DOCKETED

Docket Number:	21-ESR-01
Project Title:	Energy System Reliability
TN #:	250357
Document Title:	SB 846 Load Shift Goal Commission Report
Description:	Commission Report on the SB 846 Load Shift Goal
Filer:	Cynthia Rogers
Organization:	California Energy Commission
Submitter Role:	Public Agency
Submission Date:	5/26/2023 2:27:56 PM
Docketed Date:	5/26/2023

California Energy Commission

COMMISSION REPORT

Senate Bill 846 Load-Shift Goal Report

Gavin Newsom, Governor

May 2023 | CEC-200-2023-008

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ACKNOWLEDGEMENTS

The authors express appreciation to the staffs of the California Energy Commission, California Public Utilities Commission, and California Independent System Operator for their review and contributions to this report. The California Energy Commission would also like to acknowledge the technical support of Guidehouse, Inc., specifically in the development of the demand response tool, which was fundamental to the analysis and development of this report.

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ABSTRACT

The Load-Shift Goal Report addresses a requirement in Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) for the California Energy Commission to develop a statewide goal for load shifting to reduce net peak electrical demand. The report outlines the approach used to develop a load-shift goal in consultation with the California Public Utilities Commission and the California Independent System Operator and consider research conducted by Lawrence Berkeley National Laboratory as required by SB 846. The report also discusses the current landscape of demand response and load shifting in California and suggests policies to increase demand response and load shifting without increasing greenhouse gas emissions or increasing electric rates.

Keywords: Demand response, demand flexibility, energy reliability

Please use the following citation for this report:

Neumann, Ingrid and Erik Lyon. May 2023. *Senate Bill 846 Load-Shift Goal Report*. California Energy Commission. Publication Number: CEC-200-2023-008.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

California is experiencing a substantial shift in conditions affecting the electric grid, which is transitioning to the state's clean energy future while confronting the impacts of climate change:

- The unprecedented buildout of variable renewable energy resources such as solar and wind to meet California's clean energy goals.
- Switching or substituting of energy uses such as transportation and heating from combustible fuels to electricity.
- Increase in variability of weather patterns and in climate-driven natural disasters, resulting in more challenges to grid reliability.

Load flexibility is the capability to shift or shed electric load or demand away from times when electricity is expensive, polluting, and scarce to times when it is inexpensive, clean, and plentiful. Load flexibility must play a critical part in meeting each of these challenges by aligning customer demand with the supply of clean energy to integrate new renewables onto the grid, reduce the strain new electric load places on the grid, and help maintain electric reliability during extreme events, such as record setting heat, droughts, and wildfires. Hundreds of millions of new electric vehicles, heat pumps, and other electric loads will be coming onto the grid between now and 2045, resulting in the need for investments in grid infrastructure to support the expansion. California has an urgent opportunity to expand load flexibility as a large-scale planning and reliability resource: smoothing demand to improve grid utilization, optimizing grid infrastructure investments, and saving electric ratepayers money.

In recognition of these challenges and opportunities, Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) directed the CEC to develop a goal for shifting load to reduce net peak electrical demand and policies to increase demand response and load shifting, along with other actions necessary to support California's clean energy transition and grid reliability.

Load Flexibility Framework

For electric system planning, CEC classifies the diverse load flexibility resources into three categories:

- **Load-modifying** demand flexibility resources directly impact the load forecast and resource procurement requirements of load-serving entities. The most common category of load-modifying flexibility is time-varying rates, such as simple time-of-use (TOU) rates and hourly dynamic rates that reflect actual market and grid conditions including the marginal energy, transmission, and distribution costs of electricity. Recently, more targeted interventions to reduce peak and net peak loads, such as Power on Peninsula, a behind-the-meter battery storage pilot program, have been deployed to reduce forecasted peak demand explicitly.

- **Resource planning and procurement** load flexibility either contributes to meeting Resource Adequacy (RA) requirements or reduces RA requirements as a credit. Supply-side DR participates in the California Independent System Operator (ISO) as either economic demand response (DR) or reliability DR (with an economic bidding option) that is activated under emergency conditions. Supply-side DR programs run by IOUs and POUs are typically accounted for as credits, whereas third-party supply-side DR resources are shown on RA supply plans to meet RA requirements.
- **Incremental and emergency** load-flexibility programs are intended to increase resource availability during extreme events that are difficult to account for in standard planning practices, particularly when multiple events coincide. These programs, including the Emergency Load Reduction Program and the Demand Side Grid Support Program, serve as an insurance policy against an increasingly unpredictable and volatile climate. Emergency load-flexibility resources may be activated in response to a grid emergency or to *prevent* emergencies under conditions of high grid need. Unlike RA resources, emergency and incremental resources do *not* contribute to meeting the RA requirements of an LSE.

Statewide Load-Shift Goal

CEC defined the following key parameters for the load-shift analysis and goal-setting process:

- The **metric** for the goal is net peak demand reduction (that is, megawatts, rather than megawatt-hours) from load-flexibility interventions and programs.
- The **net peak period** is defined as the top 100 net system load hours in a year to align with the Lawrence Berkeley National Laboratory Potential Study. Correspondingly, **net peak demand** is defined as the average hourly demand over the net peak period. The net system load in each hour is defined as gross bulk system load minus utility-scale solar and wind generation.
- The **target year** for the initial load-shift goal is 2030. Updates to the goal in future Integrated Energy Policy Report (IEPR) cycles could consider additional target years beyond 2030.
- The **specificity** of the goal is a single metric at the statewide level. The goal analysis considered additional levels of granularity such as utility, sector, end use, and DR program type. However, at this juncture, CEC does not recommend subgoals for specific program types, sectors, or jurisdictions beyond the statewide goal.

Based on the modeling conducted for this report, CEC staff developed a statewide load-flexibility goal of 7,000 MW, as shown in Table ES-1. Staff view the proposed target as aspirational but achievable with robust policy support.

Table ES-1: Proposed Statewide Load-Shift Goal

2022 Load Shift Estimate	2030 Load-Shift Goal	2030 Goal (Incremental)
3,100–3,600 MW	7,000 MW	3,400–3,900 MW

Megawatts shown are measured at the customer meter.
Source: CEC staff

Many pathways exist to achieve the load-shift goal. Table ES-2 summarizes the goal alongside the current portfolio of load flexibility resources. While load-modifying flexibility is projected to make up less than half of load flexibility in 2030, it makes up roughly the majority estimated load flexibility growth potential, reflecting growth of loads under TOU rates such as electric vehicles and the policy preference for dynamic pricing-based load flexibility over event-based flexibility.

Table ES-2: Proposed Statewide Load-Shift Goal by Intervention

Category	Intervention	2022 Estimate	2030 Goal
Load-Modifying (LM)	TOU Rates	620–1,000 MW	3,000 MW
	Dynamic Pricing	30 MW	
	LM Programs	7 MW	
Resource Planning and Procurement	Economic Supply-side DR	670–825 MW	4,000 MW
	Reliability Supply-Side DR	740 MW	
	POU DR Programs (Non-ISO)	210 MW	
Incremental and Emergency (I&E)	I&E Programs	800 MW	
	Emergency Back-Up Generators*	375 MW*	
Total (nearest 100)		**3,100–3,600 MW**	**7,000 MW**

***Includes backup generators with significant local emissions, which are part of the current emergency framework but not included in the 2022 load flexibility total. Only zero- and low-emission behind-the-meter generation consistent with AB 205 (Committee on Budget, Chapter 61, Statutes of 2022) is included in the load-shift goal.**
Source: CEC staff, CPUC staff

California should continue to invest in both load-modifying and resource planning and procurement load flexibility, creating robust industries for bill management under time-varying rates, funding for load-modifying programs, and development of supply-side load flexibility resources, and allowing customers to choose the rates and programs that work best for them. Considerable uncertainty exists in the estimates of recent load flexibility impacts of TOU rates and economic supply-side DR. To realize the load-shift goal, California must define a comprehensive accounting methodology that is consistent across load flexibility resources.

The state should continue to evaluate the cost savings potential of load flexibility. The statewide load-shift goal is based on economic potential. Further analysis is needed to determine the cost-effectiveness of specific load flexibility resources and programs. The proposed goal is not intended to suggest that the state should pursue these targets without the evaluation of the cost-effectiveness of specific resources or programs that would contribute to the goal.

Policy Recommendations

CEC, in collaboration with the California Public Utilities Commission and the California ISO, developed policy recommendations related to each of the three load flexibility planning categories: load-modifying, resource planning and procurement, and incremental and emergency. These recommendations are summarized here and detailed in Chapter 4.

Load-Modifying

1. **Support hourly dynamic pricing frameworks.** The CPUC should direct the IOUs to implement dynamic pricing options for as many customers as possible, consistent with the CEC Load Management Standards (LMS) and the CPUC California Flexible Unified Signal for Energy (CalFUSE) hourly dynamic pricing proposal.
2. **Encourage rate and program designs that offer incentives for load shifting.** The CEC should support a transition toward rates and programs that account for grid needs and match customer demand with electricity supply and reliability under the LMS. As these new rates and programs become available, the CEC should explore using the LMS to transition away from rates that discourage load shifting.
3. **Provide incentives for load-shifting technologies paired with dynamic rates.** The California Legislature should establish and fund a statewide program to provide rebates for technologies with significant load-shifting capabilities such as battery storage, heat pump water heaters, thermal storage, and smart thermostats to customers that opt into rate designs and programs that encourage load shifting, consistent with the LMS.
4. **Deploy information infrastructure to support load shifting.** The CEC-developed Market-Informed Demand Automation Server (MIDAS) should be the primary method for California to communicate hourly rates, marginal greenhouse gas emissions, and grid status to consumers and their flexible devices in support of load flexibility.
5. **Adopt flexible demand appliance standards to enable appliance operations to be shifted, scheduled, or curtailed.** Under the authority of Senate Bill 49 (Skinner, Chapter 697, Statutes of 2019), the CEC should adopt flexible-demand appliance standards (FDAS) establishing requirements for testing, labeling, cybersecurity, and flexible demand capabilities for a wide range of major electric appliances and devices.
6. **Complete deployment of metering infrastructure to support load shifting.** All California utilities, including publicly owned utilities, should analyze the feasibility of advanced metering infrastructure deployment to all customers. Using this analysis, utilities should then move toward developing plans for complete AMI deployment, where feasible.

