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California Energy Commission

FINAL STAFF REPORT

Analysis of Potential Amendments to the Load Management Standards

Load Management Rulemaking

Docket Number 19-OIR-01

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California Energy Commission

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PREFACE

The Warren-Alquist Act codified in Public Resources Code Section 25403.5 sets forth the authority and duty of the California Energy Commission (CEC) to adopt load management standards.

On November 13, 2019, the CEC issued an Order Instituting Rulemaking to begin considering amendments to the *Load Management Standards* (California Code of Regulations, Title 20, §§ 1621-1625). The stated goal of the rulemaking was to amend the existing load management standards to increase flexible demand resources through electricity rates, e storage, automation, and other measures that are technologically feasible and cost-effective relative to the costs for new electrical capacity (Public Resources Code § 25403.5).

On December 17, 2019, the CEC released an invitation to a workshop on the scope of the 2020 rulemaking proceeding.

On January 10, 2020, the CEC released a Draft Scoping Memo identifying the rate structures, storage and automation technologies, and other strategies having the potential to reduce peak use or increase off-peak use.

On January 14, 2020, the CEC hosted a public workshop to share a proposed scope of the 2020 load management rulemaking proceeding and gather feedback. The CEC received public comments until January 24, 2020.

On February 14, 2020, the CEC released an invitation to a workshop to review and comment on the proposed amendments to the Load Management Tariff Standard. The CEC hosted the workshop on March 2, 2020, to publicly vet this information. A transcript of this workshop is available on Docket 19-OIR-01. Public comments were received until March 18, 2020.

From March through December 2020, the CEC worked closely with the California Public Utilities Commission, the California Independent System Operator, investor-owned utilities and publicly owned utilities, community choice aggregators, automation service providers, equipment manufacturers, and other stakeholders to refine the scope and approach necessary to achieve widespread load management.

On March 23, 2021, the CEC published a draft staff report presenting the proposed changes to the load management regulations. The CEC hosted a public workshop to present and discuss the draft report on April 12, 2021. Following this workshop, stakeholders submitted written comments to Docket 19-OIR-01. This final report has been modified to address, to the extent reasonable, the comments received following this workshop.

ABSTRACT

The Warren-Alquist Act defines load management as: "any utility program or activity that is intended to reshape deliberately a utility's load duration curve" (Public Resources Code § 25132). Load management strategies, including those established by the California Energy Commission's (CEC) first load management standards, have been used to help balance the supply and demand of energy in California since the 1970s. Today, existing load management resources are largely met by utility incentive programs that reward customers for reducing peak loads. However, these existing demand response programs are incapable of shifting loads to periods of high renewable generation, and thus are inadequate for supporting the carbon-free grid of the future. The objective of the proposed rulemaking is to increase statewide demand flexibility through amendments to the existing load management regulations (California Code of Regulations, Title 20, §§ 1621-1625).

Throughout 2020, staff worked with the California Public Utilities Commission, the California Independent System Operator, investor-owned utilities and publicly owned utilities, community choice aggregators, automation service providers, equipment manufacturers, and many other stakeholders to identify the steps needed to achieve this goal. Staff and stakeholders agreed on the need for a statewide real-time signaling system that enables automation markets to coalesce around principles and technologies for demand flexibility. In August 2021, the CEC published the pilot Market Informed Demand Automation Server, a statewide database of time-dependent electricity rates, California Independent System Operator Flex Alerts, and marginal greenhouse gas emissions signals, which can be linked to flexible loads, enabling the automation of customer end-uses in real-time.

Building on the CEC's new Market Informed Demand Automation Server system, staff proposes to adopt through regulation the following four basic requirements for the five largest electric utility service territories in California – Pacific Gas & Electric Company, San Diego Gas & Electric Company, Southern California Edison, Los Angeles Department of Water and Power, and Sacramento Municipal Utility District – and the community choice aggregators operating within these service territories to:

a) Develop retail electricity rates that change at least hourly to reflect locational marginal costs and submit those rates to the utility's governing body for approval.

b) Update the time-dependent rates in CEC's Market Informed Demand Automation Server database whenever a rate is approved or modified.

c) Implement a single statewide standard method for providing automation service providers with access to their customers' rate information.

d) Develop a list of cost-effective automated price response programs for each sector and integrate information about time-dependent rates and automation technologies into existing customer education and outreach programs.

The intent of the proposed amendments is to form the foundation for a statewide system of granular time and location dependent signals that can be used by automation-enabled loads to provide real-time load flexibility on the electric grid. The CEC can then develop flexible demand appliance standards that make use of the proposed demand automation system. With communications and automated control technologies, customers can shift electric use to take

advantage of cleaner and less expensive energy. This allows customers to optimize energy use and service quality while minimizing economic and environmental impact. Advanced meters, communications, and automation technologies make this possible today.

Keywords: Electric grid, reliability, load management, load flexibility, demand flexibility, demand response, price response, automation, real-time pricing, electricity rates, electricity tariffs, Market Informed Demand Automation Server, MIDAS, hourly rates, dynamic rates

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

Executive Summary

The goal of the proposed amendments to the load management standards is to form the foundation for a statewide system that automates the publication of time and location dependent signals that can be used by end-use automation technologies to provide real-time load flexibility on the electric grid. The combination of statewide signals and robust responsive automation markets proposed herein will enable customer-supported load management on a mass-market scale.

With the utilization of communications and automated control technologies, customers can shift the timing of electric services to take advantage of cleaner and cheaper electricity without sacrificing comfort or quality of service. Buildings and water can be precooled or preheated. Batteries and electric vehicles can be charged sooner or later than otherwise scheduled. Consumers can set dishwashing, laundry, and many other services to be automatically scheduled based on the electricity cost or greenhouse gas content. Advanced meters, communications, and automation technologies make this possible today. However, standards do not currently exist for customer devices and automation services to access utility rate information in a consistent and standardized way.

The Warren-Alquist Act establishes the California Energy Commission (CEC) as California's primary energy policy and planning agency. Public Resources Code Section 25403.5 sets forth the CEC's authority and duty to adopt load management standards. These standards are in addition to the CEC's authority in Public Resources Code Section 25402 to set building energy efficiency standards, appliance efficiency standards, and flexible demand appliance standards. The Warren-Alquist Act defines load management as: "any utility program or activity that is intended to reshape deliberately a utility's load duration curve." (Public Resources Code § 25132). Since the 1970s, load management programs, building and appliance efficiency standards, financial incentives, and consumer education have all played major roles in maintaining the reliability of the electric grid while reducing the need for expensive fossil fuel powered plants.

Each of California's more than 70 utilities and community choice aggregators offer their own load management programs. Customers interested in signing up for programs are presented with a cornucopia of offerings with an array of incentives, options, and requirements. The participation decision requires time for research and consideration of these options. Once a customer decides to participate, they may still need to coordinate installation of technologies or keep track of their event performance to avoid steep noncompliance penalties. This is in addition to tracking and understanding their underlying time-dependent tariffs for electric energy and demand services, which have their own time-dependent cost constraints. This piecemeal approach results in programs that are expensive and inequitable, and markets that cater to the demands of the utilities rather than to customers.

In 2018, Senate Bill 100 (De León, Chapter 312, Statutes of 2018) committed California to a 100 percent carbon-free electricity supply by 2045. To reach this goal, the state will need to replace fossil-fuel generation with clean energy resources. Existing demand resources, largely met by utility incentive programs, are not of sufficient size, cost-effectiveness, or flexibility to effectively support a grid comprised of carbon-free resources such as solar and wind, which are inherently intermittent and inflexible. The main objective of the proposed load management rulemaking is to develop options to address this challenge through amendments to California’s existing load management regulations (California Code of Regulations, Title 20, §§ 1621-1625).

Throughout 2020, CEC staff worked closely with the California Public Utilities Commission, the California Independent System Operator, investor-owned utilities, publicly owned utilities, community choice aggregators, automation and storage equipment manufacturers, and many other stakeholders to identify the steps needed to achieve this goal. Staff and stakeholders agreed on the need for a statewide real-time signaling system that enables automation markets to coalesce around agreed upon principles and technologies for demand flexibility. The new system, named the Market Informed Demand Automation Server or MIDAS, will be maintained by the CEC with help from participating California utilities. Through MIDAS, customers and automation service providers can link flexible loads to a machine-readable database of rates and other grid signals to automate demand flexibility.

CEC staff proposes the following four basic requirements for the five largest electric utilities service territories in California – Pacific Gas & Electric Company, San Diego Gas & Electric Company, Southern California Edison, Los Angeles Department of Water and Power, and Sacramento Municipal Utility District – and the community choice aggregators located within their boundaries:

a) **Develop retail electricity rates that change at least hourly to reflect locational marginal costs and submit those rates to the utility’s governing body for approval.** If approved by ratemaking authorities, these rates would provide customers with options for automating response to hourly and sub-hourly price signals.

b) **Update the time-dependent rates in the CEC’s MIDAS database whenever a rate is approved or modified.** The CEC’s MIDAS database of time-dependent rates can be accessed by third-party service providers to help customers automate response to electricity prices, Flex Alerts, and greenhouse gas signals.

c) **Implement a single statewide standard method for providing automation service providers with access to their customers’ rate information.** Service providers need to have customer-specific rate information to help each of their customers optimize consumption patterns and bill savings.

d) **Develop a list of cost-effective automated price response programs for each sector and integrate information about time-dependent rates and automation technologies into existing customer education and outreach programs.** Utilities must reevaluate existing programs and consider new ones to take advantage of the economic and organizational efficiencies provided by MIDAS. Education programs must also be updated, as most customers are unaware of price-responsive automation technologies and services.

Through these amendments, California will begin to develop a cost-effective statewide system that automates the publication of time and location dependent price and greenhouse gas emissions signals that can be used by mass-market end-use automation technologies to provide real-time load flexibility on the electric grid. The universally available load management opportunities proposed in this report can reduce greenhouse gas emissions by shifting flexible consumption to carbon-free hours, save consumers money by shifting consumption to lower cost periods, and more efficiently use available renewable generation.

Increased availability of automated flexible loads will also support grid resiliency and reduce the likelihood of widespread outages during system emergencies.

Staff analysis finds that the proposed amendments are technologically feasible and cost-effective relative to new electrical capacity. The estimated cost is $24 million in net present value over a 15-year period, after full implementation, and the benefit is estimated at more than $267 million over the same period, shared among utilities and all ratepayers. The proposed amendments to the load management standards are a regulatory action that would protect natural resources and the environment and are, therefore, categorically exempt from further California Environmental Quality Act review.

CHAPTER 1: Introduction

Burning fossil fuels in the electricity generation, buildings, transportation, industrial, and agricultural sectors drives changes in the Earth's climate by releasing greenhouse gases (GHGs) like carbon dioxide and methane. The State of California has set ambitious goals to reduce or eliminate GHG emissions in these sectors to mitigate the increasing impacts of climate change.

In recent years, the California state Legislature passed Senate Bill 32 (SB 32, Pavley, Chapter 249, Statutes of 2016), Assembly Bill 3232 (AB 3232, Friedman, Chapter 373, Statutes of 2018), and Senate Bill 100 (SB 100, De León, Chapter 312, Statutes of 2018) to guide state energy policy on reducing GHGs.

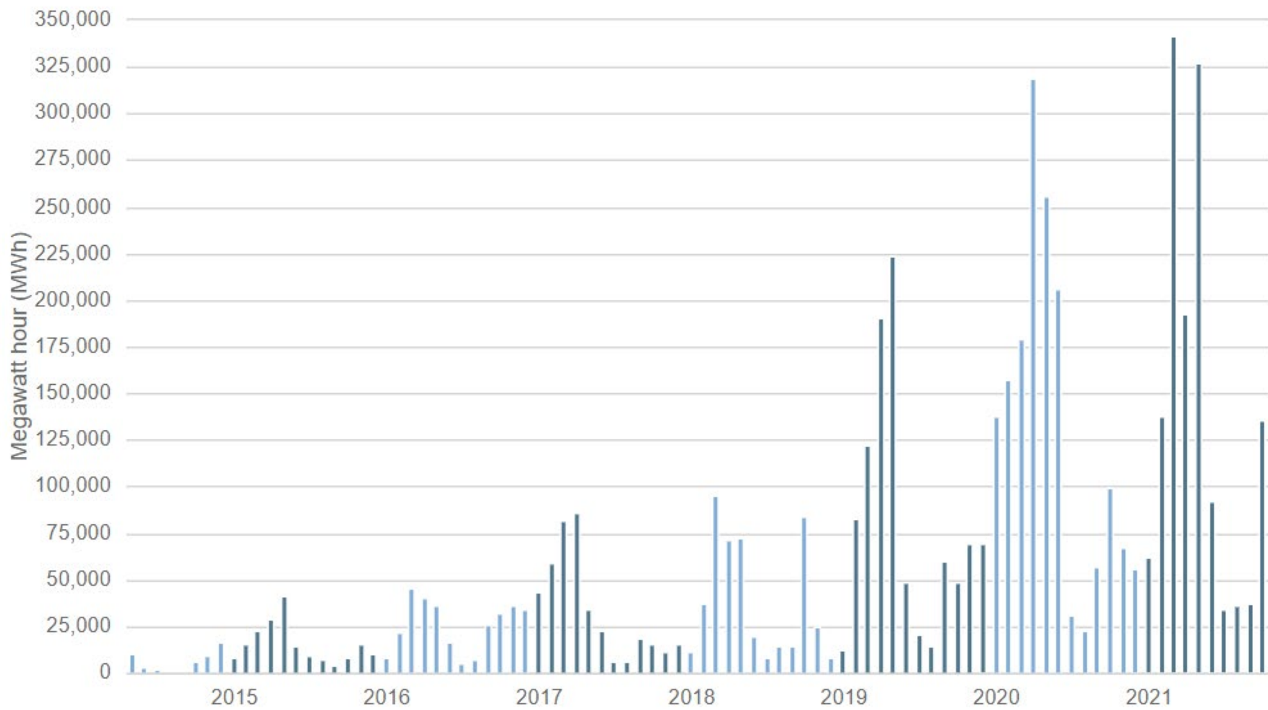
- SB 32 requires GHG emissions be reduced to 40 percent below 1990 levels by 2030.
- AB 3232 requires the California Energy Commission (CEC) to assess strategies to achieve 40 percent GHG reductions in the California building sector by 2030.
- SB 100 requires 100 percent of retail sales of electricity to be from carbon-free resources by 2045.

A key strategy for decarbonizing the electric grid is the replacement of fossil fuel electricity generation with carbon-free resources, such as solar and wind. Electric supply from these resources tends to be intermittent and inflexible, following natural daily cycles. Electric demand also varies by time of day, in a pattern that – for now – is not in sync with wind and solar supply. Today, deviations in daily electricity supply and demand patterns are largely met by conventional fossil fuel power plants.

As renewable resources replace conventional fossil fuel powered plants, the electric grid will place increasing value on resources that can balance supply and demand. The CEC has identified opportunities to optimize demand patterns using its existing load management standards authority addressing electricity rate structures, energy storage, and load automation. The standards proposed in this document will support cost-effective grid reliability through measures designed to synchronize daily electric demand with carbon-free supplies.

In the absence of this synchronization, excess renewable electricity is either "curtailed" by reducing available solar generation or exported to other markets at a loss. In the first half of 2020, the California Independent System Operator (California ISO) curtailed up to 320 gigawatt-hours (GWh) per month – enough to power more than half a million California homes, and 8 times the peak monthly curtailment of 2015 (Figure 1). Without action to increase demand flexibility, or otherwise make use of this excess generation capacity, the magnitude of this wasted resource will continue to increase.

Figure 1: California ISO Renewable Curtailments



Source: California ISO renewable curtailments, Updated 11/5/2021[1]

Today, load management in California is typically achieved through utility programs that reward customers for reducing energy use or "shedding load" during infrequent system events.[2] Large commercial and industrial interruptible programs and residential air conditioning load control programs have been used for decades to reduce peak loads when supply resources are constrained.

The transition to a carbon-free grid in California provides an opportunity for energy agencies to leverage advanced technologies to enhance the "flexibility" of demand resources – where flexibility denotes the ability to not only reduce loads at critical times, but also *increase* loads when renewable curtailments are imminent. Technologies that enable customers to shift the timing of their electricity use will allow clean energy supplies to be used rather than curtailed. Policies and regulations that increase the availability of flexible demand resources will support an affordable and reliable grid as the share of carbon-free resources expands.

Background and Purpose

The purpose of load management is to modify end-use loads to better conform to electric system supply resources, typically through time-dependent retail rates, storage, and automation. Since California's electricity generation mix is increasingly made up of intermittent

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1 California ISO managing oversupply webpage. Visited November 2021. Available at http://www.caiso.com/informed/Pages/ManagingOversupply.aspx#dailyCurtailment.

2 Unless otherwise noted, all references to utilities include IOUs, POUs, and CCAs.

renewable resources, the CEC's load management authority is a key tool for supporting the state's transition to a carbon-free grid.

Section 25403 of the Public Resources Code (PRC)[3] authorizes the CEC to, "assess the potential for the state to reduce the emissions of greenhouse gases in the state's residential and commercial building stock by at least 40 percent below 1990 levels by January 1, 2030." The assessment is to include, "Load management strategies to optimize building energy use in a manner that reduces the emissions of greenhouse gases." PRC Section 25403.5 further sets forth the CEC's authority and duty to adopt load management standards.[4]

The Warren-Alquist Act[5] defines load management as, "any utility program or activity that is intended to reshape deliberately a utility's load duration curve." (PRC § 25132). This can be interpreted to cover any intentional amplification or reduction of energy use during specified hours, including:

- Load shedding refers to short-term energy reduction.
- Load shifting refers to load shed combined with a coordinated load increase during times of high supply and/or low GHG emissions.
- Energy efficiency and strategic conservation are longer-term strategies for permanently reducing loads during hours of the year with low supply or high demand.

In 1979, the CEC's original load management regulations (California Code of Regulations (CCR), Title 20, §§ 1621-1625) compelled the implementation of marginal cost pricing, industrial time-of-use (TOU) rates, commercial building audits, and residential load control programs. As a result, California customers in all sectors have for decades provided load shifting and demand response resources in response to electricity pricing and programs.

Since adoption of the original load management regulations, technologies and markets have evolved substantially, creating significant opportunities for more advanced load management strategies. The objective of the current rulemaking is to update the existing standards to reflect recent state energy policy updates and the four decades of technology progress that have occurred since adoption of the original standards.

Universally available load management can reduce GHG emissions by shifting flexible consumption to lower GHG times, save consumers money by shifting consumption to lower cost periods, and more efficiently use intermittent renewable generation on the grid. Increased availability of automated flexible loads will also support grid resiliency and reduce the likelihood of widespread outages during system emergencies.

In parallel with the load management rulemaking, the CEC is developing Flexible Demand Appliance Standards under the authority of the PRC Sections 25213, 25218, 25402(f), and 25402.11. Flexible demand appliances will complement the proposed amendments to the load

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3 Unless otherwise noted, all references to code sections refer to the Public Resources Code.

4 The full text of the load management standards authority (PRC § 25403.5) is provided in Appendix A.

5 The Warren-Alquist State Energy Resources Conservation and Development Act, Division 15 of the Public Resources Code, § 25000 et seq., available at https://www.energy.ca.gov/sites/default/files/2021-05/CEC-140-2021-001.pdf.

management standards by allowing customers to schedule, shift, or curtail their electrical demand in response to load management signals from the electrical grid that reflect load management rates structures proposed in the amendments. (PRC § 25402(f)(7)(a)).

Current Status (Problem Statement)

Each of California's roughly 70 load serving entities (LSEs) offer their own version of load management program portfolios, largely populated by incentive programs that reward participants for load shed.[6] This approach has resulted in programs that are complex, expensive, and inequitable; resources that are limited in size and flexibility; and markets that disproportionately cater to the needs of the utilities rather than the needs of customers.

Demand resources from current incentive programs are limited in many ways. For example, most programs focus on emergency curtailment and so are designed to shed load – but cannot shift load to absorb plentiful renewable supplies. Also, utilities frequently impose program restrictions that limit participation to larger loads.

- Most programs specify a fixed time of day or week and have no mechanism for adjustment when unexpected conditions result in needs outside the specified times.
- The magnitude of a demand resource is limited by several factors – participation requirements related to load size or end-use type, high costs of customer education, necessary management time by customers, and low penetration of automated loads – meaning only a fraction of potential demand resources are available.
- Even with enough participation and automation, load shed is often limited to certain hours of the day and certain seasons of the year, while load shifting is not supported at all.

The costs of existing demand resources are high. Utilities incur high costs from incentive programs: developing and seeking approval, marketing, contracting with participants, and maintaining back-office systems. These costs are in addition to the obligatory costs of customer billing and rate development.

Customer participation in programs is also not without cost. Customers seeking information about programs are presented with a cornucopia of offerings that have different incentives, options, and requirements. The participation decision requires time for research and consideration of these options. Once decisions are made, customers may still need to coordinate installation of technologies, keep track of their event performance to avoid steep noncompliance penalties, and coordinate their managed energy use with their time-varying energy and demand rates. These costs can outweigh the customer's desire, time, and ability to self-educate and participate. Exacerbating this issue, growth in the number and reach of community choice aggregators (CCAs) has led to a substantial reduction in demand response (DR) program participation, as customers migrate from investor-owned utilities (IOUs) with mature program portfolios to CCAs, many of which are in the early stages of assessing potential for demand resources.

6 The list of California LSEs is provided in Appendix B.

Most residential load control programs involve the installation of air conditioning automation chosen and controlled by the utility. Where permitted, customer choice regarding an event is typically all-or-nothing: either allow the utility to control the end-use or opt-out of the event entirely. Opt-outs are tied to penalties or constrained to a certain number per year. Such limited customer involvement in event response impedes their interest in and understanding of peak reduction opportunities. As a result, non-event day peak reduction potential is not realized.

Typical participation incentives intended to help overcome customer barriers to signing up for programs do little or nothing to encourage ongoing customer involvement or contributions to their own load flexibility. Pay-for-performance programs resolve this by rewarding customers for their load impacts relative to an estimated baseline. At the same time, however, they create market inefficiencies and consumer inequities by benefiting inefficient customers more than the efficient ones. For example, a customer with light-emitting diode (LED) lighting will have a smaller baseline than a customer with incandescent lights. As a result, if both customers turn off their lights, the customers with inefficient equipment, and thus a larger load, would be paid more. Similarly, customers able to afford air conditioning, or occupying a home or building with the equipment already installed, have a higher baseline than those who are unable to afford it. Incentivizing load flexibility through rates rather than through payments based on baseline use resolves the inequities associated with paying those contributing most to the problem.

Existing incentive programs also create or exacerbate inefficiencies in markets. In the absence of statewide standards, technology vendors cater to utilities rather than to customers, limiting technology innovation and minimizing enhancements to user experience. Automation technology manufacturers are incentivized to withhold energy efficiency and load flexibility performance to sell peak resources into the energy markets or highest bidding aggregators.

Finally, incentive programs tend to be highly inequitable. Utilities target the largest customers, such as those with large air conditioning, battery charging, or process loads, so smaller and more efficient customers have less opportunity to benefit from participation. Utilities also target large loads like air conditioning and electric water heating for load control programs. While customers without these specific loads are not contributing to the load pressure on the grid, and have no opportunity to benefit directly from participation, they are still required to contribute through rate charges to cover the costs of running the program.

Time-dependent rates have long been considered a more efficient alternative to incentive programs. The recent implementation of default TOU rates at Pacific Gas & Electric Company (PG&E), Southern California Edison (SCE), San Diego Gas & Electric Company (SDG&E), Los Angeles Department of Water and Power, and Sacramento Municipal Utility District (SMUD) obligates regulators to consider statewide standards for technologies that support TOU cost savings. California's success in helping customers respond to time-dependent rates depends on affordable access to price and GHG signals, as well as responsive automation technologies. The proposed amendments will enable a statewide transition from an incentive-based utility command-and-control paradigm to a customer-driven price and GHG signal response paradigm.

Load Management Rulemaking Procedure and Documentation

In adopting the load management standards, the CEC must adhere to the requirements of the state's Administrative Procedure Act (APA; Government Code § 11340, et seq.), including reasonable notice of the proposed amendments along with documents that justify their feasibility and cost-effectiveness. The APA also requires state agencies to provide an initial 45-day comment period. The CEC will hold an APA public hearing following the 45-day written comment period prior to the adoption meeting. If, because of comments received during that period, CEC makes substantive changes to its proposal before adoption, the CEC will provide an additional 15-day public comment period. The proposed amendments will be placed on a CEC business meeting agenda for adoption. If adopted, the final rulemaking package will be prepared and submitted to the Office of Administrative Law (OAL) for approval.

