Vice-Chair
Patterson, Jim

Members
Bauer-Kahan, Rebecca.
Calderon, Lisa
Chen, Phillip
Connolly, Damon
Friedman, Laura
Holden, Chris R.
Patterson, Joe
Reyes, Eloise Gómez
Santiago, Miguel
Schiavo, Pilar
Wallis, Greg
Wood, Jim

California State Assembly

UTILITIES AND ENERGY

COTTIE PETRIE-NORRIS
CHAIR

Chief Consultant
Laura Shybut

Consultants
Kathleen Chen
Chase Hopkins
Lina Malova

Committee Secretary
Vanessa Gonzales

State Capitol, P.O. Box 942849
(916) 319-2083
FAX: (916) 319-2099

Tuesday, February 20th
Upon Adjournment of Floor Session – Capitol Room 126

INFORMATIONAL HEARING

Who's On First?
Coordination and Planning to Meet Our Clean Energy Sector Goals

California has set ambitious requirements for its energy sector to decarbonize. For the electricity sector, this includes an (achieved) requirement of 33% renewable electricity by the end of 2020, 50% renewable electricity by the end of 2026, 60% renewable electricity by the end of 2030, 90% renewable and zero-carbon electricity by the end of 2035, 95% renewable and zero-carbon electricity by the end of 2040, and 100% renewable and zero-carbon electricity by the end of 2045.[1] These requirements have shifted the paradigm in how California's utilities procure their resources and plan their infrastructure deployment. Meeting early goals took effort, cooperation, and strategic — sometimes, mandated — investment. However, meeting California's more stringent decarbonization goals over the next two decades will likely require even more deliberate and focused effort, cooperation, and investment to ensure success. Simply put, decarbonizing the electricity sector will be more like moving a rock uphill than pushing it down. It has rarely carried its own momentum — i.e. an easy decent — into future years of its own volition; rather, new challenges have arisen as requirements have increased. This reality necessitates not only electricity market players (the utilities, community choice aggregators, other retail sellers, developers, and transmission owners) to adjust their planning regimes, sometimes significantly and rapidly, but likewise requires a commensurate adjustment by the administrative entities in their energy planning and coordination efforts. This is not an academic exercise. In September 2022, for example, an extreme heat event taxed the electrical grid in California and across the West — forcing state regulators to literally 'dial for megawatts' of additional supply or demand reduction. Failure of the administrative entities to adjust, perhaps significantly and rapidly, along with the regulated entities, is simply not an option that state law contemplates.

This hearing is intended to assess electricity sector planning by reviewing the most critical state planning programs, recent developments in state planning, extraordinary recent interventions,

[1] See Public Utilities Code § 399.11, which sets requirements for renewable electricity procurement, as defined, in the Renewables Portfolio Standard (RPS) program; see Public Utilities Code § 454.51-454.53, which sets requirements for zero-carbon electricity that are incremental to those required for the procurement of renewable electricity per the RPS.

and emergent challenges. As evidenced by some of the challenges of the last few years that are reviewed in this document, the feedback loop between high-level planning and conditions on the ground has become increasingly complex and, perhaps, at times dysfunctional. Given the constraints of time, this hearing will focus primarily on planning for the electricity sector; though planning for decarbonizing the natural gas sector merits subsequent legislative review.

This hearing also builds on prior work by the Assembly and this Committee, including hearings during 2022 and 2023 on building transmission for the clean energy transition, improving timely customer energization on the distribution grid, improving electric grid reliability, and addressing energy affordability.[2]

Findings:

- *As reviewed in Section 1, the intersecting web of state energy planning programs and cooperation across different state entities is robust — reflecting the nature of the critical infrastructure it oversees.*
- *As reviewed in Section 2, these planning programs have had to become quicker and more assertive in recent years to respond to the evolution of California's electricity resource mix, growing demand, and changing weather patterns, among other factors.*
- *As reviewed in Section 3, extraordinary measures have nevertheless been required in recent years over and above the planning program changes discussed in Section 2, reflecting conflicts between planning systems and reality on the electric grid.*
- *As discussed in Section 4, the cadence of major planning program changes and extraordinary interventions in the electricity sector may indicate a planning regime that — despite its acceleration — is still being outpaced by changes in the grid it oversees.*
- *These changes in recent years underscore how critical energy planning and cooperation amongst the CEC, CPUC, and CAISO are. Planning for California's transition to cleaner energy resources is necessary to ensure our statutory goals are met, and critical to ensuring our goals are met as affordably and reliably as possible. Meeting our goals can occur in a variety of ways; meeting our goals efficiently ensures the least risk and harm to all. Lags in our planning regime, as the state has already experienced, lead to ballooning expenses in an effort to patch the gaps.*
- *It remains at times unclear who is the lead responsible entity for successful delivery of which set of planned outcomes. The answer to 'who's on first' depends on the program, can more than one entity at the same time, and that makes it hard for the Legislature to assess responsibilities for outcomes amidst all the planning throughput.*
- *While it is possible that coordination, including under Governor Newsom's new Infrastructure Strike Team, is improving, it is unclear how efficiently such coordination is working. More transparency could build trust between the Legislature and Administration that all bases are covered.*

Section 1: What's the plan? The State Planning Regime:

California energy planning is conducted in layered programs that are administered by several state entities. This includes the California Energy Commission (CEC), a department within the

[2] See the Committee's website for more information on these and other prior hearings here: (https://autl.assembly.ca.gov/bill-hearings/informationaloversight-hearings).

California Natural Resources Agency,[3] and the California Public Utilities Commission (CPUC), a creation of the Legislature and the voters that is embedded in the State Constitution.[4] These two state entities work in conjunction with the California Independent System Operator (CAISO), a non-profit public benefit corporation regulated by the Federal Energy Regulatory Commission (FERC), and under the supervision of a Board of Governors appointed by the Governor of California and confirmed by the California Senate.[5] The California Air Resources Board (CARB), a department within the California Environmental Protection Agency that is overseen by a Chair and Board, has input in energy planning due to its responsibilities for mobile source greenhouse gas and criteria pollutants regulation, economy-wide greenhouse gas reduction, and administration of the cap-and-trade carbon markets.

These three entities, the CEC, CPUC, and CAISO, function in an interrelated web of responsibilities that continuously inform and feed back into one another, as reflected in Figure 1 below. This is a web created partly by history and partly by the jurisdictional boundaries of the load serving entities (LSEs) this web oversees. As shown in Figure 1 and detailed more below, the CEC is primarily responsible for forecasting electricity demand (how much power will be needed); the CPUC is primarily responsible for resource needs (what mix of generation will meet the power needs in the cleanest and cheapest way possible); and the CAISO is primarily responsible for transmission needs (what infrastructure must be built to support this power flow). CARB has related responsibilities but they are due to its responsibility to plan for the broader, economy-wide emissions-reduction requirement in existing law, including through the economy-wide Scoping Plan. However, CARB is not a principal planner for energy procurement and infrastructure. CARB's economy-wide planning is coordinated and reflected in the work of the state's primary energy planners, such as by the CPUC as it adopts long-term procurement plans in Integrated Resource Planning that are pegged to specific greenhouse gas reduction scenarios. CARB is thus not the focus of this hearing. All of this energy sector planning occurs across the short-, mid-, and long-term, depending on the program and its purpose, to meet the requirements of existing law to decarbonize the electricity sector.