7. **Reduce transaction costs associated with load-flexibility program and market development.** California utilities and community choice aggregators (CCAs) should develop and maintain a Rate Identification Number (RIN) Access Tool to support third-party services' access to rate information and establish data exchange protocols to promote timely and seamless load-flexibility transactions.
8. **Promote load-modifying program development, measurement, and compensation protocols.** The CEC should support development of load-modifying programs and ensure that the data needed to measure and verify program impacts are collected, and that the analytical methods and tools are validated. Payments for program performance should reflect the full value of load flexibility, including reducing RA requirements, energy costs, and greenhouse gas emissions.

Resource Planning and Procurement

9. **Adopt an incentive-based capacity valuation approach for supply-side DR**. Consistent with the recommendations from CEC *Qualifying Capacity of Supply-Side Demand Response Working Group Final Report*, the CPUC should adopt a planning approach for DR that leverages a penalty to ensure that the capacity values submitted by DR providers are determined by reasonable, repeatable methods and that these providers deliver on capacity commitments when called upon.
10. **Explore a centralized, competitive DR marketplace to consolidate and standardize DR procurement.** CEC should explore opportunities to consolidate and standardize the DR marketplace in California to support DR growth. Paired with the above incentive-based capacity valuation recommendation, such a centralized market holds significant potential to deliver reliable, competitive DR capacity.
11. **Include an adder on wholesale market revenue for supply-side DR.** The California Legislature should allocate funding for the CEC to implement a supplement to energy market revenue to encourage DR to participate more frequently in wholesale markets. This program could be funded under the Clean Energy Reliability Investment Program or as a nonratepayer-funded dedicated program. The energy revenue adder would be paid to participating DR providers as a percentage of wholesale market revenue or value.
12. **Reform availability rules and resource requirements for DR resources participating in RA.** The CPUC and California ISO should ensure that DR receiving RA capacity value will contribute to reliability when called upon during critical or emergency conditions. Such reforms might include maximum bid prices, minimum eligibility criteria, or capacity reductions for resources with significant start-up times, commitment costs, or ramp rate limitations.

13. **Conduct an evaluation, measurement, and verification study of supply-side DR load impacts.** The CEC, in partnership with the California ISO, should evaluate performance of supply-side and other event-based DR in recent years. The CEC interval meter database can be leveraged to measure load impacts using comparison groups and other advanced methods. The CEC should make recommendations regarding the accuracy and appropriateness of different baselines for different customer groups.
14. **Explore modifications to DR participation pathways to support behind-the-meter storage.** The CPUC and California ISO should coordinate to update existing rules and requirements for DR market participation models to count exported energy from behind-the-meter (BTM) storage resources.

Incremental and Emergency

15. **Pilot approaches to compensate DR providers for incremental capacity delivered under extreme heat or other critical conditions.** Under a warming and changing climate, extreme temperatures may allow DR resources to increase capacity relative to typical peak conditions. The CEC should pilot a participation pathway under the demand-side grid support (DSGS) program to fund this incremental DR capacity from the general fund, rather than ratepayer funding sources.
16. **Pilot a pathway for behind-the-meter energy storage to support decarbonization and reliability of the electric grid in incremental and emergency programs.** Behind-the-meter (BTM) storage is a distinct resource type from DR. The CEC should pilot DSGS and Distributed Electricity Backup Assets (DEBA) program designs specific to BTM storage that reflects its capabilities, such as the ability to export energy, and encourages storage to support decarbonization and system reliability.
17. **Pilot short-duration load-shifting resources in emergency and incremental load-flexibility programs.** Some load flexibility resources that do not meet minimum RA requirements may nonetheless provide reliability benefits to California under peak and emergency conditions. The CEC should pilot and evaluate the impact of these resources in programs like the DSGS and DEBA to help determine whether they should have a permanent role in California’s demand flexibility planning paradigms.
18. **Periodically reassess the role of emergency resources in forecasting, resource procurement, and emergency planning processes.** The CEC, CPUC, and California ISO should assess whether incremental programs best fit under the core resource planning frameworks and adapt them as appropriate. The agencies and the ISO should also assess whether emergency programs are delivering the intended benefits at reasonable cost to ratepayers and taxpayers and retire those that are not.

CHAPTER 1: Introduction

Historically, electric grids were designed to meet predictable but inflexible demands with dispatchable power plants, many of which were powered by fossil fuels. In recent years, this paradigm has been inverted with recognition of the climate change impacts from the use of fossil fuels and the increasing reliance on variable renewable energy such as wind and solar to support clean energy goals. These generation technologies are generally predictable but not dispatchable, while electric demand has become more flexible. This ability to beneficially shift electric load away from times when electricity is scarce and highly polluting is known as *load flexibility*. This report outlines the tools, strategies, and potential to make the most of the load flexibility opportunity in California.

California's electric system faces three major climate change-related challenges. To address climate change emissions in the electric sector consistent with Senate Bill 100 (De Léon, Chapter 312, Statutes of 2018), California must increase the buildout of renewable and zero-carbon resources to an unprecedented rate. Solar and wind will make up a large share of these resources. To address climate change emissions in the fossil gas and petroleum sectors, many energy uses such as transportation and heating must be converted to electricity. These newly electrified end uses will increase the need for clean energy resources, as well as the transmission and distribution infrastructure required to serve them. Finally, California must adapt to the climate change impacts of more extreme heat events, droughts, and wildfires. Climate change is resulting in period of record-setting electric demand for cooling, decreased hydroelectric power availability, and higher propensity for dangerous wildfires that impact generation and transmission resources.

Load shifting and flexibility must play a critical part in meeting each of these challenges. Load flexibility can help align customer demand with the supply of clean energy, helping integrate new renewables onto the grid. New loads such as electric vehicles can be made flexible in this way from the beginning, allowing the new demand to minimize the requirement for new generation and grid infrastructure. Electric vehicles may even reduce these needs by providing power during times of high need. Finally, load flexibility can help California maintain electric reliability during extreme climate-induced events such as extreme heat events and wildfire-induced transmission outages.

Investing in demand-side resources offers a robust, cost-effective strategy that will complement other efforts the state is making. If properly implemented, as new distributed resources are added to the grid, the need for additional distribution and transmission upgrades will be reduced, hedging against potential supply chain issues with utility-scale renewables and storage deployment. Additionally, demand-side resources will provide direct benefits to customers in the form of bill savings and resiliency.

Recent technological advances have made this strategy not only realistic, but indispensable to a successful climate strategy. Increases in computing power and connectivity in household, commercial, industrial, and agricultural devices have the potential to shift use automatically to align with the availability of low-cost, clean energy, often with little or no noticeable impact to the customer. Batteries and other storage technologies can charge when renewable energy, particularly solar, is plentiful, and discharge during the net peak, effectively shifting the load away from peak and critical periods.

Taking advantage of these load-flexibility opportunities to address these challenges is critical to reducing the state's greenhouse gas emissions and maintaining and improving safety, air quality, and public health for Californians, especially those residents located in disadvantaged communities and low-income communities. In recognition of these challenges and opportunities, Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) (SB 846) directed the CEC to develop a goal for load shifting to reduce net peak electrical demand, along with other actions necessary to support California's clean energy transition and grid reliability.

In developing the load-shift goal, SB 846 directs the CEC to consult with the CPUC and California ISO and consider findings from the 2020 Lawrence Berkeley National Laboratory (LBNL) report on the shift resource through 2030 and other relevant research. In addition to setting a goal, the CEC, in consultation with the CPUC and California ISO, was directed to recommend policies to increase DR and load shifting that do not increase greenhouse gas emissions or increase electric rates. Finally, SB 846 directs the CEC to regularly update the load-shift goal target in each biennial Integrated Energy Policy Report (IEPR).

Proposed Load Flexibility Planning Framework

Load flexibility can come in a diverse array of technologies, end uses, market designs, and programs. For purposes of electric system planning, CEC classifies these diverse flexibility resources into three categories:

- **Load-modifying** demand flexibility resources directly impact the load forecast and resource procurement requirements of load-serving entities. The most common category of load-modifying flexibility is time-varying rates, otherwise known as retail tariffs. These tariff designs range from simple time-of-use (TOU) rate tariffs with two or more predictable rate periods differentiated by hour, season, or both to proposed rates that change hourly based on actual market conditions and reflect the marginal energy, transmission, and distribution costs of electricity. Recently, more targeted interventions to reduce peak and net peak loads, such as Power on Peninsula, a behind-the-meter battery storage pilot program, have been deployed to reduce forecasted peak demand explicitly.

