.com/InitiativeDocuments/Final2022LocalCapacityTechnicalReport.pdf) at <http://www.caiso.com/InitiativeDocuments/Final2022LocalCapacityTechnicalReport.pdf>.

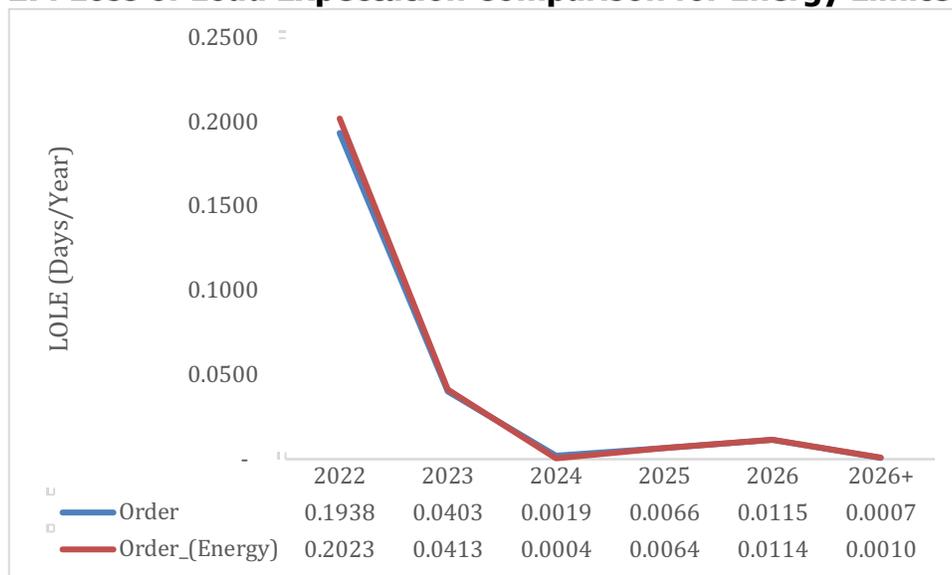
capacity method used to compare the resources on an NQC basis, or if adjustments to the model are necessary to better compare the resources in an equivalent manner.⁶²

On Energy Sufficiency Relating to BESS Charging Needs

CEC modeling indicates that the anticipated resource additions can be reasonably expected to supply sufficient energy to meet the needs for the system. Limiting imports to the CPUC-assumed specified and unspecified imports in all hours of the day, along with restricting hydroelectric generation to the NQC values between the hours of 4:00 p.m. and 10:00 p.m. (Pacific Standard Time), and to minimum generation levels outside these hours, does not meaningfully impact the reliability of the system.

The results for the energy limited scenarios are similar to the non-energy limited cases, suggesting the resource builds have sufficient energy generation during lower demand periods to sufficiently charge BESS for use during peak periods for system-wide energy needs. (See Figure 27.)

Figure 27: Loss of Load Expectation Comparison for Energy Limited Cases



Source: CEC staff

62 For example, the California ISO has conducted analyses studying the ability to integrate battery storage resources in local capacity areas given their charging limitations. See [Section 2.4](http://www.caiso.com/InitiativeDocuments/Final2022LocalCapacityTechnicalReport.pdf) at <http://www.caiso.com/InitiativeDocuments/Final2022LocalCapacityTechnicalReport.pdf>.

The 1-day-in-10-year capacity shortfalls for the Order_(Energy) scenario in 2022 exceeded the shortfall for the Order scenario by 40 MW. A similar increase in the capacity shortfall was observed for the 1-day-in-20-year and 1-day-in-100-year shortfalls in 2022, and in 2023 and 2026 for the 1-in-100 shortfalls. All other years did not have LOLEs high enough to produce even a 1-in-100 shortfall.

Further limiting energy available by reducing the total output of all the installed solar by up to 30 percent in all hours of the period had only minor impacts on reliability. This reduction increased the 1-day-in-10-year shortfall in 2022 by less than 200 MW but did not result in even a 1-day-in-10-year shortfall in 2026.

On BESS Supply Chain Concerns for Reliability

The potential for supply chain delays for BESS were explored by assuming a 20 percent delay annually for new deployment of 4-hour BESS. The 20 percent assumption used by the CEC is based on preliminary review of past years. The CEC recognizes, however, that as the buildout of BESS increases, there could be greater supply issues. The CEC is working with the CPUC, California ISO, and the Governor's Office of Business Development to track new projects coming on-line and will evaluate supply chain issues to better inform future analyses. Table 3 summarizes the reduction in total installed 4-hour BESS capacity in each year. No other changes are made to the resource builds.

