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The Intersection of Decarbonization Policy Goals and Resource Adequacy Needs: A California Case Study

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A growing number of states have instituted renewable portfolio standards (RPS) through policies and corresponding commission orders to reduce carbon emissions in the electricity sector. No state has transformed its grid with more ambitious policies than California, which introduced its RPS in 2002, initially requiring 20 percent of retail electricity sales to be served by renewable resources within 15 years.[1] This program has been adjusted multiple times, most recently by Senate Bill 100 (SB100) in 2018, which increased the requirement for carbon-free generation from electric retail sales to 60 percent by 2030 and 100 percent by 2045. The California Public Utilities Commission (CPUC) is charged with implementing this RPS program and administering compliance over the state's investor-owned utilities (IOUs), Energy Service Providers (ESPs), and community choice aggregators (CCAs).[2] The CPUC is also responsible for ensuring that jurisdictional load-serving entities (LSEs) procure enough capacity to meet the commission's resource adequacy program requirements.[3] These two objectives collided on August 14 and 15, 2020, when the California Independent System Operator (CAISO) called on utilities to initiate controlled rotating electricity outages on two occasions to maintain adequate reserves in the midst of a regional heat wave. These two load-shedding events affected 491,600 and 321,000 customers, respectively.[4] California's electric system was ultimately unable to maintain reliable operations for the first time in almost two decades.

Significant loss-of-load events on the bulk power system often result from a combination of factors. After months of collaborative investigation, the CPUC, the CAISO, and the California Energy Commission (CEC) released a final root cause analysis (referred as "root cause analysis" throughout this paper) that identifies several operational factors that contributed to the events, including: actual loads exceeding forecasts; significant variability in wind and solar output; reduced imports from neighboring states (due to transmission constraints, market rules, and high demand throughout the Western Interconnection); and significant unit derates and forced outages. According to the root cause analysis, two of

1 California is one of several states with aggressive clean energy targets, requiring 100 percent carbon-free electricity by 2045. According to the NCLS, 14 states have RPS goals of 50 percent or greater by 2045. The types of resources that qualify for California's RPS have evolved. For additional information, see Section 399.12 of Senate Bill 1078 and the CPUC's RPS Program and Legislative History.

2 The California Energy Commission (CEC) is responsible for the certification of generation facilities as eligible renewable energy resources and adopting regulations for the enforcement of RPS procurement requirements of publicly owned utilities.

3 A 1-in-2 forecast assumes there is a 50 percent probability that the forecasted peak will be less than actual peak load and a 50 percent probability that the forecasted peak will be greater than actual peak load. The demand forecasts are adopted by the CEC as part of its Integrated Energy Policy Report (IEPR) process. The 15 percent planning reserve margin (PRM) includes 6 percent to meet the Western Electricity Coordinating Council (WECC)-required grid operating contingency reserves, plus a 9 percent planning contingency to account for plant outages and higher-than-average peak demand, CAISO/CPUC/CEC Final Root Cause Analysis, p. 11.

The 50/50 load forecast assumes a normal distribution. For example, if the forecasted load for a system is 25,000 MW, there is a 50 percent chance actual load will be higher, and a 50 percent chance load will be lower.

4 Total customer outages amounted to 491,600 on August 14 and 321,000 on August 15, CAISO/CPUC/CEC Final Root Cause Analysis, p. 35.

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the three primary causal factors were related to resource planning targets that "have not kept pace" with the changing resource mix, leading to insufficient resources available to meet demand during the early evening hours.[5] The August events highlight the need for continued improvement to resource adequacy constructs, along with developing and implementing enhanced metrics to accurately assess an electric system that continues to be transformed by ambitious state decarbonization policies.

In this *NRRI Insights* paper, we examine how the evolution of California's RPS program has led to increasing system variability with higher potential for reliability events—particularly during extreme weather conditions. We further explain how the rapid retirement of baseload and dispatchable generation has outpaced replacement capacity with adequate characteristics needed to maintain system reliability. We discuss the CPUC's recent finding that future procurement decisions must balance RPS requirements with resource adequacy needs. We then explore how the continued development of advanced reliability metrics can help bridge the gap between decarbonization policy goals and resource adequacy needs. Throughout this paper, we review the ongoing CPUC and CAISO actions in response to the ongoing supply shortages and offer some additional proposals aimed at improving the state's near- and long-term reliability outlook.

California's Decarbonization Policies and System Reliability

The California legislature established the first RPS program in 2002, with subsequent decisions and process modifications introduced by the CPUC.[6] Additional legislation with more stringent requirements and associated compliance timelines were signed into law in 2003, 2005, 2015, and 2018.[7] Load-serving entities repeatedly demonstrated that they could interconnect large amounts of utility-scale wind and solar, while large amounts of rooftop photovoltaic were also installed behind the meter. During this period of relatively rapid system transformation, the CAISO continued to operate the system without any major events, reinforcing the idea that policy-makers could introduce more ambitious RPS requirements without compromising grid reliability.[8] The CAISO has facilitated the interconnection of large amounts of utility-scale wind and solar by providing open and non-discriminatory access to the wholesale transmission grid and supporting comprehensive infrastructure planning through dozens of stakeholder initiatives. These initiatives led to the deployment of over 13 gigawatts (GW) of utility-scale solar and 7 GW of wind on the CAISO system in under 18 years.[9] As a result, the CAISO system is currently able to serve over 80 percent of demand with renewables during certain periods, double the amount reported in 2015, and more than any other system in the country (**Figure 1**).[10]

The Decline of Baseload and Dispatchable Resources in California

California's rapid and ongoing growth of intermittent resources like wind and solar has flourished, while baseload and dispatchable resources have

5 CAISO/CPUC/CEC Final Root Cause Analysis, p. 1.

6 See the CPUC RPS website for a complete list of the state's RPS program.

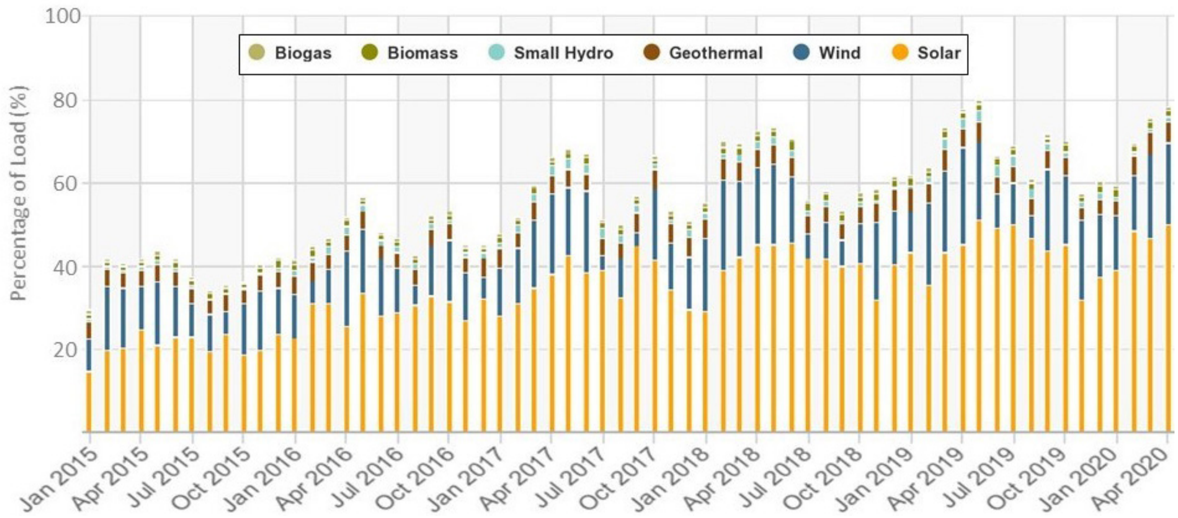
7 The 2003 Energy Action Plan I accelerated the 20 percent deadline from 2017 to 2010 (Senate Bill 107 (2006) codified the accelerated deadline into law). The 2005 Energy Action Plan II examined a further goal of 33 percent by 2020. Senate Bill 350 (2015) required all in-state utilities to source half of their electricity sales from renewable sources by 2030.