Examples: Time-of-use (TOU) rates, CalFUSE hourly dynamic rates, FlexMarket (Marin Clean Energy), Power on Peninsula – Residential (Peninsula Clean Energy, East Bay Clean Energy, and Silicon Valley Clean Energy)

- **Resource planning and procurement** load flexibility either contributes to meeting RA requirements or reduces RA requirements as a credit. Supply-side DR participates in the California ISO wholesale markets as either economic-only DR or reliability DR (with an economic bidding option) that is activated when emergency conditions materialize.[1] Supply-side DR programs run by IOUs and POUs are typically accounted for as credits, whereas third-party supply-side DR resources are shown on RA supply plans to meet RA requirements.
Examples: Proxy Demand Resources (PDRs), Reliability Demand Response Resources (RDRRs), My Energy Optimizer (SMUD)
- **Incremental and emergency** load-flexibility programs are intended to ensure reliability during extreme and coincident events that are difficult to account for in standard planning practices. Effectively, these resources serve as an insurance policy against an increasingly unpredictable and volatile climate. Emergency load flexibility resources may be activated in response to a grid emergency or activated earlier to *prevent* emergencies under conditions of high grid need. Unlike RA resources, emergency resources do *not* contribute to meeting the RA requirements of an LSE. While some of these programs are funded by ratepayers, these resources can be increasingly funded with general fund money, reducing ratepayer impacts.
Examples: Emergency Load Reduction Program (ELRP, ratepayer-funded), Demand Side Grid Support (DSGS, general fund), Distributed Electricity Backup Assets (DEBA, general fund)

1 At the time of publication, a CPUC staff proposal either to remove RDRR from the RA supply stack, making it an emergency-only program, or require RDRR to be available before an emergency is called so that it might *prevent* an emergency, is under consideration. This effort is ongoing, and the outcome may affect the future categorization or operation of RDRR.
Appendix A: Energy Division Proposal for Proceeding R.21-10-002. California Public Utilities Commission. January 20, 2023. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M501/K407/501407493.PDF.

CHAPTER 2: Demand Response History and Current Landscape

California has a long history of investing in the demand-side resources to meet growing energy needs. The CEC itself was formed in part to develop demand-side solutions for the state's growing energy needs, which otherwise would have required nuclear power plants up and down the California coast; today, the state has just one.[2] Since then, California has continued to rely on and invest in demand-side resources, especially energy efficiency. For example, Senate Bill 350 (De León, Chapter 547, Statutes of 2015) set a statewide energy efficiency goal, and Assembly Bill 3232 (Friedman, Chapter 373, Statutes of 2018) set a statewide GHG reduction goal. Investing in load reduction reduces the state's infrastructure investments and reliance on less preferred high-emission resources.

The load-shift goal requested under SB 846 builds on this history by targeting the next-generation demand-side resource — load flexibility. While energy efficiency remains a core pillar of California's climate and energy strategy, the load-shift goal reflects the understanding that *when* electricity is used can be just as important as *how much*.

Load-shifting and shedding programs to reduce peak electric demand are also not new to California. Programs and tariffs to promote DR stretch back several decades, especially among the large investor-owned utilities (IOUs). The earliest forms of DR were well-established in California before 2000. DR at this time took the form of primarily commercial and industrial interruptible tariffs and residential load control programs.

However, the nature and benefits of DR have evolved with changing grid needs and technology. In 2004, DR was put at the top of the loading order in California along with energy efficiency. Throughout the following decade, DR participation steadily grew with technological advancements that allowed for greater near- or real-time visibility, aggregation, and automated response. However, DR programs were "out-of-market" resources and were not integrated into the California ISO energy market.

A main driver of DR growth in the early 2000s was CPUC-directed funding of DR programs aimed to ensure that IOU procurement plans "first meet unmet resource needs through all available […] demand reduction resources that are cost-effective,

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[2] Frank, Richard. 2015. [Celebrating Four Decades of Energy Innovation: The California Energy Commission at 40](https://legal-planet.org/2015/01/30/celebrating-four-decades-of-energy-innovation-the-california-energy-commission-at-40/). LegalPlanet. https://legal-planet.org/2015/01/30/celebrating-four-decades-of-energy-innovation-the-california-energy-commission-at-40/

reliable, and feasible."[3] Because of this statutory cost-effectiveness guideline for ratepayer-funded DR programs, the CPUC implemented protocols to evaluate the cost-effectiveness of DR programs. The CPUC uses these protocols, as well as load impact protocols to quantify DR program savings, to evaluate the reasonableness of the IOUs' DR portfolio budget filings.

IOU DR portfolios contains a mix of programs, including tariffs and participation incentives, emerging technology, automation incentives, and pilot programs to foster innovation and scaling. Over the years, the CPUC has sought to fund DR programs to the maximum extent possible within cost-effectiveness constraints. In recent years, IOU DR programs, particularly in some IOU territories, have faced challenges in reaching cost-effectiveness thresholds.

In 2008, the CPUC initiated a discussion to integrate IOU DR programs into the California ISO energy market to promote DR as a utility-procured resource that is competitively bid into the wholesale market. Through its stakeholder process, the California ISO developed the proxy demand resource (PDR), which bid economically as generation, and reliability demand response resource (RDRR), which is operates as generation under critical grid conditions, market products in 2012. In 2014, the CPUC adopted Decision (D) 14-03-26, which bifurcated, or split, CPUC-regulated DR programs into the following two broad categories that still exist today:[4]

- **Supply-side DR**, which are event-based programs that are integrated within the California ISO energy market either as a proxy demand resource (PDR or economic) or as a reliability demand response resource (RDRR or reliability).
- **Load-modifying DR**, or demand-side DR, which reshapes or reduces the net load curve and consists primarily of time-differentiated rates. Load-modifying DR is not integrated with the California ISO energy market.

The DR bifurcation was fully operationalized for CPUC-jurisdictional DR programs in 2017. After the DR bifurcation, all event-based programs[5] (representing the majority of IOU DR program capacity) were required to participate as supply-side DR and integrated into the wholesale energy market and received capacity value through the

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3 Public Utilities Code Section 454.5(b)(9)(C)(i)

4 "Decision Addressing Foundational Issue of the Bifurcation of Demand Response Programs," accessed March 17, 2023, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K480/89480849.PDF

5 Represents the IOU supply-side programs such as Capacity Bidding Program, Base Interruptible Programs, AC cycling and Smart Thermostat programs, all-source solicitations for new capacity, and DRAM.

resource adequacy (RA) framework. Load-modifying DR after the bifurcation consisted of time-varying rate tariffs and permanent load-shifting programs.[6]

Some IOU DR programs that existed before the bifurcation were discontinued with the implementation of the bifurcation, such as the Aggregator Managed Program (AMP) and Demand Bidding Program (DBP). These programs allowed utilities to procure load supply-side DR from third-party providers. With the bifurcation and the desire to make DR more of a competitively procured economic resource, the CPUC in 2014 established the Demand Response Auction Mechanism (DRAM) which launched in 2016 and has been extended to 2024. DRAM sought to move to a competitive procurement model with greater role of third-party aggregators. In DRAM, DRPs develop aggregations of IOU or CCA customers and competitively bid them as resources into IOU auctions for RA capacity. In addition to the market-integrated IOU DR programs and DRAM, supply-side DR also consists of non-IOU RA contracts involving DR resources procured by community choice aggregators.

Since the operationalization of the DR bifurcation, supply-side DR has comprised a large majority of IOU DR capacity. Figure 1 shows RA allocations received by CPUC-jurisdictional DR programs from 2010 to 2020, including DRAM net qualifying capacity (NQC) allocations, which has been declining in recent years. The potential for increased supply-side DR has been limited by several factors including challenges related to measurement and verification of load impacts, historical underperformance, and customer enrollment of supply-side DR. These factors must be taken into consideration when assessing the scope and scale of reliable supply-side solutions that are appropriate for meeting RA obligations.

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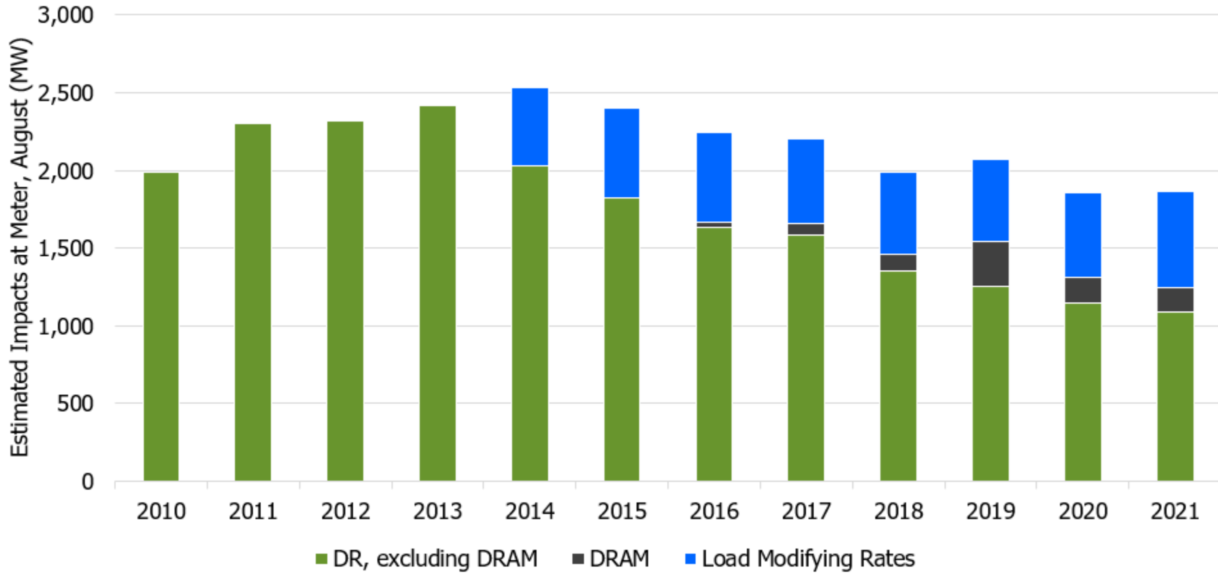
6 "Decision Addressing the Valuation of Load Modifying Demand Response and Demand Response Cost-Effectiveness Proposals," accessed March 17, 2023, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M156/K099/156099197.pdf

Figure 1: CPUC DR Program RA Allocations, 2010–2021



Note: Values are all presented "at the meter", i.e., capacity values do not include transmission and distribution losses nor a planning reserve margin.