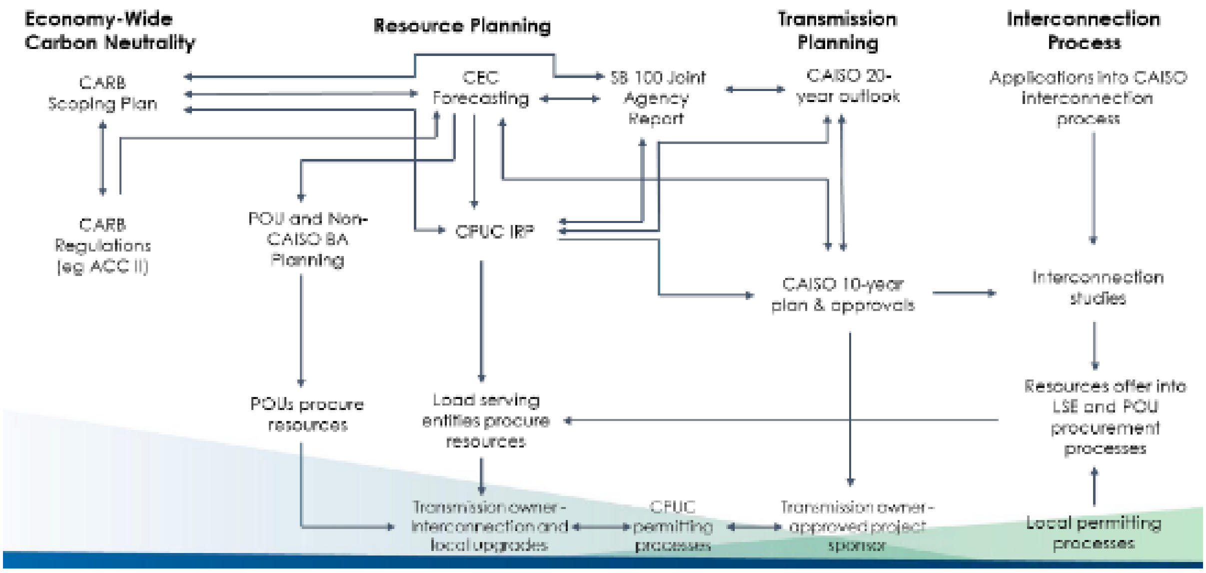
---

3 Formally, the State Energy Resources Conservation & Development Commission, as created by the Legislature (Chapter 276, Statutes of 1974).

4 The Railroad Commission of California was created in 1879, and had the authority only to set rates for railroad corporations. In 1911, the Legislature approved Senate Constitutional Amendment 47, ratified by the voters later that year as Proposition 12, which expanded the Railroad Commission's powers over railroad corporations and enabled the Legislature to broaden those powers. In 1912, the Legislature enacted the Public Utilities Act, creating the public utilities code and giving the Commission the power to regulate all public utilities in California and ensure they are *just and reasonable,* a critical term of art for ensuring utility rates are commensurate with the service provided, excluding local publicly owned utilities. Public utilities were defined far more broadly than railroad corporations, and included energy and telephone corporations. The Railroad Commission was later renamed the Public Utilities Commission. In 1974, the Legislature approved Assembly Constitutional Amendment 36, ratified by the voters later that year as Proposition 12, to shift the source of the Commission's authority to regulate public utilities beyond railroad corporations from statutes to the Constitution, where that power remains today.

5 The CAISO began operating in 1998 as a result of the electricity market restructuring required by AB 1890 (Brulte, Chapter 854, Statutes of 1996) that also partially deregulated California's energy markets, as well as due to FERC Orders 888 and 889 (both issued April 24, 1996), which set requirements for nondiscriminatory access to the transmission system and provided that an independent system owner could ensure compliance with those requirements. Today, approximately 80% of California's electricity demand is in the CAISO's primary footprint; the remainder is overseen by different grid operators (e.g. SMUD, LADWP, IID).

Figure 1 – The way in which different State planning processes feed into others.[6]



History of coordination:

Coordination amongst CARB, the CEC, CPUC, and CAISO is not new. In 2010, the then-leaders of the CEC, CPUC, and CAISO outlined in writing how each would work with the others to achieve the State's then-RPS requirement of 33% renewable generation by 2020.[7] This memorandum of understanding (MOU) formalized an agreement in which the CAISO would fulfill its role under state and federal law as the grid operator and transmission planner for its jurisdiction, based on forecast inputs determined by the CPUC, using data and analysis from the CEC. One of the outcomes of this was joint agreement on a California Transmission Planning Process, in which the CAISO and CPUC would develop an annual statewide conceptual transmission plan for further analysis in the CAISO's Transmission Planning Process. The goal of this process was to identify "least regrets" transmission facilities for consideration in the CAISO's plan, and illustrate the underlying potential of the MOU at that time to increase efficiency in cooperation amongst these three entities.

In 2022, this cooperative framework was revisited in an updated MOU. Among many other provisions, the CEC, CPUC, and CAISO agreed to greater consistency and specificity in the information relied on by all three entities, reflected in the agreement to emphasize the use of a single forecast in transmission planning and to map planned resources to specific electric grid locations (i.e. busbars). The three entities also agreed to improve how their distinct processes and responsibilities functioned in relation to one another, reflected in the CPUC agreeing to give substantial weight in siting/permitting to transmission projects in the CAISO's transmission plan, and the CAISO agreeing to prioritize the interconnection of new resources with characteristics and in locations consistent with the resource plans of the CEC and CPUC.[8] This agreement reflected substantial evolution since the 2010 MOU, reflecting the entities' awareness of needed planning modernization to meet energy sector goals.

6 SB 100 Analytical Framework Workshop, CEC Docket 23-SB-100, TN#252852.

7 MOU between the CPUC and the CAISO regarding the Revised ISO Transmission Planning Process; executed May 2010 (the CEC was not formally a signatory).

8 MOU between the CPUC, the CEC, and the CAISO Regarding Transmission and Resource Planning and Implementation; executed December 2022.

However laudable, these agreements represent only the top-line framework for state planning. Rather, hundreds of regulatory proceedings detail, analyze, and weigh — through public processes — the many different programs and operational plans that implement state goals. Those programs serve different purposes and are administered by different entities, but the most critical of these existing planning processes are as follows.