Following are some of the key documents that were docketed during the pre-rulemaking phase of the Load Management Rulemaking.

- Docket 19-OIR-01 for the Load Management Rulemaking[7] (October 21, 2019)
- Order Instituting Rulemaking Proceeding to Consider Updates to the Load Management Regulations[8] (November 13, 2019)
- Draft Load Management Rulemaking Scoping Memo[9] (January 10, 2020)
- Agenda for Workshop on Scope of Load Management Rulemaking[10] (January 14, 2020)
- Proposed Amendments to the Load Management Tariff Standard[11] (February 21, 2020)
- Transcript of the Workshop on the Proposed Amendments to the Load Management Tariff Standard[12] (March 2, 2020)
- Market Informed Demand Automation Server (MIDAS) Webinar Presentation (August 25, 2021)

7 CEC Docket Log for 19-OIR-01, Load Management Rulemaking is available at https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-OIR-01.

8 Order instituting rulemaking proceeding, 19-OIR-01, is available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=230841&DocumentContentId=62474.

9 Draft load management rulemaking scoping memo is available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=231275&DocumentContentId=63237.

10 Agenda for Commissioner workshop on scope of load management rulemaking is available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=231396&DocumentContentId=63203.

11 Staff draft load management tariff standard markup is available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=232169&DocumentContentId=64122.

12 Transcript of the March 2, 2020, staff workshop on the draft load management tariff standard is available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=232502&DocumentContentId=64523.

- Market Informed Demand Automation Server (MIDAS) Documentation[13] (September 15, 2021)

13 Market Informed Demand Automation Server (MIDAS) Documentation: Connecting to and Interacting with the MIDAS database is available at https://www.energy.ca.gov/publications/2021/market-informed-demand-automation-server-midas-documentation-connecting-and.

CHAPTER 2: Recommendations

This chapter presents recommended changes to the load management standards based on the analysis in this report. In summary, CEC staff recommends regulatory amendments that require utilities to:

a) Develop retail electricity rates that change at least hourly to reflect locational marginal costs and submit those rates to the utility's governing body for approval.

b) Update the time-dependent rates in CEC's Market Informed Demand Automation Server (MIDAS) database whenever a rate is approved or modified.

c) Implement a single statewide standard method for providing automation service providers with access to their customers' rate information.

d) Develop a list of cost-effective automated price response programs for each sector and integrate information about time-dependent rates and automation technologies into existing customer education and outreach programs.

These recommended changes to the load management standards are discussed in detail below. A discussion of potential alternatives is provided in Chapter 10.

A. Retail Rate Structures

Recommendation: Develop retail electricity rates that change at least hourly to reflect locational marginal costs and submit those rates to the utility's governing body for approval.

Staff conducted analyses of options for retail rate structures. Based on these analyses, staff proposes that utilities develop, for all customer classes, locational rates that change at least hourly to reflect system marginal costs.

The most common time-dependent electricity rates in California today are TOU rates, which are incapable of reflecting continuous price variation or disaster-driven price spikes in wholesale electricity markets. Implementation of hourly rates, whether day ahead or real-time, is expected to result in more efficient retail purchasing behavior and lower overall rates.

Benefits of locational marginal pricing signals include:

- Renewable Energy Integration. More spatial and time granularity in electricity prices would enable the demand flexibility needed to manage the location and time variations of supply inherent in a carbon-free grid.
- Efficient Pricing. Locational marginal signals would improve system efficiency through better alignment of retail rates with the cost of supplying energy at that location and time.

Some of the barriers to locational marginal pricing signals include:

- Advanced Metering Infrastructure. Over 80 percent of Californians have advanced metering,[14] but where interval meters are not installed, time-dependent rates are not possible because the meters are not able to record energy use hourly or sub-hourly.
- Utility Billing Systems. Utility billing system software may require updating prior to implementation of the new rates. CEC staff expects that rate-approving bodies will consider the costs of any necessary upgrades during the rate approval process. Where time-dependent rates such as TOU are common, upgrades are expected to be less resource intensive than upgrades from flat pricing to time-varying pricing.
- Locational Rates. The number of rates would increase by a factor directly proportional to the number of distinct locations, based on the needs of each utility's distribution system. However, this potential increase could be reduced by the number of distinct customer types. For example, a small business customer and a residential customer at the same location could pay the same price for each unit of electricity.

B. MIDAS Database Updates

Recommendation: Update the time-dependent rates in CEC's MIDAS database whenever a rate is approved or modified.

In August 2021, the CEC provided public access to the MIDAS, a statewide database of current and future time-dependent rates, GHG emissions, and California ISO Flex Alert Signals.[15] The database is hosted by the CEC and publicly accessible at https://midasapi.energy.ca.gov through an application programming interface (API). MIDAS data are provided in a standard machine-readable format called Open Automated Price Response (OpenAPR) transferred via extensible markup language (XML) and JavaScript Object Notation (JSON).

The rate data in the MIDAS database are populated by LSEs. To remain relevant, the MIDAS data must be updated when retail rates are created or modified. The benefits of an accurate MIDAS database include:

- Time and Cost Efficiencies. End-users and their Automation Service Provider (ASPs) can freely access accurate rate data, Flex Alerts, GHG emissions and other grid signals from a single, publicly-available, machine-readable source.
- Grid and Societal Benefits. These and other as-yet unconsidered time-dependent signals can be used for widespread, mass-market load optimization, grid reliability, customer bill minimization, and carbon reduction.
- Expanded Collaboration. Government agencies, utilities, researchers, and others can take advantage of the OpenAPR standard format for transmission of time-dependent rate data, reducing public and private sector time and labor costs.

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14 U.S. Energy Information Administration, Form EIA-861, 2020. Available at https://www.eia.gov/electricity/data/eia861/.

15 MIDAS is available at https://midasapi.energy.ca.gov/.

- Innovation in Technology Markets. MIDAS signals can be used to provide customers with enhanced information, automation, and bill management services.

Utilities maintain current databases for their own retail rates, so error-free XML uploads can be automated using the MIDAS API as described in the CEC's MIDAS documentation[16].

There are no known barriers to this recommendation.

C. Linking Rates to Automation Devices

Recommendation: Implement a single statewide standard method for providing automation service providers with access to their customers' rate information.

Effective price-responsive load management requires that devices know the details of their customer's assigned electricity rate. There are several ways to accomplish this, for example:

- Manual Enrollment. Customers could initiate the link directly, for example, by typing the MIDAS standard rate identification number (RIN) into the end-use, control device, or an associated smartphone application. The MIDAS standard RIN is akin to entering a real estate parcel number or vehicle identification number to access information about a home or car.
- Smartphone Application. Less error-prone methods might involve a smartphone app or instructions that directs the customer to take a photo of the RIN text, bar code, or a quick response (QR) code on the customer's electricity bill or online account. This is a common practice used today for services like depositing checks or connecting new devices to local WiFi.

Once the RIN is entered by the customer, the device or its associated cloud services can then access the rate information from MIDAS. The timing of the end-use load can then be optimized by taking into account MIDAS signals, customer's needs, and manufacturer limits.

In addition to customer self-service approaches described above, utilities could facilitate streamlined customer participation by coordinating with third-party ASPs to link devices to rates. This would require a data service that receives requests and passes customer-specific rate information including the RIN to ASPs that are authorized by the customer. The ASP can then access the rate information in the MIDAS database and facilitate the automation of customer devices accordingly.

After careful consideration of options for enabling third-party service providers to support customer participation in utilizing information stored in the MIDAS database, staff proposes the utilities facilitate both customer-driven and ASP-driven access to MIDAS as follows.

1. Provide customers with access to their RIN(s) on customer billing statements and online accounts using both text and QR or similar machine-readable digital code.

16 Market Informed Demand Automation Server (MIDAS) Documentation: Connecting to and Interacting with the MIDAS database. Available at https://www.energy.ca.gov/publications/2021/market-informed-demand-automation-server-midas-documentation-connecting-and.

2. Lead a working group of utilities and stakeholders, overseen by the CEC, to develop and implement a single statewide standard tool for authorized rate data access by third parties.

Under proposal one, customers would be empowered to link their own devices to their electricity rate.

Under the second proposal, the CEC would lead a working group of utilities and stakeholders to develop a standard statewide method or platform to facilitate sharing rate data between utilities, customers, and ASPs. Given access to individual customers' rate information, ASPs could then help their registered customers install and program automation options to respond to the time-dependent data in the MIDAS database.

D. Identify Cost-effective Programs and Educate Customers

Recommendation: Develop a list of cost-effective automated price response programs for each sector and integrate information about time-dependent rates and automation technologies into existing customer education and outreach programs.

To generate value from machine-readable rates, customers must first be aware of available rates and technologies. In post-workshop comments, stakeholders asked the CEC to consider customer education, training, and support. CEC staff proposes utilities educate and encourage customers to use automation devices to respond to prices and GHG emissions.

Under this proposal, utilities would educate customers about automation options that enable them to schedule or shift end-use loads, or to respond to price or GHG emissions signals. Utilities can also play a role in helping customers learn how to best use automated devices to respond to time-dependent energy prices and GHG emissions.

Customers with existing smart thermostats or other connected controls can automate loads to reduce or avoid activity during high-priced periods and complete activities during low-price periods. A recent study by the Smart Energy Consumer Collaborative[17] found that residential customer willingness to sign up for a time-dependent rate is 7 percent in the absence of responsive automation. Given the option to have responsive automation installed, nearly 90 percent of customers said they would or might participate. "To capitalize on this," the authors conclude, "utilities should offer smart thermostats with rate optimization to drive enrollment and satisfaction in time-based pricing programs." Behind-the-meter (BTM) batteries, electric vehicles (EVs), electric water heaters, pool pumps and spas, refrigeration, and other energy storage end-uses are also good candidates for price and GHG responsive controls.

At a minimum, the five largest utilities and the CCAs within those territories should integrate information about new rates into their existing customer education and outreach efforts to ensure that customers are aware of and able to find information on rates and automation technologies. This could potentially be rolled into existing education efforts like Energy Upgrade California and Flex Alert campaigns.

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17 Smart Energy Consumer Collaborative. September 2019. *Rate Design: What Do Consumers Want and Need Report*. Available at https://smartenergycc.org/rate-design-what-do-consumers-want-and-need/.

Educational programs that help customers program the responsive appliances they already own is another low-cost option. Research shows that renters are less adept at programming thermostats than are homeowners[18]. A basic community outreach effort to schedule thermostats to precool and avoid peak TOU rates could have a substantial effect on-peak loads and reduce customer bills at the same time. Thus, a new outreach program might involve little more than a marketing campaign asking customers to voluntarily link their devices to GHG emissions or TOU prices. A similar effort at SMUD improved uptake of the TOU response for ecobee® smart thermostats by over 30 percent.[19]

Consumer-centric metrics created to incorporate multiple factors – including functionality, performance, safety, aesthetics, sustainability, and cost – will provide customers a better understanding of the various tradeoffs. Vendors and grid operators can use the same metrics to analyze and develop more consumer-friendly products and programs.[20]

While many customers will be motivated to automate load shifting to save money or avoid a community-wide grid shutoff, others will be more motivated to avoid high GHG emissions. In such cases, free or rebated automation technologies that respond to the GHG emission signals from the Self Generation Incentive Program (SGIP) passed through MIDAS might be more appropriate than a financial incentive. Theoretically, each customer could be given the option to program their end-use response according to their own personal valuation. Customers could choose to respond entirely to prices, entirely to GHG emissions, or to some combination of the two. To gain the broadest possible effect of marginal signals, programs should provide customers with both marginal pricing and GHG signals.

See Appendix G for a list of available GHG emissions signals.

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18 Herter, Karen, and Yevgeniya Okuneva. February 2014. SMUD's Communicating Thermostat Usability Study. Available at https://documentcloud.adobe.com/link/track?uri=urn:aaid:scds:US:ef32ebd3-86da-474d-9edd-11bbc44ae013.

19 McCord, Karen, and Helen Werner (SMUD), Nathan Shannon (SECC), Kari Binley (ebobee), Jesse Smith (Demand Side Analytics). July 2020. *Educating Consumer on Time-of-Use Rates - Presentation to the Smart Energy Consumer Collaborative*. Available at: https://smartenergycc.org/educating-consumers-on-time-of-use-rates-webinar/.

20 Wang, Jackson Linda M. Zeger, Brenda Chew, and Ben Ealey. June 2020. "Designing Consumer Metrics for Grid-Connected Devices". https://sepapower.org/knowledge/designing-consumer-metrics-for-grid-connected-devices/.

CHAPTER 3: Statutory Authority

The 1974 Warren-Alquist Act established the CEC as California's primary energy policy and planning agency. PRC Section 25403.5 sets forth the CEC's authority and duty to adopt load management standards.[21] These standards are in addition to the CEC's authority to set building efficiency, appliance efficiency, and flexible demand appliance standards in PRC Section 25402.

Load management improves electric system efficiency and reliability by shifting electricity use to times with lower demand and more available energy. PRC Section 25403.5 requires load management standards to address rate structures and technologies that encourage use of electrical energy at off-peak hours, store energy during off-peak periods for use during peak periods, and automate control of daily and seasonal peak loads. The standards must be technologically feasible and cost-effective compared with the costs for new electrical capacity.

PRC Section 25403(a) authorizes the CEC to "assess the potential for the state to reduce the emissions of greenhouse gases in the state's residential and commercial building stock by at least 40 percent below 1990 levels by January 1, 2030." The assessment is to include, "Load management strategies to optimize building energy use in a manner that reduces the emissions of greenhouse gases." (PRC § 25403(a)(4).) Flexible demand appliances will capitalize on load management signals to "enable appliance operations to be scheduled, shifted, or curtailed to reduce emissions of greenhouse gases associated with electricity generation." (PRC § 25402(f)(1).) Thus, there is ample legal authority for the proposed amendments to the load management standards. Once adopted, they will be a vital part of the statewide strategy for reducing GHG emissions.

Utility Applicability

PRC Section 25403.5 (a) requires the CEC "adopt standards by regulation for a program of electrical load management for each utility service area." This includes CCA's that supply electricity to customers in these utility service areas.

PRC Section 25118 defines "service area" as "any contiguous geographic area serviced by the same electric utility." Thus, IOUs and publicly owned utilities (POUs) fall within the scope of load management regulation.

As part of pre-rulemaking activities, CEC has evaluated the role and applicability of the proposed standards to CCAs, local government entities within IOU service territories that procure power on behalf of their customers from non-utility suppliers but continue to receive transmission and distribution (T&D) services from the utility. Local governments form CCAs to expand their options to negotiate lower rates and greener resources. CCAs in California are

21 For the full text of PRC § 25403.5, see Appendix A.

growing rapidly and currently serve more than 10 million electricity customers statewide. In California, the rules governing CCAs were established under CPUC D.12-12-036.[22]

Customer participation in CCAs is provided as the default service for the identified geographic area with an opt-out provision, meaning customers have the choice to opt-out of the CCA and continue to receive electricity from their current supplier. Regardless of if with the CCA or their IOU, the customer will receive the bill from the IOU of that service area. The bill reflects costs for both the utility T&D services and the CCA energy provision.

The Warren-Alquist Act was adopted prior to the creation of CCAs. Nevertheless, CCAs operate within the geographical service territories of electric utilities. So, load management standards apply to CCAs that provide electricity to customers within these service areas. For load management standards to function in a manner that meets the intent of the statute, the standards need to apply to most electric customers. To the extent CCA service is the default provider and continues to expand in California, any other interpretation would diminish the effectiveness of the proposed amendments to the load management standards and defeat the purpose of the statute.

Regulation Objectives and Purpose

The statute requires the CEC to consider rates, storage, and automation but also provides discretion to evaluate and choose a variety of programs, techniques, systems, and mechanisms to advance load management goals. PRC Section 25403.5 (a) provides:

> In adopting the standards, the commission shall consider, but need not be limited to, the following load management techniques:
>
> 1. Adjustments in rate structure to encourage use of electrical energy at off-peak hours or to encourage control of daily electrical load.
> 2. End-use storage systems which store energy during off-peak periods for use during peak periods.
> 3. Mechanical and automatic devices and systems for the control of daily and seasonal peak loads.

Specific to rate structure, the CEC does not have exclusive or independent authority. For example, rates proposed in compliance with the load management standards are subject to approval by the CPUC, CCA governing boards, and POU governing boards.[23] As such, the proposed amendments to the load management standards address overarching structural features, while the detailed mechanics of the rate design are left to the utilities and their regulators or governing boards. The new types of proposed rate structures evaluated by the

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22 CPUC decision D.12-12-036 is available at https://www.cpuc.ca.gov/general.aspx?id=2567.

23 Although not specifically stated in the statute, the CEC has interpreted this language in the statute to also include the approval of changes in rate structure by governing boards of publicly owned utilities (POU) consistent with the POU ratemaking process. Therefore, when discussing approval of rate changes by the CPUC for IOUs, these same provisions would apply as to approval of rate changes by governing boards for POUs whether specifically stated or not.

CEC are focused on shaving energy demand during peak periods and increasing use in off-peak periods.

PRC Section 25403.5(a)(3) requires consideration of "mechanical and automatic devices and systems for the control of daily and seasonal peak loads." While this wording covers nearly every imaginable load management technology, PRC Section 25403.5(a) further broadens the CEC's authority by providing that load management standards "need-not-be-limited-to" these technologies. Thus, systems such as passive solar techniques, increased weatherization, and cool roofs could conceivably be part of the load management standards so long as they contribute to peak energy reduction.

The CEC interprets "daily peak loads" to mean the hours in which customers' aggregate loads are higher than the average load for that day. The CEC interprets "seasonal peak loads" to encompass the hours in which the aggregate loads are higher than the average load for that season.

Rate Approval

The Warren-Alquist Act also states:

> Compliance with those adjustments in rate structure shall be subject to the approval of the Public Utilities Commission in a proceeding to change rates or service. (PRC § 25403.5 (a)(1))
>
> Any expense or any capital investment required of a utility by the standards shall be an allowable expense or an allowable item in the utility rate base and shall be treated by the Public Utilities Commission as allowable in a rate proceeding. (PRC § 25403.5 (b))

As of August 2021, California has six CPUC regulated IOUs, 47 POUs, and 22 CCAs operating in the state (Table 1). POUs and CCAs maintain independent governing boards who approve retail electricity rates for their customers.[24]

Table 1: Electric Load Serving Entities in California

Type of LSE	Number Operating in California	Governing Body
California Investor-Owned Utilities	6	CPUC
Community Choice Aggregators	22	Board of Directors
Publicly Owned Utilities	47	Board of Directors
Rural Electric Cooperatives	4	Board of Directors
Energy Service Providers	15	Board of Directors

Source: CEC 2020, Electric Load Serving Entities in California

California Constitution Article XII Section 6 grants the CPUC ratemaking authority consistent with legislative authorization, stating: "The [Public Utilities] commission may fix rates, establish rules, examine records, issue subpoenas, administer oaths, take testimony, punish

24 Electric Load-Serving Entities (LSEs) in California webpage. Available at https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-load-serving-entities-lses.

for contempt, and prescribe a uniform system of accounts for all public utilities subject to its jurisdiction."[25] Consistent with the CPUC constitutional authority to set rates, the Warren-Alquist Act requires utilities under CPUC jurisdiction to submit to the CPUC for approval any rate structure required by the CEC.

Public Utilities Code (PUC) Section 451 requires the CPUC to determine whether proposed rates, services, and charges are just and reasonable. The CPUC's Rate Design Principles,[26] adopted in Decision 15-07-001 on July 3, 2015, further require the following considerations:

1. Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost.
2. Rates should be based on marginal cost.
3. Rates should be based on cost-causation principles.
4. Rates should encourage conservation and energy efficiency.
5. Rates should encourage reduction of both coincident and non-coincident peak demand.
6. Rates should be stable and understandable and provide stability, simplicity, and customer choice.
7. Rates should generally avoid cross-subsidies unless the cross-subsidies appropriately support explicit state policy goals.
8. Incentives should be explicit and transparent.
9. Rates should encourage economically efficient decision-making.
10. Transitions to the new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates and minimizes and appropriately considers the bill impacts associated with such transitions.

Proposed rates are considered by the CPUC in formal ratemaking proceedings for each utility. The state's Office of Ratepayer Advocates, consumer advocates, environmental organizations, and stakeholders review the utility application and may seek to intervene in the proceeding as parties.

There are two basic forms of ratemaking proceedings:

- CPUC General Rate Case (GRC)[27] proceedings occur on a three-year cycle. Phase I of a GRC determines the total amount of revenue the utility is authorized to collect, and Phase II assigns a share of these costs to each customer class, specifies marginal cost calculations, and determines retail rate schedules.

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25 California Constitution Sec. 6, added Nov. 5, 1974, by Prop. 12. Res.Ch. 88, 1974.

26 CPUC rate design principals are contained in CPUC Decision 15-17-001, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K110/153110321.PDF.

27 More information about CPUC General Rate Case (GRC) proceedings can be found at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-rates/general-rate-case.

- Rate Design Window[28] proceedings are shorter proceedings between GRC cycles that address rate design issues only. These proceedings, which can be initiated by either the utilities or the CPUC, take five to six months from start to finish.

The ratemaking proceeding is assigned to an administrative law judge (ALJ) and assigned commissioner. A proposed decision is issued after the matter is presented in an adjudicatory format before the ALJ and presiding commissioner. Costs associated with non-rate structure load management standards adopted by the CEC are also addressed in rate proceedings for purposes of inclusion in rates. Costs approved in rates must be just and reasonable, therefore it is important the CEC ensure any load management techniques adopted are cost-effective in order to be consistent with the intent of the load management standards and with CPUC rate design principles.

Exemptions

PRC Section 25403.5(c) provides a process for exemptions from the load management standards:

> The commission may also grant, upon application by a utility, an exemption from the standards or a delay in implementation. The grant of an exemption or delay shall be accompanied by a statement of findings by the commission indicating the grounds for the exemption or delay. Exemption or delay shall be granted only upon a showing of extreme hardship, technological infeasibility, lack of cost-effectiveness, or reduced system reliability and efficiency.

This clause allows the CEC to grant to a utility a delay or exemption in implementing one or more of the adopted standards upon making the appropriate findings.

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28 More information about CPUC rate design window optional filings can be found at https://www.publicadvocates.cpuc.ca.gov/EgyRateDesign.aspx.

CHAPTER 4: History of California Load Management Policy

> Consider a sophisticated residential customer who sees a 24-hour update, or one-hour update spot price combined with forecasts of future prices.
>
> The residence is equipped with digital logic, internal communication, metering and control hardware, and a user-friendly human-computer interface (displays, buttons, etc.). Two-way[29] electronic communication exists with the utility. The overall digital display and control system can be viewed as an expert system combined with optimization logics.
>
> The existence of the energy marketplace can cause the residential customer to purchase new appliances, etc., that are better able to respond… As time goes by, appliance manufacturers start to produce appliances designed to be able to exploit time-varying prices.
>
> - Schweppe, Fred C., Michael C. Caramanis, Richard D. Tabors, and Roger E. Bohn, *Spot Pricing of Electricity*, Kluwer Academic Publishers, Boston, MA, 1988.

Before the 1970s, electric reliability was met through "supply-side management" only – building new power plants to meet the steadily increasing demand. During the 1970s, the oil crisis, environmental concerns, and the partial meltdown at the Three Mile Island Nuclear Generating Station led to heightened public awareness of the need to bring escalating electricity consumption under control.

In California, the Warren-Alquist Act of 1974 established the CEC to respond to the energy crisis and the state's unsustainable demand growth. Among other things, the Act provided the CEC with the authority to develop appliance, building, and load management standards.

Between 1975 and 1978, Congress passed three Federal laws that laid the groundwork for the various demand-reduction and load-management strategies that collectively became known as demand-side management (DSM):

1975 – The Energy Policy and Conservation Act (EPCA)

1976 – The Energy Conservation and Production Act (ECPA)

1978 – The National Energy Conservation Policy Act (NECPA)

As state regulators began to realize that it was more cost-effective to help customers reduce energy demand through energy efficiency and better energy management than to build new power plants, the concept of "least-cost planning" was born. Under least cost planning, state energy agencies began requiring that utilities implement DSM programs wherever cost-effective.