Source: CPUC staff[7]

Time-varying rate load flexibility has grown in the years since the bifurcation with the rollout of default time-of-use (TOU) rates for IOU customers. Opportunities exist to grow DR and demand flexibility through innovative dynamic rates paired with automated enabling technology such as smart thermostats to enhance customer response.

The CEC and CPUC are working in tandem to pursue load flexibility from time-varying rates. On the CEC side, the Load Management Standard (LMS) directs utilities to make dynamic rates available to their customers. The Market-Informed Demand Automation Server (MIDAS) provides a centralized rate database that customers, developers, and devices can use to access rate information and respond accordingly. The Flexible Demand Appliance Standards (FDAS) will provide direction to device manufacturers to enable beneficial load flexibility in response to these rates. In 2022 the CPUC adopted a vision for hourly dynamic pricing to enable widespread demand flexibility, including load shifting, called the California Flexible Unified Signal for Energy (CalFUSE). The goal of CalFUSE is to achieve widespread customer adoption of low-cost, advanced flexible demand and distributed energy resource (DER) management solutions via a unified, universally accessible, dynamic economic signal.[8] Achieving this goal requires large-

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7 *2021 Resource Adequacy Report*, accessed March 17, 2023, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2021_ra_report_040523.pdf.

8 *Advanced Strategies for Demand Flexibility Management and Customer DER Compensation*, accessed

scale and cost-effective deployment and adoption of enabling technologies that allow streamlined and automated control of end-use loads and BTM DERs.

The current DR landscape in California consists of several types of programs and rates, each of which was a product of policies intended to promote the effectiveness, value, and impact of DR. Today, there are economic and reliability programs on the supply side, as well as time-varying rates, emergency-focused programs, and policies targeting future widespread adoption of dynamic pricing. In developing a goal to satisfy the requirements of SB 846, the CEC — in consultation with the CPUC and California ISO — closely considered this current landscape and future policy goals to guide the identification of potential areas of growth in the ability of DR to contribute to net peak reductions through load shifting.

Climate Change and Emergency Load Flexibility

Energy reliability in California and nationally is increasingly impacted by highly variable and extreme weather events driven by climate change. California's energy system runs reliably without issue most of the time, and the state has backup assets in place to provide energy during extreme events and avoid outages. The state's greatest energy reliability concerns are driven by a small number of hours during increasingly historic heat events when demand for electricity skyrockets to unprecedented levels and available supply is constrained. If these moments of extreme weather events coincide with other climate-driven extreme events — such as drought or fire — the state's energy system is increasingly at risk of exceeding the amount of demand the grid is capable of meeting.

Because of these conditions, the California electrical grid has experienced great strain in recent years. In 2020, a westwide heat event caused a systemwide electricity shortage of about 500 MW, resulting in rotating outages August 14 and 15. In 2021, a drought-fueled wildfire in Oregon impacted transmission lines that California depends on for reliability, resulting in loss of 3,000 MW of imports to the California Independent System Operator (ISO) territory. In 2022, the state experienced record high temperatures between August 31 and September 9. On September 6, 2022, the California ISO recorded a new record peak load at 52,061 MW,[9] nearly 2,000 MW higher than the previous record, despite significant efforts to reduce load during this peak period.

Since 2020, California energy entities have taken steps to address the potential imbalances between the electrical supply and demand in California, especially as the electric grid transforms to rely on a high penetration of renewables and low-carbon

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March 17, 2023, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/ed-white-paper---advanced-strategies-for-demand-flexibility-management.pdf

9 "California ISO Peak Load History 1998 Through 2022," accessed on March 17, 2023, https://www.caiso.com/documents/californiaisopeakloadhistory.pdf.

resources. The CEC, CPUC, California ISO, and Governor's Office substantially increased coordination and developed the Tracking Energy Development Task Force with the Governor's Office of Business and Economic Development to track new clean energy projects under development to help overcome barriers to completion. The CEC also revised the demand forecast to better account for climate change.

Between November 2019 and June 2021, the CPUC mandated an unprecedented amount of procurement, which will bring 14,800 MW of new resources on-line by 2026. In response to Assembly Bill (AB) 205 (Committee on Budget, Chapter 61, Statutes of 2022), the CEC and Department of Water Resources (DWR) have begun building out the Strategic Reliability Reserve (SRR), a portfolio of supply- and demand-side generation resources that is available under extreme and emergency conditions. The SRR, though in development during that summer, was able to provide support during the extreme heat event the state experienced between August 31 and September 9, including securing imports, additional backup generation, and load reduction that helped avert outages on September 6, when the California ISO recorded the highest demand ever in its territory.

Even with these significant resource additions and strategic reserve resources, there exists uncertainty in the supply-and-demand balance in the next five years due to weather variability and clean energy project development delays. Load shifting in all forms must play a central role in both standard resource adequacy planning and in response to emergency conditions.

CHAPTER 3: Statewide Load-Shift Goal

To determine an appropriate goal as required by SB 846, CEC staff conducted an analysis to estimate the statewide achievable potential for load flexibility. The load-shift goal analysis was performed in coordination with CPUC Energy Division and California ISO staff, who provided input and recommendations on definitions, method, sources, and assumptions for the analysis. The analysis was based primarily on data from existing CEC forecast products, such as those developed for the *2021 IEPR* and *2022 IEPR Update*, and on inputs from the California Demand Response Potential Study, Phase 4, authored by LBNL and sponsored by the CPUC (LBNL Potential Study),[10] as required by SB 846.

Goal Development

Based on the language in SB 846 that requires the load-shift goal to reduce net peak electrical demand, CEC staff defined the load-shift goal based on the metric of total **capacity** during net peak hours. LBNL characterizes the net peak DR resource (referred to as "shed" in the LBNL report) in units of capacity (for example, MW). Existing DR programs in California are already primarily valued based on capacity, though supply-side DR resources also earn energy revenue in the California ISO wholesale markets.

CEC staff recognizes the value of considering the timing not only of load reductions, but of load increases that result from shifting. For example, shifting load away from net peak hours toward periods of high renewable energy curtailment is more desirable than shifting toward periods with high GHG emissions intensity. However, for this first iteration of a load-shift goal, CEC staff focused on setting a goal using the metric of capacity reduction during net peak hours. Methods for quantifying the benefits and costs from shifting load based on drivers other than net peak will be developed and refined in future CEC efforts.

In addition to the goal metric and types of DR resources to be considered, CEC staff defined the following key parameters for the load-shift goal scope and analysis of statewide load-shift potential:

- **Goal time frame: 2030**
  For this first iteration of the load-shift goal, CEC staff suggests setting the goal with 2030 as the target year. SB 846 states that CEC should consider the LBNL "report on the Shift Resource through 2030" when developing the goal. In addition, a goal set for 2030 would align with the elements of SB 846 related to the potential extension of the operation of the Diablo Canyon Nuclear Power Plant to at least 2030. However, the analysis conducted for the goal setting can be extended to 2050 in conjunction with

10 Gerke, Brian F., et al. 2022. *The California Demand Response Potential Study, Phase 4: DRAFT Report on Shed and Shift Resources Through 2050*. Lawrence Berkeley National Laboratory, https://emp.lbl.gov/publications/overview-phase-4-california-demand.

other CEC forecasts and the LBNL Potential Study. Thus, updates to the goal in future IEPR cycles could consider additional target years beyond 2030.

- **Goal specificity: Statewide**
  The load-shift goal is defined at the statewide level. The analysis of achievable load-shift potential, as further described below, considers the potential at levels more granular than statewide, such as by sector, end use, and DR program type. Conducting the analysis at this level would increase robustness, provide insight into subcategories of DR that could be focus areas for growing DR, and guide policy recommendations. However, CEC does not currently recommend subgoals for specific program types, sectors, or jurisdictions.
- **Net peak period: Top 100 net system load hours**
  The net peak period is defined as the top 100 net system load hours in a year, and correspondingly the net peak demand is defined as the average hourly demand over the net peak period. The LBNL Potential Study also uses the top 100 net load hours to define the system peak period. The net system load in each hour is defined as gross system load minus impacts from BTM solar generation, utility-scale solar generation, and utility-scale wind generation.