<u>Long-term planning (5 to 10+ years ahead):</u>

The Scoping Plan – CARB – every 5 years:

The Scoping Plan is an economy-wide plan for achieving California's net-zero by 2045 goal. As part of this plan are estimates for how the electricity sector will need to reduce its share of greenhouse gases (GHGs). The electricity sector-specific GHG value then informs subsequent planning processes, particularly in Integrated Resource Plans, at the CEC, CPUC, or CAISO.

SB 100 Report – joint energy agencies – every four years:

This is a review of the state's progress towards its 2045 100% zero-carbon electricity goal. This includes an assessment of reliability, affordability, technical, safety, and environmental aspects of meeting the 100% goal. The first SB 100 Report was issued in March 2021 and modeled a variety of pathways to 2045 to test for ways to optimize the state's trajectory. The second SB 100 report cycle began in 2023 and is intended to pick up the analytical threads left open from the first report. A final report is scheduled for the end of 2024.

The 20-Year Transmission Outlook – CAISO:

A self-initiated study by CAISO, this document estimates the transmission infrastructure needed on the high-voltage portion of the grid administered by the CAISO in the long term — taking a longer view than the Transmission Planning Process.

The Transmission Planning Process (TPP) – CAISO – annually:

This process estimates the transmission infrastructure needed to meet the base resource portfolio provided annually by the CPUC to the CAISO. The CPUC also provides the CAISO with sensitivity portfolios with different resource mixes for CAISO to study and inform subsequent action, but not approve new transmission infrastructure based solely on. Once the final transmission plan in each TPP cycle is approved by the CAISO Board, the resulting approved infrastructure begins the development process, including permitting, licensing, and competitive solicitations as applicable.

The Integrated Energy Policy Report (IEPR) – CEC – every 2 years:

This forecasts all aspects of energy supply and demand, and includes select additional policy issues in each report that touch on critical issues impacting the demand forecast. The data from the IEPR are subsequently used to inform forecasts by the CPUC and the CAISO. It also analyzes specific policy problems relevant to the cycle in which it was issued — for the most recent IEPR, further discussed below, this included the interconnection of new resources and the growth of hydrogen infrastructure.

Long- (5 to 10+ years) to Mid-Term (2 to 5 years) Planning:

Integrated Resource Planning (IRP) – CPUC – every 2 years:

IRP provides the umbrella process by which the CPUC oversees long-term procurement for its regulated load-serving entities (electrical corporations, community choice aggregators, and electric service providers), which serve approximately 75% of the state.[9] The intent of this process is to ensure system needs are being met by the sum actions of the many LSEs in that system. The IRP looks a decade or more into the future.

In the IRP process, the CPUC first produces an estimate for what those LSEs should be procuring (the Reference System Plan), allows those entities to file their individual procurement plans, then approves those plans based on their consistency with collective system needs (the Preferred System Plan).

The Preferred System Plan that is produced by the IRP process is the basis for a number of additional planning processes, including the Transmission Planning Process by the CAISO, the CPUC Avoided Cost Calculator, the SB 100 report, and subsequent LSEs' IRP plans.

Existing law, within the IRP framework, also allows the CPUC to order the resource procurement, outside of individual LSEs' IRPs, in order to meet decarbonization targets. The CPUC's use of this authority, including for both long- and mid-term procurement, is discussed further in Section 2 below.

Integrated Resource Planning (IRP) – CEC – every 5 years:

Publicly owned utilities (POUs) are not in the jurisdiction of the CPUC and instead, generally, report to their local governing board. However, existing law does require POUs to adopt an IRP that is consistent with the state's electricity decarbonization, RPS, carbon neutrality, and other requirements. These are submitted to the CEC, which reviews each for consistency with state law and may recommend corrections for any deficiencies.[10] However, this responsibility is distinct from the broader authority granted to the CPUC in the IRP process it oversees.

Short-term planning (0-2 years ahead):

Resource Adequacy – CPUC – sub-annually:

In the wake of the Electricity Crisis of 2000-2001, the Legislature required the CPUC to establish Resource Adequacy (RA) requirements for LSEs. RA remains the State's principal electricity reliability compliance program. The CPUC sets requirements for how much RA capacity must be procured.[11] Over time, the CPUC has created three

---

9 Public Utilities Code § 454.51-454.53.
10 Public Utilities Code § 9621-9622.
11 Public Utilities Code § 380.

distinct RA requirements: system RA, local RA for locally-constrained areas of the grid, and flexible RA for ramping capacity.[12]

LSEs must procure RA-eligible capacity to meet their compliance requirements, and file both annual and monthly reports with the CPUC to show their compliance. Local RA specifically is assessed on a multi-year forward basis, but System and Flexible RA are assessed only for the year ahead.

Since just 2020, there have been nine CPUC decisions modifying, reforming, or otherwise adapting the RA program — notably more frequent than in recent years.[13]

Reliability backstop – CAISO – annually:

When LSEs struggle to comply with RA requirements, the CAISO can intervene. On a system basis, if an LSE does not meet its formal planning reserve margin requirement, the CAISO can use that as justification to procure additional resources using the Capacity Procurement Mechanism, subject to FERC requirements and limitations. The costs of this backstop procurement are allocated to all LSEs in the area of the electric grid which this procurement was needed.

When there is a specific, local reliability need, the CAISO can also retain specific generation resources that have not been contracted for by an LSE due to the cost proposed by the wholesale generator or other factors. The CAISO can designate any power plant as a Reliability Must Run (RMR) resource, and contract with that facility to ensure it will continue to operate. The costs of RMR contracts are allocated to LSEs in the area of the electric grid for which this procurement was needed. Notably, the use of RMR contracts has declined since the creation of the Local RA obligation by the CPUC.

The state is not the only entity with planning requirements in the energy sector. Electrical corporations, CCAs, publicly owned utilities, and electric service providers participate in and are subject to many of these programs, as applicable, and conduct planning for their own purposes to match. These regulated entities are joined by a variety of others that have a direct

---

12 Because these three RA requirements serve distinct functions, they are assessed differently by the CPUC. System RA is based on each entity's load forecast from the CEC plus a 15% planning reserve margin. Local RA is based on a CAISO assessment of the particular locally-constrained area if a 1-day-in-10-years weather event were to occur as well as an N-1-1 contingency (multiple contingencies, or failures, on the grid). Flexible RA is based on a CAISO assessment of the largest three-hour ramp expected, on a monthly basis.