8 California's electric system had not experienced wide-spread rotating outages since 2001, when the CAISO declared a Stage 3 emergency leading to the controllable firm load-shedding during the California Energy Crisis. The 2011 Southwest Blackout was not a controlled load shedding event, rather it was determined that the system was not operating at an N-1 state.

9 California Energy Commission's Electric Generation Capacity and Energy data indicates 11.2 GW of solar additions and 4.4 GW of wind additions between 2001 and 2019. In July 2020, the CAISO footprint has 13,383 MW of utility-sale solar and 6,977 MW of wind.

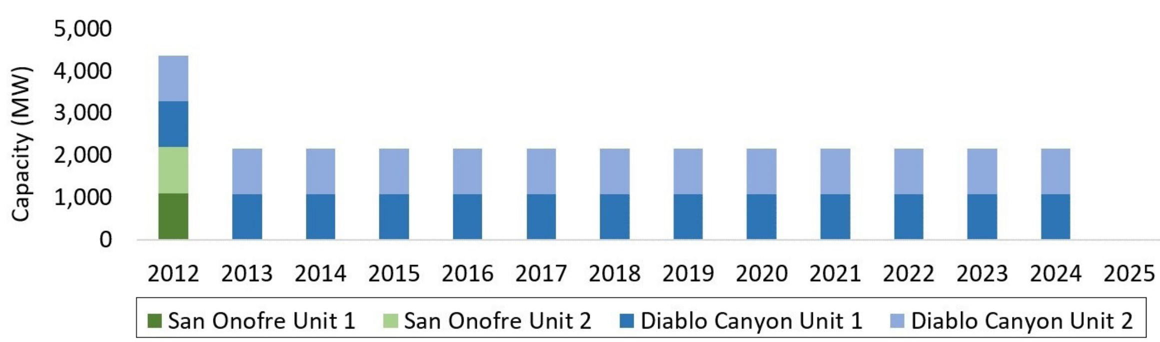
10 The CAISO system served a record 81.88 percent of system demand with renewable generation on May 2, 2020 at 1:40 p.m. The CAISO chart does not show May 2 record of renewables serving demand. Chart modified and resized by authors.

Figure 1: CAISO Monthly Maximum Percent of Load Served by



declined.[11] In 2012, the San Onofre Nuclear Generating Station (SONGS) plant was taken offline and permanently decommissioned one year later. SONGS had provided 2.2 GW of zero-emission baseload generation in close proximity to the densely populated Southern California load pockets. Four years later, plans were announced to close the state's remaining nuclear plant, Diablo Canyon, by 2025. Its two reactors total 2,160 MW and serve three million customers. Nuclear plants maintained an average 2019 capacity factor of 93 percent, compared to approximately 24 percent for solar. Thus, it would require at least 6 GW of nameplate solar capacity to fill the void created by the retirement of the Diablo Canyon plant.[12]

Figure 2: Nuclear Generation in California (2012-2025)



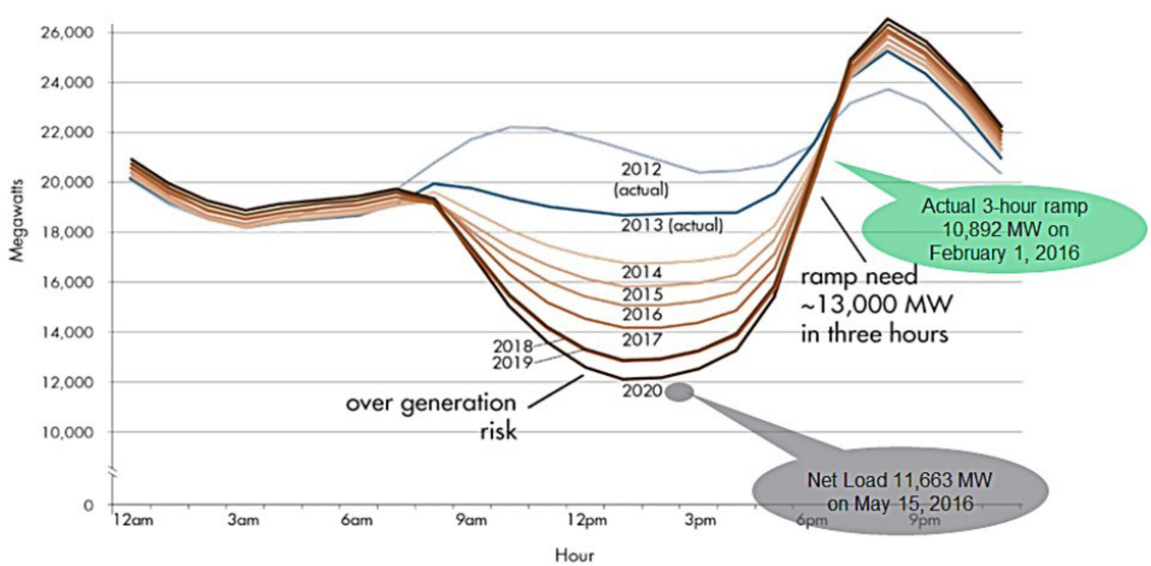
11 Baseload generation includes power plants with high capacity factors that are able to be operated at sustained output levels with limited cycling or ramping. Examples includes most nuclear, coal, and natural gas steam generators, none of which qualify toward achieving the state's RPS. California has essentially retired all coal-fired capacity.

12 EIA 2019 Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels; EFI: Optionality, Flexibility & Innovation: Pathways for Deep Decarbonization in California, p. 40.

In addition to the ongoing loss of baseload generators, dispatchable resources that are highly responsive to intermittent resources are also in decline. Ramping concerns initially emerged as a growing challenge for the CAISO more than a decade ago. Today, the majority of the state's solar resources are not dispatchable by the CAISO, but are located behind-the-meter on customer rooftops.[13] Solar output from these distributed resources (in aggregate) offsets what would otherwise be higher system loads. However, output rapidly declines after the sun sets, creating a steep ramp in demand that must be served by other resources on the CAISO system. During the same period, residential electricity demand also increases, as customers return home from work and use more appliances during the late-afternoon and early-evening (especially air conditioning). This load pattern, often referred to as the duck curve (and more recently referred to as "net-load ramps"), is exacerbated by the long, narrow, north-south geographic orientation of the state (**Figure 3**).[14, 15]

The ongoing challenges associated with meeting increasingly steep net load ramps were identified in the joint report as a contributing factor to the August 2020 events.[16] Concerns about insufficient ramping capability on the system were initially recognized by the CAISO Board of Governors in 2011 and resulted in their approval of a flexible ramping constraint interim compensation methodology. The resulting market policy established a flexible ramping product to address ". . . increasing levels of

Figure 3: The Duck Curve Highlights the Need for Responsive Resources to Address Growing Ramping Needs



13 According to the CAISO's January 2021 Key Statistics, there are 12,697 MW of utility-scale solar (includes load-serving entities participating in California's market). SEIA's Q3-2020 fact sheet indicates that a total of 29,218 MW of total installed solar.

14 If solar resources were instead spread across an east-to-west orientation, the decline in solar output would occur over a longer period as the sun sets. This would allow operators more time to identify and "ramp-up" other dispatchable resources. A ramp refers to the generator responding to the change in load or to changes in output from other generators on the system. Daily net load ramps are especially prevalent during the spring and fall and are the result of growing amounts of distributed solar resources (primarily rooftop photovoltaic) that have caused overall system demand to decline during the middle of the day (the belly of the duck, when solar output is highest). Demand then rapidly increases in the late afternoon and early evening, when solar performance declines as the sun sets, causing net load to increase rapidly.

15 The duck curve demonstrates that the net load variability required fast-acting resources to "ramp-up" as much as 10,892 MW in 3 hours during the late-afternoon on February 1, 2016. CAISO Fast Facts: What the duck curve tells us about managing a green grid (2016).