Method

At a high-level, CEC staff analyzed the statewide load-shift potential using the following methodological steps:

1. Develop **hourly gross load** estimates.
2. Develop **hourly system net load** estimates and identify **net peak period.**
3. Develop **potential DR impacts** for net peak reduction within two categories: **dynamic pricing** and **event-based DR.**

First, **hourly gross load** estimates were calculated using a combination of annual statewide electricity consumption forecasts from the *2021 IEPR* and *2022 IEPR Update* and normalized load shapes, or estimates of electricity use by hour for different uses, from the Phase 4 LBNL Potential Study. The LBNL Potential Study team provided CEC with load shape outputs from the LBNL-Load model, which uses California IOU AMI data. The combination of annual consumption forecasts from IEPR and hourly load shapes allowed CEC staff to estimate hourly load in 2030 at the level of forecast zone, sector, building type, end use, and size[11] category. The hourly gross load estimates include consumption from building end uses and electric vehicle (EV) charging. Hourly EV charging load was calculated using the charging consumption and load shape forecast from the Additional Achievable Transportation Electrification (AATE) component of the *2022 IEPR Update* corresponding to about 7.1 million vehicles in 2030.

11 *Size* refers to the maximum demand threshold values for C&I customers and is aligned with the size definitions for C&I customers in the LBNL Phase 4 potential study. C&I customers are classified into small, medium, and large based on maximum demand threshold values.

Hourly system net load was estimated first by adding the hourly gross load estimates at the sector, building type, end use, and size level up to a single total system load value. Then, this gross hourly load was adjusted by subtracting estimates of statewide hourly variable renewable generation from BTM solar, utility-scale solar, and utility-scale wind. For BTM solar, forecasts of future installed capacity were sourced from the IEPR self-generation data, while hourly load shapes were sourced from the Phase 4 LBNL Potential Study. Utility-scale wind and solar shapes are an average of 8 years of CAISO wide production for each resource type. After calculating the hourly system net load profile, the top 100 net load hours were identified and defined as the **net peak period**. Average gross load during the net peak period by segment and end use forms the baseline load for DR impact estimation.

After identifying the net peak period and gross baseline peak load, the analysis considered **potential DR impacts** within two categories: **dynamic pricing** and **event-based DR**.

The **dynamic pricing** category captures the potential from future electricity tariffs in which prices vary hourly or subhourly based on day-ahead or real-time grid conditions, as presented in CPUC's CalFUSE framework described in Chapter 2. The inputs and assumptions for dynamic pricing were based on analytical work conducted by authors from the Brattle Group[12] and discussions with CPUC staff.

The **event-based DR** category captures the potential from dispatchable, as well as load-modifying, programs. This category includes all existing supply-side DR programs but could also include event-based dispatchable programs on the demand side (not market-integrated), which do not exist but could be considered in the future.[13] The event-based DR category also includes estimated potential from exporting BTM resources like EV vehicle-to-grid (V2G) and BTM battery export. This type of potential could be realized through new or modified program designs that support more permanent or regular load shifting than current supply-side event-based DR rules permit. For this analysis, event-based DR includes load-modifying, supply-side, and emergency programs. However, the model does not distinguish between these program types. Deciding how to direct event-based interventions into load-modifying, supply-side, and emergency resources based on resource type, customer class, or end-use type or a combination is a critical policy question beyond the scope of this report.

To calculate impacts for event-based DR, CEC staff used inputs and assumptions from the LBNL Phase 4 DR Potential Study. Key inputs from the LBNL Potential Study included characterization of technological options to control end-use load, including projected saturation, performance, and unit impacts. CEC staff also obtained and applied the aggregate participation fractions by customer segment and DR technology associated with the LBNL Potential Study DR-Path model. The DR-Path model builds a cost-optimized DR supply curve with estimated achievable potential at varying levelized capacity procurement costs. The load-shift goal analysis used the LBNL Potential Study enrollment fractions associated with a

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12 Faruqui, Ahmad, et al. 2017. "*Arcturus 2.0:* A Meta-Analysis of Time-Varying Rates for Electricity." *The Electricity Journal*.

13 Emergency programs like ELRP and DSGS are event-based demand-side programs, but they are expected to expire before 2030 and would not contribute toward the load-shift goal.

levelized procurement cost equal to forecasted avoided costs in 2030 to estimate the proportion of customers that could enroll in event-based DR programs in 2030. This analysis produced an estimate of load flexibility that is economic and theoretically achievable, but does not incorporate market, behavioral, regulatory, or other barriers that may prevent this potential from being realized.

The analyses calculated total impacts from hourly dynamic pricing and event-based DR using a hierarchy in which the impacts from one category are applied before another. The hierarchy was applied to avoid double counting and overestimating impacts from load that may be participating in dynamic pricing and event-based DR. In most cases, the hierarchy placed dynamic pricing first, meaning calculated impacts from dynamic pricing were subtracted from the load that would remain available to participate in event-based DR. Dynamic pricing was placed first in the hierarchy in most cases because as a tariff-based shape DR resource, it represents a more constant alteration of demand, while event-based DR is targeted to a relatively small number of event hours.

Staff emphasizes that the hourly load shapes from the LBNL Potential Study incorporate the impacts from TOU rates. Thus, the gross baseline load for calculation of DR impacts using Phase 4 potential study shapes includes embedded TOU impacts. Consequently, the load-shift goal potential estimates using the approach described above includes only dynamic pricing and event-based DR incremental to TOU impacts. CEC staff separately obtained cumulative TOU impacts from the CPUC for consideration under load-shift goal, which is described in later sections.

Scenario Development

Using the method described above, CEC staff developed a range of scenarios with varying key input assumptions to calculate estimates of statewide achievable load-shift potential in 2030. The scenario analysis provides a range of forecasted results upon which to base a goal and provides insight into the sensitivity of results to certain inputs. Table 1 shows the parameters that CEC staff varied in the scenario analysis.

Table 1: Load-Shift Analysis Scenario Parameters

Scenario Parameter	Value 1	Value 2
Baseline Demand Variations	**<u>Reference Demand</u>:** 2022 Planning Scenario (Mid Baseline Demand, AAEE 3, AAFS 3)	**<u>High Electrification</u>:** 2022 Local Reliability Scenario (Mid Baseline Demand, AAEE 2, AAFS 4 plus additional fuel substitution modeling CARB's SIP adopted in 2022)
Enrollment Assumptions	**<u>Reference Enrollment (Dynamic Pricing)</u>:** 25% overall enrollment in dynamic pricing with 75% of enrolled customers providing technology-enabled enhanced response to dynamic rates; represents an opt-in type of offer among "early adopters" with a high percentage of enrolled customers with enabling technology	**<u>High Enrollment (Dynamic Pricing)</u>:** 80% overall enrollment in dynamic pricing with 50% of enrolled customers providing technology-enabled enhanced response and the remaining 50% providing response without enabling technology; represents an opt-out type of offer for dynamic rates with relatively lower percentage of customers with enabling technology
	<u>Reference Enrollment (Event-based DR)</u>: LBNL Phase 4 DR Potential Study aggregate achievable potential enrollment fractions by sector, segment, and end-use and enabling technology combinations for 2030	**<u>High Enrollment (Event-based DR)</u>:** 20% higher enrollment in event-based DR than the Reference case
LBNL Potential Study Load Shapes	**1-in-2 weather year**	**1-in-10 weather year**
DR Hierarchy	**Dynamic pricing preferred** before event-based DR	**Event-based DR preferred** before dynamic pricing

Source: CEC staff

The parameters in Table 1 were combined to develop six scenarios (Table 2) to assess the variations in impact values with variations in the input parameters.

Results

Table 2 shows the resulting DR potential estimates from the scenario runs for achievable potential in 2030 from dynamic pricing and event-based DR. These values are estimated at the meter.[14]

Table 2: Load-Shift Scenario Potential Results, 2030

Scenarios	Dynamic Pricing Potential	Event-Based DR Potential[15]	Total Potential
Scenario 1: Reference Demand, Reference Enrollment, 1-in-2 Weather, Dynamic pricing preferred	1,300 MW	3,800 MW	5,100 MW
Scenario 2: Reference Demand, High Enrollment, 1-in-2 Weather, Dynamic pricing preferred	3,800 MW	4,300 MW	8,100 MW
Scenario 3: High Electrification, Reference Enrollment, 1-in-2 Weather, Dynamic pricing preferred	1,400 MW	3,800 MW	5,200 MW
Scenario 4: High Electrification, High Enrollment, 1-in-2 Weather, Dynamic pricing preferred	4,100 MW	4,300 MW	8,400 MW
Scenario 5: Reference Demand, Reference Enrollment, 1-in-2 Weather, Event-based DR preferred	1,200 MW	3,900 MW	5,100 MW
Scenario 6: Reference Demand, Reference Enrollment, 1-in-10 Weather, Dynamic pricing preferred	1,400 MW	3,800 MW	5,200 MW

Source: CEC staff, CPUC staff

These results suggest that the total estimated potential ranges from about 5,000 MW to more than 8,000 MW in Scenario 4 under the most optimistic assumptions. The is analysis particularly sensitive to enrollment projections. Scenarios using a reference enrollment level based on historical customer participation rates cluster around 5,000 MW, while those using more aggressive enrollment assumptions reflecting defaulting customers onto dynamic rates cluster around 8,000 MW. At this time, no such opt-out arrangements for demand flexibility and/or demand response exist in California, so scenarios utilizing high enrollment projections

14 Estimates at the meter do not include gross-up for transmission and distribution losses nor planning reserve margin.

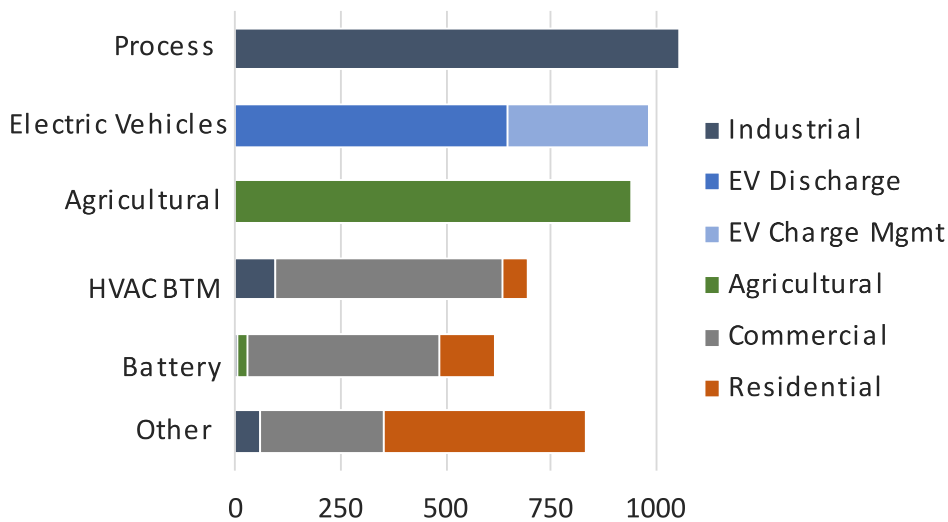
15 Includes potential from V2G and BTM battery export.

should be regarded as aspirational but not necessarily achievable by 2030 without a significant shift in policy or rates of customer enrollment in dynamic rates.