13 [Unless otherwise referenced, a referenced Decision is one by the CPUC].
Decision 20-06-002 issued 6/17/2020 implementing a central procurement option for Local RA.
Decision 20-06-031 issued 6/30/2020 refining the RA program, et al.
Decision 20-12-006 issued 12/04/2020 adopting a local capacity resource compensation mechanism and neutrality rules for the central procurement entity.
Decision 21-06-029 issued 6/25/2021 refining program accounting requirements and penalty structure, et al.
Decision 21-07-014 issued 7/16/2021 restructuring the RA program and program principles.
Decision 22-03-034 issued 3/18/2022 modifying the central procurement entity and making other revisions.
Decision 22-06-050 issued 6/24/2022 adopting a 24-hour slice of day reform framework, et al.
Decision 23-04-010 issued 4/07/2023 implementing the 24-hour slice of day framework.
Decision 23-06-029 issued 7/05/2023 refining the RA program, modifying the planning reserve margin, et al.

and indirect bearing on the electricity grid, including wholesale generators, distributed energy resource providers, customers, as well as the federal, local, and Tribal governments. But as this hearing is focused on the state's energy planners, this discussion is focused on their programs. Furthermore, the value of state planning efforts depends partly on its ability to adapt and follow the sector for which it is planning in the real world.

Section 2: **What does this look like in practice? Recent developments in electricity planning:**

While these electricity sector planning programs have histories that well exceed the last half-decade, the past few years have been particularly energetic for the CEC, CPUC, and CAISO. The following are some of the most critical events that illustrate the evolution of state energy planning in recent years. It is important to note that while the events noted below, both in Sections 2 and 3, do signal unprecedented action by state agencies, and give the appearance of an ad-hoc planning environment, these events occurred alongside the routine demand forecasting-IRP-TPP processes happening in the background that contributed to the vast majority of electricity sector procurement during this period. So while existing planning processes covered most of the system needs during the last few years, what is detailed below shows how the state agencies responded to the cracks that began to emerge in that very planning regime.

In 2019, the CPUC issued an order within its Integrated Resource Planning (IRP) proceeding that required the procurement of 3,300 megawatts of incremental resources by LSEs based on their share of load.[14] These resources were required to be at least 50% online by August 2021, 75% by August 2022, and 100% by August 2023. This was ordered based on "a significant possibility of a system resource adequacy shortfall in California by Summer 2021 if the Commission does not act to authorize the procurement of additional electric capacity resources to address system reliability" and a recognition that "[t]he Commission should act now to forestall a potential system reliability emergency by 2021 and require 'least regrets' actions with respect to OTC deadlines and LSE procurement."[15] This was the first time since its creation that the IRP process was used to order additional procurement.

In 2021, the CEC, CPUC, and CARB issued the first SB 100 Report, finding that the 2045 targets in SB 100 are achievable, although more analysis was needed to evaluate reliability issues more comprehensively. Increased diversity of resources, on a technological and geographical basis, requiring sustained, record-setting rates of building new resources, were found to lower overall resource costs and increase the feasibility of 2045 goals. A number of questions were identified requiring further analysis, including the future of natural gas generation capacity for reliability, as well as implications of energy-sector developments for the California workforce, land-use conflicts, supply chain complications, as well as regulatory and permitting processes.[16] These topics for further review underscore that the SB 100 analysis

---

14 Decision 19-11-016 issued 11/13/2019, Decision Requiring Electric System Reliability Procurement for 2021-2023 in Rulemaking 16-02-007. Megawatts referenced are measured by Net Qualifying Capacity, not nameplate capacity (which would be higher).

15 Decision 19-11-016, ibid., Findings of Fact paragraph 5, Conclusion of Law paragraph 1.

16 SB 100 Joint Agency Report: Charting to a 100% Clean Energy Future, 3/15/2021, CEC Docket 19-SB-100.

is directional and that tradeoffs are inherent to different paths forward to the State's 2045 targets.

Additionally, the CPUC ordered the large electrical corporations to seek out additional capacity able to serve both peak demand and net peak demand during that summer through an expedited process in response to the 2020 electric grid events discussed further in Section 3.[17] The CPUC shortly thereafter issued further requirements of electrical corporations, established a new demand response program (the Emergency Load Reduction Program, or ELRP), and augmented the Flex Alert process by creating a paid media campaign. That decision also created an *effective* Planning Reserve Margin (PRM) of 17.5%, which was higher than the actual PRM of 15%, and directed electrical corporations to seek to procure up to the effective margin for all customers in their service territory.[18] This sent the electrical corporations into the market for additional resources that could provide short-term capacity for both 2021 and 2022.[19] But while this guarantees additional *demand* for RA-eligible resources, it does not necessarily follow that there will be additional *supply*. Indeed, LSEs reported paying substantial increases for capacity as RA market prices have risen, particularly since 2019.[20] These sustained, tight RA market conditions have also been reported by POUs.[21]

Additionally, that year the CPUC issued another IRP order that required the procurement of an additional 11,500 megawatts of incremental new resources.[22] LSEs' share of this procurement requirement was based on load share, and was required to be online in phases starting in 2023 and 100% online by 2026. 9,500 megawatts of this incremental procurement was specifically designed to replace the capacity of the Diablo Canyon Power Plant and several thermal power plants retiring due to the one-through-cooling regulations of the State Water Resources Control Board. The balance of 2,000 megawatts from this procurement order were required to be long-lead-time resources (long-duration storage and zero-emission resources with a high capacity factor).[23]

<u>In 2022,</u> the CPUC increased the Planning Reserve Margin (PRM) for its jurisdictional LSEs from 15% in 2022 to 16% in 2023.[24] This did not modify the higher 17.5% effective PRM requirements for only the IOUs — "IOUs will continue to target the same [megawatt] totals

17 Decision 21-02-028 issued 2/17/2021, Decision Directing [the large electrical corporations] to Seek Contracts for Additional Power Capacity for Summer Reliability; Rulemaking 20-11-003.

18 Decision 21-03-056 issued 3/26/2021, Decision Directing [the large electrical corporations] to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022; Rulemaking 20-11-003.

19 Non-CPUC-jurisdictional LSEs may use separate load forecasts from the CEC's in the IEPR, do not all have the same 15% PRM, and do not file RA plans with the CPUC. AB 209 (Committee on Budget, Chapter 251, Statutes of 2022) established a process for POUs within CAISO to collaborate with the CEC to "develop recommendations about approaches" to determine an appropriate minimum PRM for POUs. This process is meant to conclude by December 31, 2023, but it is unclear when it will be completed.

20 CPUC, 2021 Resource Adequacy Report, April 2023

21 CMUA Letter to Siva Gunda, "AB 209 (2022) Planning Reserve Margin Process and Reliability," March 22, 2023.

22 Decision 21-06-035 issued 6/30/2021, Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026), in Rulemaking 20-05-003. Megawatts referenced are measured by Net Qualifying Capacity, not nameplate capacity (which would be higher).

23 A subsequent order, discussed below, in 2023 would delay the deadlines for procuring some of these resources due to LSEs' difficult securing new resources.

24 Decision 22-06-050 issued 6/24/2022, Decision Adopting Local Capacity Obligations for 2023-2025, Flexible Capacity Obligations for 2023, and Reform Track Framework; Rulemaking. 21-10-002.

for contingency resources, despite the change in LSE RA requirements."[25] However, it nevertheless increased the number of LSEs seeking additional RA resources in a tight market. That decision also increased the formal PRM to 17% for all LSEs beginning in 2024.