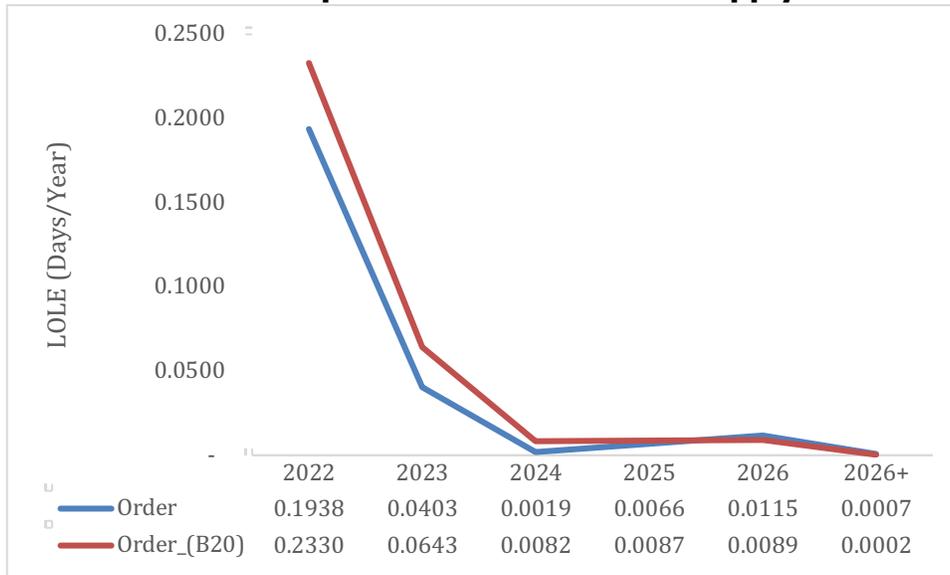
Table 3: Reduction in the Total Installed Capacity for 4-Hour BESS (MW)

	2022	2023	2024	2025	2026
Order_(B20)	326	482	1,269	383	8
Order_(R.ELCC, B20)	331	493	1,143	343	8

Source: CEC staff

These delays did not have a material effect on the reliability of the system, as shown in Figure 28. In 2022, the only year with an LOLE exceeding 0.1 day per year, the roughly 330 MW of delayed energy storage results in an increase in the 1-day-in-10-year shortfall by 389 MW in the Order_(B20). This increase in the shortfall capacity corresponding with a similar reduction in energy storage capacity is consistent with expectations. However, this pattern is not consistently maintained for the 1-day-in-20 year and 1-day-in-100-year shortfalls, likely due to the more sensitive nature of those values to random draws in the model.

Figure 28: Loss of Load Expectation for the BESS Supply Chain Scenarios



Source: CEC staff

After 2022, these delays do not result in the LOLE exceeding 0.1 day per year for the scenarios studied.

As noted above, the current resource procurement path for the state appears to be sufficient to support a 1-day-in-10-year LOLE target, except for 2022, which requires additional resources. The reliance of nonemitting resources does not appear to adversely impact reliability compared to procuring thermal resources. As a result, the clean energy path for the state should not affect system reliability over the period of this study. Lastly, it appears that increasing reliance on energy storage at levels proposed does not appear to have an impact on system reliability. Staff completed only

a limited analysis of supply chain impacts. While modest supply chain impacts do not appear to substantially impact reliability, the state needs to continue to monitor and evaluate energy storage deployment and the associated impact on reliability.

This analysis is the result of the development of a new approach to informing procurement decisions. The CEC created the model in 2021, improved it with input from the CPUC and public stakeholders, and will continue to improve the model and generate analyses like this one each year for a reliability outlook. The CEC is also expanding the scope of costs and benefits of different scenarios. The CEC is evaluating approaches to analyzing the social costs and nonenergy benefits of different resource build scenarios. This approach, when developed, will be applied across the CEC's modeling efforts, as appropriate, to ensure that scenarios are evaluated to a broader set of criteria such as greenhouse gas emissions reductions and equity and environmental impacts. In his proposed budget, Governor Gavin Newsom proposed allocating \$7 million in 2022–2023 to support improvements to energy modeling activities, including better reflecting climate change in state energy planning and policy development. The funding would also support analytical efforts presented in the *2021 IEPR, Volume IV: California Energy Demand Forecast*. The CEC looks forward to additional input to improve this analysis to inform decision-making.

Demand Response

Demand flexibility, or demand response, is the practice of managing customer electricity usage in response to economic incentives. Demand response is increasingly important for utilities and wholesale market operators to balance electricity supply and demand, especially under critical grid conditions. Demand response can alleviate the stress on the grid, reduce operational costs and greenhouse gas emissions, and play a critical role in ensuring grid reliability and price stability.

Customers of all types, from residential to industrial, can participate in demand response by reducing their electricity usage or by shifting it to other times in the day. Although demand response is conventionally viewed as customers *decreasing* electricity usage, demand response can also help balance electricity supply and demand by *shifting* electricity usage to times when the grid has plentiful electricity generation from renewable resources like solar and wind.

Demand response increasingly holds the potential to provide California with various economic and environmental benefits, including:

- Providing greater reliability to the grid and helping prevent rotating outages.
- Avoiding the purchase of high-priced energy.
- Avoiding the consumption of fossil fuels, which result in air quality issues and contribute to climate change.
- Aligning electric demand with renewable energy generation.
- Avoiding the over-procurement of generation resources.

- Avoiding the construction of new generation and transmission infrastructure.

Demand response programs in California are largely directed by the CPUC and administered by California's three regulated investor-owned utilities.⁶³ Independent commercial entities known as third-party demand response providers or aggregators also provide demand response services to investor-owned utility and community choice aggregator customers.

Although there are many possible approaches to classifying demand response, one taxonomy divides demand response into two primary categories: dispatchable demand response and nondispatchable demand response.⁶⁴ For purposes of this report, dispatchable demand response is referred to as *supply-side* demand response and non-dispatchable as *load-modifying* demand response. CPUC decisions in 2014 and 2015 bifurcated CPUC-jurisdictional demand response programs into supply-side and load-modifying demand response.