29 Elsewhere in the chapter the authors recognized that one-way communication is adequate.

1970s – Research and Development

In 1976, the CEC began to research and develop the first load management standards. The load management team worked closely with state and local industry advocates like the Farm Bureau, California Large Energy Consumers Association (CLECA), and swimming pool manufacturers to pursue field pilots and research. Due to limited experience in either the United States (U.S.) or Europe, research into utility pricing options and cost-effectiveness analysis looked to academic venues. One of the key focal points for CEC efforts was the emerging Massachusetts Institute of Technology research on homeostatic controls for real-time pricing.[30]

Utilities in the midwestern U.S. were already using time-scheduled storage water heaters to reduce peak loads, but few other forms of residential or commercial appliance control were common. End-use control technologies were limited to timers or relays that interrupted the flow of power, communication technologies were confined to powerline and narrowband FM radio frequencies, and electro-mechanical metering systems were incapable of supporting time-dependent pricing options, much less real-time pricing.

With this background, the CEC, in collaboration with the CPUC and the five largest California electric utilities,[31] undertook 26 U.S. Department of Energy (DOE)-sponsored research pilots. A collaborative CEC-utility working group, in conjunction with advice from national experts, established detailed protocols to govern uniform experimental design, data collection, and analysis. To support the effort, the CEC designed and implemented the first ever automated end-use load research system.

The pilots themselves were designed to test TOU pricing as well as a broad range of communication technologies, control switches, control strategies, marketing, and customer recruitment methods. These and other treatments were targeted to a representative range of geographic and climate zones throughout California. The main lessons learned during this original research included:

1. **Customer willingness.** Customers were willing to accept reduced levels of air conditioning and water heating service in exchange for lower energy bills.
2. **Customer equity.** Payment incentives tended to overpay or underpay customers for their household's specific load and energy impacts. Payments also rewarded customers who owned the targeted appliances without parallel benefits for customers that did not own the electric air conditioners or water heaters – the sources of the high peaks in the first place. These equity issues were not present where incentives were tied to time-differentiated pricing options.
3. **Load Control.** Properly designed load control strategies achieved load and energy impacts throughout the targeted peak period and beyond but had many drawbacks.

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30 Fred C. Schweppe, Richard D. Tabors, and James L. Kirtley. Homeostatic Control: The Utility/Customer Marketplace for Electric Power. MIT Energy Laboratory Report MIT-EL 81-033. September 1981. Available at https://pdfs.semanticscholar.org/c17e/931b8dd739f18566197dacc95a2397e14398.pdf.

31 Pacific Gas & Electric Company, Southern California Edison, San Diego Gas & Electric Company, Los Angeles Department of Water and Power, and Sacramento Municipal Utility District.

- Customers had limited ability to influence control of their own devices to address health, religious, or other special circumstances.
- Control equipment physically installed into the wiring of customer-owned appliances required time consuming, expensive procedures, and jeopardized customer appliance warranties.
- Once installed, utility-controlled switches were subject to tampering and shielding by customers or service providers, undermining load impacts.
- Standalone time-clock controllers proved to be ineffective for two reasons: (1) periodic power outages interfered with time synchronized control, and (2) scheduling operations to fixed time periods rendered the load response inflexible.

The CEC concluded that customers were willing to manage their loads to save money, and that load management was feasible, but that real-time pricing would be required to expand load flexibility equitably and effectively. Since advanced meters and communication technologies were needed to enable real-time pricing, load management could not substantially advance until technology advanced. In the meantime, the load management standards required by the Legislature moved forward with the best available technology at the time.

1979 – The First Load Management Standards

In 1979, the CEC adopted four load management standards for the five largest electric utilities in the state: PG&E, SCE, SDG&E, LADWP, and SMUD. The four standards addressed rate structures, residential load control, swimming pool pump time control, and commercial building audits:

- The *Load Management Tariff Standard* (CCR, Title 20, § 1623) required utilities to develop marginal cost-based rates, using recommendations provided by a taskforce[32] comprised of staff from the CEC, CPUC, the five largest California utilities, and several consumer interest groups. The outcome of this effort was the establishment of mandatory time-of-use rates for customers with greater than 500 kilowatt (kW) of peak demand.
- The *Residential Load Management Standard* (CCR, Title 20, § 1622) required utilities to develop residential load control programs. The programs provided participants with remote switches for their space heaters, water heaters, and air conditioners. The utility could then shut down the devices for short periods during peak or emergency times. In return, participating customers received rebates and payments applied to their electric bills.
- The *Swimming Pool Filter Pump Load Management Standard* (CCR, Title 20, § 1624) required a large-scale effort to educate customers about efficient operation of swimming pool filter pumps. Customers were encouraged to install timers that would shut off the pumps during designated peak hours each day, while maintaining sufficient filtration and circulation.

32 Recommendations provided by the taskforce are available at https://digital.library.unt.edu/ark:/67531/metadc1052699/m2/1/high_res_d/5188919.pdf.

- The *Non-residential Load Management Standard* (CCR Title 20 § 1625) was an initiative to audit both small and large commercial customers to identify ways they could reduce peak load or shift it to off-peak periods.

Adoption of the CEC load management standards obligated California's electric utilities to achieve fixed customer participation and load control implementation targets within a two-year time frame. These programs were implemented and successfully contributed to peak load reductions in California for decades. Vestiges of these first standards can be found in today's commercial TOU rates and audits, and residential load control programs like SMUD's Peak Corps and SCE's Summer Discount programs.

Despite the relative success of the first load management standards, the underlying issues with incentive payments, load control, and the need for expanded time-dependent rates remained. Awaiting progress in metering, automation, and communications technologies, the CEC load management standards remained at a standstill for the next two decades.

1990s – Electric Utility Industry Restructuring

While California load management efforts stalled in anticipation of technology advancements, annual energy efficiency budgets grew rapidly from near zero in the 1970s to between $200 million and $600 million each year throughout the 1980s and 1990s.

In 1992, the U.S. Energy Policy Act required states to adopt an Integrated Resource Planning (IRP) process under which utilities would compare supply- and demand-side resources in determining the best mix for reliable service. In addition, utility investments in demand-side programs and services were required to be as profitable as supply-side investments, specifying monitoring and verification of demand-side measures. These measures put demand-side strategies on equal footing with supply-side strategies.

On September 23, 1996, California Governor Pete Wilson signed the Electric Utility Industry Restructuring Act (Assembly Bill 1890 (AB 1890), Brulte, Chapter 854, Statutes of 1996), which set the rules for a new electric system market structure to take effect on March 31, 1998. Prior to this date, electric utilities were responsible for generation, transmission, distribution, metering, and billing services. The restructuring bill transferred the first two of these outside the purview of the IOUs through the following changes:

- Direct Access. PG&E, SCE, SDG&E, PacifiCorp, Sierra Pacific Power, and Bear Valley Electric were required to provide their customers direct access to any seller of electricity operating in their area. Customers located in the service territories of these IOUs could choose their electric generation supplier. The intent of this change was to open competition in electricity markets and reduce retail electricity rates.
- California ISO. To ensure equal opportunity for generation suppliers, AB 1890 created an independent, statewide transmission system operator. The California ISO was given responsibility for scheduling the purchase and sale of electricity over the high voltage transmission system and ensuring the reliability of the grid.

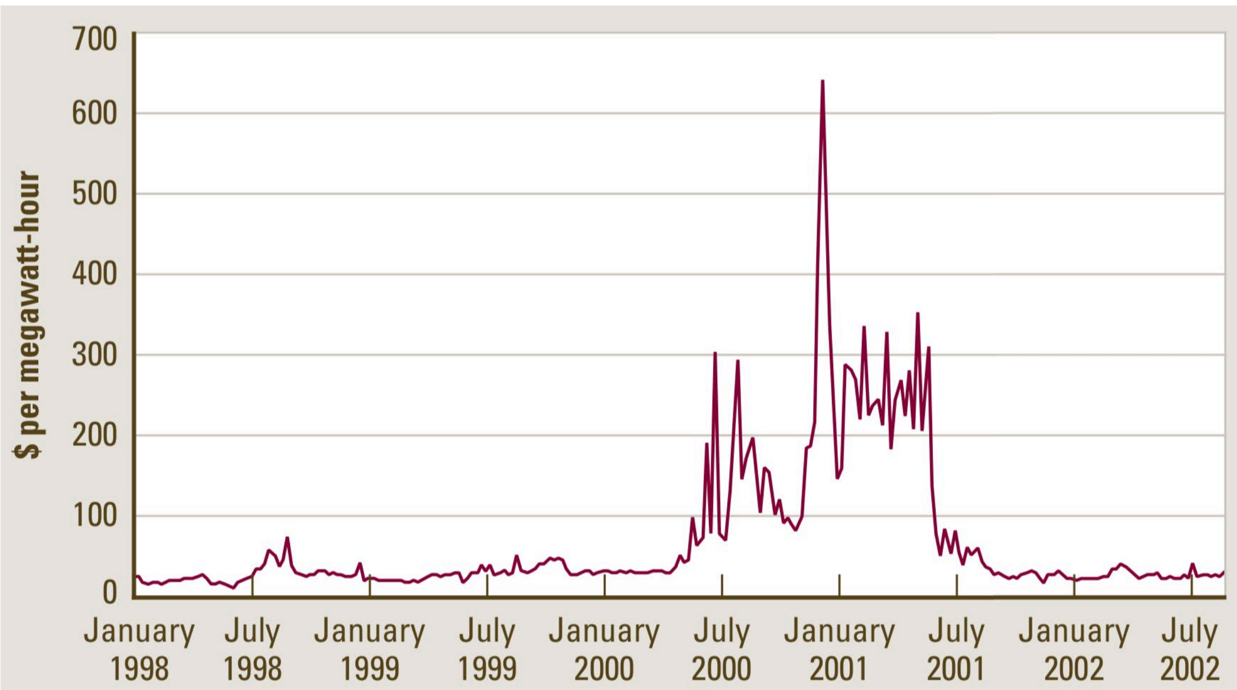
On March 31, 1998, AB 1890 went into effect. Utilities began to divest their power generation facilities while continuing to provide customers with distribution, metering, and billing services. Generators began selling their electricity on the new real-time "spot" market.

2000-2005 – The California Electricity Crisis and its Aftermath

In the summer of 2000, the California real-time electricity market began showing signs of volatility. Peak spot prices increased an order of magnitude beyond those of previous years, from roughly $30 per megawatt-hour (MWh) to over $300 per MWh (Figure 2).

On June 14, 2000, PG&E initiated a blackout for the first time in its history, affecting nearly 100,000 customers in San Francisco. Over the following year, the IOUs were forced to sell high-cost wholesale power at a loss and the California ISO called nine emergency events, initiating rolling blackouts that affected millions of customers. On September 20, 2001, in Decision 01-09-060, the CPUC suspended the right for customers to enter direct access agreements with generators, and energy prices normalized.

Figure 2: Weekly Average Peak Prices in West Coast Spot Markets, 1998-2002



Source: Pechman, 2007

The estimated cost of the electricity crisis to the state exceeded $40 billion. High on the list of casualties were the IOUs, financially damaged by the revenue imbalance of high purchase costs and low retail rates. This imbalance ultimately resulted in PG&E, the largest utility in the state, filing for bankruptcy.

In response to the crisis, DSM resurged as the best short-term solution. In 2001, California Governor Davis issued several executive orders, asking the state's residents and businesses to reduce energy use by 10 percent. Executive Order D-18-01 ordered the Department of Consumer Affairs to begin the state's multi-million dollar "Flex Your Power" public awareness campaign, which included radio and television advertisements as well as extensive web content.

The California Legislature passed several bills funding emergency DSM programs aimed at reducing peak demand.[33] Together, these bills appropriated over $500 million dollars for DSM programs. Over $250 million of this was appropriated to the CEC for peak electricity demand and energy conservation measures.

The CEC quickly installed 25,000 interval meters for nonresidential customers with maximum electric demands over 200 kW pursuant to Assembly Bill 29X (ABX1 29, Kehoe, Chapter 8, Statutes of 2001)[34] which lowered the mandatory TOU threshold from 500 kW to 200 kW. The CEC also channeled significant resources into further expanding the installation of advanced metering infrastructure and building technologies that would enable time-dependent rates for all customers, under the notion that price-responsive demand could prevent future wholesale market volatility.

The CPUC approved four new IOU demand response programs for summer 2001:

- **Basic Interruptible Program**. Offered fixed rate discounts of about 15 percent to large customers in exchange for demand reductions.
- **Voluntary Demand Reduction Program**. Compensated participants a fixed amount for each MWh of reduction.
- **Optional Binding Mandatory Curtailment Program**. Excused large participating loads from rotating blackouts in exchange for reduced demand as needed.
- **Air Conditioner Cycling Programs**. Issued participants an incentive in exchange for utility control of their air conditioner during occasional peak periods as needed.

The California ISO also administered demand response programs, separate from the IOUs:

- **Demand Relief Program**. Paid large customers to commit to reducing load during peak demand.
- **Discretionary Load Curtailment Program.** Paid demand response aggregators per MWh to arrange curtailment of many smaller loads.
- **Ancillary Services Load Program**. Allowed large participants to bid load reduction in the same way generators bid supply.

In 2003, the 1.5 gigawatts (GWs) of demand response in California consisted largely of emergency programs that powered down commercial buildings, industrial operations, and residential air conditioners; however, a consensus was growing that time-dependent rates must be part of the solution to California’s electricity woes.

33 AB 970 (Ducheny, Chapter 329, Statutes of 2000), ABX1 29 (Kehoe, Chapter 8, Statutes of 2001), and SBX1 5 (Sher, Chapter 7, Statutes of 2001).

34 ABX1 29 (Kehoe, Chapter 8, Statutes of 2001). Available at http://leginfo.ca.gov/pub/01-02/bill/asm/ab_0001-0050/abx1_29_bill_20010412_chaptered.html.

In an effort to redirect and align the state energy agencies on price-responsive demand resources, the Legislature declared in Senate Bill 1976 (AB 1976, Torlakson, Chapter 850, Statutes of 2002):[35]

- Californians can significantly increase the reliability of the electricity system and reduce the level of wholesale electricity prices by reducing electricity usage at peak times.
- Dynamic pricing, including real-time pricing, provides incentives to reduce electricity consumption in precisely those hours when supplies are tight and provides lower prices when wholesale prices are low.
- Real-time pricing integrates information technology into the energy business, and creates new markets for communications, microelectronic controls, and information.

Section 2 of SB 1976 directed the CEC, in consultation with the CPUC, to report to the Legislature and the Governor regarding the feasibility of implementing real-time pricing for electricity in California. In their report, the CEC estimated a potential long-run response to dynamic rates of between 3.4 and 15 percent (Table 2) and recommended that the state deploy a system of advanced metering systems to enable dynamic pricing, provided favorable cost-effectiveness analysis (CEC 2003).[36]

Table 2: Predicted Impacts of Dynamic Pricing

	Dynamic Rates as Default	**Dynamic Rates as Default**	**Voluntary Switch to Dynamic Rates**	**Voluntary Switch to Dynamic Rates**
	Low	High	Low	High
Short-Run Demand Response				
Total Megawatts (MW)	-2,200	-11,000	-2,100	-3,800
Percent of Peak Demand in 2013	-4.8	-24	-4.7	-8.4
Long-Run Demand Response				
Total Megawatts (MW)	-2,100	-6,900	-1,500	-5,200
Percent of Peak Demand in 2013	-4.6	-15	-3.4	-12

Source: CEC 2003, Feasibility of Implementing Dynamic Pricing in California

Simultaneously, the CEC and CPUC collaborated on parallel proceedings to investigate advanced metering, demand response, and dynamic pricing (CPUC Resolution 02-06-001; CEC Docket 02-DR-01).[37] In their Order Instituting Rulemaking, the CPUC observed the collaboration, writing: "As our first task in this proceeding, we will consider a strategic

35 SB 1976 (Torlakson, Chapter 850, Statutes of 2002). Available at http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=200120020SB1976.

36 Feasibility of Implementing Dynamic Pricing in California, October 2003, 400-03-020F. Available at https://escholarship.org/uc/item/1t57s3n2.

37 Docket log for 02-DR-01, Demand Response Order Instituting Rulemaking and Information Collection, available at https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=02-DR-01.

approach to the orderly development of demand-responsiveness capability in the California electricity market over the next 18 months. We are aware that the CEC has initiated work on this, both through their strategic planning and through installation of interval meters at customer sites with average demands of 200 kW and above, and we will seek to coordinate our efforts on an ongoing basis."

Over the next three years, staff from both agencies, in consultation with the California ISO, worked hand in hand to develop and implement California's loading order, the Statewide Pricing Pilot, the Demand Response Vision document, and new utility demand response programs.

2003 – California's Loading Order

The state's loading order established in the *2003 Energy Action Plan*[38] was adopted by both the CEC and the CPUC. The loading order prioritizes investments in conservation, energy efficiency, and demand response first; renewable energy and distributed generation second; and finally, in clean fossil fuel sources and infrastructure improvements. In 2004, the CPUC directed IOUs to follow the loading order in meeting resource needs. Since then, California IOUs have endeavored to employ energy efficiency and demand-side resources first, followed by renewable generation.

2003-2004 – The California Statewide Pricing Pilot

In May of 2003, the CPUC approved funding for the Statewide Pricing Pilot in Decision 03-03-036, a collaborative project supervised by the CPUC and the CEC, and implemented by the three large investor-owned electric utilities: PG&E, SCE, and SDG&E.[39] The main goal of the pilot and the accompanying impact evaluation was to develop a model for predicting residential and small commercial demand response under alternative pricing plans. The pilot involved placing roughly 2000 residential customers and 500 small commercial customers on experimental TOU and critical peak price (CPP) rate structures.

A study of the residential customer response indicated significant response to CPP events. Averaged across 27 events called between July 2003 and September 2004, residential customers with no automation (no responsive thermostat) provided up to 13 percent peak load drop during 5-hour events, while participants equipped with responsive thermostats shed 25 percent during 5-hour events, and 41 percent during 2-hour events.

Compared to buildings without responsive thermostats, buildings with air conditioning automation shed four times as much electrical load during critical peak events above 90 degrees Fahrenheit[40] (Figure 3).

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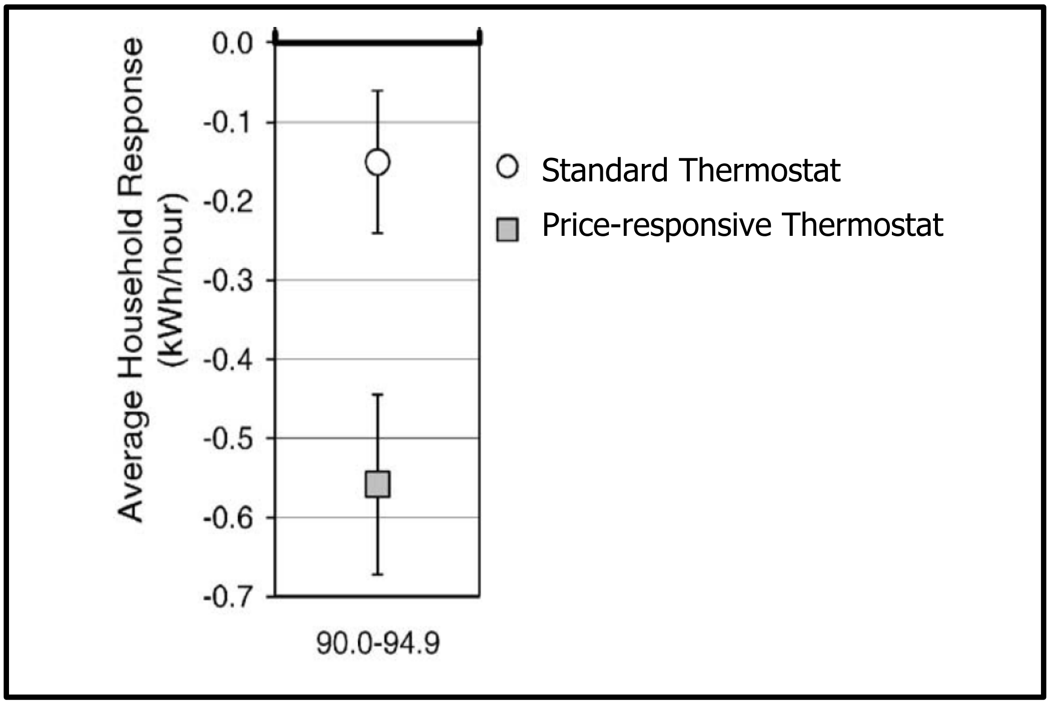
38 Energy Action Plans CPUC webpage. Available at https://www.cpuc.ca.gov/eaps/.

39 CPUC Decision 03-03-036. Interim opinion in phase 1 adoption pilot program for residential and small commercial customers, available at https://docs.cpuc.ca.gov/publishedDocs/published/FINAL_DECISION/24435.htm.

40 An exploratory analysis of California residential customer response to critical peak pricing of electricity.

Figure 3: Statewide Pricing Pilot CPP Response, with and without Air Conditioning Automation



Source: Herter, McAuliffe, and Rosenfeld, 2007

A demographic analysis of residential customers results indicated that high-use customers responded significantly more in kW reduction than did the low-use customers, while low-use customers saved significantly more in percentage reduction of annual electricity bills than did high-use customers. This result calls into question the equity of targeting only high-use customers for dynamic tariffs.

Across income levels, average load and bill changes were statistically indistinguishable, as were satisfaction rates. However, high-use customers earning less than $50,000 annually were the most likely of the groups to see bill increases, and about 5 percent experienced bill increases of 10 percent or more. This suggests that low-income customers with higher-than-average energy consumption should be targeted for increased energy efficiency and price-responsive automation measures prior to enrollment in dynamic rates.

Significant response rates were also found in the commercial sector: 6 to 9 percent peak load drop for commercial customers with no enabling technologies, and 14 percent peak load drop for commercial customers with responsive thermostats. Results for TOU rates were inconclusive. An analysis of responses to two different event TOU peak price levels – 50 cents per kWh and 68 cents per kWh – showed no statistical difference between the two.

2006-2015 – Interval Metering and Time Varying Rates

Following the success of the Statewide Pricing Pilot and responding to recommendations provided in the *2007 Integrated Energy Policy Report* (IEPR)[41], the CEC opened an informational and rulemaking proceeding on demand response rates, equipment, and protocols (Docket 08-DR-01). The main objective of the proceeding was to "adopt regulations and take other appropriate actions to achieve a price responsive electricity market." In particular, the CEC hoped to accelerate the implementation of interval meters and dynamic rates to expand load flexibility in the state beyond emergency demand response programs. The proceeding succeeded in garnering widespread involvement and collaboration with the CPUC, utilities, and other stakeholders.

Later that year, the CPUC issued its "Decision Adopting Dynamic Pricing Timetable and Rate Design Guidance for Pacific Gas & Electric Company," which provided a timeline for the IOUs to begin rolling out TOU and dynamic rates, listing the overall objectives of rate design as:[42]

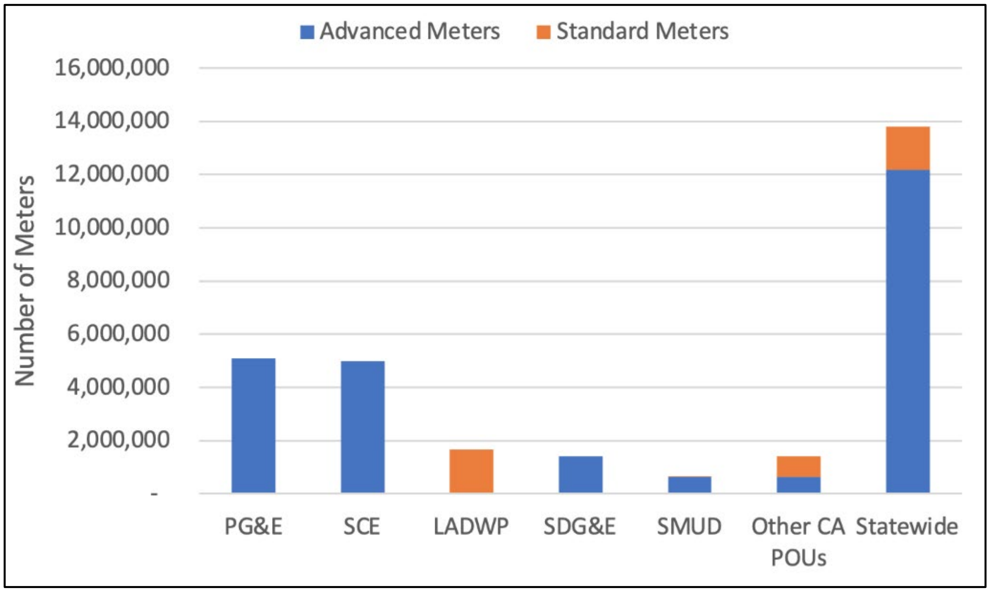
- To reflect the marginal cost of providing electric service so that consumers make economically efficient decisions.
- To flatten the load curve to reduce capital costs over time.
- To reduce load during short-term electricity supply shortfalls.