16 CAISO/CPUC/CEC Final Root Cause Analysis. Executive Summary ES.2, pp. 3-5.

variable energy resources and behind the meter generation…" which contributes to the operational challenges associated with ramping capability.[17] The flexible ramping product promotes securing enough ramping capability in the 5-minute and 15-minute market to address the variability of wind and solar resources.[18] Unlike baseload generation, which provides relatively constant output, generation capable of ramping allows the CAISO to dispatch these plants to change output based on the changing needs of the system. These impacts are on the demand-side (due to the variability of distributed rooftop solar PV), as well as the supply side (due to changes in output from utility-scale wind and solar). Accordingly, the CAISO needs additional flexible resources capable of responding to increasingly variable system conditions. Flexible resources include the ability to perform the following functions:[19]

- Sustain upward or downward ramps
- Change ramp directions quickly (react quickly and meet expected operating levels)
- Respond to operator dispatch to maintain output for a defined period of time
- Store and modify time of energy use
- Start-up from a zero or low-electricity operating level with short notice (i.e., rapid start-up)
- Start and stop multiple times per day
- Provide accurate operating capability projections (i.e., the metered output from a unit matches the information provided to the system operator)

However, resources on the CAISO system with many of these characteristics have been taken out of service at a rapid pace. Approximately 9 GW of natural gas fired generation was removed from service within five years, including many combustion or combined-cycle plants that can respond rapidly to net load ramps.

Table 1: Capability of Different Power Generating Technologies to Provide Flexibility

Plant Type	Start-up Time	Max Change in 30 Seconds (%)	Max Ramp Rate (%/min)
Simple Cycle CT	10 - 20 min	20 - 30	20
Combined Cycle CT	30 - 60 min	10 - 20	5 - 10
Coal Plant	1 - 10 hr.	5 - 10	1 - 5
Nuclear Plant	2 hr. - 2 d	< 5	1 - 5

The ramp rates for most simple-cycle and combined-cycle gas turbine models are shown in **Table 1** and compared with other generating technologies.[20]

Meanwhile, the CAISO previous projections that the 3-hour ramp would grow to 13,000 MW by 2020, actually occurred on January 1, 2019, with an actual 3-hour ramp rate of 15,639 MW.[21] Despite these alarming trends, an additional 1.9 GW of dispatchable capacity was taken offline between June 2019 and June 2020.[22]

Replacement Capacity Must Address the System's Changing Reliability Needs

Generation retirements to meet RPS requirements or

17 CASO Revised Draft Final Proposal - Flexible Ramping Product, p. 3.

18 The Flexible Ramping Product requirements for the 15-minute market is usually higher than the requirement for the real-time dispatch, since there is uncertainty observed between the two market intervals, CAISO Energy Markets Price Performance, p. 72.

19 CAISO Fast Facts: What the duck curve tells us about managing a green grid, 2016, p. 2.

20 Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices (2020). (p.10).

21 Actual ramps have been as high as 14,360 MW during a 3-hour period, CAISO projecting 3-hour ramping needs to surpass 20,000 MW by 2022, p. 20. The net load is defined as system load minus renewable generation, including distributed generation (primarily rooftop photovoltaic), solar thermal, and wind power in California. The net load ramp also refers to the evening period of greatest ramping needs driven by the quickly diminishing solar output. Projections and actual data provided by the CAISO's Flexible Capacity Needs and Availability for 2020, p. 22.

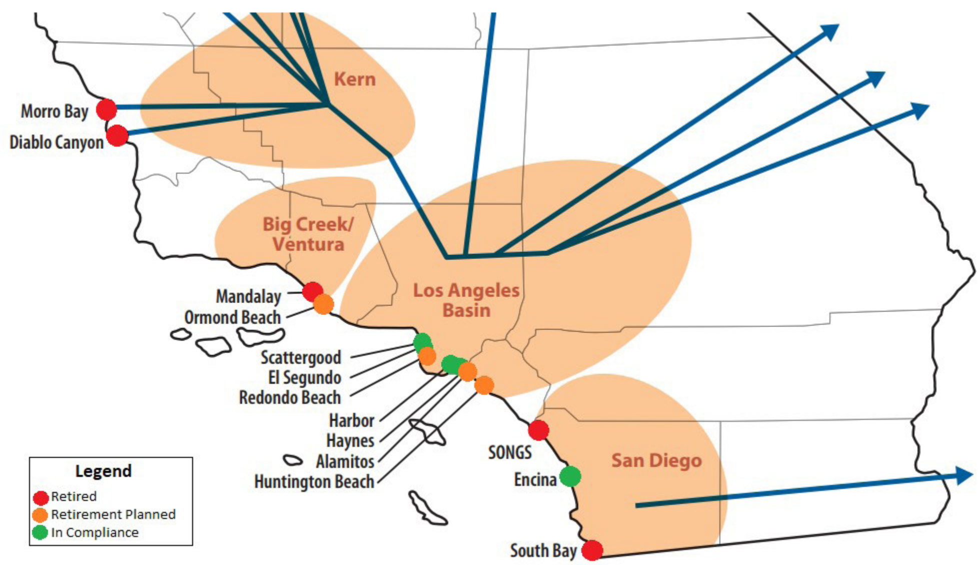
22 A total of 1,926 MW of dispatchable generation was taken out of service from June 1, 2019 to June 1, 2020, CAISO 2020 Summer Loads and Resources Assessment, p. 27.

comply with the California State Water Board's ongoing regulations that phase-out once-through-cooling (OTC), have occurred without securing enough adequate replacement capacity needed to address the operational challenges associated with increased system variability.[23] Former FERC Commissioner Cheryl LaFluer recognized this problem: "In the past three years, California has closed 5,000 MW of gas generation in anticipation of building 3,000 MW of battery storage that is still on the drawing board. In a heat wave, when every resource is needed, this gap in resources came home to roost."[24]

Former Energy Secretary Ernest Moniz also observed that "there is a shortage of [generating] capacity" and warned California policymakers that a combination of solar power and battery storage would not be able to fill the state's projected demand for electricity during the coming decade.

The ongoing retirements of nuclear capacity will significantly reduce the baseload capacity in Southern California. Concurrently, the most concentrated phase-out of gas-fired generation is occurring in the Los Angeles region.[25] To maintain system reliability, replacement capacity must be capable of providing essential reliability services to aid operators in managing growing net-load ramps caused by intermittent wind and solar. Transmission additions or reinforcements can further support the deliverability of resources across the system.[26] Of the 19 identified OTC plants (totaling 20,600 MW), more than half (10,400 MW) have been taken out of service since 2010. As shown in Figure 4, seven of the remaining plants are located near load

Figure 4: Southern California Generation Impacted by the Once-Through Cooling Phase-out Policy



23 Once-through cooling (OTC) technology causes adverse environmental impact by pulling large numbers of fish and shellfish or their eggs into a power plant's cooling system. Organisms may be killed or injured by heat, physical stress, or by chemicals used to clean the cooling system. Larger organisms may be killed or injured when they are trapped against screens at the front of an intake structure.

24 LaFleur, Cheryl A., What's Ailing California's Electric System?, Columbia University Earth Institute, September 2, 2020, https://blogs.ei.columbia.edu/2020/09/02/whats-ailing-californias-electric-system/.

25 The Los Angeles Department of Water and Power (LADWP) plans to retire three natural gas-fired power plants (1,211 MW) by 2025. EFI California Energy Study Outlines Ambitious Agenda to Maintain Global Leadership, p. 39.

26 "Deliverability" refers to a generator's ability to deliver its energy to load during different system conditions, including expected congestion caused by other generators' output, https://www.caiso.com/Documents/Jan2-2020-TariffAmendment-ImplementDeliverabilityAssessmentMethodologyEnhancements-ER20-732.pdf.

centers (Los Angeles and San Diego) providing reactive power, voltage support, inertia, and other essential reliability services to those areas. We expand on the importance of maintaining essential reliability services in the next section.

After the August events, then-President and CEO of CAISO, Steve Berberich highlighted the CAISO's requests to address projected capacity shortfalls needed to maintain established levels of resource adequacy.[27] The joint root cause analysis further recognized the need to "... address electric sector reliability and resiliency considering evolving policy goals of the state."[28] One proposed approach involves more cautious planning approaches for capacity retirements. In recognition of the recent capacity shortages highlighted by the August events, regulators at California's State Water Board extended OTC compliance deadlines and corresponding scheduled retirements of four power plants.[29] The continued availability of this generation will help maintain system reliability through 2023, as appropriate replacement capacity is identified and brought online.