That year, the CAISO issued its first-ever 20-Year Transmission Outlook, which estimated that just the high-voltage transmission grid would require the following over the next 20 years:

- $10.74 billion in upgrades to existing lines;
- $8.11 billion to integrate offshore wind resources; and,
- $11.65 billion to integrate out-of-state resources.

While these costs would be developed and amortized over multiple years, this is a significant increase in infrastructure and cost. CAISO has since indicated an update to its 2022 Outlook is forthcoming, likely concurrent to the 2023-2024 Transmission Planning Process.

In 2023, the CPUC again issued an order within the IRP proceeding that required the procurement of an additional 2,000 megawatts in 2026 and another 2,000 megawatts in 2027, in addition to amounts previously ordered in this process.[26] This order also delayed the deadline for the 1,000 megawatts of long-lead-time resources and 1,000 megawatts of long-duration storage ordered in 2021, citing potential project delays.

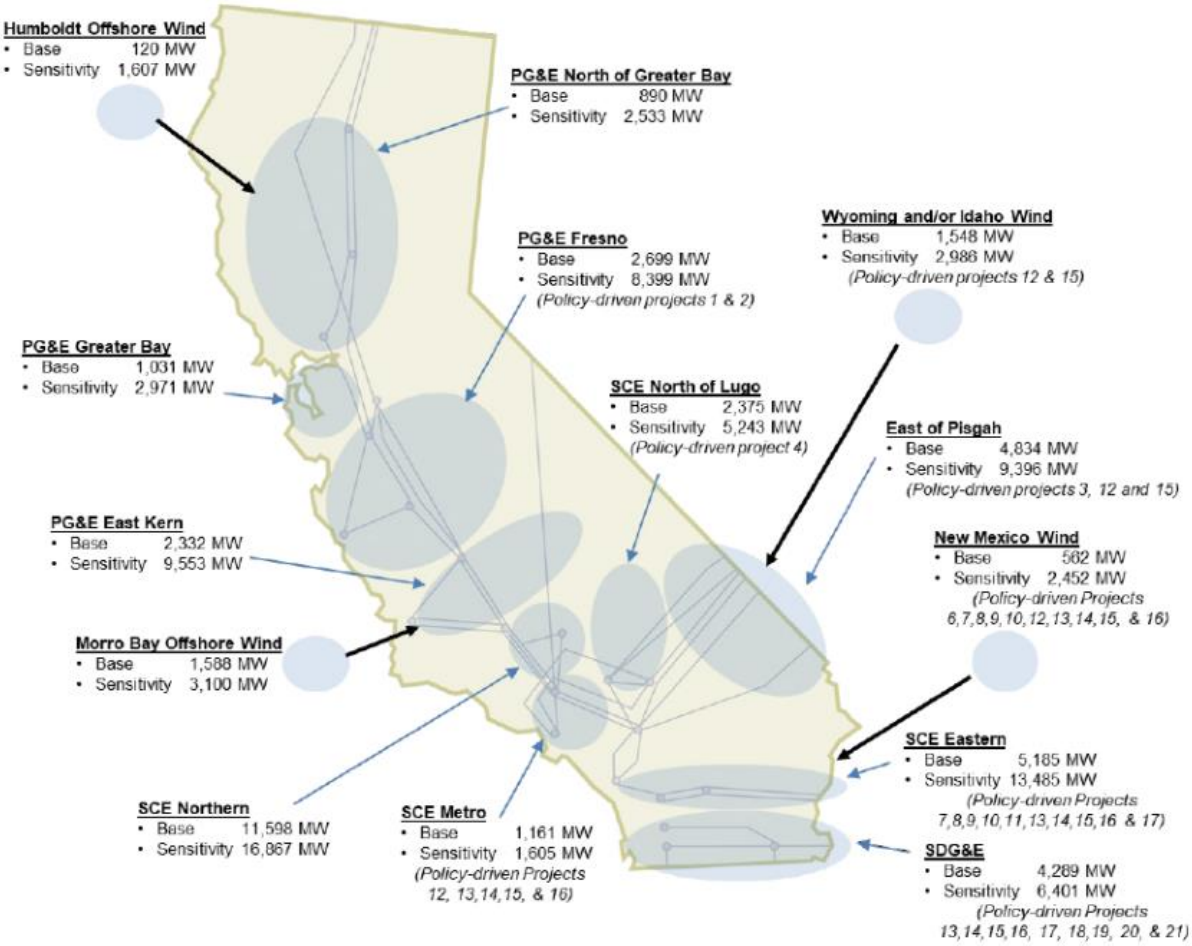
Additionally, the CAISO approved the 2022-2023 TPP in May 2023, using the then-estimate that 40,000 megawatts of new resources would be needed over the next 10 years. A higher estimate will be used in the 2023-2024 TPP. This plan determined the following were needed:

- 45 transmission projects with a total cost of $7.3 billion, ranging in individual cost from $4 million to $2.3 billion. These needed projects were weighed against a large variety of alternatives and found to be needed to meet reliability, policy, and economic requirements.
- Pursuant to CAISO's FERC tariff, only 3 of these projects were eligible for competitive solicitation.
- The reliability and policy projects included 12 that specifically serve to reduce natural gas generation in locally-constrained portions of the grid.

[25] Pg. 22, D. 22-06-050, *Ibid.*

[26] Decision 23-02-040 issued 2/23/2023, Decision Ordering Supplemental Mid-Term Reliability Procurement (2026-2027) and Transmitting Electric Resources Portfolios … et al.; Rulemaking 20-05-003. Megawatts referenced are measured by Net Qualifying Capacity, not nameplate capacity (which would be higher).