Load Flexibility Potential by End Use and Sector

This section details the load flexibility potential by end use and sector in the reference scenario (1). Collectively, industrial processes, EV-related interventions (vehicle-to-grid, vehicle-to-building, and managed charging), and agricultural load flexibility (not including batteries) make up 58 percent of the estimated potential, as shown in Figure 2. BTM battery storage and HVAC loads make up another 26 percent, bringing the total potential of these five categories to 84 percent of the total load flexibility resource potential.

Figure 2: Load Flexibility Potential by End Use and Sector



Source: CEC staff

Statewide Load-Shift Goal

Based on the results of the scenario runs in Table 2, CEC staff proposes a total statewide load flexibility goal of 7,000 MW as summarized in Table 3. CEC staff views the goal as aspirational but achievable with robust policy support.

Table 3: Proposed Load-Shift Goal

2022 Load Shift Estimate	2030 Load-Shift Goal	2030 Goal (Incremental)
3,100–3,600 MW	7,000 MW	3,400–3,900 MW

Source: CEC staff

The load-shift goal is set at the statewide level and does not intend to set subgoals for specific program types, sectors, or jurisdictions. However, Table 4 illustrates that the majority of expected load flexibility growth will come from load-modifying flexibility. The table includes estimates of existing capacity in summer 2022 for comparison. Collectively, these resources have the potential to reduce or meet capacity needs by 3,000 MW. All values are estimated at the meter.

Table 4: Proposed Load-Shift Goal by Intervention

Category	Intervention	2022 Estimate	2030 Goal
Load-Modifying (LM)	TOU Rates	620–1,000 MW	3,000 MW
	Dynamic Pricing	30 MW	
	LM Programs	7 MW	
Resource Planning and Procurement	Economic Supply-side DR	670–825 MW	4,000 MW
	Reliability Supply-Side DR	740 MW	
	POU DR Programs (Non-ISO)	210 MW	
Incremental and Emergency (I&E)	I&E Programs	800 MW	
	Emergency Back-Up Generators*	375 MW*	
Total (nearest 100)		**3,100–3,600 MW**	**7,000 MW**

***Includes backup generators with significant local emissions, which are part of the current emergency framework but not included in the 2022 load flexibility total. Only zero- and low-emission behind-the-meter generation consistent with AB 205 (Committee on Budget, Chapter 61, Statutes of 2022) is included in the load-shift goal.**

Source: CEC staff, CPUC staff

Load-modifying flexibility, including TOU and hourly dynamic pricing and load-modifying programs, are expected to grow. TOU rates will continue to send durable price signals to shift load off-peak and may be combined with supply-side DR and load-modifying programs. As more electric loads are connected to the grid, such as EV chargers and water heaters, the load impacts of TOU rates are expected to grow. At the same time, dynamic pricing supporting infrastructure such as the CEC's Market-Informed Demand Automation Server and Flexible Demand Appliance Standards will be made broadly available, enabling customers to save on electric bills and encouraging them to opt into these dynamic rates. Incentives for load-shifting equipment such as storage can help customers on dynamic rates maximizing savings and lower bill risk. Load-modifying programs are nascent but poised to grow as CEC staff determines the processes and requirements for such programs to explicitly reduce peak load forecasts.

Economic supply-side DR may also contribute significant load flexibility. Economic DR has struggled in recent years with issues related to enrolling customers, capacity approval processes, event measurement, and performance. In January 2022, the CEC submitted to the CPUC a proposal for capacity valuation and measurement, including performance-based incentives that CEC staff believes can address many of these historical challenges, reverse the recent trend in declining economic DR capacity, and show growth by 2030. More work is required to refine and implement these recommendations. In contrast, reliability DR is not expected to grow significantly from 2022 to 2030 because the programs are mature.

Emergency program designs are likely to change over the next 5 to 10 years, but whether the overall capacity contribution of these resources grows will be determined by a series of future policy decisions. Rather, emergency programs may serve as on-ramps to existing load flexibility programs and serve as pilot programs, helping grow demand-side and RA resources. While programs such as DSGS are expected to expire by 2030, initiatives developed through funding from the Clean Energy Reliability Investment Plan, if appropriated, could expand load flexibility.

Even as the state pursues new and aggressive strategies to advance load flexibility, significant barriers to achieving the proposed 7,000 MW goal remain. This figure most closely resembles the high-end parameters assumed in the scenario analysis, and in particular the highest enrollment projections. For example, 80 percent overall enrollment in dynamic pricing is indicative of an opt-out rate design, as opt-in programs have not historically seen such high participation rates. The CalFUSE dynamic rates staff proposal in the CPUC's Load Flexibility proceeding is currently crafted as an opt-in framework, in part due to statutory restrictions on real-time pricing for residential default rates.[16] Thus, to achieve the goal a paradigm shift in customer participation levels or significant growth in other load-modifying programs will be needed.

In addition, dramatic cost reduction of technologies to enable DR and/or new deployment strategies will need to come to fruition to achieve the levels of DR-enablement technology penetration assumed. Cost-effectiveness constraints aimed at maintaining just and reasonable rates will be a factor in determining the extent to which IOU ratepayer funds can be used to drive this transformation. Nonratepayer funding sources will be essential to fill the gap. For all these reasons, the goal should be regarded as aspirational but achievable with significant technological, market, regulatory, and possibly statutory changes.

The state should continue to evaluate the cost savings potential of load flexibility. The statewide load-shift goal is based on economic potential. Further analysis is needed to determine the cost-effectiveness of specific load flexibility resources and programs. The proposed goal is not intended to suggest that the state should pursue these targets without the evaluation of the cost-effectiveness of specific resources or programs that would contribute to the goal.

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[16] Public Utilities Code Sections 745(a) and (b).

CHAPTER 4: Policy Recommendations to Increase Load Shifting

The following chapter lays out a framework for the future of load shifting in California, followed by specific policy recommendations to achieve this vision. In California's clean energy future, businesses, households, and other customers can save or even earn money for actions that contribute to a clean, reliable, and affordable electric grid. Interested customers can choose among four approaches to load shifting: dynamic and other time-varying rates, supply-side demand response (DR), load-modifying resource programs (or similar programs for POUs), and incremental programs. In some cases, these approaches may be combined.

The gold standard for realizing load flexibility opportunities is dynamic rate design, where the price of electricity changes at least hourly to reflect the carbon intensity of the grid and the need to conserve in support of local and system reliability. Under this system, customers who install technologies like smart thermostats, battery storage, or other web-connected appliances are rewarded by buying energy when it is least expensive — and cleanest — and exporting energy to the grid when the need is greatest. These technologies are enabled by California's investments to allow devices to receive these price signals and respond in ways that are optimal to the customer and the grid, with limited action required by the customer. As more customers move into dynamic rates, their load flexibility benefits all customers by flattening the demand profile and allowing the grid to operate more efficiently throughout the year and with fewer power plants needed to meet the peak net demand.

Virtually all other customers still face incentives for daily load shifting under time-of-use (TOU) rates, which encourage customers to avoid using major electric appliances like dishwashers and clothes dryers during hours when the grid is likely to be under greatest strain. These TOU rates shift load away from the net peak — rather than the overall peak demand — to align with California's patterns of electric supply and demand. Accordingly, customers are encouraged to migrate to rates that encourage load shifting through incentives over those that do not, such as those that include charges for peak demand regardless of the time of day or rates that increase with total consumption regardless of the time of day.

In this future, supply-side DR will allow these customers to adapt their electric consumption in support of the grid. On days with high grid needs, these customers will be able to earn money by reducing their electric demand. While some of these actions may be taken proactively by customers, most will occur automatically based on demand response events that are communicated directly to devices.

Providers of supply-side DR participate in a streamlined, competitive market to deliver critical load reductions at lowest cost. DR providers assess their own capacity capabilities based on past data and future resource growth projections. A penalty system imposes discipline to ensure these capacity values are achievable and providers deliver on their commitments.

For supply-side DR to succeed in California's energy markets, reliable and transparent measurement of load impacts and demonstrated capacity is critical. These measures ensure that buyers and sellers of DR energy and capacity products, as well as policy makers, can all agree and understand whether commitments were met. Accordingly, CEC will offer measurement and verification of load impacts using comparison groups derived from its interval meter database for resources that existing baselines do not model accurately.