The CPUC has also taken steps to address the concern regarding ongoing capacity shortages, indicating that "at least 3,300 MW of incremental system resource adequacy capacity and renewable integration resources would be needed by summer 2021."[30] The CPUC has contracted for 2,906 MW of Net Qualifying Capacity, scheduled to be online by August 1 of 2021, consisting primarily of intermittent resources and new storage technologies (**Table 2**).[31] Wind and solar resources have lower capacity factors and provide less consistent output compared to fully

Table 2: New Resources Expected – Sum of Net Qualifying Capacity (MW) by Load Serving Entity (LSE) and Technology Type

Sum of Net Qualifying Capacity (NQC), September NQC Megawatts (MW)					
	Online by 8/1/2021	Online by 8/1/2022	Online by 8/1/2023	Online post 8/1/2023	Grand Total
Contracted NQC MW	**2,388**	**840**	**481**	**267**	**3,977**
Investor-Owned Utility (IOUs)	*1,769*	*548*	*33*	*10*	**2,360**
Energy Storage	1,221	548	25	10	**1,804**
Solar plus Storage	494				**494**
Solar	38		8		**47**
Wind	16				**16**
Community Choice Aggregators (CCAs)	*584*	*274*	*427*	*257*	**1,543**
Solar plus Storage	152	81	269	257	**759**
Energy Storage	240	113	80		**433**
Solar	85	58	78		**221**
Wind	96	9			**105**
Geothermal		14			**14**
Small Hydro	12				**12**
Electric Service Providers (ESPs)	*35*	*18*	*21*		**74**
Solar	35	3	6		**43**
Solar plus Storage			15		**15**
Wind		15			**15**
Confidential or Uncontracted NQC MW	**518**	**156**	**693**		**1,368**
Grand Total NQC MW	**2,906**	**996**	**1,175**	**267**	**5,345**

27 August 17 briefing: "We told the CPUC 4,700 MW was needed through 2022 and that the gap started in 2020...Despite all that, only 3,300 MW was authorized for procurement, but that's not starting [until] 2021." Additionally, Berberich emphasized "...the situation we are in could have been avoided...For many years we have pointed out to the procurement authorizing authorities that there was inadequate power available."

28 CAISO/CPUC/CEC Final Root Cause Analysis. (p.75).

29 The State Water Resources Control Board amendment extends OTC compliance or phase-out dates at four fossil fuel power plants as follows: Compliance dates for Alamitos Units 3, 4, and 5 (1,165 MW), Huntington Beach Unit 2 (225 MW), and Ormond Beach Units 1 and 2 (1,516 MW) extended until December 31, 2023; the compliance date for Redondo Beach Units 5, 6, and 8 (850 MW) extended until December 31, 2021.

30 CPUC Rulemaking 20-11-003: Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021. (p.10)

31 CPUC Status of New Resources Expected, as of December 2020 (See slide 7).

dispatchable resources, especially during peak demand periods, as demonstrated during the August events.[32] Battery storage technology accounts for a small portion of the resource mix, with the CAISO currently operating 216 MW of installed capacity.

Battery Storage as Replacement Capacity Faces Remaining Operational and Market Hurdles

Relying primarily on battery storage additions to address near-term supply shortages poses reliability risks for several reasons. First, while the CAISO has demonstrated the ability to incorporate new technologies, operators still have limited experience with dispatching batteries on the system. Operators must contend with a learning curve associated with the deployment of a novel technology to develop an understanding of the behavioral characteristics and potential challenges associated with large-scale battery storage. Second, the CAISO has identified that the performance and effectiveness of battery storage systems are highly dependent on their location. Battery systems located near load centers can face challenges in accessing available transmission to ensure they are able to be charged and available when called upon.[33] Alternatively, batteries located long distances from load centers may face transmission congestion when attempting to inject power where needed. Related market performance issues are also still in development. A CAISO stakeholder initiative is underway to determine appropriate locational price signals to promote battery charging and availability windows that align with system needs.

Finally, it is important to recognize that even the most advanced batteries can provide continuous, stable energy output for limited durations (approximately four hours).[34] Extreme heat waves can last for days. CAISO's Steve Berberich has suggested that as much as 15,000 MW of fast-acting batteries (of different duration levels and various technologies) would be needed for California to achieve 100 percent renewables by 2045. Ongoing measures by the CAISO and the CPUC to monitor the impact of additional battery storage will help ensure that this technology can be reliably added to California's system to help offset the loss of dispatchable generation.

Reliance on Imports from Neighboring States

The transformation of California's system towards 100 percent carbon-free resources has also increased dependence on imported power from neighboring states. On average, the state relies on imported power to serve approximately a quarter of its annual electricity demand. However, maximum net imports during high-load conditions actually declined from 11,147 MW in 2017 to 8,792 MW in 2019, despite the ongoing expansion of the Western Energy Imbalance Market (EIM).[35] This trend indicates that the availability of imports needed for high load periods could be at risk during a time when CAISO may be most dependent on them.[36]

While the EIM has helped to promote coordinated resource sharing by allowing participants to access CAISO's real-time market, notable benefits won't be recognized until participants can also bid in the

32 According to the CAISO/CPUC/CEC Final Root Cause Analysis, "…with today's new resource mix, behind-the-meter and front-of-meter (utility-scale) solar generation declines in the late afternoon at a faster rate than demand decreases. These changes in the resource mix and the timing of the net peak have increased the challenge of maintaining system reliability…" (p.4). Resource performance will be further discussed in the next section.

33 Transmission congestion can occur in load centers that make it difficult for batteries to charge during certain periods, since lines are already loaded to serve demand. Congestion can also make it difficult for batteries to inject power in some areas of the system.

34 Whereas existing storage technology can provide longer durations, the four-hour output requirement is a function of the RA rules. Specifically, the rules only require that a storage facility produce at least four hours of output to be classified as RA.

35 The EIM participants across the Western Interconnection can bid into the CAISO's real-time market to buy and sell power close to the time electricity is consumed. It offers system operators real-time visibility across neighboring grids. The ability to share a larger pool of resources can support resource adequacy needs by increasing balancing capabilities and reducing costs. "High-load conditions" are described by the CAISO as load that is "equal to or greater than 43,000 MW," CAISO/CPUC/CEC Final Root Cause Analysis, p. 4.

36 CAISO/CPUC/CEC Final Root Cause Analysis, p. 4.

day-ahead market. This would allow entities throughout the west to efficiently plan and commit resources based on price signals. The day-ahead commitment will also help the CAISO identify transfer capability, system congestion, and potential resource shortages with more time to secure additional generation. This ongoing stakeholder initiative to unlock such benefits has been under discussion for several years due to unresolved concerns of some EIM members.

Despite the potential progress toward an extended day-ahead market or a Western RTO, the limitations of the existing transmission infrastructure are also a concern. During the August events, transmission paths across both the California-Oregon Intertie and Nevada-Oregon Border were heavily congested, as "…transmission constraints ultimately limited the amount of physical transfer capability into the CAISO footprint."[37]

Importing additional power into California will likely require transmission upgrades or additions, assuming that neighboring states are willing to offer these imports in the future. Entities across the west could begin to withhold exporting power to meet decarbonization policies in their own state. For example, Washington State's RPS of 100 percent renewables by 2045 may limit hydro exports to California. Similarly, plant retirements in Arizona, Nevada, and New Mexico may further diminish the CAISO's current access to out of state resources.

The importance of reliance on imports from neighboring states necessitates continued collaboration to better understand how individual state policy goals will impact transfer capability. In the northeast, the Integrated Clean Capacity Market (ICCM) puts individual state energy policies at the center of a revised resource adequacy market, while modernizing existing resource adequacy constructs throughout the PJM Interconnection. Specifically, the ICCM promotes a flexible market framework to accommodate states at varying levels of progress toward a decarbonized electric system so that the energy goals of some states can be supported without imposing any costs on other states with differing policy priorities.