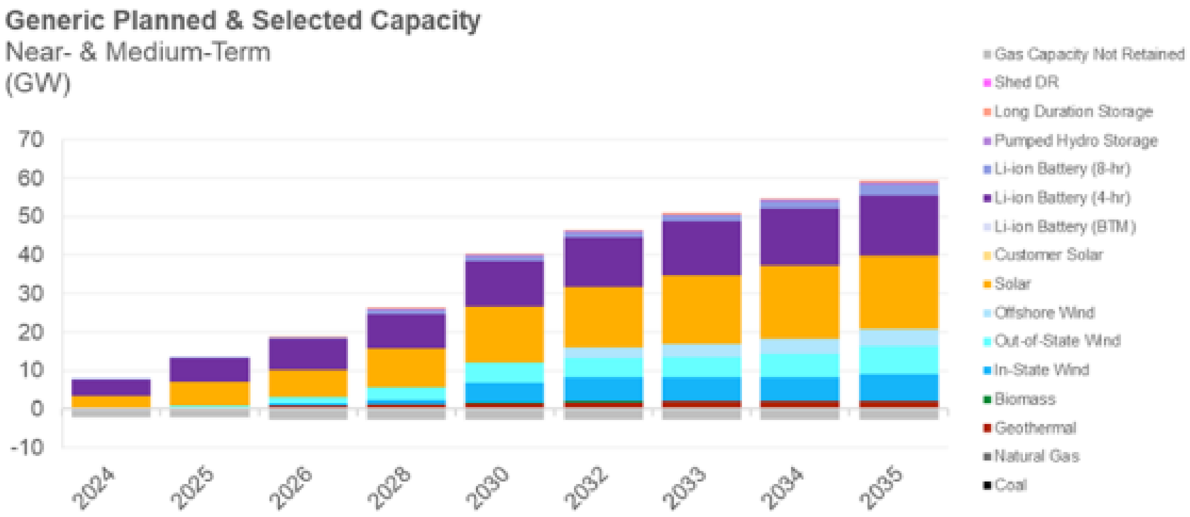
Figure 2: Transmission capacity projects for development by zone in the base scenario, as well as the sensitivity (study) scenarios for comparison, in the approved 2022-2023 CAISO Transmission Plan. It is possible that the forthcoming 2023-2024 TPP may include projects that the 2022-2023 TPP below only studied as sensitivity scenarios.



In 2024, the CPUC is considering a proposed decision that would, if approved as proposed, adopt a Preferred System Plan (PSP) with a 25 million metric ton greenhouse gas reduction target by 2035. This proposed decision, if adopted, would also formally set a reliability target of a 1-day-in-10-years loss of load expectation. A loss of load expectation is a reliability planning metric that, in the case of a one-in-ten as proposed here, estimates the resources needed to ensure reliability during all grid conditions except for the most severe occurring on one day in ten years. Different reliability analyses using different loss of load expectations, such as the less conservative one-in-two. As shown in Figure 3, this proposal identifies 56,600 megawatts of new resources needed by 2035 in the PSP. This includes 19,000 megawatts of solar, 15,000 megawatts of 4-hour battery storage, and an equal 6,100 each of both in-state and out-of-state wind. Compared to today, this means doubling California's nameplate solar facilities, more than tripling California's nameplate battery storage capacity, and doubling in-state wind energy production, among other points of growth — an unprecedented change.

Figure 3 – if approved by the CPUC, new resources required to 2035 in the most recent PSP:[27]

Planned and Selected Resource Capacity (MW) for 25 MMT Core Case



Additionally, in the forthcoming 2023-2024 TPP, the CAISO will use an elevated estimate that 70,000 megawatts of new resources will be needed by 2033 (an estimate modeled in the 2022-2023 TPP but only as a sensitivity portfolio; it has now been elevated; the CPUC makes this determination). A draft plan is scheduled to be published by March 31, 2024, and is scheduled to be reviewed by the Board of Governors for approval in May 2024.

***Section 3:* What is the outcome of State planning in practice on the electric grid?**

Recent events have illustrated the substantive challenges facing the State's electricity grid, its operators, its owners, its state planners, and the customers they all serve. This series of events outside the typical planning regime may indicate the pace of change in practice outpacing the pace of change in planning, including the following events.

In 2020, on August 14-15, when the temperature was more than 110 degrees in the Sacramento and Central valleys, the CAISO was forced to initiate temporary, rotating electricity outages in California to ensure grid stability. On both days, the CAISO had to declare a Stage 3 grid emergency (the highest level) as emergency demand response resources were utilized, incremental import transmission capacity secured, and additional resources sought, were insufficient in the face of demand when combined with unexpected power plant outages that struck on both days. The Stage 3 grid emergencies of 120 minutes on August 14 and 20 minutes on August 15 (not the same as the shorter length of any customer's outage) were necessary in order to prevent a larger, uncontrolled resource deficiency from destabilizing the western grid. Subsequent extraordinary actions, including the suspension of restrictions on power plants' fuel use, air quality impact, and maximum generating capacity pursuant to an executive order, as well as customer conservation, lowered demand by up to 4,000 megawatts each day and avoided another Stage 3 emergency through that heat event.[28]

[27] Proposed Decision issued 1/10/2024 in IRP Proceeding, Rulemaking 20-05-003. This decision is pending before the CPUC and is subject to change.

[28] Executive Order N-74-20, issued August 17, 2020, following Governor Newsom's declaration of a State of Emergency on August 16, 2020. No stage 3 emergency was declared after August 15 through August 19.

In the Root Cause Analysis produced jointly after these events by the CAISO, CEC, and CPUC, 2 of the 3 major causal factors that led to rotating outages during this climate change-induced extreme heat wave were related directly to State planning programs. This analysis found that climate change was exacerbating heat events in a manner that exceeded RA and planning targets — demand exceeded the PRM. It also found that resource planning targets were not keeping pace with how the increased deployment of renewables were shifting supply and demand during the early evening hours of the summer. Peak electricity demand net of solar, instead of the gross demand peak, was becoming the harder of the two to serve due to sustained heat into the evening while the sun set. On both August 14 and 15, the Stage 3 emergency occurred not during peak demand but later, during the net peak. While these events were a confluence of factors beyond those mentioned here, the joint analysis recognized that the planning programs administered by its authors were partly to blame for the emergency. As such, several recommendations in that Analysis sought changes to the planning programs.[29]

In 2021, during the summer Governor Newsom proclaimed a state of emergency and issued an executive order that waived air quality, water discharge, and other requirements for stationary and maritime electricity generators to increase demand-side resources.[30] As the result of another State of Emergency subsequently proclaimed by the Governor, which issued a series of orders seeking the modification of both electricity supply and demand, the Department of Water Resources (DWR) also took the unprecedented step of procuring four 30 megawatt mobile natural gas turbine generators using funding authorized by the Department of Finance from the Disaster-Response Emergency Operations Account.[31] These generator units were subsequently installed outside Roseville and Yuba City, and are intended to be used by DWR to increase capacity during periods of stress on the electric grid. This was the first time since the Electricity Crisis of 2000-2001 that DWR was directed to take such a supply-side intervention for California's electricity grid beyond its usual procurement responsibility for the State Water Project.

In 2022, Governor Newsom proposed a sweeping series of energy policies and programs as part of the May Revision to the Governor's January Budget Proposal. Among many other provisions, this included using expansive General Fund resources for electric grid reliability.[32] The Legislature modified and approved the creation of the Electric Supply Strategic Reliability Reserve Program, which included $2.37 billion for wholesale, bulk resources administered by

[29] Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave. Published January 13, 2021, and prepared jointly by the CAISO, CPUC, and CEC.

[30] Proclamation of a State of Emergency issued by Governor Newsom on 6/17/2021. See also related, subsequent Executive Order N-11-21 issued 7/10/2021 making provisions for berthed ships to shift from shore power to auxiliary engine generation.