Demand response programs that make up supply-side demand response are designed to reduce demand when dispatched by the California ISO and are considered analogous to other "supply-side" generation resources like power plants. Consistent with the taxonomy referenced above, supply-side demand response consists of dispatchable demand response resources integrated into California ISO wholesale markets and counted for resource adequacy. Supply-side demand response resources are bid into the California ISO market and get dispatched by the California ISO based on grid needs. Supply-side demand response consists of both IOU managed demand response and third-party managed demand response. Supply-side demand response resources are compensated for capacity by the load serving entity (LSE), which is the distribution utility or electric utility that has a service obligation and are compensated for energy by the California ISO if dispatched. Also consistent with this taxonomy, load-modifying demand response is any program for demand flexibility that is not classified as supply-side demand response (such as nondispatchable). Load-modifying demand response is typically driven by time variant rates. Any associated load reduction is counted in reduced peak demand forecast. Compensation is typically provided via bill savings.

63 Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric.

64 "Incentive Mechanisms for Leveraging Demand Flexibility as a Grid Asset – An Implementation Guide for Utilities and Policymakers," prepared for National Renewable Energy Laboratory (NREL) by Guidehouse, Inc. May 11, 2021.

There are two types of California ISO-participating supply-side demand response resources: “economic” resources, bid into the market under normal operating conditions and formally called proxy demand resources (PDR), and “emergency” demand response, which is only called upon during supply-shortage conditions and formally called reliability demand response resources (RDRR). Both types are dispatchable and are counted for resource adequacy.

Economic demand response is triggered by economic or price signals and participates in the California ISO market as PDR. Economic demand response exists for both IOU and CPUC-jurisdictional third-party providers (non-IOU). This economic demand response is made up of various IOU demand response programs including A/C cycling, capacity bidding program, IOU local capacity requirement contracts, demand response auction mechanism, and LSE demand response resource adequacy contracts. IOU PDR is “credited” while the non-IOU PDR is mostly shown on supply plans as resource adequacy to the California ISO. DR is unique amongst supply-side resources in its treatment as an RA resource. While some supply-side DR resources are shown on supply plans, another larger portion is not and are instead treated through a process known as “crediting.” Under crediting, IOU-implemented DR resources can be counted as a reduction in the amount of RA capacity required — that is, they are “credited” against the total demand instead of “shown” as resources to meet that demand.

Emergency demand response is triggered by emergency grid conditions and participates in the California ISO market as a RDRR. This emergency demand response is made up of various IOU demand response programs including the base interruptible program and the agricultural pumping interruptible program. RDRR in the California ISO market can be triggered by the California ISO after at least a warning is declared.⁶⁵ These programs are managed by the IOUs and are credited by the CPUC against the RA obligations of CPUC-jurisdictional LSEs.

In terms of relative size, the amount of supply-side demand response far exceeds the amount of load-modifying DR. The current CPUC-jurisdictional demand response portfolio (as of 2021) consists of approximately 1,500 MW of supply-side demand

65 California ISO. Alert, Warning, and Emergency Notifications [webpage](https://www.caiso.com/informed/Pages/Notifications/NoticeLog.aspx), <https://www.caiso.com/informed/Pages/Notifications/NoticeLog.aspx>.

response versus 85 MW of load-modifying demand response. A breakdown of this portfolio is provided in the table below.⁶⁶

Table 4: Current CPUC DR Portfolio (as of 2021)

Supply-Side DR (~ 1500 Aug MWs)	Load-Modifying DR
<ul style="list-style-type: none"> • IOU managed DR: <ul style="list-style-type: none"> ○ Emergency (<u>804 Aug MWs</u>) <ul style="list-style-type: none"> ▪ Base Interruptible Program ▪ Agricultural Pumping Interruptible Program ○ Economic (<u>393 Aug MWs</u>) <ul style="list-style-type: none"> ▪ Capacity Bidding Program ▪ AC Cycling ▪ Local Capacity Requirement Contracts • 3rd Party managed DR: <ul style="list-style-type: none"> ○ Demand Response Auction Mechanism (<u>206 Aug MWs</u>) ○ Community Choice Aggregator RA-DR Contracts (<u>120 Aug MWs</u>) 	<ul style="list-style-type: none"> • IOU managed DR: (<u>85 Aug MWs</u>) <ul style="list-style-type: none"> ○ Permanent Load Shifting* ○ Time of Use* ○ Critical Peak Pricing ○ Real Time Pricing <p>* Load impact incorporated in reduced peak demand forecast</p>

Source: CPUC

Capacity Value of Supply-Side DR

There are differing perspectives on how the load reduction capability of supply-side demand response (SSDR) is planned and counted. While the accounting system to measure the value of demand response has never been perfect, in part because it is hard to account for customers’ actual behavior compared to their expected behavior, the extreme heat events in 2020 focused greater attention on the challenges with counting on and accounting for supply-side demand response. This renewed focus on

⁶⁶ Demand response programs directed or administered by other local regulatory authorities, such as those operated by municipally owned utilities, are not included in this analysis.

the capacity value of demand response resulted in proposals made by the California ISO discussed below.