In the near-term, the CAISO may also consider modifying the assumptions for projected imports in their seasonal assessments, which currently assume the inclusion of non-RA imports, despite the risk that this energy may not be available during extreme weather events throughout the region. Future projections of import availability could also include scenarios that examine increased limitations due to potential transmission constraints and/or EIM market rules that impose transfer limits (e.g., flexible ramping sufficiency test).[38]

Limitations of Demand Response

The preliminary root cause analysis partially addresses the issue of procuring additional resources through a recommendation that the CPUC and CEC collaborate "to expedite the regulatory and procurement processes to develop additional resources that can be online by 2021. This will most likely focus on resources such as demand response and flexibility. . . "[39] In November 2020, the CPUC opened a proceeding to address reliability needs for the 2021 summer. Three of the four CPUC proposals supported demand-side solutions.[40]

Demand response and other demand-side management programs have traditionally been used to reduce peak capacity investment needs by reducing electricity consumption during emergency events. However, demand response programs vary significantly in how they are controlled and dispatched by the system operator. Demand response performance is also a concern, as well as limitations on the number of times a program participant can be called upon to respond per season or year. In evaluating

37 Ibid, p. 48.

38 CAISO/CPUC/CEC Final Root Cause Analysis. "On August 14 and 15, the CAISO failed for less than two hours on each day and a cap was imposed on the transfer limit into the CAISO." See B.3.4 Energy Imbalance Market, pp. 130-131.

39 CAISO/CPUC/CEC Preliminary Root Cause Analysis, Preliminary Recommendations ES.5, p. 15.

40 CPUC Press Release, "CPUC Acts to Establish Policies and Procedures for Ensuring Grid Reliability during Extreme Weather Events," p. 1.

these proposals, it will be important to recognize the flexibility limitations associated with demand response, particularly in the inland portion of the state, where there is less tolerance for cutting air conditioning or temporarily suspending the operation of agricultural pumping stations during the summer months.[41] For this reason, demand response programs need to complement, not substitute for "iron in the ground" capacity.

Supplemental Reliability Procedures

Despite the ongoing system retirements described above, the system operator holds two important backstops to address unresolved resource adequacy deficiencies and/or meet specified reliability needs. The first backstop, the capacity procurement mechanism (CPM), provides an economic incentive to keep generators online. The CAISO tariff provides two compensation options. The CPM resource can either receive compensation based on its capacity bid price up to the CPM soft offer cap (set at $6.31/kw-month),[42] or the CPM resource can offer capacity at a cost above the soft offer cap. Offering capacity above the cap requires the provider to file a justification for the higher price with the FERC. Both options allow the CPM resource to retain all future revenues earned in the CAISO markets.[43] The CPM provides a useful tool for incenting retiring resources to remain online, although the CAISO may need to revisit the soft offer cap in 2021.[44] Future revisions to the program will likely be informed by the August events, including the impacts of 1,900 MW of dispatchable generation taken out of service between October 2019 and January 2020.[45]

The second reliability backstop allows the CAISO to designate certain power plants as Reliability Must-Run (RMR).[46] This delays any scheduled retirements or recalls mothballed units when needed to meet the established reliability criteria. Prior to the summer of 2020, the CAISO designated three natural gas units (totaling approximately 125 MW) to remain available for the 2020 summer.[47] Even with the extended availability of these RMR units, system operators did not have enough controllable resources to serve load during the August supply shortages.

While these backstop mechanisms are effective, regulators might also wish to examine policies that further promote the mothballing of certain plants. Similar to the RMR approach, this would involve collaborating with the CAISO to identify units that would remain idle, but not decommissioned, to support compliance with environmental requirements, but available to address future capacity shortages and local resources adequacy concerns. Similar approaches have been introduced in Texas, where NRG Energy restarted a 385 MW natural gas-fired combined-cycle plant that had been mothballed since 2016, for the 2020 summer season, partly to address tight supply conditions in ERCOT. Germany, a country with decarbonization goals similar to California's, used a similar approach to return approximately 1.4 gigawatts of mothballed

41 The CPUC, CEC, and the CAISO assign derates to DR programs based upon the results of DR load impact studies and program dispatch requirements (e.g., price, demand, location, duration).

42 This cap is based on the fixed operations and maintenance costs, ad valorem taxes, and insurance costs of a reference unit, plus a 20 percent adder to that total cost. See FERC's May 29, 2020, Order Accepting CAISO Tariff Revisions.

43 A 2019 stakeholder initiative to increase the soft offer cap was rejected in mid-2020 when it was determined that the current soft offer cap was still relevant to the existing grid composition.

44 A higher offer cap may further incent additional generation, or incent existing generators to remain operational, instead of retiring.

45 Including: Alamitos units 1, 2, 6, 7 (844 MW); Redondo unit 7 (493 MW); Inland Empire Energy Center Unit 1 (340 MW); and Huntington Beach Unit 1 (225 MW).

46 Local Reliability Criteria are unique to the transmission systems of each of the Participating Transmission Owners. Local Reliability Criteria and related Local Capacity Requirements reflect CAISO, NERC, and Western Electricity Coordinating Council (WECC) Planning Standards, as well as WECC Operating Criteria (OC) Path Ratings and System Operating Limits (SOL).

47 These units included Greenleaf Unit 2 (47 MW), the E.F. Oxnard plant (48 MW), and Channel Islands Power plant (27 MW).

gas plants to service in 2020.[48] Introducing market mechanisms to keep certain capacity idle but operable could help California meet carbon emission reduction goals, while still maintaining enough standby capacity for periods when system reliability is threatened. Examples of this process include ERCOT's Operating Reserve Demand Curve, PJM's capacity markets, ISO-New England's competitive forward capacity auctions (used competitive forward capacity auctions, and other market structures for securing system supply to meet projected resource adequacy needs.

The next section examines ongoing efforts by the CPUC and the CAISO to enhance their infrastructure planning approaches. We also explore potential opportunities for regulators and operators to more accurately capture the changing reliability characteristics (and potential risks) associated with an increasingly variable system.

Addressing Resource Adequacy Needs through Enhanced Planning Metrics

The final root cause analysis recognized that "changes in the resource mix and the timing of the net peak have increased the challenge of maintaining system reliability [and] . . . additional work is needed to ensure that sufficient resources are available to serve load during the net peak period and other potential periods of system strain."[49]

In order to understand the additional work that is underway, it is important to identify the multiple participants that share responsibility for infrastructure planning in California. These entities and planning processes have remained largely intact since the late-1990s, with key responsibilities summarized in **Table 3.**[50]

California's infrastructure planning processes necessitate close collaboration with – and input from – both the CAISO and CEC. System-wide and local reliability requirements, as well as flexibility needs, are ultimately developed within the CPUC's resource adequacy (RA) program.[51] Established after the 2000-2001 California Energy Crisis, this program creates requirements for jurisdictional LSEs to maintain resource availability through contractual obligations. The planning reserve margin (PRM) is a critical element of the RA program and is used to

Table 3: Primary Entities Involved in California's Resource Planning Processes

CPUC	Jurisdictional LSEs	CAISO	CEC
Manages the state's Integrated Resource Plan and Long-Term Procurement Plan (IRP-LTPP). This process is designed to ensure that the electric sector meets its GHG reduction targets while maintaining reliability (with a resource adequacy program) at the lowest possible cost. This process involves modeling the system topology and market dispatch results to determine the appropriate resource portfolio needed to meet policy goals.	Must submit individual IRPs (based on the parameters in the IRP-LTPP) for CPUC review and approval.	Develops an annual Transmission Planning Process used to identify needed transmission upgrades and inform the CPUC's IRP-LTPP process.	Develops long-term energy demand forecasts as part of their Integrated Energy Policy Report (IEPR). The CEC's IEPR demand forecasts are inputs into the CPUC's long-term resource planning process and the short-term annual resource adequacy process, used to establish RA procurement obligations for LSEs.

48 Germany met over 40 percent of the country's power consumption with renewables in 2019, exceeding the 2020 target of 35 percent one year ahead of time. The government is now taking aim at 65 percent by 2030, as stated in its Climate Action Programme 2030.

49 CAISO/CPUC/CEC Final Root Cause Analysis, p. 5.

50 A detailed process is available within the CPUC's Long-Term Procurement Plan History and Related Process Documentation. (See Process Diagram (v3.8). While the terminology has changed since the release of the v3.8, the CPUC has not released an updated diagram.

51 CPUC Integrated Resource Plan and Long-Term Procurement Plan (IRP-LTPP).

establish monthly requirements to ensure LSEs procure sufficient resources for the CAISO to reliably operate the system. The PRM targets also inform the commission's procurement decisions.