Load-modifying resource programs, a nascent resource type, may also grow significantly in California's flexible load portfolio. These programs, such as a recent distributed BTM battery storage pilot run by San Francisco Bay Area CCAs, procure resources to reduce load predictably from the perspective of the grid operator and host distribution utility. While these resources are not considered to *serve* load in the same sense of supply-side DR, they are procured and deployed to reduce the peak load forecast of an LSE. Accordingly, load-modifying resource programs are valued for capacity by reducing the RA requirement of an LSE.

Over the next few years, emergency load shifting programs will test innovative, alternative pathways for customers to participate in demand response. The CPUC's ELRP and CEC's DSGS will continue to compensate customers for incremental reductions to existing DR commitments. DSGS and the DEBA programs will continue to experiment with program designs to compensate customers for peak net demand reductions and energy exports that *prevent* emergency conditions rather than simply respond to them.

Over time, the future of these emergency load-shifting programs will be regularly reassessed. Emergency programs will either be maintained as resources of last resort, adapted into core planning and reliability programs, or discontinued if they do not deliver the expected benefits. To the extent possible, these programs will serve as an on-ramp to move customers into existing programs and resources. Where existing policies and programs do not exist, CEC will evaluate the impact and cost-effectiveness of the program designs, and the most successful can be adapted to more durable policies and programs.

The following recommendations support this vision for load shifting and demand flexibility in California.

Load-Modifying

1. **Support hourly dynamic pricing frameworks.** The CPUC should direct the IOUs to implement hourly pricing options for as many customers as possible, consistent with the CEC Load Management Standards (LMS) and the CPUC CalFUSE proposal in the Load Flexibility proceeding (R. 22-07-005). For residential and small commercial customers, allow customers to opt in. For medium-to-large commercial and industrial customers, pilot as an opt-in tariff option but consider switching to a default tariff option and eventually a required tariff.
2. **Encourage rate and program designs that offer incentives for load shifting.** The CEC should support a transition toward other nonhourly time-varying rates and customer programs that account for grid conditions and match customer demand with electricity supply and grid reliability under the LMS. As these new rates and programs

become available, the CEC should explore using the LMS to transition away from rate designs that discourage load shifting, such as noncoincident demand charges and tiered rates that increase with consumption regardless of time.

3. **Provide incentives for load-shifting technologies paired with dynamic rates.** The California Legislature should establish and fund a statewide program to provide rebates for technologies with significant load shifting capabilities such as battery storage, heat pump water heaters, thermal storage, and smart thermostats to customers that opt into rate designs and that encourage load shifting, consistent with the LMS. Ensure technologies included in the program can deliver load flexibility and reliably shift load in response to price signals from the MIDAS or similar platform.
4. **Deploy information infrastructure to support load shifting.** The CEC-developed Market-Informed Demand Automation Server (MIDAS) should provide a central source for digital rate connectivity to expand demand-side response into new sectors, and communicate hourly rates, marginal GHG, and grid status to consumers and their flexible devices. The CEC should support interoperability standards for devices to receive and respond to information provided by MIDAS or another source of electricity price and grid information.
5. **Adopt flexible demand appliance standards to enable appliance operations to be shifted, scheduled, or curtailed.** Under the authority of Senate Bill 49 (Skinner, Chapter 697, Statues of 2019), the CEC should adopt flexible demand appliance standards (FDAS) establishing requirements for testing, labeling, cybersecurity, and flexible demand capabilities for a wide range of major electric appliances and devices. The standards will apply to new appliances sold or offered for sale, rented, imported, distributed, or leased for use in California. The first FDAS for pool controls are in a formal rulemaking and will be followed by electric water heaters. Because heating, ventilation, and air conditioning (HVAC) is a primary driver of annual peak and net peak conditions, the CEC should prioritize FDAS for thermostats.
6. **Complete deployment of metering infrastructure to support load shifting.** All California utilities, including publicly owned utilities, should analyze the feasibility of advanced metering infrastructure deployment to all customers. Using this analysis, utilities should then move toward developing plans for complete AMI deployment, where feasible.
7. **Reduce transaction costs associated with load flexibility program and market development.** Participation in load flexibility programs and services should be as straightforward and effortless as possible, and barriers for developing load flexibility programs and services should be minimized. With that goal, California utilities and community choice aggregators (CCAs) should develop and maintain a Rate Identification Number (RIN) Access Tool to support third-party services' access to rate information for their customers, as specified in the LMS. The utilities and CCAs should establish data exchange protocols to promote timely and seamless load-flexibility transactions.

8. **Promote load-modifying pilot program development, measurement, and compensation protocols.** The CEC should develop protocols to support load-modifying programs that provide regular, consistent load reductions that can provide value through reduced RA requirements. Payments for program performance should reflect the full value of load flexibility, including reducing RA requirements, energy costs, and greenhouse gas emissions. Data needed to measure and verify program impacts should be collected, validated, and applied to determine these values.

Resource Planning and Procurement

9. **Adopt an incentive-based capacity valuation approach for supply-side DR**. Consistent with the recommendations from CEC *Qualifying Capacity of Supply-Side Demand Response Working Group Final Report*, the CPUC should adopt a planning approach for DR that allows providers to develop future estimates of resource capacity, using a penalty mechanism to ensure reasonable capacity value development and delivery of capacity commitments. The CEC should continue to collaborate with the CPUC and contribute to this effort.
10. **Explore a centralized, competitive DR marketplace to consolidate and standardize DR procurement.** Drawing on experience and learnings from competitive programs such as the CPUC's DR Auction Mechanism (DRAM) and Capacity Bidding Program (CBP) and other POU-administered programs, CEC should explore opportunities to consolidate and standardize the DR marketplace in California to support DR growth. Paired with the incentive-based capacity valuation recommended above, such a centralized market holds significant potential to deliver reliable, competitive DR capacity.
11. **Include an adder on wholesale market revenue for supply-side DR.** The California Legislature should allocate funding to the Clean Energy Reliability Investment Program or a nonratepayer-funded dedicated program to provide an incentive for DR to participate more actively in energy markets with a supplement to energy market revenue. The Legislature should direct the CEC to implement this program. The energy revenue adder would be paid to participating DR providers as a percentage of wholesale market revenue or value. This approach encourages not only a higher quantity of load reductions, but the highest value load reductions. Unlike renewable energy, which has benefitted from the Renewables Portfolio Standard policy, DR has yet to receive an explicit public or ratepayer subsidy to reflect the GHG emissions reductions of DR. An energy market revenue adder would shift the overall balance of DR revenue from capacity to energy so that DR providers would compete to be dispatched more frequently in the market.
12. **Reform availability rules and resource requirements for DR resources participating in RA.** The CPUC and California ISO should ensure that DR receiving RA capacity value can be available if critical or emergency conditions arise. For example, CEC supports the California ISO Department of Market Monitoring's recommendation to require economic DR (specifically PDR) "to be available in the residual unit commitment

… process."[17] CEC also supports the CPUC Energy Division proposal to "consider establishing a bid cap for RA-eligible [PDRs] bidding into the California [ISO] wholesale energy market that is below the price trigger for [RDRRs]."[18] The CPUC should consider additional requirements for RA DR, such as bid caps, minimum eligibility criteria, or capacity reductions for resources with significant start-up times, commitment costs, or ramp rate limitations.

13. **Conduct an evaluation, measurement, and verification study of supply-side DR load impacts.** The CEC, in partnership with the California ISO, should evaluate performance of supply-side and other event-based DR in recent years. The CEC interval meter database can be leveraged to allow measurement of these load impacts using nonparticipant comparison group baselines and other advanced methods, where appropriate. The CEC should compare these results with performance derived from California ISO settlement baselines to assess the relative accuracy of these methods and compare performance across DR providers, programs, and resource types. The CEC should make recommendations regarding the accuracy and appropriateness of different baselines for different customer groups. Based on the results, the CEC may consider developing and maintaining open-source and open-access software, allowing regulators and service providers to measure and verify load impacts using recommended approaches and baselines.
14. **Explore modifications to DR participation pathways to support BTM storage.** The CPUC and California ISO should coordinate to update existing rules and requirements for DR market participation models to count exported energy from BTM storage resources at individual customer sites. These changes should maintain compatibility and consistency with existing deliverability requirements and the Rule 21 interconnection framework.

Incremental and Emergency

15. **Pilot approaches compensating DR providers for incremental capacity delivered under extreme heat or other critical conditions.** The QC of weather-sensitive DR resources is derived from performance under typical peak temperature conditions. Under a warming and changing climate, extreme temperatures are becoming more common. When such extremes occur, such weather-sensitive resources may have additional capacity relative to these typical peak conditions, but current incentives provide little financial incentive to deliver incremental capacity above that commitment. The CEC should pilot a DSGS participation pathway to fund incremental DR capacity from nonratepayer funding sources.

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17 Department of Market Monitoring. *Demand response issues and performance 2022*. California Independent System Operator. 2023. http://www.caiso.com/Documents/Demand-Response-Issues-and-Performance-2022-Report-Feb14-2023.pdf.

18 Energy Division. *Appendix A: Energy Division Proposal for Proceeding R.21-10-002*. California Public Utilities Commission. 2023. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M501/K407/501407493.PDF.