To determine the capacity of each resource eligible to be counted toward meeting the CPUC's resource adequacy requirement, the CPUC develops qualifying capacity (QC) values based on what the resource can produce during periods of peak electricity demand. The CPUC-adopted QC counting conventions vary by resource type. For DR, the QC values are set based on historical performance using the load impact protocols (LIPs).⁶⁷

In the CPUC's resource adequacy⁶⁸ proceeding (Rulemaking 19-11-009), the California ISO proposed to discontinue credits and require all resources counting as RA capacity to be shown on a California ISO supply plan. The California ISO stated that unlike other RA resources, credited DR resources are not shown on supply plans and not subject to California ISO tariff provisions, such as a must-offer obligation. The California ISO stated that these resources do not allow the California ISO to meet reliability needs and, if they fail to perform, they are not subject to resource adequacy availability assessment mechanism (RAAIM)⁶⁹ charges. In the same proceeding, the California ISO proposed that an ELCC method be used to determine the QC of SSSDR, rather than a LIP-based approach, because the California ISO believes that the LIP-based approach may overvalue the contribution of SSSDR to reliability. In support of its proposal, the California ISO cited an ELCC study prepared by Energy + Environmental Economics (E3) that analyzed 2019 bid data submitted by PG&E and SCE, and then subsequently

67 The LIPs were adopted by the CPUC in D.08-04-0501 and prescribe a set of guidelines for estimating the impact on load resulting from demand response activities. These guidelines established a consistent method for measuring actual historical performance across demand response resources and for forecasting anticipated future performance. The LIPs are used as resource adequacy counting rules for demand response qualifying capacity.

68 California has a resource adequacy (RA) program that is jointly administered by the California ISO and CPUC (and other local regulatory authorities) in the California ISO balancing authority area. The RA program seeks to secure sufficient capacity when and where needed to support the safe and reliable operation of the California ISO grid. The California ISO and local regulatory authorities establish RA capacity requirements for load-serving entities. LSEs procure RA resources (for example, those resources with qualifying capacity) to meet their RA capacity requirements. The LIP is the current method for determining the QC of a SSSDR resource.

69 Through the RAAIM, the California ISO assesses non-availability charges and provides availability incentive payments to RA resources based on whether their performance falls below or above, respectively, defined performance thresholds.

updated with 2020 bid data, and found that the LIP method overvalued DR capacity contributions by 19 to 23 percent more than an ELCC method.

In the same proceeding, some parties favored continued reliance on the LIP-based approach, while other parties identified problems with using bid data as inputs to an ELCC model, which led PG&E and SCE to develop an alternative ELCC proposal. PG&E and SCE's proposal was called "LIP-informed ELCC." The difference between the two proposals is that the LIP-informed ELCC uses modeled load impacts from the LIPs to generate the annual capability profile instead of bids, as was used by E3. SCE submitted that such a method would sufficiently address the California ISO's concerns with the LIP to enable it to revise its tariff to treat DR as a variable resource. If the CPUC were to adopt this approach, PG&E recommended a RAIM exemption for DR on supply plans for 2022.

CPUC Energy Division staff did not believe a sufficient record had been developed to move to any form of an ELCC approach. Energy Division staff proposed that the CPUC request the CEC launch a working group process in the *2021 Integrated Energy Policy Report (IEPR)* to develop recommendations for a comprehensive measurement and verification (M&V) strategy for demand response, including a new demand response QC method addressing *ex post* and *ex ante* load impacts for the 2023 RA compliance year, and submit recommendations to the CPUC. The CPUC found consensus among parties in support of the proposed CEC-led stakeholder working group process.

Accordingly, in its decision⁷⁰ the CPUC asked the CEC to launch a stakeholder working group process in the *2021 IEPR* and make actionable recommendations on the following issues:

- 1) Whether the California ISO's ELCC proposal is reasonable and appropriate to determine demand response QC and what modifications, if any, should be considered.
- 2) Whether the LIP + ELCC proposal is reasonable and appropriate to determine demand response QC and/or what modifications, if any, should be considered.
- 3) Whether other proposals that may be presented in the CEC's stakeholder process are reasonable and appropriate to determine demand response QC.

70 CPUC. June 25, 2021. [Decision 21-06-029](https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/final-2022-ra-guide-clean-101821.pdf). <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/final-2022-ra-guide-clean-101821.pdf>.

- 4) Whether and to what extent alignment of DR M&V methods in the operational space for California ISO market settlement purposes with methods to determine RA QC in the planning space should be achieved, and if so, how.
- 5) Whether, and if so what, enhancements to intracycle adjustments to demand response QC during the RA compliance year, as adopted in D.20-06-031, are feasible and appropriate to account for variability in the DR resource in the month-ahead and operational space.
- 6) Whether implementation of any elements of demand response QC method modifications that might be adopted by the commission should be phased in over time.
- 7) Whether, and if so how, any changes to demand response adders should be reflected in DR QC method.

In its decision, the CPUC requested the CEC to submit its recommendations to the CPUC no later than March 18, 2022. The CPUC also requested, to the extent possible, that the CEC's recommendations include specific QC values for consideration.

CEC Response to the CPUC's Request

To help advance SDR programs that participate in California ISO wholesale markets and contribute to reliability, the CEC has agreed to analyze and propose improvements to how California plans and accounts for the capacity of this important resource and its contribution to reliability. To accomplish this end goal, the CEC launched a working group process with utilities, the California ISO, demand response providers and other stakeholders to develop solutions that further unlock the reliability benefits these programs can have for consumers and the grid.