[31] July 30, 2021 Proclamation of a state of emergency by Governor Newsom; August 10, 2021, notice of the Department of Finance to the Joint Legislative Budget Committee authorizing $171.5M from the Disaster-Response Emergency Operations Account to the Department of Water Resources. subsequent Department of Finance in a January 18, 2022, letter to the Joint Legislative Budget Committee, $40.3M in additional funding was required to ensure the units met air emission requirements, electric grid upgrades, and upgrades to meet reliability requirements — $10M of which was provided from funding for unanticipated contingencies, after notice to the Joint Legislative Budget Committee. The Budget Act of 2022 subsequently provided the balance of funding requested by the Governor over two fiscal years.

[32] The 2022 May Revision included proposals of $4.25 billion for DWR Strategic Reliability Reserve program activities, $950 million for the Distributed Electricity Backup Assets program, $970 million for the Self Generation Incentive Program, $295 million for the Demand Side Grid Support program, and $250 million for a Infrastructure Bank transmission financing authority. All figures are over multiple fiscal years.

DWR, as well as $700 million for distributed resources and $295 million for demand response programs administered by the CEC.[33]

As a result, DWR used its Strategic Reliability Reserve program funding in 2022 for the following additional electricity resources:

- 1,646 megawatts of additional, extra firm energy imported by electrical corporations at-cost above their normal requirements;
- 82.4 megawatts of diesel generators leased from two electrical corporations;
- 120 megawatts from the four State-owned natural gas turbine generators. These are the same units procured the previous summer and designated as the State Power Augmentation Program were shifted into the Reliability Reserve Program.

The 2022 Budget also included resources for new clean energy resources, including $900 million for the Self Generation Incentive Program (distributed solar and storage resources), $1 billion for the Clean Energy Reliability Incentive Program, a $250 million clean energy transmission financing authority to be administered by the State Infrastructure Bank, $380 million for long-duration storage incentives, $100 million in hydrogen grant incentives, and a variety of other programs. The total for this Energy Package within the Budget was $7.9 billion.

In August of that same year, Governor Newsom also proposed that Diablo Canyon Power Plant should operate beyond 2025, reversing a settlement agreement reached by PG&E and parties in 2016 and subsequently reflected in law.[34] Following Governor Newsom's proposal, the Legislature subsequently made provision to allow the Plant to operate until 2030 under specified conditions and authorized DWR to loan PG&E up to $1.4 billion in General Fund resources to pursue relicensing of the facility by the U.S. Nuclear Regulatory Commission.[35] This loan is subject to partial reimbursement from PG&E as the prospective recipient of federal grant dollars, excluding portions PG&E is allowed to retain. Diablo Canyon Power Plant has a combined nameplate capacity of approximately 2,200 megawatts.

In 2023, Governor Newsom proposed as part of the Governor's January Budget Proposal a trailer bill that made various changes to State energy policy, including allowing DWR to act as a central procurement entity for long-term resources at the request of the CPUC, imposing penalties on LSEs that rely on Reliability Reserve Program resources, and modifying the CPUC's IRP authority. The Legislature later modified and approved this proposal expanding the resources available to the State in energy planning.[36] The CPUC now has the ability to order the procurement of specified long-lead time resources that are not showing up in LSEs IRPs by asking DWR to act as a central procurement entity, with costs applied to the ratepayers that benefit from this new capacity (and the cost of which may be reduced using rate revenue bonds).

---

33 The 2022 Budget Act included $2.37 billion for the DWR Strategic Reliability Reserve program, $700 million for the CEC Distributed Electricity Backup Assets program, and $295 million for the CEC Demand Side Grid Support demand response program. The Budget also included $900 million for the Self Generation Incentive Program and $250 million for a State Infrastructure Bank Transmission Financing Authority. All figures are over multiple fiscal years.

34 SB 1090 (Monning, Chapter 561, Statutes of 2018).

35 SB 846 (Dodd, Chapter 239, Statutes of 2022).

36 AB 1373 (Garcia/Ting/Becker, Chapter 367, Statutes of 2023).

Governor Newsom also issued an executive order directing the creation of an Infrastructure Strike Team, to include at least 8 sub-groups including one on energy issues, led by senior counselors to the Governor and Cabinet-level appointees, and supported by an interdepartmental team of staff.[37] The energy portion of the Strike Team, this unit is led by the President of the CPUC, the Secretary of the Natural Resources Agency (CNRA), and the Director of the Governor's Office of Business & Economic Development, led by senior staff from the CPUC, CNRA, and the Governor's Office, and supported by staff from all of these entities as well as the CEC, CAISO, and Department of Finance.[38] This substantially supplanted the previously-created Tracking Energy Development Task Force for energy issues specifically. While the focus of this Strike Team is creating opportunities and unblocking barriers for the specified categories of new infrastructure, it is, as yet, unclear what progress has resulted from this intensive interdepartmental strike team.

DWR used its Strategic Reliability Reserve program funding in 2023 for the following additional electricity resources:

- An estimate of 6,000 megawatts, expected to be refined, of additional, extra firm energy imported by electrical corporations at-cost above their normal requirements;
- 120 megawatts from the four State-owned natural gas turbine generators. These are the same units procured the previous summer and designated as the State Power Augmentation Program were shifted into the Reliability Reserve Program.
- 18 megawatts of additional contracted generation.
- 0 megawatts of natural gas stationary generators at three sites in the Central Valley, but 144 megawatts of capacity is expected to be available from these resources now.

37 Executive Order N-8-23, issued by Governor Newsom on 5/19/2023.
38 See more detail published by the Newsom Administration here: https://build.ca.gov/about/

Figure 4 – the following resources were available to improve reliability conditions in 2023, including the ESSRRP:[39]

Type	Contingency Resource	Available MW July	Available MW August	Available MW September
SRR	DWR Electricity Supply Strategic Reliability Reserve Program*	148	148	148
SRR	Demand Side Grid Support+	315	315	315
SRR	Distributed Electricity Backup Assets (under development)	0	0	0
CPUC	Ratepayer Programs (ELRP, Smart Thermostats, etc.) **	366	404	434
CPUC	Imports Beyond Stack	325	930	825
CPUC	Capacity at Co-gen or Gas Units Above Resource Adequacy	235	158	86
DWR	DWR SWP***	0	0	0
Non-Program	Balancing Authority Emergency Transfers	500	500	500
Non-Program	Thermal Resources Beyond Limits: Gen Limits	60	60	60
Non-Program	Thermal Resources Beyond Limits: Gen Limits Needing 202c	25	25	25
	Total	**2,040**	**2,612**	**2,444**

*Does not include an additional 144 MW of projects that are not on-line yet but expected to be available before the end of the year.

**Does not reflect actual 2022 ELRP enrollment. Instead, provided values are forecasted projections of ELRP impact based on an updated load impact protocol (LIP) evaluation from ELRP event experience in 2022.