16. **Pilot a pathway for behind-the-meter energy storage to support decarbonization and reliability of the electric grid in emergency and incremental programs.** BTM storage is a distinct resource type from DR. The CEC should pilot DSGS and DEBA program designs specific to BTM storage that reflects its characteristics and capabilities, such as the ability to export energy. Offer incentives for storage behavior in support of policy goals, including decarbonization and system reliability.
17. **Pilot short-duration load-shifting resources in emergency and incremental load flexibility programs.** Some load flexibility resources, such as those with less than four hours of continuous capacity, may nonetheless provide reliability benefits to California under peak and emergency conditions. The CEC should pilot and evaluate the impact of these resources in programs like the DSGS and DEBA programs in the state reliability reserve to help determine whether they should have a permanent role in California's demand-side, RA, or emergency-only planning paradigms.
18. **Periodically reassess the role of emergency and incremental resources in demand-side, RA, and emergency planning processes.** The CEC, CPUC, and California ISO should assess whether emergency program designs, such as those under ELRP, DSGS, and DEBA, best fit under the core demand-side or RA planning frameworks and adapt them as appropriate. The agencies and the ISO should also assess whether emergency program designs are cost-effectively delivering the intended benefits and retire those that are not.

Issues to Watch

Other critical issues related to load shifting and demand response are in development. This report makes no recommendations on these topics, but they are flagged for the importance of these topics to load shifting in California.

A. **Improving the availability of reliability DR resources.** CPUC Energy Division staff has proposed that RDRRs either be removed from the RA supply stack and considered strictly emergency-only resource, or to maintain RA status and require RDRRs to available for dispatch at or before an Energy Emergency Alert (EEA) 1 so these resources can be used to avoid emergency conditions.[19] The California ISO has expressed support for the idea that for a DR resource "to qualify as [RA], [RDRR] should be available for dispatch at least upon a declaration of an [Energy Emergency Alert (EEA)] Watch," as opposed to at an EEA 1.[20] CEC supports the notion that RA

19 Energy Division. *Appendix A: Energy Division Proposal for Proceeding R.21-10-002*. California Public Utilities Commission. 2023. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M501/K407/501407493.PDF.

20 Comments of the California Independent System Operator Corporation on Resource Adequacy Phase 3 Workshop and Proposals. California Independent System Operator. 2023. http://www.caiso.com/Documents/Feb24-2023-Comments-Workshop-AllProposals-ImplementationTrackPhase3-ResourceAdequacyProgram-R21-10-002.pdf.

resources should be required to be available in nonemergency conditions to avoid emergency conditions.

B. **Ensuring low-friction third-party DR enrollment.** Third-party DR providers have long cited customer attrition through the "click-through" process of customer meter data sharing through the IOU website. Ongoing CPUC proceeding A.18-11-015 is intended to address this issue and make meter data sharing with third-party service providers as easy and seamless as possible. The outcome of this effort may have a significant impact on the ability of third-party supply-side DR to thrive in California.

APPENDIX A: Acronyms and Abbreviations

Term and Acronym (if applicable)	Definition
Additional Achievable Transportation Electrification (AATE)	A scenario framework for electricity system planning used in the California Electricity Demand Forecast that allows for transportation electricity demand above the baseline transportation forecast that captures existing and upcoming policies and programs that are reasonably expected to occur.
Behind-the-meter (BTM)	Encompasses energy resources that are located on the customer side of a utility electricity or gas meter. This includes equipment such as rooftop solar systems and on-site batteries.
California Energy Commission (CEC)	California's primary energy policy and planning agency.
California Flexible Unified Signal for Energy (CALFUSE)	A comprehensive policy roadmap, the centerpiece of which is a unified, universally accessible, dynamic, economic retail electricity price signal. The roadmap consists of a three-pillar structure addressing 1) the presentation of electricity prices to customers and smart devices, 2) electricity rate reform, and 3) customer options to optimize energy consumption and generation.
California Independent System Operator (California ISO)	Independent organization that maintains electricity reliability on the majority of California's electrical grid and operates a wholesale energy market.
California Public Utilities Commission (CPUC)	State agency responsible for regulating services and utilities, protecting consumers, safeguarding the environment, and assuring access to safe

	and reliable utility infrastructure and services.
Capacity	The system’s ability to supply the electricity demand for a given time interval. This amount of power is typically measured in megawatts (MW) or other units of energy over time and helps entities project just how large of an electricity load the system in question can serve.
Climate change	Climate change refers to a change in the state of the climate that can be identified (for example, by using statistical tests) by changes in the mean and/or the variability of those properties and that persists for an extended period, typically decades or longer. Climate change may be due to natural internal processes or external forces such as modulations of the solar cycles, volcanic eruptions, and persistent anthropogenic changes in the composition of the atmosphere or in land use. Anthropogenic climate change is defined by the human impact on Earth's climate, while natural climate change is the natural climate cycles that have been and continue to occur throughout Earth's history. Anthropogenic (human-induced) climate change is directly linked to the amount of fossil fuels burned, aerosol releases, and land alteration from agriculture and deforestation.
Community choice aggregator (CCA)	Community choice aggregators lets local jurisdictions aggregate, or combine, their electricity load to purchase power on behalf of their residents. In California, CCAs are legally defined by state law as electric service providers and work together with the region’s existing utility, which continues to provide customer services.

Demand response (DR)	Changes in electric usage by demand-side resources from normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.
Demand Side Grid Support (DSGS)	A program that offers incentives to electric customers that provide load reduction and backup generation to support the state's electrical grid during extreme events, reducing the risk of blackouts.
Distributed energy resource (DER)	Electricity-producing or controllable loads that are directly connected to a local distribution system. It includes demand response, rooftop solar, energy efficiency, and battery storage.
Electric vehicle (EV)	Vehicle powered by electricity.
Flexible Demand Appliance Standards Rulemaking (FDAS)	A rulemaking where flexible demand appliance standards will promote technologies to schedule, shift, and curtail appliance operations to support grid reliability, benefit consumers, and reduce greenhouse gas emissions associated with electricity generation.
Greenhouse gas (GHG)	Gases in Earth's atmosphere that trap heat.
Integrated Energy Policy Report (IEPR)	CEC biennial report on major energy trends and issues facing California's electricity, gas, and transportation fuel sectors. It contains policy recommendations to address issues.
Investor-owned utility (IOU)	Privately owned electricity and gas providers.
Load	An end-use device or an end-use customer that consumes power. Load should not be confused with demand,

	which is the measure of power that a load receives or requires.
Load flexibility	A strategy of enabling automation of building and appliance loads to continuously adapt the timing of electricity use in response to frequent and ongoing signals. Like energy efficiency, load flexibility is intended to be invisible: acting to reduce GHG emissions without reducing the quality of customer service.
Load management	Adjustments in utility rate structure, programs for energy storage, or programs for demand response automation to encourage use of electrical energy at off-peak hours or to encourage control of daily electrical load. (California Pub. Res. Code Section 25403.5)
Load Management Standards	The intent of load management standards is to encourage electricity customers to shift electricity demand away from high-demand periods, when peaking power plants and other polluting generators are in use, to times when lower-cost clean electricity is available. Utilities and state programs can encourage this shift through electricity rates that reflect actual grid conditions.
Load-modifying programs	Load-modifying demand response programs are programs typically driven by time-variant rates and any associated load reduction is counted in reduced peak demand forecast.
Load-serving entity (LSE)	An electric customer's retail supplier or federal power marketing administration.
Load shed	Partial reduction or complete curtailment of an electrical load in response to an economic or reliability signal.

Load shifting	The process of moving electricity loads from one time of the day to another.
Market Informed Demand Automation Server (MIDAS)	CEC's Market Informed Demand Automation Server (MIDAS) is a database of current, future, and historical time-varying rates, GHG emissions associated with electrical generation, and California Flex Alert Signals. The database is populated by electric load-serving entities (LSEs), WattTime's Self-Generation Incentive Program (SGIP) application programming interface (API), the California ISO, and other entities that are registered with the MIDAS system.
Megawatt (MW)	A unit of power equal to 1 million watts, especially as a measure of the output of a power station.
Net peak electrical demand	The maximum electricity demand in a system minus utility-scale wind and solar generation in a given time period. Daily peak net demand typically occurs later in the evening than peak demand.
Peak demand	The highest amount of electric demand within a particular period. Daily electric peaks on weekdays occur in late afternoon and early evening. Annual peaks occur on hot summer days.
Proxy Demand Resource (PDR)	Economic demand response comprised of a load or aggregation of loads that bid into the California ISO market under normal operating conditions.
Publicly owned utility (POU)	A nonprofit utility provider owned by a community and operated by municipalities, counties, states, public power districts, or other public organizations.
Rate Identification Number (RIN)	The unique identifier established by the CPUC for an electricity rate.

Reliability Demand Response Resource (RDRR)	Emergency demand response comprised of a load or aggregation of loads that bid into the California ISO market during supply-shortage conditions.
Resource adequacy (RA)	The program that ensures that adequate physical generating capacity dedicated to serving all load requirements is available to meet peak demand and planning and operating reserves, at or deliverable to locations and at times as may be necessary to ensure local area reliability and system reliability.
Scenario	A plausible description of how the future may develop based on a coherent and internally consistent set of assumptions about key driving forces (for example, rate of technological change, prices) and relationships. Note that scenarios are neither predictions nor forecasts but are used to provide a view of the implications of developments and actions.
Senate Bill 100 (De León, Chapter 312, Statutes of 2018) (SB 100)	This bill requires that by 2045 renewable and zero-carbon energy sources must supply 100 percent of electric retail sales to end-use customers.
Strategic Reserve Reliability (SRR) Program	This program provides funding to help ensure electricity reliability during extreme weather events while the state transitions to a clean energy future.
Supply-side demand response	Dispatchable DR resources integrated into California markets, counted for resource adequacy.