Limitations of Existing Resource Adequacy Metrics

As discussed earlier, jurisdictional LSEs must procure enough capacity to serve the peak demand forecast, plus a 15 percent PRM.[52] To demonstrate this concept, we examine California's planning reserve margin leading up to the August 2020 events.[53] From a seasonal planning perspective, the CAISO system appeared to have had adequate planning reserves going into the summer of 2020. The CAISOs projected 46,903 MW of capacity to be available in August, with a 1-in-2 net peak load forecast of 40,370 MW. Using NERC's reserve margin method would have indicated that this was a healthy reserve margin of 17.1 percent, excluding the projected 1,339 MW of demand response capability:[54]

$$\textit{CAISO Reserve Margin} = \frac{\text{Peak Resources–Forecasted Load}}{\text{Forecasted Load}} = \frac{46{,}903–40{,}037}{40{,}037} = 17.1\%$$

The reserve margin metric provides a snapshot of system adequacy and reliability at the highest forecasted demand. It is based on the important assumption that system reliability will be maintained throughout all other hours of the analysis period (planning horizon). Based on traditional planning criteria, a 17.1 percent margin (well-above the 15 percent PRM target) indicated that the system had adequate planning reserves for the 2020 summer season. However, the current PRM target of 15 percent was established in 2004, based on "analysis of then-current market data and forecasts of how the market was expected to evolve due to anticipated increases in renewables, energy efficiency, demand response, and other factors."[55] A significant finding of the final root cause analysis of the August events was that "resource planning targets have not kept pace to lead to sufficient resources that can be relied upon to meet demand in the early evening hours. This makes balancing demand and supply more challenging."[56]

California's PRM targets are based on Loss of Load Expectation (LOLE) modeling, designed to measure the reliability of an electric system, based on assumptions that incorporate a variety of conditions.[57] The PRM targets are ultimately dependent on the level of system reliability that the CPUC determines to be acceptable for the state. Currently, PRM targets are developed based on an annual LOLE target ranging from 0.095 to 0.105. This roughly translates to 1 loss of load event over a 10-year period. The CAISO's current LOLE assumptions combine multiple loss-of-load events occurring within one day into a single event (for purposes of counting events toward a reliability targets).[58] Accordingly, the analysis fails to capture a series of smaller events that could, in aggregate, impact system reliability.

Annual LOLE Target ≈ .01 ➔ **PRM Target = 15%**

The LOLE analysis and the more commonly referenced reserve margin have both been heavily relied-upon by the industry for decades. Although useful and informative, these metrics must be examined in the proper

52 Like RA, IRP modeling is also based on the CEC's adopted 1-in-2 demand forecast plus a 15 percent PRM.

53 This example is a simplistic example examining the entire CAISO system. PRM requirements apply to individual of LSEs.

54 NERC (the North American Electric Reliability Corporation) defines the reserve margin as "…the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage" (p.35). Available demand response capability: CAISO 2020 Load and Resources Report, p. 5.

55 CPUC Rulemaking 19-11-009. Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations, pp. 18-19.

56 CAISO/CPUC/CEC Final Root Cause Analysis, pp. 1, 4, 38.

57 CPUC 2020 ELCC Methodology Working Group – Review of ELCC Study improvements, September 2019.

58 CPUC Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions – Guidance for Production Cost Modeling and Network Reliability Studies, p. 11.

context. Baseball enthusiasts don't rely on a single statistic to evaluate a player. They examine the player's on-base percentage (OPS), runs batted in (RBI), home runs (HR), stolen bases (SB), and dozens of other measures of performance in various aspects of the game. Measuring resource adequacy and system reliability should be no different – especially considering the significant changes on California's system during the past decade.

Increasingly, the LOLE and deterministic reserve margin approaches do not fully capture the level of resource adequacy for systems with large amounts of intermittent wind and solar. This is because the LOLE methodology was initially developed to measure the resource adequacy of systems with mostly controllable resources (e.g., large hydro, fossil-fired, and steam-powered generators) serving relatively predictable load patterns. Because these resources were controllable by system operators, planners made procurement decisions based largely on serving changing demand projections. Today, system operators also have reduced control over the supply side due to growing levels of utility-scale wind and solar that is variable in nature (i.e., operators cannot increase wind speed). On the demand side, load projections have also grown in complexity with the rapid deployment of distributed solar PV, which causes net-load to fluctuate based on cloud cover and other factors that are outside the system operator's control.

The CPUC took action to address these concerns prior to the 2020 summer supply shortages. Their June 2020 order initiated a review of the PRM target range, authorizing the commission's Energy Division to facilitate a working group to develop a set of assumptions for use in an LOLE study.[59] After the August events, the commission also opened an Emergency Reliability rulemaking to prioritize resource adequacy and resource procurement for the 2021 summer season. Several entities involved in California's resource planning efforts responded, including CAISO:

> The CAISO greatly appreciates the Commission's efforts to increase resource adequacy procurement to address summer 2021 reliability. Importantly, this incremental procurement should be tied to an increase in the planning reserve margin (PRM) to 20 percent for two critical reasons. First, increasing the PRM will ensure new resources do not substitute for existing capacity, thus leading to little or no net increase in the resource adequacy resource fleet. Second, increasing the PRM will allow the CAISO to use its capacity procurement mechanism (CPM) to backstop to the higher PRM.[60]

The CAISO subsequently revised its recommendation to 17.5 percent.

Increasing the PRM will improve short-term resource adequacy by requiring jurisdictional LSEs to secure additional reserve capacity.[61] The CPUC will ultimately need to examine the cost implications associated with a higher PRM requirement. The commission might also consider developing a PRM range with localized requirements to address areas facing insufficient resources or transmission constraints. Local reserve requirements designed to co-optimize the energy dispatch and reserve schedules could promote local market prices that reflect constraints based on reserve availability in a sub-area.[62]

The Case for Hourly Modeling

Because LOLE and reserve margin analyses are becoming a smaller part of the resource adequacy puzzle, the CPUC recognized that "a LOLE value of 0.1, which is a direct translation of the decades old industry "one day in ten years" standard, may warrant

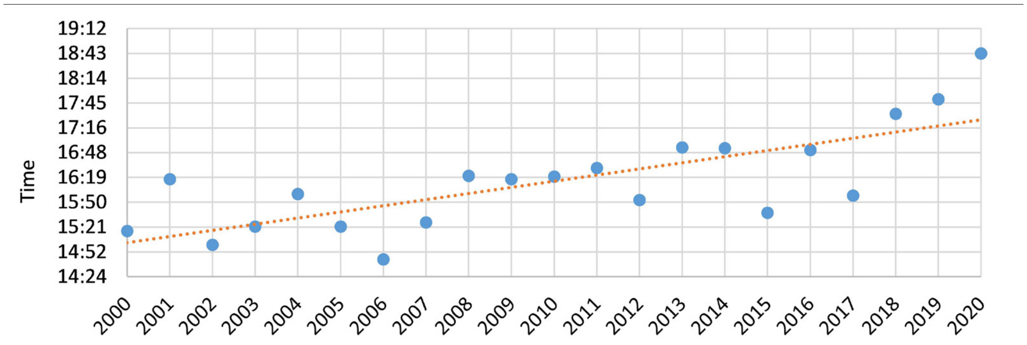
59 CPUC Decision 20-06-031. Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations, pp. 4, 21, 89.

60 CAISO Responses to Ruling Proposals and Questions. Response to question 5, p. 3.

61 Any change in the PRM would not apply to non-firm (independent power producers) capacity, as the CPUC will likely require all qualifying resources to provide qualifying RA.

62 William Hogan has suggested this approach for ERCOT, Harvard Electricity Policy Group: Priorities for the Evolution of an Energy-Only Electricity Market, 2017.