In 2009, PG&E, SCE, SDG&E, and SMUD began rolling out advanced metering infrastructure (AMI) along with time-varying rates for nonresidential customers. By 2013, these four utilities had installed over 12 million electric interval meters, enabling TOU and dynamic rates for nearly 100 percent of their customers. Roughly 90 percent of customers statewide now have the advanced metering required for time-varying rates (Figure 4). Of the utilities addressed by the load management standards, only LADWP does not yet have widespread AMI; however, they are in the process of developing plans to roll out AMI over the next decade.

41 Integrated Energy Policy Report – IEPR CEC webpage. Available at https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report.

42 California Public Utilities Commission, Decision #08-07-045. July 31, 2008.

Figure 4: Electricity Meters at California Utilities in 2021



Source: CPUC, 2020

CHAPTER 5: California Load Management Today

Across most of the U.S., electricity customers in all sectors have opportunities to benefit financially through participation in demand response programs. As touched on earlier in this report, utilities use two basic tools for encouraging demand response: (1) incentive-based programs, which pay or otherwise reward customers for managed electrical loads, and (2) time-varying rates, which charge customers prices that better correspond to the true cost of electricity. Although programs that involve paying customers to reduce their demand have long been considered inefficient alternatives to charging time-varying rates, these programs continue to be implemented and expanded at substantial cost to ratepayers.

Electric demand can be modified manually, automatically, or both. Generally, automated response outperforms manual response, while the combination of automated and manual response is most effective, since not all end-uses can be automated.[43]

Following is a review of the incentive programs and time-varying rates available in California.

Incentive Programs and Pilots

Incentive-based load management programs provide customers with participation incentives in the form of cash payments, bill credits, rate discounts, and reduced-cost technology installation. In return for these benefits, program participants either (a) allow the utility or aggregator to control their electricity end-uses during grid events or (b) manage the response themselves but incur penalties when promised load impact relative to a calculated baseline demand is not realized.

Most load management programs are implemented by the electric utilities through contractual agreements with customers. Over the past five years, PG&E, SCE, and SDG&E have also begun to contract with demand response providers or "aggregators," who market to and subscribe groups of customers for utility programs. The aggregators are then rewarded for their accumulated capacity. Customers can choose from several authorized California aggregators to act on their behalf with respect to receipt of incentive payments and payment of penalties. (See Appendix D for a list of DR aggregators.)

In 2019, incentive programs at PG&E, SCE, and SDG&E totaled roughly 1,200 MW, while demand response providers contributed another 570 MW.

Load Control Programs

Participants in load control programs receive a bill credit for allowing their utility to interrupt their electric service temporarily. By transmitting a signal to a control device installed on their pumping or air conditioning equipment, utilities automatically turn off customer loads for the duration of the event:

43 Examples of end-uses that can be manually but not automatically managed include microwave ovens and hair dryers.

- SCE Summer Discount Plan[44]
- SCE Agricultural & Pumping Interruptible Program
- SDG&E Residential AC Saver[45] and AC Saver Thermostat[46]
- SDG&E Commercial AC Saver[47] and Smart Thermostat Program[48]
- LADWP Power Savers[49]
- SMUD Peak Corps[50]

Base Interruptible Program (BIP, TOU-BIP)

The Base Interruptible Program (BIP) provides short-term load reductions on the day of California ISO emergency curtailments. BIP is integrated into the California ISO market as a Reliability Demand Response Resource. Nonresidential customers may enroll directly with their utility or with a third-party aggregator and must take service under a demand TOU rate schedule.

Prior to enrollment, customers must demonstrate their ability to meet a designated level of demand by participating in a curtailment test of maximum potential event duration. During events, participants are required to manage their load at or below this "firm service level" demand baseline.[51]

Capacity Bidding Program (CBP)

The Capacity Bidding Program (CBP) is a program that rewards aggregators for being available to reduce load, and then again for actual energy reductions during events. Residential customers can participate in CBP only by enrolling through an aggregator, while nonresidential customers have the option to qualify for self-aggregation. CBP is integrated into the California

44 SCE Summer Discount Plan. Available at https://www.sce.com/sites/default/files/inline-files/135650_DR%20Programs%20Fact%20Sheet%200520%20FINAL%20WCAG.pdf.

45 SDG&E Residential AC Saver. Available at https://www.sdge.com/residential/savings-center/rebates/your-heating-cooling-systems/summer-saver-program.

46 SDG&E AC Saver Thermostat. Available at https://www.sdge.com/residential/savings-center/energy-saving-programs/reduce-your-use/reduce-your-use-thermostat.

47 SDG&E Commercial AC Saver. Available at https://www.sdge.com/businesses/savings-center/energy-management-programs/demand-response/summer-saver-program.

48 SDG&E Smart Thermostat Program. Available at https://www.sdge.com/business-thermostat.

49 LADWP Power Savers. Available at https://enrollmythermostat.com/ladwp/.

50 SMUD Peak Corps. Available at https://www.smud.org/en/In-Our-Community/Help-your-Community/Peak-Corps.

51 PG&E BIP information. Available at https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-BIP.pdf. SCE PIP information. Available at https://www.sce.com/sites/default/files/inline-files/135650_DR%20Programs%20Fact%20Sheet%200520%20FINAL%20WCAG.pdf. SDG&E BIP information. Available at https://www.sdge.com/businesses/savings-center/energy-management-programs/demand-response/base-interruptible-program.

ISO as a Proxy Demand Resource and so must comply with California ISO tariff requirements. (See PG&E CBP, SCE CBP, and SDG&E CBP)[52]

Self-Generation Incentive Program (SGIP)

Newer demand response programs are heavily focused on the use of energy storage systems. The largest of these, the CPUC's SGIP,[53] sets aside over $700 million dollars for California IOU programs that install responsive energy storage, including batteries and heat pump water heaters.[54]

Proxy Demand Resource Pilots

The Excess Supply Demand Response Pilot (XSP)[55] is focused on testing the capabilities of demand-side resources to increase load during times of anticipated excess renewables supply or negative wholesale energy prices. XSP is open to aggregators within the PG&E service territory. Despite being touted as a test for "price responsive" resources, the XSP is an incentive-based program that relies on capacity payments relative to the California ISO's 10-in-10 baseline estimate, which measures performance as the difference between event usage and the average usage of 10 recent and similar non-event days.

The Supply Side II Demand Response Pilot[56] is also open to customers and aggregators within the PG&E service territory. Each participant must register at least 100 MW of capacity made up of one or more residential or nonresidential locations within a single utility sub-load aggregation point (sub-LAP). Capacity and energy payments are calculated using event-day deviations from the California ISO 10-in-10 baseline.

Demand Response Provider (DRP) Programs

Demand Response Providers (DRP) offer programs that combine both manual and automated demand response, but their success can be limited by lack of access to customer data and market rules that limit financial opportunity. See Appendix D for a list of non-utility demand response providers with links to their offerings.

Time-dependent Rates

Time-dependent rates are designed to reflect the time-dependent marginal cost of electricity more accurately, on a daily, hourly, or sub-hourly basis. The more closely retail prices are aligned with marginal costs in space and time, the better customers can manage flexible loads,

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52 PG&E CBP information. Available at https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-CBP.pdf. SCE CBP information. Available at https://www.sce.com/sites/default/files/inline-files/135650_DR%20Programs%20Fact%20Sheet%200520%20FINAL%20WCAG.pdf. SDG&E CBP information. Available at https://www.sdge.com/businesses/savings-center/energy-management-programs/demand-response/capacity-bidding-program.

53 CPUC's Self-Generation Incentive Program. Available at https://www.selfgenca.com/.

54 Self-Generation Incentive Program Handbook. March 2020. Available at https://www.selfgenca.com/.

55 Excess Supply Demand Response Pilot (XSP). Available at https://olivineinc.com/services/our-work/xsp/.

56 Supply Side II Demand Response Pilot. Available at https://olivineinc.com/services/our-work/ssp/.

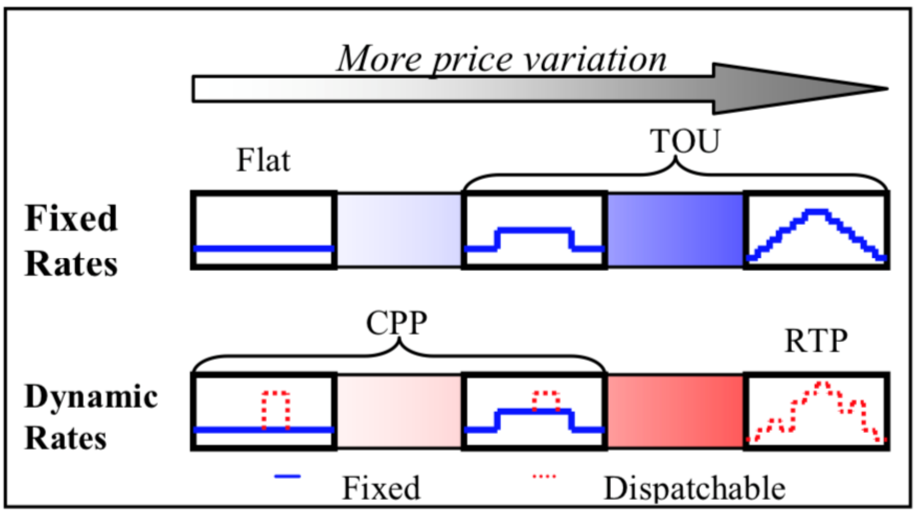
enabling further development of carbon-free supply resources and improving system efficiency.

Relative to the flat and tiered rates that have dominated residential rate design until the past few years, time-varying electricity rates are designed to mirror the variability in wholesale electricity prices, with the intended effect of discouraging electricity use during periods of high demand and encouraging use when supplies are plentiful.

Unlike the incentive programs described above, time-dependent rates have the added benefit of reducing overall energy use, since customers on time-dependent rates have a strong incentive to install efficiency measures that reduce peak loads.

Common time-dependent rate designs can be categorized into three basic groups: TOU, CPP, and real-time pricing (RTP) (Figure 5).[57] By the end of 2020, more than half of California customers were on time-dependent rates, and dynamic rates accounted for over 900 MW of load flexibility at the California IOUs.

Figure 5: Rate Designs in Order of Increasing Variation and Precision



Source: Herter, McAuliffe, and Rosenfeld, 2003

The following section addresses types of rate design in more detail.

Time-of-Use Pricing

TOU pricing refers to a rate structure in which rates vary according to the time of day, season, and day type. Higher rates are charged during peak demand hours of the day. Such rates have at least two prices, peak and off-peak, with some having a third commonly referred to as a shoulder, part-peak, or mid-peak.

Pros. Under TOU pricing, customers have an incentive to conserve electricity during the higher priced periods and shift electricity use to the lower priced periods. Thus, relative to flat or tiered pricing, TOU pricing results in a more efficient use of resources and can reduce costs for both the utility and customers. As discussed earlier in this report, studies show that

57 The authors consider Variable Peak Pricing (VPP) a more dynamic form of CPP.

automation devices programmed with TOU periods are effective in improving demand flexibility and lowering TOU bills.

Cons. While TOU rates are a significant improvement over flat or tiered rates, they are not dynamic, meaning they cannot be called to relieve system emergencies. TOU prices and time periods are fixed well in advance. TOU rates can be changed only by changing the tariff itself, a process that can take years to complete. Thus, TOU rates are incapable of reflecting continuous hourly variation or disaster-driven price spikes in wholesale electricity markets, resulting in inefficient retail purchasing behavior and higher overall rates.

Status. TOU pricing became the default rate for large commercial and industrial customers at PG&E, SCE, SDG&E, LADWP, and SMUD in the 1980s following the first load management standards. Smaller nonresidential customers were added to default TOU rates in 2009 following the CEC and CPUC collaboration on demand response, advanced metering, and dynamic rates.

In 2013, SMUD became the first utility in the state to approve residential rate reform focused on moving away from tiered rates by implementing default TOU rates. Their decision was based on the successful results of their Smart Pricing Options pilot, which showed a 6 percent peak load savings with default residential TOU rates[58].

Following SMUD's change, the CPUC ordered PG&E, SCE, and SDG&E to conduct a pilot of default TOU rates in the residential sector. The results of the pilot[59] indicated statistically significant 4-9 PM peak impact reductions of 2-4 percent in the winter and 4-6 percent in the second summer of study (Table 3). Based on these successful outcomes, the CPUC ordered the IOUs to transition residential customers to default TOU rate plans beginning in 2019 (D.15-07-001).

Table 3: California IOU Weekday 4-9 PM Load Reductions Under TOU Pricing

IOU 4-9 PM TOU Rate	Winter 2016/2017 (Percent)	Summer 2017 (Percent)
PG&E Rate 3	3.5	5.6
SCE Rate 3	3.2	4.0
SDG&E Rate 1	2.3	4.6

Source: Nexant 2018, California Statewide Opt-in Time-Of-Use Pricing Pilot

58 Public Interest Energy Research (PIER) Energy Savings Through Smart Controls in Multifamily Housing Study: Impact Analysis. Available at https://businessdocbox.com/Green_Solutions/94744060-Public-interest-energy-research-pier-energy-savings-through-smart-controls-in-multifamily-housing-study-impact-analysis.html.

59 Nexant, Inc. and Research Into Action. March 2018. *California Statewide Opt-in Time-of-Use Pricing Pilot*. Available at https://energynews.us/wp-content/uploads/2020/09/Statewide_Opt-in_TOU_Evaluation-Final_Report-2.pdf.

Links to utility time-of-use sites:

- PG&E: Residential TOU, Commercial TOU[60]
- SCE: Residential TOU, Commercial TOU[61]
- SDG&E: Residential TOU Pricing Plans, EV pricing plans, Commercial TOU[62]
- LADWP: Residential TOU, Commercial/Industrial TOU[63]
- SMUD: Residential TOU[64]

A more complete list of time-varying rates can be found in Appendix C.

Critical Peak Pricing (CPP)

Under CPP, customers are given a rate discount in exchange for high peak prices on 5 to 15 days per year, referred to as critical peak days or "event" days, as determined by the utility in advance of expected grid constraints. Utilities can call event days as needed to avoid, for example, outages or the use of expensive peaking power plants.

A typical CPP tariff might have 60 event-hours in one year offset by a discounted rate in the other 8,700 hours. Utilities typically notify customers the day before an event day by text, phone, and email, and sometimes through an automation signal directly to connected devices. To provide further predictability, CPP event periods are typically (but not always) aligned with TOU peak periods.

Pros. CPP rates improve on the accuracy of flat, tiered, or TOU pricing by allowing utilities to initiate dynamic price increases on short notice when expecting critical peak demands. Because CPP rates are designed to be revenue neutral, customers who can save during events are likely to save on their annual bills. Automation devices that receive CPP event signals can significantly increase CPP response. This also bypasses the need for customers to be aware or present and allows for personal customer decisions about end-use response.

Cons. Many California utilities, including PG&E, SCE, SDG&E, and SMUD, provide CPP event using OpenADR technology. One of the major drawbacks of OpenADR is that it is not

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60 PG&E Residential TOU rates. Available at https://www.pge.com/en_US/residential/rate-plans/rate-plan-options/time-of-use-base-plan/time-of-use-plan.page. PG&E Commercial TOU rates. Available at https://www.pge.com/en_US/small-medium-business/your-account/rates-and-rate-options/compare-rates.page.

61 SCE Residential TOU rates. Available at https://www.sce.com/residential/rates/Time-Of-Use-Residential-Rate-Plans. SCE Commercial TOU rates. Available at https://www.sce.com/business/rates/time-of-use.

62 SDG&E Residential TOU pricing plans. Available at https://www.sdge.com/whenmatters. SDG&E Electric Vehicle pricing plans. Available at https://www.sdge.com/residential/pricing-plans/about-our-pricing-plans/electric-vehicle-plans. SDG&E Commercial TOU rates. Available at https://www.sdge.com/businesses/pricing-plans/time-use-tou-pricing-plans-business.

63 LADWP Residential TOU rates. Available at https://www.ladwp.com/ladwp/faces/ladwp/aboutus/a-financesandreports/a-fr-electricrates/a-fr-er-electricrateschedules. LADWP Commercial/Industrial TOU rates. Available at https://www.ladwp.com/ladwp/faces/ladwp/aboutus/a-financesandreports/a-fr-electricrates/a-fr-er-stcommindrates.

64 SMUD Residential TOU rates. Available at https://www.smud.org/en/Rate-Information/Residential-rates.

commonly available in residential control devices such as thermostats. This lack of automation limits the effectiveness of residential CPP and likely limits participation levels as well.

Although CPP rates improve load flexibility relative to TOU rates, allowing more refined temporal response by offering increased incentives at especially critical times, their effectiveness is restricted by contractual limits. Most CPP rates are available for less than two percent of the hours in the year, and on summer afternoons only. In addition, where CPP periods are misaligned with TOU peak periods, TOU automation has reduced effectiveness.

Status. In February 2010, the CPUC approved CPP for PG&E customers in Application 09-02-022.[65] PG&E refers to its commercial CPP offerings as Peak Day Pricing,[66] and its residential CPP as SmartRate.[67] In March 2013, the CPUC approved CPP for SCE customers in Application 11-06-007.[68] CPP is the default option for all of SCE's nonresidential customers, including agricultural and water pumping customers (Rate Schedules TOU-GS-1, TOU-GS-2, TOU-GS-3, TOU-8, and TOU-PA-3). SCE does not offer a residential CPP rate. In December 2012, the CPUC approved CPP for SDG&E customers in Application 10-07-009.[69] This proceeding was reopened and consolidated with Application 19-03-002[70] in June 2019. CPP is the default option for all of SDG&E's large nonresidential customers (Rate Schedule CPP-D Time of Use Plus).[71]

Real Time Pricing (RTP)

Real-time pricing plans charge a customer the real-time or near real-time price for all or part of their electricity use. The effectiveness of RTP depends on the method for communicating the price to the consumer and an interval meter for measuring the customers hourly, 15-minute or 5-minute energy use to bill against a rate of the same frequency. When grid supplies are low or demand is high, the wholesale price of electricity tends to increase, motivating customers to reduce electricity use. When renewable resources are plentiful, the wholesale price of electricity is low or negative, encouraging customers to shift services to times with an abundance of zero-carbon energy. This benefits customers by reducing their

65 PG&E Application 09-02-022. Available at https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A0902022.

66 PG&E Peak Day Pricing program information. Available at https://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/demandresponse/peakdaypricing/PDPGuide_tools_tips.pdf.

67 PG&E SmartRate program information. Available at https://www.pge.com/en_US/residential/rate-plans/rate-plan-options/smart-rate-add-on/smart-rate-add-on.page.

68 Application 11-06-007. Available at https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1106007.

69 Application 10-07-009. Available at https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1007009.

70 Application 19-03-002. Available at https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1903002.

71 SDG&E's large commercial and industrial rate schedule CPP-D. Available at https://www.sdge.com/businesses/savings-center/energy-management-programs/demand-response/critical-peak-pricing.

electricity bills, while at the same time improving system reliability, lowering GHG emissions, and relieving upward pressure on wholesale market prices.

One of the longest running real-time pricing programs in the U.S. is a two-part real-time pricing plan offered by Georgia Power. Under their plan, large commercial and industrial customers are charged a fixed price for their baseline electricity consumption in a typical year. When a customer exceeds their baseline, they pay the spot price for the amount above the baseline. When a customer consumes less than their baseline amount, the utility pays the customer the spot price for the difference.[72]

Pros. While the dynamic nature of CPP rates provide a better temporal connection between wholesale and retail markets than do flat or TOU tariffs, as with TOU rates, CPP price values are fixed – predetermined and documented in the tariff sheets. RTP price values, in contrast, are determined no more than a day or two prior to being charged. Thus, RTP rates can be said to be the most accurate reflection of market conditions in near real-time.

Cons. Real-time electricity rates are unavailable in California with very few exceptions. SCE's large commercial and industrial RTP rate plan[73] charges hourly electricity prices that vary based on the time of day, season, and temperature. Demand charges are incurred on top of the time and temperature varying rates.

Status. Historically, the CPUC has supported RTP in concept. For example, in 2008 the CPUC wrote:

> RTP is the best rate to promote economic efficiency and equity between customers. RTP can also connect retail rates with California's greenhouse gas policies if wholesale energy prices reflect the cost of greenhouse gas emissions.
>
> For example, when wholesale energy prices are being set by inefficient generation sources with high greenhouse gas emissions, RTP could reflect the cost of greenhouse gas emissions and discourage retail customers from consuming polluting power. Conversely, if other time periods are dominated by non-emitting resources such as nuclear, water, and wind, RTP could signal to customers that the supply of power is clean…The January 23, 2008 Ruling recommended that RTP should be based on the CAISO's day-ahead hourly market prices… customers could be offered a voluntary RTP rate based on day-of prices since some limited number of customers may be willing to respond to day-of prices… Developing the details of how to index the CAISO's day-ahead hourly price to the retail rate should wait until the MRTU day-ahead market is operating and can be assessed… In this decision, we will adopt the following general guidance:
>
> - The energy charge should be indexed to the CAISO's day-ahead hourly market prices.

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72 Georgia Power RTP-DA-5 Rate Schedule. Available at https://www.georgiapower.com/content/dam/georgia-power/pdfs/business-pdfs/rates-schedules/RTP-DA-5.pdf.

73 SCE's large commercial and industrial RTP rate plan. Available at https://www.sce.com/sites/default/files/inline-files/RTP%20Fact%20Sheet%200918_WCAG_3.pdf.

- At least initially, RTP should be based on day-ahead hourly market prices that have been aggregated across PG&E's service territory. As the market develops, locational prices should be considered. (Decision 08-07-045)

In Decision 12-12-004, the CPUC stated:

> Commission policy favors making dynamic rates available to all classes of electricity customers.

In Decision 17-01-006, the CPUC again indicated support for dynamic rates, including real-time pricing.[74] Recently, the CPUC approved a dynamic Vehicle-to-Grid Integration rate and the Public Grid Integration Rate, which includes a component tied to the California ISO Day-Ahead Hourly Price.

In 2019, the CPUC denied a petition for rulemaking on real-time pricing on the grounds that rate designs should be addressed in general rate cases.[75] However, later that same year, the CPUC hosted a workshop on dynamic rates and real-time pricing as part of SDG&E's General Rate Case Phase 2 Proceeding (Application 19-03-002), signaling a willingness to consider the issue. Workshop attendees discussed existing dynamic rates, shared preliminary proposals for new rates, and explored implementation issues.[76]

On April 6, 2020, the California Solar and Storage Association, OhmConnect, Inc., and California Energy Storage Alliance filed joint testimony[77] as the Joint Advanced Rates Parties (JARP) under CPUC proceeding A.19-03-002.[78] Their testimony proposed that an RTP rate be made available to all customer classes on an opt-in basis. Since then, SDG&E and the JARP have been engaged in settlement discussions. On August 27, 2020, the CPUC issued an

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74 See, e.g., at Appendix 2 Illustrative Time-Varying Rates Compendium of Rate Designs Discussed in Rulemaking 15-12-012.

75 CPUC. March 2019. Decision Denying Petition to Open a Rulemaking to Consider Real Time Pricing for Electricity and Demand Charge Reforms. Decision D.19-03-002. See finding of fact 12. Available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M273/K643/273643295.PDF.

76 SDG&E 2019 GRC Phase 2 (A.19-03-002). July 2019. Workshop on Marginal Costs & Revenue Allocation. Available at https://www.sdge.com/sites/default/files/regulatory/GRCP2_A1903002_workshop1_07292019_Final%20%28003%29.pdf.