***These resources are projected one week ahead. For the first time since 2006, DWR expects to provide 100 percent of requested water supplies but will reduce pumping demand to the maximum extent possible when energy demand is highest while still making critical water deliveries.

+Available MW are based on enrollment.

Section 4: Where does the State go from here?

As reviewed in Section 2 above, since 2019 the state's energy planners have taken a series of at-times unprecedented steps forward within their planning framework. But as reviewed in Section 3 above, they have also had to take extraordinary measures outside the normal energy policy planning process with growing frequency.

Maintaining reliability while also driving progress toward the State's energy decarbonization requirements is a core function of the work of the CEC, CPUC, and CAISO. But serious

---

39 Joint Reliability Planning Assessment, Fourth Quarterly Report, issued 12/01/2023 .

challenges remain from the near- to the long-term. Since 2020, thousands of megawatts of new resources have been procured and interconnected to the grid by LSEs and publicly owned utilities. Another nearly two thousand megawatts of resources have been made available in the ESSRRP using General Fund. Thousands of megawatts of behind-the-meter solar has been installed.[40] Significant ratepayer and General Fund resources are being used to increase demand-side modifiers to electricity consumption.

Figure 5 – Resource additions from January 2020 through August 2023:[41]

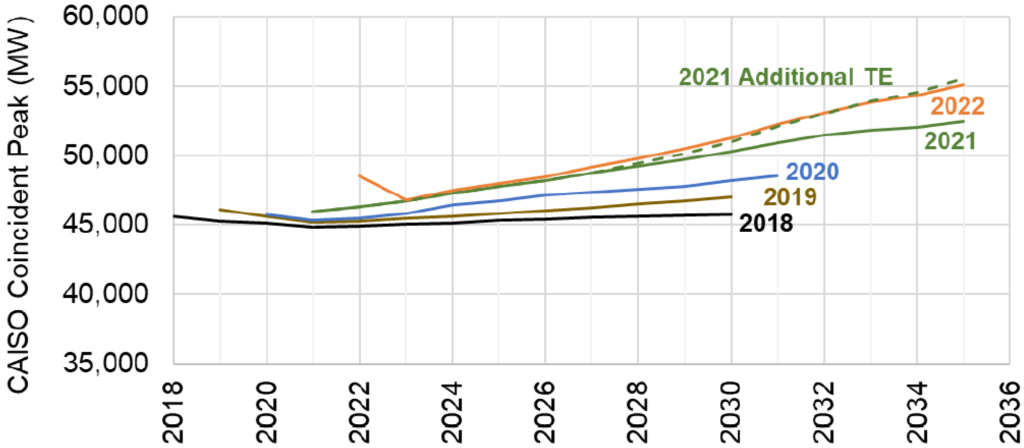
Technology Type	Nameplate Capacity (MW)	Estimated Sept. Net Qualifying Capacity (NQC) MW	Number of Projects*
Storage	4,919	4,556	69
Solar	3,993	345	64
Hybrid (Storage/Solar)	1,034	464	17
Wind	783	103	20
Geothermal	41	31	1
Biogas, Biomass, Hydro	36	1	9 (2,3,4)
Subtotal SB 100 Resources, In-California Independent System Operator	10,806	5,499	180
Natural Gas, incl. Alamitos & Huntington Beach	1,477	1,474	12
Total Resources, In-California Independent System Operator	12,282	6,973	192
New Imports, Pseudo-Tie[2] or Dynamically Scheduled	1,689	727	13
Total Resources, Including Imports	13,971	7,701	205

However, demand continues to grow as climate change exacerbates heat events and more Californians electrify their homes, businesses, and vehicles. In each of the prior five IEPRs, the net peak demand forecasts for the future have changed. Each IEPR incrementally revised demand forecasts upward — illustrating that not only is electricity demand growing, it is growing faster than our forecasts can anticipate and faster than our planning regime can keep pace.

40 Measured in nameplate capacity, not Net Qualifying Capacity (a different metric based on the reliability value of the resource). Note that Figure 5 numbers of wholesale resources are shown by both valuations. See also the 2023 adopted IEPR for annual figures through 2022 on distributed resources (noting that the Figure 5 above is through 2023), in which cumulative behind-the-meter solar installed through 2022 was more than 14,000 megawatts and behind-the-meter storage installed was more than 1,000 megawatts.

41 Joint Reliability Planning Assessment, Fourth Quarterly Report, 12/01/2023.

Figure 6 – The Demand Forecast over time has been revised upward, 2018 to 2022 IEPRs:[42]



Clearly, the State's energy planners are accelerating their work to meet the pace of change. This is illustrated in the ratcheting up of CEC demand forecasts in the IEPR, in procurement required by the CPUC in IRP, and of transmission infrastructure called for by the CAISO. But it is just as clear that the pace of change on the grid may yet be faster still. This can be seen in the lags in the pace of new resource interconnection due to various delays and demand forecasts growing as fast as they can be produced. All the while, climate change continues to exacerbate these challenges by making weather patterns, heat events, and precipitation rates more volatile — and so too, making summer electricity demand and available generation (particularly, hydroelectric generation) harder to manage.

As the state's energy planners have recognized, "[p]lanning models and approaches need to be enhanced to account for greater weather variability. The state will benefit from updated planning strategies for bringing on new resources faster and at a larger scale while engaging more closely with communities on solutions that meet their needs."[43] This reflects some consensus that planning must continue adapting to the changing electricity sector it serves. But the question for this Committee is whether that adaptation is occurring fast enough, and if not, how reliability and affordability are compromised while the planning regime plays catch-up.

# # # # #

42 2023 adopted Integrated Energy Policy Report at pg. 102, showing the planning forecast for managed net peak demand in the 2018-2022 IEPRs.

43 Joint Agency Reliability Planning Assessment First Quarterly Report at p. 8.

Appendix: Acronyms Used

CAISO	California Independent System Operator
CEC	California Energy Commission
CARB	California Air Resources Board
CCA	Community Choice Aggregator
CPUC	California Public Utilities Commission
DWR	Department of Water Resources
DEBA	Distributed Electricity Backup Assets program [by CEC, in ESSRRP]
DSGS	Demand Side Grid Support program [by CEC, in ESSRPP]
ESSRRP	Electric Supply Strategy Reliability Reserve Program [by DWR and CEC]
FERC	Federal Energy Regulatory Commission
IEPR	Integrated Energy Policy Report [by CEC]
IRP	Integrated Resource Planning
LSE	Load Serving Entity [electrical corporation, CCA, or electric service provider]
PRM	Planning Reserve Margin [may be either the actual PRM or effective PRM]
POU	Publicly Owned Utility [not to be confused with a public utility, a broader term]
PSP	Preferred System Plan [in IRP by CPUC]
RA	Resource Adequacy [by CPUC]
RPS	Renewables Portfolio Standard
RSP	Reference System Plan [in IRP by CPUC]
TPP	Transmission Planning Process [by CAISO]

# # # # #