Figure 5: The Summer Peak Is Occurring Later in the Day



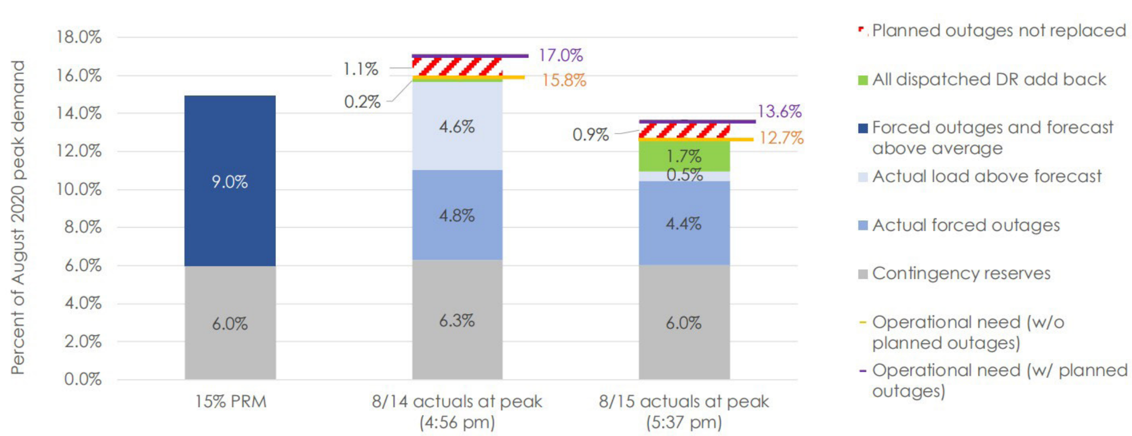
reconsideration in light of the sophisticated hourly models and advanced computing available now. . . "[63] Hourly modeling is necessary to address the changing load patterns, which have pushed seasonal system peaks further into the evening (**Figure 5**).[64]

Figure 6 demonstrates that the CAISO system was able to reliably serve load during the both peaks on August 14 and 15 and "although a PRM comparison is informative, the rotating outages both occurred after the peak hour..."[65] Hourly modeling can provide important insights for planners, allowing them to identify and prepare for potential reliability risks that occur outside of the peak period.

Resource Adequacy Accountability

The final root cause analysis recommended increasing RA requirements for LSEs to address extreme weather events.[66] However, as the number of CCAs and smaller electric service providers (ESPs) continues to increase, it's important to ensure these entities are providing sufficient levels of RA capacity. CCAs and ESPs currently provide 26 percent of the load formerly served by the state's three largest investor-owned

Figure 6: August 2020 PRM and Actual Operational Need during Peak



63 CPUC Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions – Guidance for Production Cost Modeling and Network Reliability Studies, p. 11.

64 Figure created by NRRI staff using the following CAISO data: CAISO historic peak loads; CAISO Key Statistics – August 2020.

65 CAISO/CPUC/CEC Final Root Cause Analysis, p. 43.

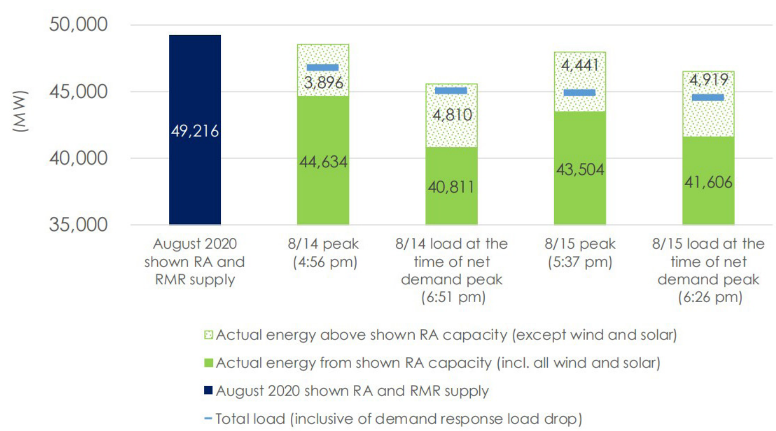
66 Ibid, pp. 91-92.

utilities (IOUs).[67] The CPUC has warned that this trend contributes to a state-wide planning process that is less consolidated and "creates a more complex paradigm for assessing both system reliability and whether California is on-track to achieve its climate goal. While CCAs and ESPs are subject to the same annual RPS Procurement Plan (RPS Plans) requirements as required by the IOUs, recent RPS Plans show that many CCAs and ESPs continue to provide minimal information in their RPS Plans… inadequate procurement planning may cause LSEs to not meet the state's requirements, resulting in negative implications for reliability of the power system."[68] As CCAs continue to expand their generation portfolios and customer base, these entities must be increasingly involved in planning activities and held accountable for meeting system reliability requirements.[69] The CPUC plans to address challenges during the coming years within their IRP-LTPP program by possibly introducing enforcement penalties for CCAs and ESPs that fail to provide them with adequate planning data.[70]

Developing More Robust Resource Adequacy Metrics

Recognizing these shortfalls, system planners across the country have made significant progress in improving resource adequacy metrics, moving away from deterministic approaches and toward a greater focus on stochastic and probabilistic methods. One of the recommendations of the final root cause analysis called on the CAISO to coordinate with the CPUC and other stakeholders to "refine the counting rules as they apply to hydro resources, demand response resources, renewable, use limited resources, and imports."[71] The analysis further indicated that the actual output of RA and reliability-must-run (RMR) capacity did not reflect their projected availability (**Figure 7**).[72, 73]

Figure 7: August 2020 Shown RA and RMR Capacity vs. August 14 and 15 Actual Energy Production



The CPUC and CAISO will benefit by further examining these discrepancies and updating the underlying assumptions used in future RA and RMM projections. In terms of actual performance by resource type, the final root cause analysis further reported that the natural gas generation fleet collectively experienced between 1,704 MW to 2,371 MW of forced outages, more than any other resource.[74] These outages translate to between 4-6 percent of the natural gas generation fleet that was not already scheduled to be

67 CCAs allow for communities to join together to choose their electric provider and sources of electricity.

68 *CPUC 2019 RPS Annual Report to the Legislature,* p. 54.

69 According to the CPUC, "load allocated to CCAs in the year ahead process went from two percent of the peak in 2016 to 25 percent of the peak in 2019. Energy Division anticipates 'this trend towards disaggregation of load to continue…'" CPUC Rulemaking 17-09-020, p. 21.

70 Additional information on the CPUC gap analysis that addresses CCA RA shortfalls is available here: California Customer Choice Project - Choice Action Plan and Gap Analysis.

71 CAISO/CPUC/CEC Final Root Cause Analysis, p.72.

72 Ibid, p. 110.

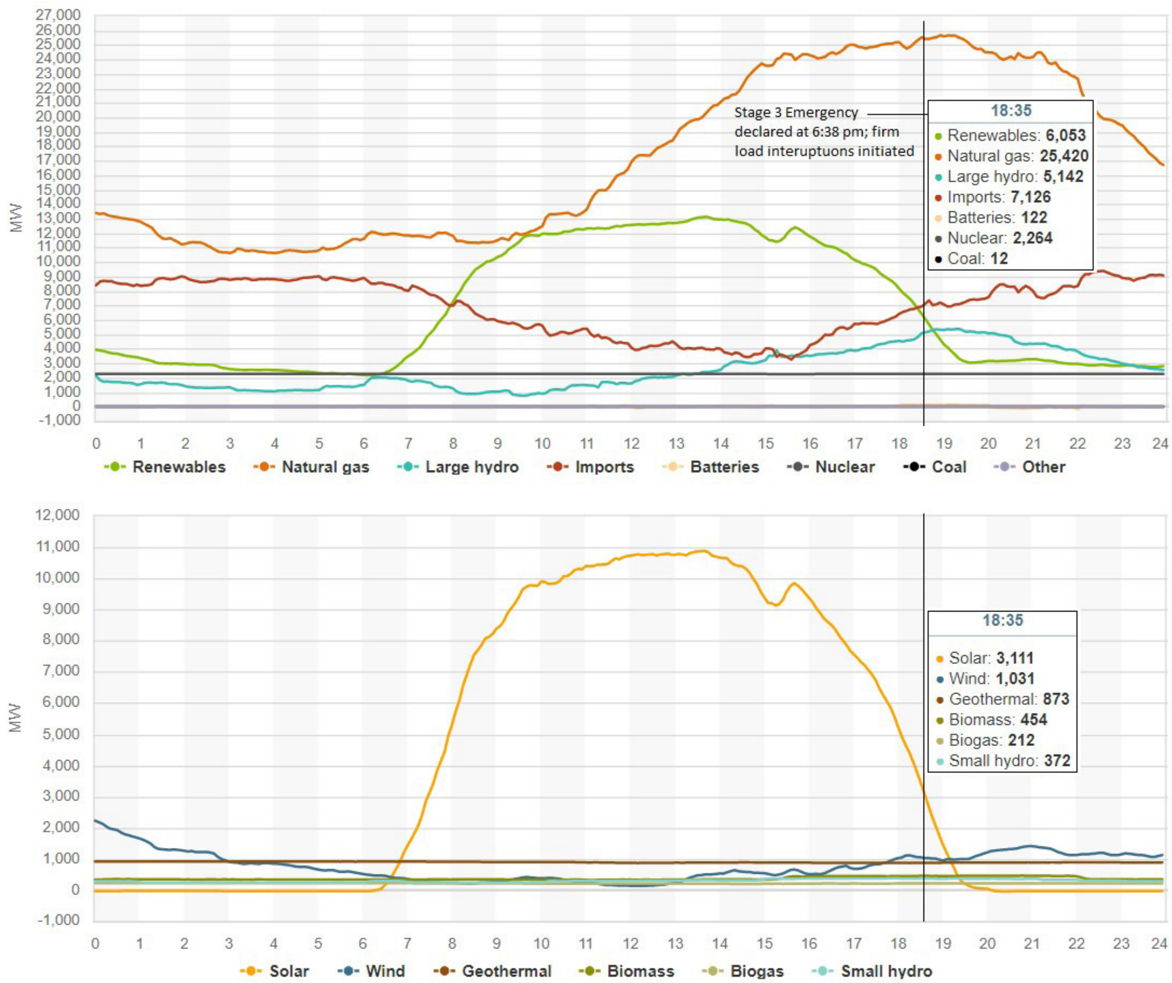
73 Assumes all wind and solar counts as RA supply; CAISO/CPUC/CEC Final Root Cause Analysis, p. 110.