Approach

To launch the stakeholder working group process, the CEC held a staff workshop focused on QC of supply-side DR on July 19, 2021. The workshop was subsequently incorporated into the IEPR docket. Immediately following the July 19 workshop, CEC staff formed two stakeholder working groups. One working group, called the "QC Methodology Working Group," was established to identify and define an array of methods for counting the capacity of supply-side DR resources. The purpose of the second working group, called the "Principles Working Group," was to identify a set of principles that a QC method should meet. Participation in both working groups was open to all interested stakeholders. The CEC publicly noticed the creation of an online form that let stakeholders indicate which working group they wanted to participate in and whether they would be interested in serving as a stakeholder lead of either working group. The response was positive with most stakeholders opting to participate in both

working groups.⁷¹ Two volunteers were selected as stakeholder leads for the two working groups.⁷²

These two working groups began meeting August 2, 2021. Due to the limited time available to respond to the CPUC request by March 2022, it was determined that the working groups would need to meet frequently. Thus, a working group meeting was held every Monday morning for two hours, with each working group meeting on alternate Mondays. Between August and October, each working group met five times. This frequency of working group sessions was successful and within just a few months produced both an array of potential supply-side DR capacity counting methods and a set of principles to evaluate the options. Based on this progress, CEC staff combined the two working groups in October 2021 into one working group to move to the next phase of effort. The new combined working group was named the "Supply-Side Demand Response Qualifying Capacity Working Group."

In October 2021, stakeholders communicated to CEC staff that due to timelines of other processes and proceedings, completing a permanent solution for RA year 2023 was infeasible. Between the QC compliance schedule for RA year 2023 that had begun and the launch of the RA reform workshop process that could significantly change the requirements of a DR QC methodology, stakeholders noted any methodology adopted would likely be too late for implementation in RA year 2023 and incompatible for RA year 2024. In response, CEC staff suggested quickly developing interim recommendations (for RA year 2023 only) that could be adopted with minimal changes and moving the report deadline sooner.

To that end, in October 2021 the working group turned its focus to identifying interim options for the 2023 RA year. Over time, the working group coalesced on two interim proposals: LIP-informed ELCC (originally termed LIP + ELCC) and a market-based

71 Stakeholder organizations represented include Sunrun, California ISO, Enel X North America, Recurve, Olivine, OhmConnect, CPUC Energy Division, CPUC Public Advocates Office, Hy Power Salton Sea, SCD Energy Solutions, Grounded Analytics, Southern California Edison, Pacific Gas & Electric, Barkovich & Yap, Inc. for the California Large Energy Consumers Association (CLECA), California Efficiency + Demand Management Council (CEDMC), CPower, SDG&E, Middle River Power, Leap, CalCCA, Powerflex, NRG Curtailment Solutions, Jay Luboff Consulting, Demand Side Analytics, Opinion Dynamics, California Energy Storage Alliance, Verdant Associates, Enchanted Rock, and EnergyHub.

72 Stefanie Wayland of Grounded Analytics volunteered and was selected as the stakeholder lead of the QC Methodology Working Group. Luke Tougas, a consultant on behalf of CEDMC, volunteered and was selected as the stakeholder lead of the Principles Working Group.

approach modeled after those used in other ISOs in the nation such as PJM and the New York ISO. The “PJM/NYISO” approach was proposed by the California Energy Demand Management Council (CEDMC). From that point forward, the working group continued to discuss and focus on these two proposals for RA year 2023.

On December 3, 2021, an IEPR workshop was held to inform the IEPR record on supply-side demand response and its role in reliability and resource planning. This IEPR workshop provided an opportunity to inform the IEPR record on the progress made in the CEC-led stakeholder working group process. This included reporting on the work products developed, namely the array of methods for counting the capacity of SSSR resources and a set of principles that a method should meet. The workshop included presentations on interim proposal options under development that could potentially be implemented in 2022 for the 2023 resource adequacy year.

Stakeholders expressed support for focusing the remainder of the stakeholder working group process on development of options that could be implemented in 2022 for the 2023 resource adequacy year. To that end, staff is producing an interim report containing recommendations for SSSR counting methods to be considered as options by the CPUC for the 2023 resource adequacy year. These options are not intended to set any precedent relative to long-term consideration of methods for the 2024 resources adequacy year, but to enable their testing and comparison to the status quo method in use in 2021. To further facilitate the potential for these interim options to be deployed in 2022, staff will submit the interim report to the CPUC in February 2022 (rather than March 2022). Following submittal of the interim report to the CPUC, the stakeholder working group process will continue its work during 2022 to identify and recommend a long-term method for the 2024 resource adequacy year and beyond.

Principles

The principles are designed to be used in evaluating and comparing different SSSR capacity counting methods. While it is ideal that a method would meet all principles, in reality, it is expected that each method will meet individual principles to varying degrees, so the principles can be used to evaluate tradeoffs between the different methods.

In the December 3, 2021, workshop, CEC reported out on a set of principles developed to date through the working group process. These principles evolved through multiple rounds of written and verbal comments through the workgroup process. CEC requested public input on this list during the IEPR workshop and will incorporate that feedback as well as working group input to make a final list in the recommendation to the CPUC.

The set of principles includes the following:

1. The QC methodology should be transparent and understandable.
2. The QC methodology should use best available information regarding resource capabilities, including recent historical performance and participant enrollment and composition projections.

3. The QC methodology should allow DR providers to quickly determine or update QC values.
4. The QC methodology should be consistent and compatible with the resource adequacy program.
5. The QC methodology should account for any use limitations, availability limitations, and variability in output of DR resources.
6. The QC methodology should translate a DR resource's load reduction capabilities into its contribution to reliability.
7. The QC methodology should include methods to determine delivered capacity (ex-post) that are compatible with the determination of qualifying capacity (ex-ante).
8. The QC methodology should not present a substantial barrier to participation in the RA program.
9. The QC methodology should flexibly account for the reliability contribution of a resource given the other resources on the system.