77 California Public Utilities Commission. April 2020. Prepared Testimony of the California Solar and Storage Association, OhmConnect, Inc., and California Energy Storage Alliance ("Joint Advanced Rate Parties"). Available at https://static1.squarespace.com/static/5b96538250a54f9cd7751faa/t/5e8cc24904f0de100a1532c2/1586283083337/2020-04-06+Joint+Advanced+Rate+Parties+Testimony+on+SDG%26E+2019+GRC+Application+-+FINAL.pdf.

78 CPUC proceeding A.19-03-002. Available at https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1903002.

extension of the statutory deadline[79] to allow time for evidentiary hearings and briefs prior to the issuance and review of a final decision D.21-07-010, which was filed on July 15, 2021.

Automated Demand Response

Automated Demand Response or "AutoDR" is a technology that enables CBP customers to automate their load management routine. Utilities offer programs that help customers install and manage their AutoDR technologies as standalone programs or to be combined with other incentives such as CBP or time-varying rates, discussed in the next section. (See SMUD PowerDirect®, SDG&E Technology Incentives).[80]

Summary of California Load Management Programs

Table 4 provides a categorization of currently available load management programs in California. While this list is not exhaustive, it highlights some of the shortcomings of California's current portfolio of demand response resources. First, the table makes clear that most programs benefit customers through incentive payments or installed technologies – strategies that have serious shortcomings as previously mentioned and more thoroughly discussed in following sections.

Although time-varying rates have become widely available, options for customer automation are generally limited or non-existent. Successful automated price response pilots and programs in California and elsewhere may hold clues to effective future implementations.[81]

Table 4: Summary of Demand Response Programs in California

Program Type	Customer Benefit	Control	Examples	Behavior Rewarded?
Load Control	Incentive	Utility	PG&E SmartAC SCE Summer Saver SMUD Peak Corps SGIP	No
AutoDR	Incentive	Customer	CBP+AutoDR PTR+AutoDR	Yes
TOU rate	Bill savings	Customer	TOU rates	Yes
CPP rate	Bill savings	Customer	CPP rates CPP+AutoDR	Yes
RTP rate	Bill savings	Customer	SCE RTP	Yes

79 CPUC Decision 20-08-052. Available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M346/K098/346098820.PDF.

80 SMUD PowerDirect® information. Available at https://www.smud.org/en/Business-Solutions-and-Rebates/PowerDirect-Technology. SDG&E Technology Incentives program information. Available at https://www.sdge.com/businesses/savings-center/energy-management-programs/demand-response/technology-incentives.

81 SMUD Summer Solutions Time-of-Day Rates webpage. Available at https://www.smud.org/en/Rate-Information/Time-of-Day-rates/Time-of-Day-5-8pm-Rate. Oklahoma Gas and Electric SmartHours webpage. Available at https://www.oge.com/wps/portal/ord/residential/pricing-options/smart-hours/.

Note: "Customer" control may be managed by customers or customer-chosen ASPs. "Utility" automation may be managed by utilities or utility-chosen ASPs.

Source: CEC Staff, 2020

CHAPTER 6:
Load Management Efforts at the CEC

PRC Section 25402 directs the CEC to: "reduce the wasteful, uneconomic, inefficient, or unnecessary consumption of energy, including the energy associated with the use of water, *and to manage energy loads to help maintain electrical grid reliability*" (emphasis added). As detailed in Chapter 2 on the History of Load Management in California, the CEC exercised its authority to advance early load management efforts through regulation. Since 1979, the CEC has continued efforts to address load management, through standards, research and development projects, data analysis, and reporting. More recently, as a foundation for the proposed load management standard amendments herein, the CEC has developed a pilot statewide database intended to seed freely available mass-market demand automation.

Statewide Standards

The Warren-Alquist Act of 1974 established the CEC's broad ranging authority to create standards for appliances, buildings, and load management. This authority has been expanded over time to address new situations, trends, and technology. This section describes each of these standards authorities and provides information on further resources.

Flexible Demand Appliance Standards

Senate Bill 49 (SB 49, Skinner, Chapter 697, Statutes of 2019)[82] authorizes the CEC to adopt regulations establishing standards and labeling requirements for flexible demand appliances, which can schedule, shift, or curtail electric demand of appliances, in order to reduce the greenhouse gases emitted in electricity generation (PRC § 25402(f)(1)). This is separate and distinct from the CEC's authority to prescribe energy efficiency standards and labeling requirements "for minimum levels of operating efficiency" of appliances to reduce their energy consumption (PRC § 25402(c)(1)(A)).

SB 49 directs the CEC to establish standards and labeling requirements "to facilitate the deployment of flexible demand technologies" for appliances. These standards and labeling requirements encompass technical measures taken by energy customers, third parties, load-serving entities, or a grid balancing authority (with customers' consent) "that will enable appliance operations to be scheduled, shifted, or curtailed to reduce emissions of greenhouse gases associated with energy generation" (PRC § 25402(f)(7)(A)). The regulations the CEC adopts must be feasible and cost-effective. Starting on January 1, 2021, the CEC must describe any actions it has taken pursuant to SB 49 in the IEPR (PRC § 25402(f)(6)).

82 Senate Bill 49 (SB 49, Skinner, Chapter 697, Statutes of 2019). Available at https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200SB49.

In October 2020, the CEC issued an Order Instituting Rulemaking to adopt regulations to establish standards for flexible demand technologies for appliances (Docket 20-FDAS-01).[83] This proceeding is being conducted in coordination with existing and future Building Energy Efficiency Standards and proposed load management standards efforts. The proposed amendments will complement the ability of flexible demand appliances to better schedule, shift, or curtail their electric demand. More information on this effort can be found on the Flexible Demand Appliances website.[84]

Building Energy Efficiency Standards Related to Load Management

PRC Section 25402(a)(1) authorizes the CEC to, "Prescribe, by regulation, lighting, insulation, climate control system, and other building design and construction standards that increase efficiency in the use of energy and water for new residential and new nonresidential buildings." The California Energy Code consolidates demand response control requirements in California Code of Regulations, Title 24, Section 110.12, which includes the requirement for OpenADR certification or the ability to respond to a demand response signal from a certified OpenADR certified virtual end node, where applicable. Other sections of the Energy Code are related to or address load management, including the following Joint Appendices (JA):

- JA-3 Time Dependent Valuation[85]
- JA-5 Technical Specifications for Occupant Controlled Smart Thermostats[86]
- JA-11 Qualification Requirements for Photovoltaic System[87]
- JA-12 Qualification Requirements for Battery System[88]
- JA-13 Qualification Requirements for Heat Pump Water Heater Demand Management System[89]

83 CEC Docket 20-FDAS-01, Flexible Demand Appliance Standards. Available at https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=20-FDAS-01.

84 Flexible Demand Appliances website. Available at https://www.energy.ca.gov/proceedings/energy-commission-proceedings/flexible-demand-appliances.

85 California Building Energy Code, JA-3 Time Dependent Valuation. Available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=223245-4.

86 California Building Energy Code, JA-5 Technical Specifications for – Occupant Controlled Smart Thermostats. Available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=223245-6.

87 California Building Energy Code, JA-11 Qualification Requirements for Photovoltaic System. Available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=223245-6.

88 California Building Energy Code, JA-12 Qualification Requirements for Battery System. Available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=223245-13.

89 California Building Energy Code, JA-13 Qualification Requirements for Heat Pump Water Heater Demand Management System. Available at https://www.energy.ca.gov/sites/default/files/2020-07/JA13_Qualification_Requirement_HPWH_DM_ADA.pdf.

More information on this effort can be found on the Building Energy Efficiency Standards website.[90]

Load Management Standards

Pursuant to PRC Section 25403.5(a)(1-3) the CEC is required to, "adopt standards by regulation for a program of electrical load management for each utility service area."[91] In meeting this mandate the CEC is required, but not limited to, consideration of adjustments in rate structure, end-use storage, and mechanical and automatic mechanisms that control daily and seasonal peak load.

Existing load management standards can be found in CCR Title 20, Article 5, Sections 1621-1625, as listed below:

- § 1621. General Provisions.[92]
- § 1622. Residential Load Management Standard.[93]
- § 1623. Load Management Tariff Standard.[94]
- § 1624. Swimming Pool Filter Pump Load Management Standard.[95]
- § 1625. Non-Residential Load Management Standard.[96]

More information on this proceeding can be found on the Load Management Standards website.[97]

Research and Development Funding

EPIC Research and Demonstration Projects

California's Electric Program Investment Charge (EPIC) funds the CEC's EPIC program, which in turn provides funding to public and private entities for the advancement of energy research

90 CEC Building Energy Efficiency Standards website. Available at https://www.energy.ca.gov/programs-and-topics/programs/building-energy-efficiency-standards.

91 Public Resource Code Section 25403.5 (a). Available at https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=PRC&sectionNum=25403.5.

92 California Code of Regulations, § 1621. General Provisions. Available at https://govt.westlaw.com/calregs/Document/I927F2FC0D44E11DEA95CA4428EC25FA0.

93 California Code of Regulations, § 1622. Residential Load Management Standard. Available at https://govt.westlaw.com/calregs/Document/I74822F10FB3911DEB55BEB7A3F18BAB6.

94 California Code of Regulations, § 1623. Load Management Tariff Standard. Available at https://govt.westlaw.com/calregs/Document/I74B5E940FB3911DEB55BEB7A3F18BAB6.

95 California Code of Regulations, § 1624. Swimming Pool Filter Pump Load Management Standard. Available at https://govt.westlaw.com/calregs/Document/I74E117F0FB3911DEB55BEB7A3F18BAB6.

96 California Code of Regulations, § 1625. Non-Residential Load Management Standard. Available at https://govt.westlaw.com/calregs/Document/I93D2D8E0D44E11DEA95CA4428EC25FA0.

97 Load Management Standards website. Available at https://www.energy.ca.gov/proceedings/energy-commission-proceedings/2020-load-management-rulemaking.

and technology demonstration. The EPIC program has funded multiple research projects related to dynamic pricing and load flexibility. A searchable list of current research is available on the CEC's Energy Innovation Showcase[98], and a full list of completed research reports is available on the Energy Research and Development Reports and Publications website.[99]

On September 9, 2020, the EPIC program released a competitive solicitation to fund up to $16 million to establish a flexible load research and deployment hub (CalFlexHub). The purpose of the hub is to conduct applied research, development, demonstration, and deployment projects that advance flexible load technologies and their market adoption.

The solicitation required bidders to "develop new demand flexibility technologies consistent with California's building energy efficiency, appliance, and load management standards," further specifying: "The CEC's 2020 Load Management Rulemaking has begun implementation of an online database for statewide electricity pricing and GHG signals. To the extent that the rulemaking is successful in timely implementation of this database and system, the Hub research projects should be compatible with and make use of the data resulting from the load management standards and use the resulting statewide rate database for automation signaling."

The CEC received three proposals by the due date of November 19, 2020. Each proposal was screened, reviewed, evaluated, and scored using the solicitation criteria. The final Notice of Proposed Award identifies each applicant, their score, and recommended funding amounts.[100]

Lawrence Berkeley National Laboratory was awarded a four-year, $16 million, EPIC grant for CalFlexHub to develop a communication system that provides utility rates and GHG signals from the CEC's MIDAS database. This signal communication will enable virtually all Californians and their compatible devices, including those without internet access, to receive the signal to support the load management standards.

Demand flexibility projects tested and demonstrated under CalFlexHub will respond to MIDAS so those devices can dynamically adjust their demand based on price, GHG intensity, and user preference. Some initial projects include developing and demonstrating load flexible combined heat pumps for space conditioning and water heating, optimizing thermal or battery storage with other load flexible end-uses, and building-related vehicle-grid integration in residential and commercial applications.

More information on this effort can be found on the California Flexible Load Research and Deployment Hub website.[101]

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98 CEC's Energy Innovation Showcase. Available at http://innovation.energy.ca.gov/.

99 Energy Research and Development Reports and Publications website. Available at https://www.energy.ca.gov/energy-rd-reports-n-publications.

100 Flexible Load Research Hub Notice of Proposed Award. Available at https://www.energy.ca.gov/sites/default/files/2021-01/GFO-19-309%20NOPA%20Cover%20Letter%20%26%20Results%20Tbl_ADA.docx.

101 California Flexible Load Research and Deployment Hub website. Available at https://www.energy.ca.gov/solicitations/2020-09/gfo-19-309-california-flexible-load-research-and-deployment-hub.

Fuels and Transportation Demonstration Projects

The CEC's Clean Transportation Program provides annual investments of up to $100 million using funds collected from vehicle and vessel registration, vehicle identification plates, and smog abatement fees. The program was established by Assembly Bill 118 (AB 118, Núñez, Chapter 750, Statutes of 2007),[102] which took effect January 1 2008, and was extended through January 1, 2024, by Assembly Bill 8 (AB 8, Perea, Chapter 401, Statutes of 2013).[103] The CEC plays a critical role in reaching the state's goal of getting 1.5 million zero-emission vehicles on California roads by 2025 by accelerating the development and deployment of advanced transportation and fuel technologies, including electric vehicle charging infrastructure.

More information on this effort can be found on the Clean Transportation Program website.[104]

Data and Analysis

The CEC houses several data collection and analysis efforts that could be leveraged for future load management activities.

Hourly Electric Load Model

Hourly load forecasts are an important component for predicting the hourly load impacts expected through load management strategies. The Hourly Electric Load Model simulates 8,760 annual load ratios relative to the annual average hourly load – one simulation for each hour in the year. The annual energy forecast is applied to these hourly values and adjusted for hourly profiles for climate change impacts, electric vehicle charging, solar generation, behind-the-meter storage, and rate impacts, among other factors. More information on this effort can be found on the IEPR Docket 19-IEPR-03.[105]

Interval Meter Database

The CEC warehouses hourly meter data for all bundled electricity customers served by the five largest utilities in the state — PG&E, SCE, SDG&E, LADWP, and SMUD — the same utilities regulated by the load management standards. These utilities submit data reports monthly or quarterly for the period ending 90 days prior. Like the hourly electric load model, the hourly values in the interval meter database will enable the CEC and others to better model the hourly impacts of load management and other decarbonization strategies. More information on

102 Assembly Bill 118 (AB 118, Núñez, Chapter 750, Statutes of 2007). Available at http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200720080AB118.

103 Assembly Bill 8 (AB 8, Perea, Chapter 401, Statutes of 2013). Available at https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB8.

104 CEC Clean Transportation Program website. Available at https://www.energy.ca.gov/programs-and-topics/programs/clean-transportation-program.

105 Electricity and Natural Gas Demand Forecast IEPR Docket (19-IEPR-03). Available at https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-03.

this effort can be found on the Energy Data Collection Rulemaking website[106] and Docket[107] (18-OIR-01).

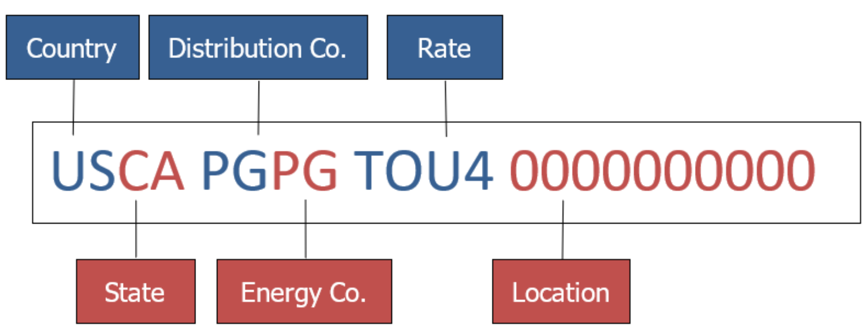
MIDAS Database

MIDAS is a database developed and hosted by the CEC that consists of current and future time-dependent rates, greenhouse gas emissions, and California Flex Alert signals. The publication of the MIDAS database will allow manufacturers to standardize the design of devices that enable customers and third-party demand response providers to automate load flexibility to:

- Generate bill savings as customers shift demand to lower price periods.
- Reduce GHG emissions through better alignment with renewable supplies.
- Improve efficiency and reliability of grid operations.

MIDAS is publicly accessible at https://midasapi.energy.ca.gov in a standard machine-readable format through an API that supports both extensible markup language (XML) and JavaScript Object Notation (JSON) responses to queries. The rates in MIDAS are uploaded by electric LSEs. The MIDAS format and support allows device manufacturers and California customers to access customer rate information in automating price responsive load shifting through a standard Rate Identification Numbers (RIN). RIN are unique to each rate and include standardized codes for country and state; distribution and energy company (co.); rate; and location (Figure 6). With the use of RINs, customers, utilities, ASPs, and others can match individual automation devices to the relevant electricity price, GHG, or grid signals ensuring appropriate load management for the customer at that site. The MIDAS database is being designed to be scalable to the national or international level via the country and state IDs included in the RIN.

Figure 6: MIDAS Rate Identification Number Format



Source: CEC Staff, 2020

106 Energy Data Collection Rulemaking webpage. Available at https://www.energy.ca.gov/rules-and-regulations/energy-suppliers-reporting/clean-energy-and-pollution-reduction-act-sb-350/energy-data-collection-rulemaking.

107 Energy Data Collection – Phase 2 Rulemaking Docket (18-OIR-01). Available at https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=18-OIR-01.

Currently, the limited release of MIDAS contains existing time-dependent electricity prices from PG&E, SCE, SDG&E, LADWP, and SMUD, and passes through GHG signals from SGIP and load Flex Alerts from California ISO. As of the date of this report, this is the current design of the MIDAS system. However, there may be changes that are not reflected in this report. Future iterations of MIDAS will facilitate the publication of all time-dependent and dynamic utility electricity rates and other time-dependent grid signals in a machine-readable format.

MIDAS is a foundational component of the load flexibility envisioned in the proposed load management standards and a critical component facilitating research conducted under EPIC's Flexible Load Research Hub. The database will also expand the scope, capabilities, and benefits of the Flexible Demand Appliance Standards and Building Energy Efficiency Standards.

Reporting

Integrated Energy Policy Report (IEPR)

Senate Bill 1389 (SB 1389, Bowen, Chapter 568, Statutes of 2002) requires the CEC to prepare a biennial IEPR that assesses major energy trends and issues facing the state's electricity, natural gas, and transportation fuel sectors and provides policy recommendations to conserve resources; protect the environment; ensure reliable, secure, and diverse energy supplies; enhance the state's economy; and protect public health and safety (PRC § 25301(a)). Preparation of the IEPR involves close collaboration with Federal, state, and local agencies and a wide variety of stakeholders in an extensive public process to identify critical energy issues and develop strategies to address those issues.

With respect to load management, the CEC is required to evaluate "the potential impacts of electricity and natural gas load management efforts, including end-user response to market price signals, as a means to ensure reliable operation of electricity and natural gas systems" (PRC § 25303(a)(5)), and is tasked with "analyzing the success of and developing policy recommendations for public interest energy strategies… [which] include but are not limited to … implementing load management." (PRC § 25305).

The 2021 IEPR will include a discussion of load impact on both near term resiliency as well as building decarbonization. More information on this effort can be found on the IEPR website.[108]

California Energy Efficiency Action Plan

The *2019 California Energy Efficiency Action Plan* (*EE Action Plan*) covers issues, opportunities, and savings estimates pertaining to energy efficiency in California's buildings, industrial, and agricultural sectors. The *EE Action Plan* fulfills the mandates in PRC Sections 25310(c) and 25943(f).

One of the three main goals of the *2019 EE Action Plan* is to reduce greenhouse gas emissions from the buildings sector. Load management standards are a critical strategy for obtaining this

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108 CEC Integrated Energy Policy Report (IEPR) webpage. Available at https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report.

goal, as increased load flexibility in building will enable the building sector to automatically avoid the use of high-carbon electricity.

More information on this effort can be found on the CEC's Energy Efficiency in Existing Buildings website.[109]

Building Decarbonization Assessment (AB 3232)

AB 3232 directs the CEC to "assess the potential for the state to reduce the emissions of greenhouse gases in the state's residential and commercial building stock by at least 40 percent below 1990 levels by January 1, 2030." (PRC § 25403(a)). The assessment includes, "Load management strategies to optimize building energy use in a manner that reduces the emissions of greenhouse gases." (PRC § 25403(a)(4)).

On August 13, 2021, the CEC published the California Building Decarbonization Assessment, Final Commission Report. The report states, "Demand flexibility will be critical for supporting the grid and transitioning to a carbon-free energy system in the short term and mid-term. Demand flexibility is a particularly promising strategy for reducing GHG emissions in buildings, with the potential to reduce GHG emissions significantly hour to hour, or even minute to minute. Such flexibility requires the presence of automated control technologies for quick reactions to incoming utility signals." The report can be found on the Building Decarbonization Assessment website and more information on the proceeding can be found in the Building Decarbonization Docket (Docket 19-DECARB-01).[110]

SB 100 Joint Agency Report

Senate Bill 100 (SB 100, De Leon, Chapter 312, Statutes of 2018) establishes a landmark policy requiring that 100 percent of retail electric sales come from renewable energy and zero-carbon resources by 2045. It requires the CEC, CPUC, and California Air Resources Board to issue a joint report to the Legislature in 2021, and every 4 years thereafter.

The analysis in the 2021 Senate Bill 100 Joint Agency Report is intended to be the first step in an iterative and ongoing effort to assess barriers and opportunities to implementing California's 100 percent clean energy policy.[111] The report includes system modeling to provide insights into the feasibility, potential costs, and resource requirements of a carbon-free energy portfolio. Initial findings of the report suggest that SB 100 is achievable, but opportunities remain to reduce overall system costs.

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109 CEC Energy Efficiency in Existing Buildings webpage. Available at https://www.energy.ca.gov/programs-and-topics/programs/energy-efficiency-existing-buildings.

110 AB 3232 Building Decarbonization Assessment webpage. Available at https://www.energy.ca.gov/data-reports/reports/building-decarbonization-assessment. Building Decarbonization docket (19-DECARB-01). Available at https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-DECARB-01.

111 2021 Senate Bill 100 Joint Agency Report. Available at https://www.energy.ca.gov/publications/2021/2021-sb-100-joint-agency-report-achieving-100-percent-clean-electricity.

More information on this effort can be found on the SB 100 Joint Agency Report webpage and the SB 100 Docket (Docket 19-SB-100).[112]

112 SB 100 Joint Agency Report webpage. Available at https://www.energy.ca.gov/sb100. SB 100 Joint Agency Report: Charting a path to a 100% Clean Energy Future docket (19-SB-100). Available at https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-SB-100.

CHAPTER 7: Proposed Amendments

As detailed earlier in this paper, the CEC has presented, released, and taken input on proposed amendment language since 2020. The CEC has considered all public comments received in developing the proposed amendments. The proposed amendments advance the following four requirements on specified utilities to:

a) Develop retail electricity rates that change at least hourly to reflect locational marginal costs and submit those rates to the utility's governing body for approval.

b) Update the time-dependent rates in the CEC's statewide rate database whenever a rate is approved or modified.

c) Implement a single statewide standard method for providing automation service providers with access to their customers' rate information.

d) Develop a list of cost-effective automated price response programs for each sector and integrate information about time-dependent rates and automation technologies into existing customer education and outreach programs.

The intended outcome of these proposed amendments is to facilitate load management activities by building owners. The standards form the foundation for a statewide demand automation system that aggregates and publishes time-dependent rate information from utilities. This data can be used by mass-market end-use automation to provide time- and location-specific demand flexibility. Such a system would enable automation markets to coalesce around agreed upon principles and consumer technologies for load management.

As with building and appliance standards, the proposed load management standards are consumer centric and consumer protective. Under this paradigm, customers are expected to proactively manage their electricity bill through customer-chosen and customer-controlled automation. This automation can be optimized with the help of a service provider or purchased and installed directly by the customer or the customer's contractor.

The combination of statewide signals and robust responsive automation markets will support customer-supported load management on a mass-market scale. With communications and automated control technologies, customers can shift electric services to take advantage of cleaner and cheaper supplies, while benefiting from electric services at equal or improved quality. Buildings and water can be precooled or preheated. Batteries and electric vehicles can be charged sooner or later than otherwise scheduled. Dishwashing, laundry, heating, cooling, and many other services can be postponed. Advanced meters, communications, and automation technologies make all this possible today.

The proposed amendments would require utilities to submit their load management plans to the CEC for review and approval and would provide for exemptions, modification, or delays under certain circumstances.

The proposed regulatory language is a separate document, docketed as part of the rulemaking package.

CHAPTER 8: Cost-Effectiveness

The goal of this chapter is to show that the levelized cost of the proposed load management system is less than the levelized cost of new electrical capacity, as required by statute (PRC § 25403.5 (b)). Levelized cost represents the present value of manufacturing and lifetime operation costs divided by lifetime energy production or storage capacity. This metric was chosen to allow comparison between different technologies with unequal life spans, capital costs, and capacities.