74 CAISO/CPUC/CEC Final Root Cause Analysis, p.87. (Includes derates to individual units, as well as unit outages.)

out of service. The natural gas generation fleet served over half of the state's load when the Stage 3 Emergency was declared at 18:38 on August 14.[75] During the same period, actual output from 24,016 MW of installed renewable resources served 6,053 MW (14.3 percent) of load.[76] Renewable output (particularly solar) actually decreased by 1,064 MW during the next 15-minutes as net load continued to increase, finally peaking at 18:51. In contrast, output from dispatchable resources, including natural gas and in-state large hydro, increased by 321 MW during the same 15-minute period, serving 73.1 percent of net load during the peak. Although renewable resources performed as expected, their overall contribution during the peak period further highlights the performance attributes of each resource—especially during extreme weather events (**Figure 8**).

The CAISO has already begun using more sophisticated approaches for assessing resource adequacy with increased renewables, including the Unloaded

Figure 8: August 14, 2020 Total Supply Performance at 18:35 (Beginning of Stage 3 Emergency)



75 Assumes the California Energy Commissions 2019 Installed In-State Electric Generation Capacity (latest available), with a natural gas generation fleet totaling 40,382 MW. Natural gas performance at 18:50-18:55pm (5-minute market) was providing 25,539 to serve the net demand peak (42,237) at 18:51 p.m. on August 14. See the CAISO supply trend data for August 14, 2020. Demand data: CAISO/CPUC/CEC Final Root Cause Analysis, pp. 44-45.

76 CAISO Key Statistics – July 2020. See Installed renewable resources (as of 8/01/2020), p. 3.

Capacity Margin (UCM). This metric measures the amount of surplus resources or capacity that can respond within 20 minutes or less during the forecasted demand during a specified interval.[77] Similar to a reserve margin, the UCM metric is expressed as a percentage, but it is more comprehensive, because it captures multiple hours (beyond the peak period). The CAISO's 2020 Load and Resources Assessment demonstrated that the median UCM for all 2,928 summer hours (modeled within each of the 2,000 summer scenarios), was 41.3 percent.[78] Levels of UCM above the operating reserve requirement for any given hour (typically around 6 percent) indicate the amount of capacity projected to be available to address system contingencies (beyond the NERC operating reserve requirement). The Minimum Unloaded Capacity Margin (MUCM), the lowest UCM from each of the 2,000 scenarios modeled, is used to establish the probability of various events occurring. Continuing to enhance stochastic production simulation tools will enhance the CAISO's ability to assess the widest array of load, wind, and solar outages, as well as understand historic performance profiles. This tool can also provide planners with a distribution of potential outcomes and probabilities. The ongoing Resource Adequacy Enhancements initiative will depend on input from the CPUC and other stakeholders to determine the appropriate reliability criteria, as well as the quantity and attributes needed to address existing resource portfolio deficiencies.

NERC, the FERC-designated electric reliability organization (ERO) in the United States, has codified multiple reliability attributes provided by different resources. These essential reliability services (ERS) include frequency and voltage support, as well as ramping and balancing capability. The ERS capabilities and operating behaviors of conventional generators are well-documented, compared to those of relatively new wind and solar technologies. NERC states that "changes in the generation resource mix and technologies are altering the operational characteristics of the grid and will challenge system planners and operators to maintain reliability, thereby raising issues that need to be further examined."[79] Measuring a system's level of ERS offers a more comprehensive approach to resource adequacy by examining other important reliability attributes. NERC indicates that overall system reliability can be maintained…

> as the resource mix evolves, provided that sufficient amounts of essential reliability services are available.[80] [NERC further emphasizes that]. . . merely having available generation capacity does not equate to having the necessary reliability services or ramping capability to balance generation and load. It is essential for the electric grid to have resources with the capability to provide sufficient amounts of these [essential reliability] services and maintain system balance.[81]

Although wind and solar resources can provide certain types of ERS (e.g., synthetic inertia), there must also be adequate levels of frequency response, ramping capability, inertia, and reactive support for voltage control. Operators rely on these essential reliability services to operate the system under a variety of conditions, including extreme weather events that can cause generator outages and increase variability in wind and solar output.

Conclusion

The contributing factors leading to the August 2020 reliability events in California have been examined, and the lessons-learned from the events can be applied to other states that are introducing policies

77 CAISO, 2020 Load and Resources Assessment, p. 6.

78 Taking into account the unloaded capacity margin for all of 2,928 summer hours (June 1 through September 30) within each of the 2,000 summer scenarios. According to the 2020 Load and Resources Assessment: "The unloaded capacity refers to any portion of online generation capacity that is not serving load and offline generation capacity that can come online in 20 minutes or less to serve load as well as curtailable demands such as demand response, interruptible pumping load, and aggregated participating load that can provide non-spinning reserve or demand reduction. The unloaded capacity includes operating reserves the system procures. The Unloaded Capacity Margin (UCM) is the excess of the available resources, within 20 minutes or less, over the projected load expressed as a percentage on an hourly basis."

79 NERC Sufficiency Guidelines White Paper, December 2016, p. iv.

80 Ibid, p. vii.

81 Ibid, p. iv.

aimed at rapidly decarbonizing the grid, often leading to the addition of intermittent and behind-the-meter resources. These include:

- Systems with increasing amounts of intermittent resources (e.g., wind and solar) will require additional modeling and stochastic metrics that can provide a more complete measure of resource adequacy and help identify associated reliability risks.
- The continued development of advanced reliability metrics, including those that examine risks beyond the peak hour, can inform policy and regulatory decisions to promote the reliable transformation to a cleaner system.
- Existing planning processes and reliability constructs need to better identify the system impacts of retiring resources, examining the status of essential reliability services on the system, including ramping capability, frequency response, and inertia.
- Future projections of RA availability and ELCC values should be reviewed and modified to incorporate resource performance during the August events.[82]
- Regionalization can help promote reliability by efficiently pooling resources; however, increased coordination will be needed to recognize the impacts of transmission constraints and individual state policy goals.

These approaches can inform policy makers and state regulators charged with balancing the responsibilities of managing RPS compliance and resource adequacy requirements.

82 "Based on further analysis by the DMM, the actual production of all resources shown as RA or obligated under an RMR contract was sufficient during the peak but insufficient during the net demand peak period to meet all load, losses and spinning and non-spinning reserve obligations on August 14 and 15," CAISO/CPUC/CEC Final Root Cause Analysis, pp. 109-110.

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