Options Proposed by Working Group Members

At the workshop, CEC staff reported on the working group's efforts to identify and describe different methods for determining qualifying capacity. Generally, the proposals have fallen into one of four categories:

1. **Effective Load Carrying Capability (ELCC):** The purpose of an ELCC framework is to determine the equivalent quantity of "perfect capacity" (a hypothetical resource that can change its output instantaneously and faces no outages) that a variable or energy-limited resource provides over the course of a year. The ELCC model inputs the capability profiles of DR resources across all hours of the year and under varying weather conditions, then runs electric reliability simulations over many years. The QC of a resource is the capacity amount the resource contributes without increasing the probability of a forced outage.
2. **Market-Based Approaches:** Under a market-based approach, DR providers estimate the capability of their resources and claim a corresponding capacity value. Unlike other proposals and the *status quo*, which require significant up-front rigor and oversight in estimating future capacity, the market-based paradigm employs incentive mechanisms — namely financial penalties for underperformance — to ensure compliance. This approach differs dramatically from simply developing a new methodology to estimate future QC, but similar approaches are used in other ISOs such as the New York ISO and PJM. Because the penalty mechanism incentivizes accurate forecasting, DR providers may use any proprietary analytical tools they choose to determine their QC values.
3. **QC Enhancements:** QC Enhancements fall under the same *status quo* framework of estimating resource capabilities under a given set of planning

conditions. These proposals contrast ELCC-based approaches, which represent a fundamentally different paradigm for valuing a contribution to reliability. These enhancements include changes to the assumptions used to determine QC, such as the period of day, assumed planning temperatures, and accounting for DR resource shapes and constraints to better reflect a contribution to reliability.

4. **Streamlined LIPs:** Many stakeholders have emphasized the difficulty and expense of complying with the LIPs and have suggested process improvements to reduce the associated cost and effort. Stakeholders have suggested eliminating or simplifying protocols and reporting requirements that are unnecessary for calculating the QC value.

In support of the CPUC's request for actionable recommendations for the 2023 RA year, the working group turned its attention to potential interim solutions that may be implemented before all potential methodologies can be sufficiently assessed and vetted. As noted above, two gained traction amongst the working group and stakeholders are working with CEC staff to assess the feasibility of implementing such proposals for the 2023 RA year. These proposals include the following:

1. **LIP-informed ELCC:** The LIP-informed ELCC proposal uses the overall ELCC logic and framework described in the ELCC description above. However, this proposal uses outputs from the LIPs to represent resource availability instead of historical bids, as originally proposed by the California ISO. The load impact profiles apply the same regression models used in the *status quo* but apply a wider range of conditions expected over the course of a year by month, temperature, and day of week. Using LIP outputs rather than historical bids addresses concerns that measurement limitations for some DR resources would influence DR provider bidding behavior and therefore bias the resulting QC values.
2. **"PJM/NYISO" Market-based Model:** Under this proposal modeled on other independent system operators (ISOs), DR providers assess the future capabilities of their resources and claim the corresponding capacity value. As proposed, this approach would apply the same capacity counting methods as in the *status quo*, namely the monthly average load impact under 1-in-2 weather conditions over the AAH time frame, excluding Sundays and holidays. DR providers would be incentivized to accurately assess their resources' capabilities through a performance-based penalty system based on the scale of demonstrated capacity (DC) relative to the amount committed in supply plans, as shown in Table 5. Because the penalty mechanism incentivizes accurate forecasting, DR providers may use any proprietary analytical tools they choose to determine their QC values.

Table 5: PJM/NYISO Model Penalty Structure

DC Relative to CC	Penalty
≥ 90%	None
<90% to ≥75%	10% of DC
<75% to ≥50%	25% of DC
<50%	50% of DC

Source: CEC staff

The CEC will continue to engage with the working group to explore the options presented in the workshop. In February 2022, the CEC will provide a report to the CPUC describing the outcomes of the stakeholder working group process, including the CEC recommendations on options for counting the capacity of SSSR resources, both for the interim and the long-term.

CHAPTER 6:

Recommendations

Securing electric system reliability in the face of climate change and as the state expands clean energy deployment will require an iterative approach to managing the system — through planning, implementation, and continuous assessment. Continuous assessments are managed through the Integrated Energy Policy Report (IEPR) proceeding, California Public Utilities Commission (CPUC) proceedings, and California Independent System Operator (California ISO) stakeholder initiatives. Maintaining situational awareness of past and anticipated system performance is a critical component of continuous assessment. Likewise, research and development is critical to developing solutions to improve system reliability.

Situational Awareness

- The California Energy Commission (CEC) should continue to develop and refine near-, mid- and long-term reliability analyses. The near-term analysis is an annual assessment of the need for contingencies under extreme weather conditions, termed the *stack analysis*. It will be developed by March of each year for the coming summer. The midterm analysis is a California Reliability Outlook, which is a loss-of-load analysis for the next five-year period. It will be developed by July of each year. For the long term, the CEC will continue to develop an analysis of electric system reliability under different clean-energy deployment and electrification scenarios to support Senate Bill 100 (De León, Chapter 312, Statutes of 2018) requirements and inform policy development.
- The California ISO, CEC, and CPUC should work to increase the transparency of transmission network upgrades and interconnection processes to assist communities, load-serving entities (LSEs), and developers in their planning. This work will include examining the alignment of the California ISO transmission planning processes, CPUC integrated resource planning, and LSE procurement activities to ensure use of best available information for decision-making.
- The CPUC, CEC, California ISO, and the Governor’s Office of Business and Economic Development (GO-Biz) should continue to monitor new clean energy project development to identify potential delays of projects that are critical to reliability and coordinate with stakeholders (for example, developers, local permitting authorities, federal agencies) to support timely deployment.
- With the rapid development of battery energy storage systems (BESS), a formal statewide tracking and evaluation database needs to be established. The database should include annual performance and safety updates as the CEC and other relevant state agencies continue to monitor the improvements to the construction and safety frameworks.