Currently, California needs new electrical capacity during peak demand hours in the late afternoon and early evening in the summer. Since solar energy is limited during these hours and new fossil gas generation is no longer environmentally sustainable, utility-scale battery storage is the standard strategy for new electrical capacity in California. CPUC ordered additional energy storage procurement in 2021.[113]

Currently, due to the low numbers of commenced utility-scale battery storage projects and the heterogeneity of those projects, published studies on the levelized cost of storage (LCOS) of utility-scale batteries are limited. Among the few published studies, Lazard's study shows that the LCOS of battery storage ranges between $80 and $140 per MWh in 2020 (Lazard 2020).[114] Lawrence Berkeley National Laboratory's annual Utility-Scale Solar 2020 Update also contains limited information on the power purchase agreement (PPA) contract prices of battery storage paired with solar, and it shows that the levelized PPA price of battery ranges between $50 to $80 per MWh for projects completed in 2023.[115] After adjusting for difference in project timeline, battery roundtrip efficiency, and other factors, these two studies' results are consistent. For this analysis, we use $110 per MWh as the midpoint of the range proposed in Lazard's study. Therefore, the proposed LMS is determined to be cost effective if the levelized cost of the equivalent storage capacity created by the proposed load management standard amendments ($/MWh) is lower than $110 per MWh.

$$LCOS\ of\ LMS < \$110/\mathrm{MWh}$$

The levelized cost of the proposed load management standards is the expected net system costs divided by the load shifting by MIDAS-compatible end-uses. The relevant equation is:

$$LCOS\ of\ LMS = \frac{Net\ Cost\ of\ LMS\ (\$)}{Energy\ Shifted\ (MWh)} = \frac{A - B}{SUM(C)} < \$110/\mathrm{MWh}$$

113 CPUC Decision R.20-05-003. Available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K155/389155856.PDF.

114 Lazard Levelized Cost of Storage Analysis, version 6.0 (2020). Available at https://www.lazard.com/media/451418/lazards-levelized-cost-of-storage-version-60.pdf.

115 Mark Bolinger, Jo Seel, Dana Robson, and Cody Warner. November 2020. *Utility-Scale Solar Data Update: 2020 Edition Report*. Available at https://emp.lbl.gov/publications/utility-scale-solar-data-update-2020.

Where:

A = The Net Present Value of the cost of LMS over 15 years

B = The Net Present Value of the cost reductions enabled by LMS or "BTM" battery charging optimization

C = Potential peak period energy shift from MIDAS-compatible end-uses

When combined, the goal can be written in the form of the following inequality:

$$LCOS\ of\ LMS = \frac{A - B}{SUM(C)} < \$110/MWh$$

Demonstration that this inequality holds requires either that value B exceeds value A (in which case sum of C values is irrelevant) or that the sum of energy shift values in the denominator is large enough to offset the difference between A and B. In this latter case, the analysis need not attempt a thorough investigation of all potential end-uses. Rather, the analysis considers end-uses one at a time until the cost-effectiveness threshold is met. Thus, the absence of any end-use in this analysis is in no way a reflection of an absence of potential.

Cost of Proposed Amendments (A) = $24 million

The first step in the cost analysis is identifying and gathering relevant costs for this rulemaking. The cost of the proposed amendments includes the development, implementation, and ongoing operation and maintenance costs (Table 5) of the following activities:

1. MIDAS operation and maintenance, by the CEC
2. Billing system upgrades by utilities to handle at least 24 price changes per day
3. Rates reporting by named utilities to the CEC
4. Customer education on load management programs, rates, and technologies
5. A utility system to authorize and provide ASPs with customer rate identifiers
6. ASP over-the-air software upgrades to enable MIDAS-compliant automation

Table 5: Estimated Cost of Proposed Load Management Standard Amendments

Item / Activity	Entity	Development & Implementation	Annual Maintenance	15-Year NPV†
MIDAS	CEC	$ 60,000	$ 250,000	$ 3,005,000
Billing System	Utilities	$ 4,800,000	$ 60,000	$ 5,506,000
Rates Reporting	Utilities	$ 150,000	$ 75,000	$ 1,032,000
Customer Education	Utilities	$ 1,50,000	$ 75,000	$ 10,316,000
ASP Authorization	Utilities	$ 150,000	$ 75,000	$ 1,032,000
ASP Software Upgrades	ASPs	$ 300,000	$ 150,000	$ 2,064,000
Voluntary Marginal Signal Program	Utilities	$ 450,000	$ 75,000	$ 1,332,000
Total		**$ 7,410,000**	**$ 1,435,000**	**$ 24,287,000**

†Inflation Rate of 2 percent per year and Discount Rate of 5 percent per year

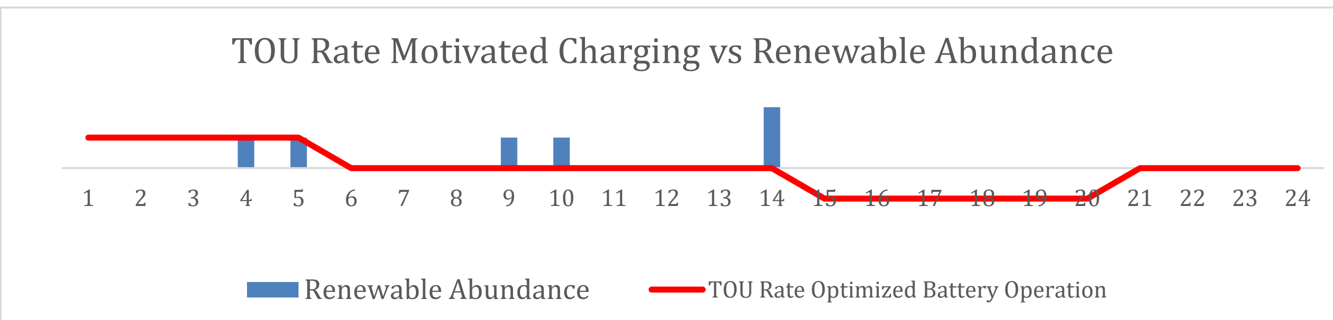
Source: CEC Staff, 2021

Value of Optimizing BTM Battery Charging (B) = $74 million

The next step is to identify the benefits of the proposed load management amendments that are attributable to only LMS but not utility-scale battery systems. If a benefit can be achieved by both LMS and utility-scale battery system, such benefit will not affect the cost-effectiveness comparison outcome, and is therefore excluded. One of the largest potential benefits uniquely attributable is that LMS, as an information infrastructure, can enable the optimization of residential BTM battery charging. For this analysis, staff assumes the time-dependent rates made available statewide through MIDAS will enable batteries to optimize the timing of charging (i.e., avoid peak charging and maximize charging during times of renewable energy abundance where locational marginal price is zero or close to zero).

The current design of electric rates in many utility territories have elements that lead to suboptimal timing of charging or underutilization of battery capacity. Many TOU electric rates have nighttime energy costs that are equal to or lower than midday energy costs (Figure 7). These rate designs do not incentivize existing and future residential batteries to use abundant low marginal cost daytime renewables energy. Some electric rates have small peak to off-peak difference in winter, causing valuable battery capacity to sit idle despite common renewable abundance or even curtailment in the winter.

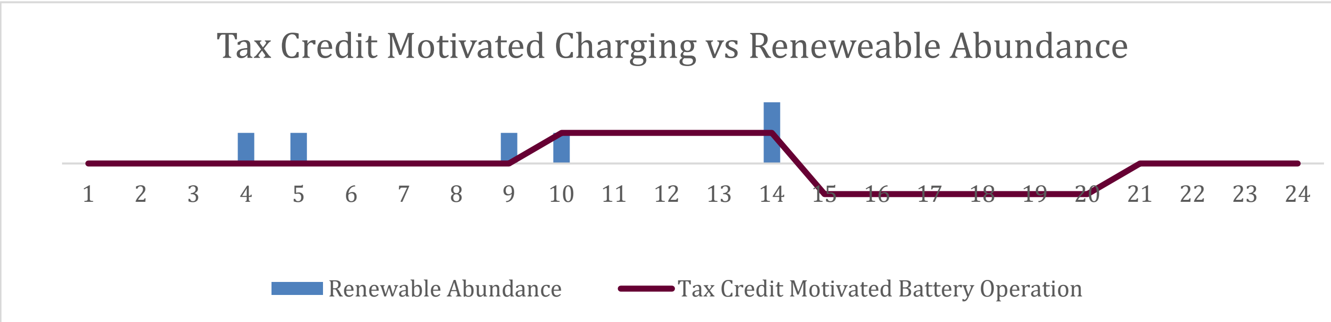
Figure 7: TOU Rate Motivated Charging vs Renewable Abundance



Source: CEC Staff

While current Federal investment tax credits (ITC) encourage charging during the day by requiring tax credit claimers to charge their battery with 75 percent or more renewable energy, as battery costs fall over time and tax credits expire starting in 2024, the diminishing financial benefit of ITC might not be able to overcome the conflicting financial signals from these rate designs. Residential BTM battery owners currently do not have access to granular information on exactly what time of the day renewables are available. Therefore, they can only automate their batteries to charge based on the rough estimate that, throughout a year, renewables are most likely to be abundant between 10am to 2pm on average. This lack of granular information led to residential BTM batteries to be set on a rigid year-round schedule of daytime charging. This rigid schedule, motivated by ITC, while captures more renewable energy, is still not optimal. Renewable energy abundance or excess can occur at nighttime from wind and other power sources, and daytime renewable energy may not be abundant in rainy and cloudy days or hours (Figure 8).

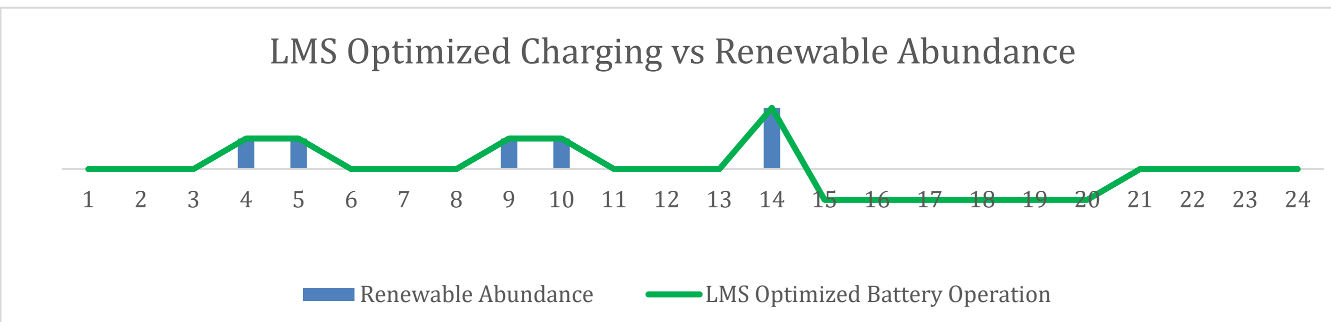
Figure 8: Tax Credit Motivated Operation vs Renewable Abundance



Source: CEC Staff

The MIDAS system will be able to sustainably optimize the timing of the charging of residential BTM batteries with intelligent price signals that eliminate conflicting financial signals and encourages charging whenever renewables are abundant and marginal prices are low or zero (Figure 9). MIDAS is tailor-made for intermittent renewable resources.

Figure 9: LMS Optimized Charging vs Renewable Abundance



Source: CEC Staff

Based on the 2020-2030 California ISO territory hourly load forecast published by the CEC, residential BTM battery charging load will reach slightly more than 900 MWh per day in the summer days in 2025.[116] The hourly load forecast projects that this 900 MWh daily charging capacity will be able to utilize 190,000 MWh of renewable energy annually in 2025, provided that these BTM battery have an appropriate pricing system encouraging daytime charging in place.

Assuming zero cost for charging from otherwise curtailed renewables, and TOU motivated nighttime charging at the California ISO's 2019 locational marginal prices, the net financial value of this shifted battery resource is $34.60 per MWh. After adjusting for an initial linear ramp up period of three years, this per MWh value translates to a net present value over 15 years of roughly $74 million.

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[116] Forecast is available at https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report/2019-iepr MID-MID scenario used.

Load Shifting Benefits using Existing Control Technologies (C)

The first end-use assessed for load management is thermal storage in residential buildings using in-place advanced thermostats with programming and communication capabilities. These devices can accept or retrieve rate information for the customer from the MIDAS database and develop a customized control strategy based on the rate information, the customer's preferences, and the thermal properties of their building's envelope. Customer control strategies might consist of intelligent pre-cooling during off-peak hours, and moderate increases of setpoint temperatures during the peak period. This control strategy can reduce peak period cooling load while maintaining comfort for the customer. However, the cost-effectiveness depends on the building envelope since a well-insulated building can more effectively keep the heat out.

This analysis estimates the statewide energy shift from air conditioning using the following formula:

$$C_{AC} = E_{AC,Peak} rmp$$

Where:

$E_{AC,Peak}$ = California statewide peak period residential cooling load

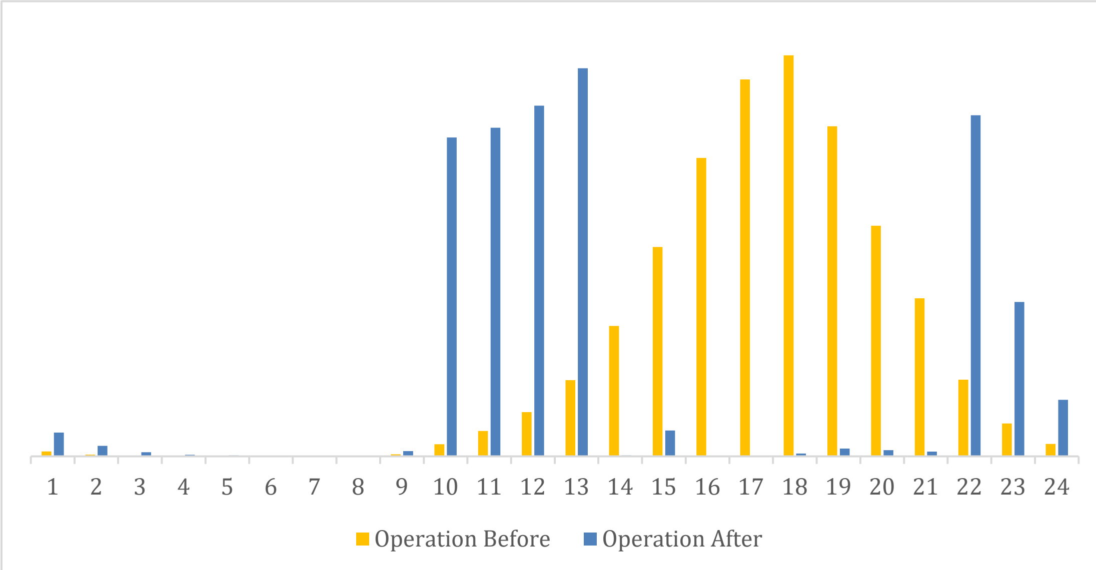
r = average cooling load reduction percentage

m = Advanced Thermostat market share in California

p = percentage of Advanced Thermostat participating

The analysis team used California Building Energy Code Compliance (CBECC) modeling software to estimate the energy impact of this control strategy in select California climate zones. As can be seen in Figure 10, pre-cooling uses energy from 10 am to 1 pm, when cheap renewable energy supplies are plentiful. Pre-cooling, combined with thermostat setpoint setback during peak hours, enables a cooling load near zero during the peak period and a 55 to 65 percent reduction of household electricity load. The modeling result shows that on an annual basis, this cooling strategy can achieve cooling load reduction r larger than 95 percent.

Figure 10: CBECC Model Results for Air Conditioning Load Shifting



Source: CEC Staff, 2020

Over the past eight years, multiple studies have successfully demonstrated the effectiveness of advanced thermostats in reducing customers' peak period cooling load by employing the aforementioned intelligent control strategy. Among them, OhmConnect's 2020 Load Impact Evaluation shows that the program's best performing tier of customers reduce household electricity load from 1.5 kW to 0.67 kW, a 56 percent reduction.[117] SMUD's Residential Summer Solutions Study also shows that customers under similar pricing incentives (TOU rate plus Critical Peak Pricing) reduce household electricity load by 58 percent.[118] The field study results are consistent in magnitude and percentage with the results of CBECC model under similar temperature and control strategy.

With both field studies and the energy modeling analysis showing consistent results, it is reasonable to assume that the proposed load management standards can enable advanced thermostats to achieve 90 percent cooling load reduction during peak periods for individual participants, a number based on, but more conservative than CBECC result of 0.95. The analysis sets $r = 0.90$.

Benefits of air conditioning optimization were projected to statewide participation using the following assumptions:

- Homogeneous existing advanced thermostat ownership of 13.8 percent across CA (Source: ecobee/Statista). While market share of advanced thermostats is projected to increase significantly beyond 13.8 percent with high certainty, this analysis elects a conservative approach and assumes no market share increase.

117 2020 Load Impact Evaluation for OhmConnect's DR Resource. Available at https://cdaexternal.s3.us-west-2.amazonaws.com/OhmConnect_2020/OhmConnect_PY2020_Report_FINAL.pdf.

118 SMUD's Residential Summer Solutions Study: August 2011. Available at https://eta.lbl.gov/news/events/2011/08/26/smud-s-residential-summer-solutions-study .

- 26 percent of existing smart thermostat owners participate in MIDAS optimization (Source: ecobee)
    - 40 percent participation in hot summer areas where space cooling cost is high (e.g., Fresno), which account for 30 percent of the state's population
    - 20 percent participation in mild summer areas (e.g., San Francisco), which account for 70 percent of the state population
- Daily load shifting in summer months (June-September)
    - Buildings with suitable building envelopes will perform intelligent pre-cooling leveraging near-zero LMP and carbon emissions
    - Buildings shed peak hour cooling load by 90 percent, a more conservative value than was indicated by CBECC modeling and field studies
- 15-year equipment life
- Initial participation ramp up is assumed to be three years and linear

Results of this analysis indicate the following:

- After participation is fully ramped up, 120 GWh of peak energy consumption could be shifted off-peak.
- Over 15 years, 1,700 GWh of peak energy could be shifted off-peak.
- Summer peak load reduction potential for air conditioning averages 180 MW.
- Annual peak cost savings averages $6 million statewide. (Note that this is not a factor in the battery comparison since batteries can achieve the same savings.)

Results and Scenario Analysis

Returning to the original inequality to be investigated, staff estimates that the net cost of the proposed load management standard amendments is negative.

$$LCOS\ of\ LMS = \frac{Cost\ of\ LMS(\$)}{Energy\ Shifted(MWh)} = \frac{\$\,22\,million - \$74\,million}{1700\ GWh} = -\$29/MWh$$

To test the robustness of these estimates, the analysis team considered multiple "what-if" scenarios to test potential assumption errors:

1. Halve the cost avoidance of battery optimization: -$8/MWh LMS < $110/MWh Battery
2. Increase LMS cost by 100 percent: $ 7/MWh LMS < $110/MWh Battery

The authors note that many loads not considered in this analysis have potential for load shifting. For example, office buildings could precool to shut down air conditioning at 3 pm or 4 pm, and dim or extinguish indoor night lighting, while other commercial and industrial buildings could precool refrigerated rooms and warehouses or schedule electric pumping and water heating systems to avoid the peak. In the residential sector, dryers, dishwashers, and heat pump water heaters all have great potentials to leverage LOAD MANAGEMENT STANDARDS and MIDAS to avoid peak hour usage. While these end-uses are outside the scope of this analysis, the proposed statewide load management system can and should facilitate such activities where they are cost-effective.

For additional details on this analysis, see Appendix E.

CHAPTER 9: Feasibility

Historically, the dual implementation of time-dependent price signals linked to automation has been hindered by a chicken and egg problem. Policymakers have been hesitant to institute time-dependent pricing without price-responsive technologies to help customers respond. At the same time, vendors have no reason to develop price-responsive technologies until time-dependent rates are widely available.

Over the past decade, rates at PG&E, SCE, SDG&E, and SMUD have evolved to be increasingly dynamic. This means that most customers, from the largest industrial factory to the smallest mobile home, will be charged TOU rates by the end of 2020.[119] This provides the state with an unprecedented opportunity to tap into customer eagerness to lower their electricity bills and GHG emissions through automated price response. This effort is particularly important to pursue in the residential sector during and post-COVID pandemic due to the increasing number of people working from home.[120] In addition, as residential devices tend to be less expensive with shorter lifetimes, the resulting higher turnover rates offer more immediate potential for flexibility benefits.

A. Develop Locational Hourly Rates

The proposed load management standard amendments require utilities to develop locational hourly or sub-hourly rates that can be offered to all customers. The creation of rates that change at least hourly in step with marginal wholesale costs is feasible because it has been successfully done for pilots and other subsets of the customer population. Examples of such rates in California include:

- SCE's experimental RTP for the Retail Automated Transactive Energy System project[121]
- SCE's proposed two-part RTP
- SDG&E's Power Your Drive hourly rate[122]

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119 The prevalence of time-varying rates at LADWP is low because only 3 percent of customers have interval meters.

120 Bureau of Labor Statistics, U.S. Department of Labor, *The Economics Daily*. Workers ages 25 to 54 more likely to telework due to COVID–19 in February 2021. Visited October 2021. Available at https://www.bls.gov/opub/ted/2021/workers-ages-25-to-54-more-likely-to-telework-due-to-covid-19-in-february-2021.htm.

121 Cazalet, Edward, Michel Kohanim, and Orly Hasidim (California Energy Commission). June 2020. *A Complete and Low-Cost Retail Automated Transactive Energy System (RATES).* Publication Number: CEC-500-2020-038. Available at https://www.energy.ca.gov/publications/2020/complete-and-low-cost-retail-automated-transactive-energy-system-rates.

122 SDG&E's Power Your Drive. Available at https://www.sdge.com/residential/electric-vehicles/power-your-drive/power-your-drive-ev-drivers.

- PG&E's 2020 General Rate Case Phase II Commercial & Industrial Real Time Pricing Pilot and Research for Other Customer Classes[123]

Locational marginal signals are also feasible. The SGIP delivers separate marginal GHG emissions signals for each of 11 California ISO sub-regions [124] at five-minute intervals. The SGIP GHG signals are now available in MIDAS. A similar approach can be used to deliver locational pricing.

B. Maintain the MIDAS Database of Electricity Rates

The proposed load management standard amendments require PG&E, SCE, SDG&E, LADWP, and SMUD, and the current 22 (and future) CCAs located within these utilities' service areas to aggregate and upload all time-dependent rate data using the MIDAS API. Automation of such data uploads is a standard task commonly done by utility information technology staff. Thus, this requirement is feasible.

C. Support Customer Ability to Link Devices to Electricity Rates

The proposed load management standard amendments require two methods for ensuring that customer devices can be linked to the appropriate rate.

(1) Provide customers access to their RIN(s) on customer billing statements and online accounts using both text and quick response (QR) or similar machine-readable digital code.

The technology required for adding text and QR codes to paper bills and online accounts is commonplace and feasible.

(2) Collaborate to establish and lead a working group of utilities and stakeholders, overseen by the Commission, to develop and implement a statewide standard tool for authorized rate data access by third parties.

The purpose of this proposed standard is to develop a statewide method for use by all California utilities to (a) simplify third-party efforts to coordinate with multiple utilities, and (b) enable more efficient customer outreach and participation. In lieu of prematurely choosing a technology for communicating customer RINs from utilities to authorized energy service providers, staff recommends forming a working group to consider options and best practices.

This requirement is feasible.

D. Identify and Implement Cost-Effective Customer Programs

Identifying and implementing cost-effective customer programs is a basic function of utility business. This requirement is feasible.

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123 PG&E 2020 General Rate Case Phase II Commercial & Industrial Real Time Pricing Pilot and Research for Other Customer Classes. Available at https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A1911019/3989/396370031.pdf.

124 California Self-Generation Incentive Program GHG Signal. Available at http://sgipsignal.com/grid-regions.

CHAPTER 10: Considered Alternatives to the Proposed Amendments

As discussed previously, CEC staff recommends regulatory amendments that require utilities to:

a) Develop retail electricity rates that change at least hourly to reflect locational marginal costs and submit those rates to the utility's governing body for approval.
b) Update the time-dependent rates in the CEC's MIDAS database whenever a rate is approved or modified.
c) Implement a single statewide standard method for providing automation service providers with access to their customers' rate information.
d) Develop a list of cost-effective automated price response programs for each sector and integrate information about time-dependent rates and automation technologies into existing customer education and outreach programs.