Planning

- The CEC, CPUC and California ISO should develop a common approach to incorporating climate change into system planning, including a set of climate scenarios to be considered. This approach includes building off Electric Program Investment Charge (EPIC) research that will support incorporating climate change into the demand forecast and anticipated EPIC research to quantify benefits of resilience planning and consider the needs of equity communities in such planning.
- Consider statutory changes to enable more rapid deployment of clean energy technologies. Potential enablers include local financing and economic benefits, and expediting permit processes and judicial review, as well as consolidating review at the state level for essential generation, storage, and transmission projects.
- Evaluate whether changes to the planning reserve margin (PRM) are warranted based on climate change impacts and increasing variable generation resources.
- The CEC should evaluate the need for long duration storage, beyond existing EPIC research, to further understand the need and value of long duration storage, particularly as the state increases electrification.
- Track new clean energy projects to understand frequency of delays and identify whether issues, such as supply chains and permitting, can be improved to support greater clean energy technology buildout.
- Consider policy mechanisms and project viability measures that encourage LSEs to select projects in areas where interconnection and transmission network upgrades have a viable and timely path forward.
- Identify opportunities to integrate longer-term Senate Bill 100 resource planning and mapping efforts and the California ISO's 20-Year Transmission Outlook, when available in 2022, with the CPUC's integrated resource planning and resulting procurement orders.
- Examine alignment of the California ISO transmission planning, CPUC and non-CPUC jurisdictional LSE integrated resource planning to ensure use of best available information for decision-making.
- To address the current and growing BESS deployment, a consistent, statewide approach to permitting and emergency response capabilities should be adopted to ensure that every jurisdiction is consistent and expert in siting BESS and responding to BESS operational issues.

Implementation

- The CEC and CPUC continue to collaborate to restructure the state's demand response program to shift to an approach that will take advantage of flexible-demand appliances and the market-informed demand automation server (MIDAS).
- The CEC should develop an approach to modeling social costs and nonenergy benefits of different scenarios to provide a more comprehensive analysis that can be applied in near-, mid-, and long-term analyses (such as the stack analysis, California Reliability Outlook, and Senate Bill 100 modeling).
- The CEC and CPUC should work to expand dynamic rate plans and encourage the rollout of automated devices. The CPUC and CEC will need to coordinate with the smaller non-CPUC-jurisdictional entities and community choice aggregators to encourage these entities to implement similar rate plans and automate access to them.

Research and Development

- The CEC should invest in research that creates or improves (in terms of performance, cost, and ratepayer benefit) clean-energy technology innovations that accelerate California's transition to a zero-carbon electric grid.
- The CEC should invest in applied research that supports integration of climate considerations into electric planning, operations, and technology investment. This integration includes improving characterization of the climate conditions under which the grid must reliably operate now and in the future, improving supply and demand forecasting over a range of timescales, and improving situational awareness and forecasting of wildfire-related risks to grid operations. The CEC should coordinate any such research that is funded through EPIC with the LSE EPIC administrators, and encourage their participation in CEC EPIC projects, particularly those related to improving grid operations for reliability and resiliency. This research, in turn, informs technology and policy options that can contribute to grid reliability in the context of decarbonization.
- The CEC should invest in increasing customer load flexibility in the residential, commercial, and industrial sectors to support grid reliability. This work includes overcoming technical, market, and regulatory, barriers that reduce adoption and use of load-flexible technologies. It also includes improving the suite of technology options available to energy users to allow them to better adapt their load to system conditions as flexible power consumers.
- The CEC should invest in advancing zero-carbon firm dispatchable resources as alternatives to fossil fuel generation, including backup generators.
- The CEC should prioritize demonstrations of short- and long-duration energy storage, particularly in areas most adversely affected by reliability issues, such as in tribal communities and other under-resourced communities. This includes

communities that are in high-risk wildfire zones or have experienced public safety power shutoff events in the past. The CEC should invest through EPIC in market facilitation solutions addressing nonprice barriers to market deployment and grid utilization of clean energy technology innovations that improve grid reliability and resiliency. The purpose of these investments should be to accelerate California's transition to a zero-carbon electric grid.