In addition to the proposed amendments, the CEC evaluated the following alternatives:

Alternative 1: Expand DR Incentive Programs

Under Alternative 1, California would further invest significant resources to expand the scale of DR incentive programs to meet the challenge of the projected higher peak hour demand resulting from hotter climates. Utilities would be required by the state to expand current incentives programs to reward more aggregators and more customers for load control and other forms of demand response, while response to time-dependent rates such as TOU would continue largely unsupported by automation.

Some of the shortcomings of only expanding demand response include:[125]

- Higher Cost
    - Utilities must market programs, contract with participants, and maintain administrative and control systems, all of which is more expensive than using time-dependent rates and automation for demand response. To achieve an equal level of load control, CEC staff estimates that the total cost over the same 15-year period will be $133 million, more than six times the cost of the proposed standards.
    - "Pay-for-performance" programs are based on load drop from "baseline" load shapes. High costs to estimate these load impacts are borne by DR providers and

125 Derived in part from Herter, Karen, Patrick McAuliffe, and Arthur Rosenfeld. November 2003. Cost-Effectiveness of Price Response in the Residential Sector: Preliminary Findings from the California Experience - 3rd International Conference on Energy Efficiency in Domestic Appliances and Lighting (EEDAL). Publication Number: LBNL-53440. Available at https://eta-publications.lbl.gov/sites/default/files/LBNL-53440.pdf.

their customers, while the ongoing costs of CPUC efforts to ensure accuracy – constant and ultimately futile – are largely borne by ratepayers.
    - Programs are prone to being particularly cost-ineffective in non-curtailment, zero-benefit years.
- Limited Demand Resources
    - Customer time commitment and inconvenience costs are high, and value is low, so participation is low.
    - Load shed is limited to the hours of the day specified in the program design.
    - Load shifting and energy storage to prevent renewable curtailment is not supported.
    - Only the largest customers are currently targeted in existing programs, so only a fraction of cost-effective demand resources are available.
    - TOU price signals do not change frequently enough to stimulate the demand flexibility needed for real-time load management on a carbon-free grid.
- Limited Customer Involvement, User Experience, and Sustainability
    - Residential programs are limited to certain end-uses, control technologies, and control strategies, chosen and controlled by the utility.
    - Residential customer control, if available, is usually limited to a complete override of the event control strategy.
    - Limited applicability and involvement impedes customer interest in and understanding of peak reduction opportunities, so transfer of load management strategies to non-event day TOU peak periods is less likely.
    - Upfront incentives help overcome barriers to initial participation but do little or nothing to encourage ongoing contributions to load flexibility.
- Limited Market Benefits
    - In the absence of statewide standards, technology vendors cater to utilities rather than to customers, limiting technology innovation and minimizing enhancements to user experience. It is also prone to create a patchwork of approaches that could be difficult to aggregate or synchronize.
    - Customers and automation service providers are incentivized to withhold energy efficiency and load flexibility performance to sell inflated peak resources into "supply-side" energy markets or to the highest bidding demand response provider (aggregator).
- Equity Issues
    - "Pay-for-performance" payments, based on load drop from an estimated baseline, benefit the inefficient customers more than the efficient customers.
    - Utilities target the largest customers, so smaller and more efficient customers have less opportunity to benefit from participation.
    - Utilities target the largest end-uses, such as space cooling and electric water heating, so customers without those loads have no opportunity to benefit from participation yet contribute through rates to the costs of running those programs.

Even if the current paradigm were enhanced to allow for more precise demand response through payment for response to finer grid signals, many of the above inefficiencies would remain.

Some of the major benefits of locational hourly and sub-hourly price response over TOU rates and traditional demand response programs include:

- Lower prices encourage off-peak energy use, reducing renewable curtailment.
- Higher prices encourage peak reductions, reducing ramping issues.
- Customers of any size can participate with any end-use and control technology.
- Customers can choose their own level of response according to their own valuation of electricity services.
- The ensuing customer motivation to acquire and benefit from price-responsive automation will encourage innovation in technology markets.
- Mass-market diffusion of automated load flexibility is facilitated.
- Utilities need not maintain separate "participant" databases as existing systems already track applicable rates.
- Utilities can focus their efforts on educating customers about available technologies and strategies instead of programs.
- Utilities can reduce or replace more expensive demand response programs.

Under Alternative 1, the MIDAS database would not be regularly updated by utilities, meaning the rate data in MIDAS would become obsolete and irrelevant over time. If the MIDAS database is not accurate and up-to-date, customers cannot take advantage of the associated automation technologies and services to improve demand flexibility, reduce bills, and support a carbon-free grid.

Under Alternative 1, utilities would not increase their efforts to encourage customers to purchase, install, and use marginal price- and signal-responsive automation devices. Research shows that customers are much more willing to sign up for time-dependent rates if they are provided automation technology that they can set and forget. The full benefits of time-dependent rates like TOU and hourly rates will not be realized without end-use automation.

For these reasons, Alternative 1 was not chosen.

Alternative 2: Do Not Standardize a Process for Customer Rate Data Access

Under Alternative 2, California utilities would develop and implement hourly electricity rates or marginal signal programs (a and d) and update the MIDAS database whenever rates change (b), to enable customers to access up-to-date rates and perform price-based demand response automation. They would also have to list the RIN on customer bills and online accounts. Alternative 2 differs from the recommended amendments in that it does not require the utilities and state agencies to work together to develop a statewide standard Rate Data Access Tool (c) to support third-party automation services.

Alternative 2 would have a moderately lower cost relative to the proposed amendments, totaling $21 million over the same 15-year period. However, Alternative 2 is also projected to be less effective in encouraging mass-market demand automation, resulting in lower total benefits compared to the proposed amendments.

Under Alternative 2, each utility would have to either implement hourly rates and signals without a Rate Data Access Tool or develop their own method for providing rate information to ASPs. Both options are inefficient.

The cumbersome process of obtaining customer account information and rate information is a significant participation barrier frequently cited by utility demand automation program administrators. Without a smooth, automated access tool for interested customers, demand automation providers have seen customer participation in demand flexibility programs drop from 55 percent to 9 percent[126].

If each utility develops a separate process for Customer Rate Data Access, ASPs will need to invest significant time and resources to interface with each of the more than 70 utilities in California. This would increase development costs, lower economies of scale, raise barriers to market entrance, and limit competition. Consequently, adoption rates would be slowed and customer benefits reduced.

For these reasons, Alternative 2 was not chosen.

126 EnergyHub. 2021. Optimizing the Demand Response Program Enrollment Process. Available at https://f.hubspotusercontent40.net/hubfs/415845/White%20papers%20(2021)/EnergyHub_OptimisingEnrollmentProcess_Whitepaper_2021.pdf.

CHAPTER 11: Equity

Energy equity encompasses the equitable access to the benefits of energy infrastructure, and equitable access to resources for energy improvement. This Chapter examines two key equity aspects of the proposed amendments: how they will improve energy equity among ratepayers, particularly disadvantaged communities; and how California can further ensure enhanced equity during their implementation.

The proposed amendments will foster energy equity

The load management amendments are designed to improve equity relative to the current paradigm of traditional DR programs through fairer compensation mechanisms.

- Traditional DR programs target and reward larger customers with high peak loads while excluding smaller customers with low peak loads. However, customers with low peak loads provide equal contribution to the reliability of the grid as do those who reduce load to their level when called upon. Similarly, utilities target the largest end-uses, such as cooling and electric water heating, so customers without those loads have no opportunity to benefit from participation yet contribute through rates to the costs of running those programs. The proposed amendments would enable and foster rates and programs that reward all participants equally.
- “Pay-for-performance” payments, based on load drop from an estimated baseline, benefit the inefficient customers more than the efficient customers.
- Many residential DR programs rely on reward mechanisms involving annual payments, so that a high performing participant is rewarded the same as a low performing participant. While simple and straightforward, this approach not only discourages high performance and lowers the effectiveness of traditional DR programs, but also leads to overcompensation for low performers and under-compensation for high performers.
- The proposed hourly and sub-hourly rates allow participants to benefit according to their success with energy efficiency, load shifting, and demand shedding. Under this mechanism, all customers can benefit financially commensurate with their contribution to grid needs.

Adoption of the load management standards is projected to benefit customers in disadvantaged communities with existing flat load shapes.

A recent analysis by researchers from the Citizens Utility Board in Chicago, Illinois shows that customers with flatter load shapes are more likely to benefit from marginal cost rates and flatter load shapes were more likely in urban and low-income areas.[127] Thus, many customers

127 Zethmayr, Jeff, Ramandeep Singh Makhija (Citizens Utility Board). *Six unique load shapes: A segmentation analysis of Illinois residential electricity consumers*. Available at http://ipu.msu.edu/wp-content/uploads/2019/06/ClusterAnalysisFinal.pdf.

in disadvantaged communities with flat load shapes would benefit from a voluntary switch to marginal cost rates, without the need of other upfront investment.

Customers that are not yet in hourly rate or hourly signal programs also benefit from the energy cost savings induced by load management standards.

A common concern regarding load management standards is that the economic benefits might be limited to only customers who have the knowledge and the resources to obtain automation devices to participate in hourly tariffs and/or programs. This analysis shows that customers who choose not to participate in load management rates and programs will still benefit from the load management. As overall system peak demand decreases, the marginal and average costs of electricity also decrease. This effect, known as the Demand Response Induced Price Effect (DRIPE), benefits all customers.

According to Commonwealth Edison's 2020 annual report on its hourly pricing program,[128] participating customers enjoy $5.4 million in bill savings. At the same time, all customers in the service territory also enjoy a DRIPE of $9.4 million. California has a higher mix of intermittent renewable resources and a more uneven load shape relative to Illinois due to a hotter and dryer climate. Thus, the DRIPE benefit is expected to be much larger for California.

Potential measures to further enhance equity in the implementation of load management standards

While the load management standards will improve equity with its inherent qualities, staff also identified several potential measures the state and the utilities can take to ensure and further enhance equity in the implementation of load management standards:

- Provide one-year shadow-billing safeguards to customers in disadvantaged communities to ensure that customers who switch see bill savings.
- Offer additional discounts and rebates on automation devices for customers in disadvantaged communities, such as customers already on California Alternative Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) rates.
- Identify low-cost options for areas with limited broadband services.
- Couple load management standards with Federal and state rural broadband investments to allow rural customers to immediately enjoy financial benefits enabled by broadband access.
- Couple load management standards with community microgrid efforts to optimize use of intermittent renewable resources and reduce reliance on energy storage resources for customers in rural and high wildfire risk areas.
- Offer hourly tariffs that are proportional to, but a discount off the marginal cost of electricity, to customers in low-income rate programs.
- Offer discounts separate from the hourly tariffs to offset the costs for CARE, FERA, and medical customers, without reducing their incentives to shift discretionary loads in the home.

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128 Elevate Energy. April 2021. *Commonwealth Edison Company's 2020 Hourly Pricing Annual Report*. Available at https://www.icc.illinois.gov/docket/P2015-0602/documents/311279/files/542596.pdf.

CHAPTER 12: Environmental Analysis

None of the proposed changes to the load management standards regulations would cause a direct or reasonably foreseeable indirect physical change in the environment.

Class 7 and 8 Exemptions

California Code of Regulations, Title 14, Sections 15307 and 15308 exempt actions taken by a regulatory agency to "assure the maintenance, restoration, or enhancement of a natural resource" and actions taken to "assure the maintenance, restoration, enhancement, or protection of the environment where the regulatory process involves procedures for protection of the environment." The proposed load management standards will have no significant effect on the environment and fall squarely within the categorical exemptions of Sections 15307 and 15308. This project's activities are being undertaken in furtherance of the CEC's load management standards program to ensure that energy demand is sufficiently flexible to maximize the amount of load that is met with carbon-free resources. The proposed amendments provide California with the suitable economic incentives and the necessary information infrastructure for load management automation. These tools will enable California to better manage the electricity demand and better align it with intermittent renewable resources. Consequently, they reduce the need for fossil-fuel generation by at least an estimated 1,700 GWh over 15 years as described in Chapter 8, and reduce 374 metric tons of greenhouse gas emissions, which will minimize the impact of the electricity system on the environment and the climate crisis. These actions are taken to assure the maintenance, restoration, or enhancement of a natural resource and to assure the maintenance, restoration, enhancement, or protection of the environment. Further, none of the exceptions to exemptions listed in CEQA Guidelines Section 15300.2 apply to this project. Additionally, there is no reasonable possibility that the activity will have a significant effect on the environment due to unusual circumstances. For these reasons, this project is exempt from CEQA.

Common Sense Exemption

The development and adoption of these amendments to the CEC's load management standards regulations are also exempt from CEQA under the commonsense exemption. CEQA only applies to projects that have the potential for causing a significant effect on the environment. (CCR Title 14, § 15061(b)(3)). A significant effect on the environment is defined as a substantial, or a potentially substantial, adverse change in the environment, and does not include an economic change by itself (PRC § 21068; CCR Title 14, § 15382). The goal of the proposed amendments to the load management standards is to form the foundation for a statewide system that automates the publication of time and location dependent signals that can be used by mass-market end-use automation to provide real-time load flexibility on the electric grid. The combination of statewide signals and robust responsive automation markets proposed in this action will enable customer-supported load management on a mass-market scale providing signals and tools to further support the reliability of the grid and reduce reliance on fossil-fuel generated electricity. No significant adverse impacts to the environment have been identified as resulting from this action. For these reasons, adoption of the amendments to the CEC's regulations would not be subject to CEQA under the commonsense exemption of Section 15061(b)(3).

Conclusion

As shown above, the proposed update to the load management standards is a regulatory action that would protect natural resources and the environment and is, therefore, categorically exempt from further CEQA review under Sections 15307 and 15308 of the CEQA Guidelines. Additionally, it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment and, therefore, this project is exempt pursuant to the commonsense exemption under Section 15061(b)(3) of the CEQA Guidelines.

Chapter 13: Economic and Fiscal Impact Analysis

Introduction

This analysis considers economic impacts to California jobs, businesses, competitive advantages and disadvantages, and benefits and costs to Californians from the proposed amendments.

This analysis also considers the fiscal impacts to state and local governments, including LADWP, SMUD and CCAs, which are public agencies, as discussed in Chapter 3. Over the long term, staff found impacts to local and state governments through initial investments and increased operational cost, but also substantially larger benefits resulted from energy costs saving. The fiscal impact results for the current fiscal year (FY22), and two subsequent years (FY23 and FY24), and the relevant assumptions and calculations are provided in this chapter.

For this report, staff analyzed the proposed amendments and the two alternatives discussed in Chapter 10. Alternative 1 is an expansion of DR incentive programs to meet future electricity demand. It is a more cost burdensome and stringent alternative compared to the proposed amendments. Alternative 2 is a less stringent set of standards that removes the standardization of RIN access tool from the proposed regulation. Staff modeled and evaluated all three scenarios and calculated the total costs and benefits of each case.

Economic Impacts

If approved, the proposed amendments to the regulation will be fully implemented when utilities implement hourly tariffs or hourly signal programs. The deadline for this implementation is three years after the effective date of the regulation. By 12 months after full implementation, CEC estimates that the 12-month economic cost impact will be approximately \$2.47 million, and the 12-month economic benefits impact will be approximately \$8.2 million. Therefore, the proposed regulation does not qualify as a “Major Regulation,” which is defined as a regulation that will have an economic impact in an amount exceeding \$50 million in any 12-month period between the date estimated to be filed with Secretary of State through 12 months after the regulation is estimated to be fully implemented. The timetable of economic impacts is shown in Table 6 below.

Table 6: Timetable of 12-Month Economic Impacts (End of Period)

	Milestone	Cost Impacts	Benefit Impacts
	Filed with Secretary of State	NA	NA
Effective Date	Following Quarter after Filed with Secretary of State	NA	NA
One Year After Effective date	Partial Implementation	2,470,000	$0
Two Year After Effective Date	Partial Implementation	2,470,000	$0
Three Years after Effective Date	Full Implementation (Utilities Implement Hourly Rates or Hourly Signal Programs)	2,470,000	$0
Four Years After Effective Date	12 Month after Full Implementation	$1,435,000	$8,243,000

Source: CEC Staff, 2021

For additional details on the analysis, please see Appendix E.

The proposed amendments will have direct cost and benefit impacts on three large private businesses: IOUs of PG&E, SCE, and SDG&E. Small businesses are unlikely to have direct cost impacts. LADWP, SMUD, and CCAs are public agencies, as discussed in Chapter 3, and are discussed below under the fiscal impacts section.

The proposed amendments will not affect the ability of California businesses to compete with other states, as PG&E, SCE, and SDG&E do not operate outside of California.

The economic impacts of the proposed amendments are insufficient to cause the creation or elimination of businesses.

The proposed amendments may indirectly provide potential expansion opportunities for private businesses such as smart device manufacturers and ASPs. Smart device manufacturers may bring to market new smart devices that work well with the new hourly tariffs or hourly signal programs proposed in the regulation. ASPs may leverage the proposed standardized RIN access tool and smart devices to attract more customers previously deterred by the obstacles in the enrollment processes. The indirect potential economic impact to device manufacturers and ASPs remains too uncertain to estimate but will likely remain very small relative to the total long term core energy benefits, and therefore excluded from the total cost and total benefits estimates.

The proposed amendments may expand employment opportunities by a limited number in the territories of the utilities affected. Additional skilled labor may be needed in sectors such as information technologies, software engineering, program administration, marketing, and outreach. CEC estimates that eight new full time equivalent jobs may be created, and no jobs are likely to be eliminated because of the proposed amendments.

Estimated Cost

The total cost of the proposed amendments is estimated to be $24 million in net present value over a 15-year period from 2025 to 2040. The cost breakdown for typical businesses is shown in Table 7 below.

Table 7: Estimated Cost to Businesses

	Initial Cost	Annual Cost	Years
Typical Business (IOU)	$1,560,000	$195,000	2026-2041
Small Business	0	0	2026-2041

Source: CEC Staff, 2021

Other economic costs may include ASPs that may upgrade and maintain their software to capture the new business opportunities. The potential costs to ASPs are estimated to be approximately $15,000 per year.

The CEC projects that the utilities are likely able to recover the entirety of the initial and annual costs from the projected savings from the lower costs of electricity they procure to supply customers without raising rates. In the unlikely event the projected savings cannot fully cover the costs, the proposed amendments may cause adverse impacts on the utilities. The utilities may avoid the potential adverse impacts by passing on the compliance costs onto their customers, which may cause adverse impacts on ratepayers. The compliance costs of utilities are projected to be small relative to their revenue, as all IOUs have annual electric revenue of more than $1 billion in 2019. Ratepayers are projected to receive energy savings that exceed the potential passed-on costs, resulting in net benefits. Therefore, the CEC has made an initial determination that the proposed amendments are unlikely to have a statewide adverse economic impact directly affecting business and individuals, including the ability of California businesses to compete with businesses in other states.

No small business will be required to take action to comply with the proposed amendments. Nevertheless, the proposed amendments may impose costs on the utilities who may pass these costs on to their customers, including small businesses. Customers who voluntarily participate in hourly tariffs or hourly signal programs may incur program costs passed on from their electric utilities. However, the CEC is not aware of any significant cost impacts to customers, including small businesses.

Estimated Benefits

The total statewide benefits over the lifetime of the amendments are estimated to be $267 million. The benefits include reduced cost of charging residential BTM batteries, and reduced cost of electricity consumption at peak hours. Reductions of peak hour energy production also reduce GHG emissions associated with climate change impacts. The total statewide benefits will be shared among the utilities, the automation service providers, and virtually all Californians, as an overwhelming majority of Californians are electricity users.

Alternatives to the regulations

As stated in Chapter 10 and earlier in this chapter, two alternatives were considered and analyzed. Alternative 1 is an expansion of DR incentive programs to meet future electricity demand. Alternative 1 is more cost burdensome and stringent. Alternative 2 is a less stringent standard that removes the standardization of a RIN access tool from the proposed regulation.

The costs and benefits from the regulations and the two alternatives are shown in Table 8 below.

Table 8: Total Benefits and Costs of the Proposed Regulation and Alternatives

	Benefits	Costs
Proposed Amendments	$267,357,000	$24,287,000
Alternative 1	$192,998,000	$149,362,000
Alternative 2	$209,480,000	$22,955,000

Source: CEC Staff, 2021

Assumptions and calculations for Alternative 1 and Alternative 2:

Proposed Amendments:

The total cost of the proposed regulation over the 15 years is $24 million. For the details of the cost breakdown, please refer to Table 5 in Chapter 8.

The total benefits of the proposed amendments over the 15 years are estimated to be $267 million. The benefits breakdown is shown in Table 9 below.

Table 9: Proposed Amendments Benefits

Propose Amendment	15-Year NPV Benefit
Advanced Thermostats Load Reduction	$192,998,000
*Res BTM Charge Optimization	$74,359,000
Total	$267,357,000

Source: CEC Staff, 2021

*For assumptions and calculations for the monetary value of $74 million for the optimization of residential BTM battery charging, please refer to Chapter 8.

Advanced thermostats are projected to shift 1,700 GWh load away from peak hours over 15 years. The calculation is provided in Chapter 8. The monetary value of the 1,700 GWh is then estimated using the state average of per unit avoided cost of electricity in 2025, based on

CPUC's 2020 version of the Avoided Cost Calculator. [129] The unit avoided cost is adjusted for an inflation rate of 2 percent per year for the next 15 years from 2025 onward. The 15-year breakdown of the nominal benefits from Advanced Thermostats is show in Table 10 below.

Table 10: Benefits from Advanced Thermostats

Proposed Amendment Implementation Year	Monetary Benefits from Advanced Thermostats Load Reduction
Year 1	$5,950,949
Year 2	$12,139,937
Year 3	$18,574,103
Year 4	$18,945,585
Year 5	$19,324,497
Year 6	$19,710,987
Year 7	$20,105,206
Year 8	$20,507,311
Year 9	$20,917,457
Year 10	$21,335,806
Year 11	$21,762,522
Year 12	$22,197,772
Year 13	$22,641,728
Year 14	$23,094,562
Year 15	$23,556,454
15-Year NPV (Round down to the nearest thousand)	$ 192,998,000

Source: CEC Staff, 2021

Alternative 1 is an expansion of current DR incentive programs to meet future electricity demand. The costs and benefits of DR incentive programs depends on their scale. In this analysis, the scale of the DR incentive programs is set such that they can reach 3.6 percent of the state's 13 million households, at the same level as the proposed regulation is projected to reach.

The 15-year Net Present Value (NPV) cost of Alternative 1 is estimated below. Alternative 1 is more cost burdensome and stringent than the proposed amendments as shown in Table 11 below.

129 Energy and Environmental Economics. CPUC 2020 Avoided Cost Calculator for Distributed Energy Resources (DER). Available at https://www.ethree.com/public_proceedings/energy-efficiency-calculator/.

Table 11: Alternative 1 Costs

Alternative 1 (DR Incentive Programs)	Initial Cost	Annual Cost	15-Year NPV Cost
Incentive Program Administration	$ 1,500,000	$ 750,000	$ 10,315,000
Incentive Program Customer Reward	NA	$ 10,465,000	$ 139,047,000
Total			$ 149,362,000

Source: CEC Staff, 2021

Since the scale of the DR incentive programs is set to match the same participation rate of 3.6 percent as the proposed amendments, Alternative 1 is projected to create the same level of benefits from advanced thermostat load reduction as the proposed amendments at $192 million. However, Alternative 1 does not provide the infrastructure nor the hourly signals for residential BTM batteries to optimize their charging, therefore no benefits from the end-use are estimated. The benefits of Alternative 1 are summarized in Table 12 below.

Table 12: Alternative 1 Benefits

Alternative 1 (DR Incentive Programs)	15-Year NPV Benefit
Advanced Thermostats	$192,998,000
Total	$192,998,000

Source: CEC Staff, 2021

Alternative 2 is a less stringent alternative that develops and implements hourly electricity rates or marginal signal programs and updates the MIDAS database whenever rates change (Recommendation a, b, and d in Chapter 2). Alternative 2 differs from the recommended amendments in that it does not require the utilities and state agencies to work together to develop a statewide standard Rate Data Access Tool (Recommendation c in Chapter 2) to support third-party automation services. Alternative 2 costs are shown in Table 13 below.