Acronyms

AB	Assembly Bill
BESS	battery energy storage systems
CAL FIRE	California Department of Forestry and Fire Protection
California ISO	California Independent System Operator
CDWR	California Department of Water Resources
CEC	California Energy Commission
CF	capacity factor
CPUC	California Public Utilities Commission
CRO	California Reliability Outlook
DR	demand response
E3	Energy + Environmental Economics
EIM	energy imbalance market
ELCC	effective load carrying capability
ELRP	Emergency Load Reduction Program
GHG	greenhouse gas
GO-Biz	Governor’s Office of Business and Economic Development
GW	gigawatt-hour
GWh	gigawatt
IEPR	Integrated Energy Policy Report
IOU	investor-owned utility
IRP	integrated resource planning
LADWP	Los Angeles Department of Water and Power
LIP	load impact protocols
LOLE	loss of load expectation
LSE	load-serving entity
M&V	measurement and verification

MW	megawatt
NOAA	National Oceanic and Atmospheric Administration
NQC	net qualifying capacity
OTC	once-through cooling
PDR	proxy demand resources
PRM	planning reserve margin
PSP	preferred system plan
PV	photovoltaic
QC	qualifying capacity
RA	resource adequacy
RAAIM	resource adequacy availability assessment mechanism
RDRR	reliability demand response resources
SACCWIS	State Advisory Committee on Cooling Water Intake Structures
SB	Senate Bill
SSDR	supply-side demand response
SWRCB	State Water Resources Control Board

APPENDIX A:

California Publicly Owned Utility Energy Storage Procurement Targets

Assembly Bill 2514 (Skinner, Chapter 469, Statutes of 2010), amended by Assembly Bill 2227 (Bradford, Chapter 606, Statutes of 2012), requires California’s publicly owned utilities (POUs) to develop energy storage procurement targets. The legislation requires POUs to determine appropriate targets, if any, to procure viable and cost-effective energy storage systems to be achieved by 2016 and by 2020. The initial targets were required to be submitted to the California Energy Commission by October 1, 2014, summarized in the *2015 Integrated Energy Policy Report (2015 IEPR)*, and updates were provided in the *2017 Integrated Energy Policy Report (2017 IEPR)*. The following table depicts the POU’s submitted compliance reports for the January 1, 2021, filings.

Although the table below reflects the energy storage targets reported by POUs in response to AB 2514, it is not a complete reflection of all energy storage installed by the California POUs. Some POUs not listed in the table have energy storage installed on their systems but did not include those systems in their AB 2514 targets because the projects were not installed in direct response to AB 2514. For example, Los Angeles Department of Water and Power’s board-approved a plan to accelerate the procurement of 178 megawatts (MW) of battery storage to address reliability impacts resulting from constrained operations at the Aliso Canyon natural gas storage facility. Although many California POUs have found that energy storage is not cost-effective for their systems, they continue to maintain an interest in energy storage in the event future conditions make energy storage more attractive.

Table A-1: POU Energy Storage Targets

Utility	2017 Voluntary Target	Compliance Filing due 1/1/2021	Additional Voluntary Target
Alameda Municipal Power	0 MW	0 MW	0 MW
Anaheim, City of	1 MW	0 MW – refocus on new 50 MW goal	50 MW
Azusa, City of	0 MW	0 MW	0 MW
Banning, City of	0 MW	0 MW	0 MW
Burbank, City of	0 MW	0 MW	
Cerritos, City of	1% of peak load	0 MW	Extends 1% of peak load through 2021

Utility	2017 Voluntary Target	Compliance Filing due 1/1/2021	Additional Voluntary Target
Colton, City of	0 MW	0 MW – 8 ICE projects installed	0 MW
Corona, City of	1% of peak load	*pending*	0 MW
Glendale Water & Power	2 MW BESS Project	2 MW Skylar Pilot Project Adopted Dec. 2016	0 MW
Gridley, City of	0 MW	0 MW	0 MW
Healdsburg, City of	0 MW	0 MW	0 MW
Imperial Irrigation District	5 MW	0 MW due to cost/delays	0 MW
Kirkwood Meadows Public Utility District	0 MW	0 MW	0 MW
LADWP	155.4 MW: 128.4 MW transmission, 25 MW distribution, 2 MW of customer side	309.1 MW: 301.3 MW transmission, 7.8 MW customer side	0 MW – defers to Integrated Resource Planning (IRP) process going forward
Lodi, City of	0 MW	0 MW	0 MW
Lompoc, City of	0 MW	0 MW	0 MW
Merced Irrigation District	0 MW	0 MW	0 MW
Modesto Irrigation District	0 MW	0 MW	0 MW
Moreno Valley, City of	0 MW	0 MW	0 MW
Needles, City of	0 MW	0 MW	0 MW
Palo Alto, City of	0 MW	0 MW	0 MW
Pasadena, City of	0 MW	0 MW	0 MW

Utility	2017 Voluntary Target	Compliance Filing due 1/1/2021	Additional Voluntary Target
Pittsburg, City of	0 MW	0 MW	0 MW
Port of Oakland	0 MW	0 MW	0 MW
Rancho Cucamonga, City of	0 MW	0 MW	0 MW
Redding, City of	0 MW	0 MW	0 MW
Riverside, City of	6 MW	14 MW	0 MW
Roseville, City of	0 MW	0 MW	0 MW
San Francisco Public Utilities Commission	0 MW	0 MW	0 MW
Shasta Lake, City of	0 MW	0 MW	0 MW
Silicon Valley Power	0 MW	0 MW	0 MW – defers to IRP process going forward
SMUD	9 MW BTM goal	12/2020 8.94 MW of energy storage, officially met 9.03 MW and filed update Jan 2021	0 MW – defer to IRP process
Truckee Donner PUD	0 MW	0 MW	0 MW
Turlock Irrigation District	0 MW	0 MW	0 MW – considering pilot project in future
Ukiah, City of	0 MW	0 MW	0 MW
Vernon, City of	0 MW	0 MW	0 MW – defers to IRP process
Victorville, City of	1% of peak load	*pending*	0 MW

Source: CEC