Table 13: Alternative 2 Costs

Alternative 2 (No RIN Access Tool)	Initial Cost	Annual Cost	15-Year NPV Cost
MIDAS System	$60,000	$250,000	$3,005,000
Billing System Modifications	$4,800,000	$60,000	$5,506,000
Rates Reporting	$150,000	$75,000	$1,032,000
Customer education	$1,500,000	$750,000	$10,316,000
ASP Software Upgrades	$300,000	$15,000	$1,032,000
Marginal Signal Program	$450,000	$75,000	$2,064,000
Total	$7,260,000	$990,000	$22,955,000

Source: CEC Staff, 2021

Staff analysis found that Alternative 2 is projected to save costs compared to the proposed amendments but would also lead to significant delay of the realization of benefits, therefore reducing the total NPV of benefits over a 15-year period. Based on a conservative estimate of equivalent delay of five years, and an annual discount rate of 5 percent, the benefits will be reduced by 21.6 percent cumulatively compared to the proposed regulation in both the advanced thermostats and BTM batteries end-uses. Consequently, the total benefits of Alternative 2 is also reduced by 21.6 percent compared to the proposed amendments as shown in Table 14 below.

Table 14: Alternative 2 Benefits

Alternative 2 (No RIN Access Tool)	15-Year NPV Benefit
Advanced Thermostats	$ 151,218,000
Res BTM Batteries Charge Optimization	$ 58,262,000
Total	$ 209,480,000

Source: CEC Staff, 2021

Fiscal Impact

This analysis evaluates the fiscal impacts for the current fiscal year (2021-2022) and two subsequent fiscal years: 2022-2023 and 2023-2024.

The proposed amendments affect the following local government entities: LADWP, SMUD, and CCAs in the IOU service territories. SMUD has fully implemented AMI, while LADWP has not.

This analysis consists of the following cost assumptions, calculations, and results:

1. The CEC assumes that LADWP will implement an hourly GHG signal program. The entirety of the initial costs will fall into the time window of 2022-2024. The cost breakdown is shown in Table 15 below.

Table 15: Estimated LADWP Implementation Costs, by Fiscal Year

LADWP	2021-2022	2022-2023	2023-2024
Marginal Signal Program	$0	$225,000	$225,000
Customer education	$0	$150,000	$150,000
ASP authorization (RIN Access tool)	$0	$15,000	$15,000
Total Cost	$0	$390,000	$390,000

Source: CEC Staff, 2021

2. The CEC assumes that SMUD will implement hourly tariffs. The entirety of the initial costs will fall into the time window after 2023 as shown in Table 16 below.

Table 16: Estimated SMUD Implementation Costs, by Fiscal Year

SMUD	2021-2022	2022-2023	2023-2024
Billing System Modifications	$0	$600,000	$600,000
Customer education	$0	$150,000	$150,000
ASP authorization (RIN Access tool)	$0	$15,000	$15,000
Total Cost	$0	$765,000	$765,000

Source: CEC Staff, 2021

3. The CEC assumes that CCAs in IOU service territories will pass through the hourly tariffs that are developed and implemented by the IOU in whose service territory they are located. This implementation strategy is projected to result in no direct costs or benefits for the CCAs but will be most aligned with grid needs. CCAs' customers will benefit from energy costs reduction. CCAs' reporting effort is expected to be negligible as CCAs only need to inform CEC about the hourly tariffs they pass through from their respective IOU.

Implementation of the proposed load management standards by LADWP, SMUD, and all CCAs in the IOU service territories are assumed to be fully financed from electricity sales revenue collected by these local government entities and are not reimbursable by the state.

No projected annual savings by the local government entities by fiscal year 2023-2024, as savings come from implementation of hourly tariffs and hourly signals programs, and the deadline for implementation is three years after effective date and is projected to be at least after 2025.

The CEC currently maintains the MIDAS database. The cost to CEC is estimated to be $300,000 a year to maintain the MIDAS database and manage compliance.

State government agencies are not expected to see savings in fiscal year 2021-2022, 2022-2023, and 2023-2024. After implementation of hourly tariffs and hourly signal programs, which is projected to be no earlier than December 2025, some state agencies' facilities may see savings from reduced energy bills due to the implementation of load management standards.

Implementation of the proposed amendments to the load management standards is not expected to impact Federal funding of state programs.

For additional details on the analysis, please see Appendix E.

ACRONYMS AND DEFINITIONS

Acronyms

AB	Assembly Bill
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
APA	Administrative Procedure Act
API	Application Programming Interface
ASP	Automation Service Provider
BIP	Base Interruptible Program
BTM	Behind-the-Meter
CARE	California Alternative Rates for Energy
CBECC	California Building Energy Code Compliance
CBP	Capacity Bidding Program
CCA	Community Choice Aggregator
CCR	California Code of Regulations
CEC	California Energy Commission
CLECA	California Large Energy Consumers Association
CPP	Critical-Peak Pricing
DACAG	Disadvantaged Communities Advisory Group
DER	Distributed Energy Resource
DLAP	Default Location Aggregation Point
DR	Demand Response
DRIPE	Demand Response Induced Price Effect
DRP	Demand Response Provider
DSM	Demand-Side Management
ECPA	Energy Conservation and Production Act
EPCA	Energy Policy and Conservation Act
EPIC	Electric Program Investment Charge
EV	Electric Vehicle

FERA	Family Electric Rate Assistance
GHG	Greenhouse Gas
GRC	General Rate Case
GWh	Gigawatt-Hour
IEPR	Integrated Energy Policy Report
IOU	Investor Owned Utility
IRP	Integrated Resource Planning
ISO	Independent System Operator
ITC	Investment Tax Credit
JARP	Joint Advanced Rates Parties
JSON	JavaScript Object Notation
kW	Kilowatt
LADWP	Los Angeles Department of Water and Power
LAP	Location Aggregation Point
LCOS	Levelized Cost of Storage
LED	Light Emitting Diode
LMP	Locational Marginal Price
LMS	Load Management Standards
LSE	Load Serving Entity
MIDAS	Market Informed Demand Automation Server
MW	Megawatt
MWh	Megawatt-Hour
NECPA	National Energy Conservation Policy Act
NPV	Net Present Value
PG&E	Pacific Gas & Electric Company
POU	Publicly Owned Utility
PPA	Power Purchase Agreement
PRC	Public Resources Code
PURPA	Public Utility Regulatory Policies Act (Pub. L. 95–617, 92 Stat. 3117, 1978)

QR	Quick Response
RIN	Rate Identification Number
RTP	Real-Time Pricing
SB	Senate Bill
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SGIP	Self-Generation Incentive Program
SMUD	Sacramento Municipal Utility District
Sub-LAP	Sub-Location Aggregation Point
T&D	Transmission and Distribution
TOD	Time of Day
TOU	Time-of-Use
U.S.	United States
VPP	Variable-Peak Pricing
XML	Extensible Markup Language
XSP	Excess Supply Demand Response Pilot

Definitions

Advanced Metering Infrastructure	Advanced metering infrastructure means an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers.
Application Programming Interface	An intermediary that allows two software programs to communicate with each other. A set of definitions and protocols that allow technology products and services to communicate with each other via the internet. (RapidAPI)
AutoDR	Automated Demand Response. A generic term for the automation of electric end-use response to occasional demand response event signals.
Automation Service Providers	Within the context of load management standards, a general term that refers to companies that administer grid flexibility of electricity consumers with little to no human activity.
AutoPR	Automated Price Response. A generic term for the automation of electric end-use response to a continuous stream of time-dependent price and emissions signals.

Commercial	Building sector that includes a wide variety of building types such as high-rise multifamily, offices, retail, restaurants, campuses, and hospitals.
Decarbonization	Activities that reduce greenhouse gas emissions.
Demand Flexibility	Refers to the ability to reduce, shift, increase, and shed energy consumption in response to a grid opportunity or challenge.
Demand Resource	Installed measures, systems, or strategies that result in changes in end-use customer electricity demand.
Demand Response	Changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized. (Federal Energy Regulatory Commission Definition).
Electrification	Converting end-uses from a combustible fuel source to electricity.
Granularity	The granularity of data refers to its level of detail. A low level of granularity indicates data that is more finely grained, while a higher level of granularity indicates fewer, larger components. In the case of rate data, granularity refers to the frequency with which the price changes in time and the size of the area to which it applies in space. A 5-minute rate that applies at the transformer level is said to have a lower level of granularity than a TOU rate that applies at the service territory level.
Load Aggregation Point	A set of pricing nodes as specified in Section 27.2 of the California ISO Tariff that are used for the submission of Bids and Settlement of Demand.
Load Flexibility	A strategy of enabling automation of building 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	Any activity intended to reshape a load duration curve. (Warren-Alquist Act 1974)
Load Shed	Short term energy reductions or curtailments in response to prices or other grid signals.
Load Shift	Load shed combined with a coordinated load increase during times of high supply and/or low GHG emissions.
Locational Marginal Price	The change in electricity price caused by a change in electricity supply and demand during a specified time interval at a specified location.
OpenADR	Open Automated Demand Response. An open source, two-way information exchange demand response model standard.

OpenAPR	Open Automated Price Response. The open source, one-way information exchange price response model standard used by the MIDAS system.
Pricing Node (PNode)	A single California ISO network node or subset of network nodes where a physical injection or withdrawal [of electricity] is modeled and for which a Locational Marginal Price (LMP) is calculated and used for financial settlements.
Residential	A building sector that includes single family homes, multifamily units, townhouses, and condominiums.
Strategic Conservation	Long-term or permanent reductions in energy use targeted at hours of the day or year expected to have a low supply-demand ratio.
Sub-Load Aggregation Point (Sub-LAP)	A California ISO defined subset of pricing nodes (PNodes) within a default location aggregation point (LAP) that are used for the submission of Bids and Settlement of Demand.

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APPENDIX A: Public Resources Code Section 25403.5

Current Public Resources Code Section 25403.5, as of October 2021:

(a) The commission shall, by July 1, 1978, adopt standards by regulation for a program of electrical load management for each utility service area. In adopting the standards, the commission shall consider, but need not be limited to, the following load management techniques:

(1) Adjustments in rate structure to encourage use of electrical energy at off-peak hours or to encourage control of daily electrical load. Compliance with those adjustments in rate structure shall be subject to the approval of the Public Utilities Commission in a proceeding to change rates or service.

(2) End-use storage systems which store energy during off-peak periods for use during peak periods.

(3) Mechanical and automatic devices and systems for the control of daily and seasonal peak loads.

(b) The standards shall be cost-effective when compared with the costs for new electrical capacity, and the commission shall find them to be technologically feasible. Any expense or any capital investment required of a utility by the standards shall be an allowable expense or an allowable item in the utility rate base and shall be treated by the Public Utilities Commission as allowable in a rate proceeding.

The commission may determine that one or more of the load management techniques are infeasible and may delay their adoption. If the commission determines that any techniques are infeasible to implement, it shall make a finding in each instance stating the grounds upon which the determination was made and the actions it intends to take to remove the impediments to implementation.

(c) The commission may also grant, upon application by a utility, an exemption from the standards or a delay in implementation. The grant of an exemption or delay shall be accompanied by a statement of findings by the commission indicating the grounds for the exemption or delay. Exemption or delay shall be granted only upon a showing of extreme hardship, technological infeasibility, lack of cost-effectiveness, or reduced system reliability and efficiency.

(d) This section does not apply to proposed sites and related facilities for which a notice of intent or an application requesting certification has been filed with the commission prior to the effective date of the standards.

APPENDIX B: Load Serving Entities

Investor-Owned Utilities in California

Bear Valley Electric Service
Liberty Utilities
Pacific Gas & Electric Company
PacifiCorp
San Diego Gas & Electric Company
Southern California Edison Company

California Community Choice Aggregators

Apple Valley Choice Energy
Clean Power Alliance
CleanPowerSF
Desert Community Energy
East Bay Community Energy
King City Community Power
Lancaster Choice Energy
Marin Clean Energy
Monterey Bay Community Power
Peninsula Clean Energy Authority
Pico Rivera Innovative Municipal Energy
Pioneer Community Energy
Rancho Mirage Energy Authority
Redwood Coast Energy Authority
San Jacinto Power
San José Clean Energy
Silicon Valley Clean Energy Authority
Solana Energy Alliance
Sonoma Clean Power
Valley Clean Energy Alliance
Western Community Energy

Rural Electric Cooperatives

Anza Electric Cooperative, Inc.
Plumas-Sierra REC
Surprise Valley Electric Cooperative
Valley Electric Association

Publicly Owned Utilities

Alameda Municipal Power
Azusa Light and Water

Biggs Municipal Utilities
Burbank Water and Power
City of Anaheim
City of Banning
City of Cerritos
City of Corona
City of Healdsburg's Electric Department
City of Industry
City of Lompoc's Electric Division website
City of Needles
City of Palo Alto
City of Riverside
City of Santa Clara dba Silicon Valley Power
City of Shasta Lake
City of Ukiah
City of Vernon
Colton Public Utilities
Department of Water Resources
Eastside Power Authority
Glendale Water and Power
Gridley Electric Utility
Imperial Irrigation District (IID)
Island Energy
Kirkwood Meadows Public Utility District
Lassen Municipal Utility District
Lathrop Irrigation District
Lodi Electric Utility
Los Angeles Department of Water and Power (LADWP)
Merced Irrigation District
Metropolitan Water District of Southern California
Modesto Irrigation District (MID)
Moreno Valley Electric Utility
Pasadena Water and Power
Port of Oakland
Port of Stockton
Power and Water Resource Pooling Authority
Power Enterprise of the San Francisco PUC
Rancho Cucamonga Municipal Utility
Redding Electric Utility
Roseville Electric
Sacramento Municipal Utility District (SMUD)
Shelter Cove Resort Improvement District
Trinity Public Utilities District
Truckee Donner Public Utility District
Turlock Irrigation District (TID)
Victorville Municipal Utility Services

Electric Service Providers (ESPs)

3 Phases Renewables
American Powernet
Calpine Energy Solutions
Champion Energy Services
Commercial Energy of California
Constellation Energy
Direct Energy Business
EDF Industrial
Gexa Energy California
Just Energy Solutions
Liberty Power Delaware
Liberty Power Holdings
Palmco Power CA
Pilot Power Group
Praxair Plainfield

Source: CPUC list of Registered Service Providers

APPENDIX C:
Non-Utility Demand Response Providers

CPUC Registered Non-Utility DR Providers	Residential and/or Small Commercial	Service Territories
EnergyHub, Inc. CPUC-DRP-0002 www.energyhub.com	YES	PG&E SCE
OhmConnect, Inc. CPUC-DRP-0003 www.ohmconnect.com	YES	PG&E SCE SDG&E
Stem, Inc. CPUC-DRP-0005 www.stem.com	NO	PG&E SCE SDG&E
IPKeys Power Partners, LLC CPUC-DRP-0006 www.ipkeyspowerpartners.com	NO	SCE
Olivine, Inc. CPUC-DRP-0007 www.olivineinc.com	YES	PG&E SCE SDG&E
Engie Storage Services NA LLC *formerly, Green Charge Networks LLC* CPUC-DRP-0008 www.engiestorage.com/ www.business-government/	NO	SCE SDG&E
Chai, Inc. CPUC-DRP-0009 www.chaienergy.com	YES	SCE
DBA eMotorWerks, Inc. Now a part of Enel X Enel X North America Inc. CPUC-DRP-0021 https://www.enelx.com	YES	
AutoGrid Systems, Inc. CPUC-DRP-00011 http://www.auto-grid.com	YES	PG&E SCE SDG&E
Advanced Microgrid Solutions, Inc. CPUC-DRP-00012 www.advmicrogrid.com	NO	SCE
EDF Trading North America, LLC CPUC-DRP-00013 www.edftrading.com/	NO	PG&E SCE

CPUC Registered Non-Utility DR Providers	**Residential and/or Small Commercial**	**Service Territories**
NRG Curtailment Solutions, Inc. CPUC-DRP-00014 www.demandresponse.nrg.com	NO	PG&E SCE SDG&E
Sunrun Inc. CPUC-DRP-00015 www.sunrun.com	YES	PG&E
Tesla, Inc. CPUC-DRP-00016 www.tesla.com/commercial	NO	PG&E SCE
Leapfrog Power, Inc. DBA Leap. CPUC-DRP-0017 www.leap.ac	YES	PG&E SCE SDG&E
Enerwise Global Technologies, Inc. *DBA CPower* CPUC DRP-0018 www.cpowerenergymanagement.com	NO	SCE SDG&E
Shell Energy North America, L.P. CPUC-DRP-0019 www.shell.com	NO	PG&E SCE SDG&E
Trane Grid Services LLC CPUC-DRP-0020 www.trane.com	NO	PG&E SCE SDG&E
Enel X North America Inc. CPUC-DRP-0021 https://www.enelx.com	NO	PG&E SCE
Voltus, Inc. CPUC-DRP-0022 https://www.voltus.co/	NO	PG&E SCE

Source: CPUC

APPENDIX D:
Tariffs with Time-Varying Rates

Table 17 summarizes the most common time-varying rates at LSEs to which the load management standards apply.

Table 17: Time-Varying Rates at IOUs and POUs

Utility	Residential	Commercial and Industrial	Electric Vehicle
PG&E	E-TOU-C E-TOU-D	A-1 A-6 AG-C Primary B-6 Single Phase B-19 Secondary E-19-Secondary	EV2-A* BEV-1
SCE	TOU-D-Prime* TOU-D-5-8PM* TOU-D-4-9PM	TOU-GS-1* TOU-GS-1 (D) TOU-GS-1 (E) TOU-GS-1 (ES) TOU-GS-1 (LG) TOU-GS-2 (D) TOU-GS-2 (E) TOU-GS-3 (D) TOU-GS-3 (E)	TOU EV-1* TOU-EV-7 (D) TOU-EV-7 (E) TOU-EV-8 TOU-EV-9-PRI TOU-EV-9-SEC TOU-EV-9-SU
SDG&E	TOU DR1* TOU DR2 TOU DR-P	TOU-A TOU-A-2 TOU-A-3	EV-TOU* EV-TOU-2* EV-TOU-5*
LADWP	R-1B	A-1B	
SMUD	Time-of-Day 5-8PM	GS-TOU1 GS-TOU2 GS-TOU3 Small C&I Primary GS-TOU3 Small C&I Secondary	

*Approved for the SGIP program

Source: CEC Staff

APPENDIX E: Staff Assumptions and Calculation Methods

Annual Discount Rate: 5 percent
Annual Inflation Rate: 2 percent

Table 18, 19 and 20 provide additional details on the calculation for the estimated peak hour load reduction by advanced thermostats in the residential sector enabled by LMS. Table 18 summarizes statewide results, including current annual peak hour cooling energy in GWh and cooling load in GW, estimated statewide energy savings and load reduction. Table 19 summarizes the results in hot summer areas, which include CEC Electricity Demand Forecast Zone 3, 5, 9, 10, 11, 13, 17. The hot summer areas are assumed to have 40% participation rate due to higher economic incentive for participation. Table 20 summarizes results in cool summer areas, which include CEC Electricity Demand Forecast Zone 1, 2, 6, 7, 8, 12, 14, 16. The cool summer areas area assumed to have 20% participation rate to lower cooling load and consequently lower economic incentive for participation.

Table 18: Statewide Average Advanced Thermostat First Year Savings

Res Sector	Annual Peak 4-9 Cooling Energy	Summer Peak 4-9 Cooling Load Average	Annual Peak 4-9 Cooling Cost
State Total	3122 GWh	4.5 GW	$ 456,325,889
Smart Thermostat Installation Base (percent)	14	14	14
Participation (percent)	26	26	26
Peak Cooling Load Saving (percent)	90	90	90
First Year Savings (Before Ramp up Adjustment)	122 GWh	0.18 GW	$ 17,852,848

Source: CEC Staff

Table 19: Hot Summer Area Advanced Thermostat First Year Savings (Forecast Zones 3, 5, 9, 10, 11, 13, 17)

Res Sector	Annual Peak 4-9 Cooling Energy	Summer Peak 4-9 Cooling Load Average	Annual Peak 4-9 Cooling Cost
State Total	1776 GWh	2.6 GW	$ 262,387,796
Smart Thermostat Installation Base (percent)	14	14	14
Participation (percent)	40	40	40
Peak Cooling Load saving (percent)	90	90	90
First Year Savings (Before Ramp up Adjustment)	88.210 GWh	0.129 GW	$ 13,035,426

Source: CEC Staff

Table 20: Mild Summer Area Advanced Thermostat First Year Savings (Forecast Zones 1, 2, 6, 7, 8, 12, 14, 16)

Res Sector	Annual Peak 4-9 Cooling Energy	Summer Peak 4-9 Cooling Load Average	Annual Peak 4-9 Cooling Cost
State Total	1347 GWh	1.9 GW	$ 193,938,092
Smart Thermostat Installation Base (percent)	14	14	14
Participation (percent)	20	20	20
Peak Cooling Load Saving (percent)	90	90	90
First Year Savings (Before Ramp up Adjustment)	33 GWh	0.046 GW	$ 4,817,422

Source: CEC Staff

Participation Ramp Up Adjustment: Both end-uses, advanced thermostats, and residential BTM batteries are modified with a reasonable linear participation ramp up. Ramp up to full participation is assumed to be three years, starting from implementation of hourly tariffs and hourly signals programs, to three years after implementation. After adjustment for program ramp up and inflation, the savings are shown in Table 21, Table 22, and Table 23 below.

Table 21: Advanced Thermostat Benefits by Year

	Advanced Thermostats Load Reduction Economic Benefits ($)	Advanced Thermostat Load Reduction (GWh)
Year 1	$ 5,950,949	41
Year 2	$ 12,139,937	81
Year 3	$ 18,574,103	122
Year 4	$ 18,945,585	122
Year 5	$ 19,324,497	122
Year 6	$ 19,710,987	122
Year 7	$ 20,105,206	122
Year 8	$ 20,507,311	122
Year 9	$ 20,917,457	122
Year 10	$ 21,335,806	122
Year 11	$ 21,762,522	122
Year 12	$ 22,197,772	122
Year 13	$ 22,641,728	122
Year 14	$ 23,094,562	122
Year 15	$ 23,556,454	122
15 Year Total	$ 192,998,000*	1,700**

*15 Year NPV, rounded down to the nearest thousands

**Rounded down to the nearest hundred

Source: CEC Staff

Estimated greenhouse gas emission reductions associated with the 15 year total estimated 1,700 GWh load reduction is calculated by applying the residential electricity average hourly emission factors for the summer months June through October and peak times 4-9pm according to the 2022 TDV methodology.[130] Average summer peak emission factor is calculated to be 0.22 metric tons per GWh, therefore the 15 year total estimate greenhouse gas emission savings is:

$$1{,}700\ GWh\ x\ 0.22\frac{MTCO2e}{GWh} = 374\ MTCO2e$$

Table 22: Res BTM Battery Charge Optimization Benefits by Year

	Residential BTM Battery Charge Optimization Economic Benefits
Year 1	$2,292,830
Year 2	$4,677,372
Year 3	$7,156,379
Year 4	$7,299,507
Year 5	$7,445,497
Year 6	$7,594,407
Year 7	$7,746,295
Year 8	$7,901,221
Year 9	$8,059,246
Year 10	$8,220,431
Year 11	$8,384,839
Year 12	$8,552,536
Year 13	$8,723,587
Year 14	$8,898,058
Year 15	$9,076,020
15 Year NPV*	$74,360,000

*Rounded down to the nearest thousands

Source: CEC Staff

Table 23: Summary of Economic Benefits by Year

	Advanced Thermostat	Res BTM Charge Optimization	Total Benefit
Year 1	$5,950,949	$2,292,830	$8,243,779
Year 2	$12,139,937	$4,677,372	$16,817,309
Year 3	$18,574,103	$7,156,379	$25,730,482
Year 4	$18,945,585	$7,299,507	$26,245,092
Year 5	$19,324,497	$7,445,497	$26,769,994

[130] 2022 TDV CH4 20yr 15RA, available at: https://efiling.energy.ca.gov/getdocument.aspx?tn=233259

	Advanced Thermostat	Res BTM Charge Optimization	Total Benefit
Year 6	$19,710,987	$7,594,407	$27,305,394
Year 7	$20,105,206	$7,746,295	$27,851,501
Year 8	$20,507,311	$7,901,221	$28,408,532
Year 9	$20,917,457	$8,059,246	$28,976,703
Year 10	$21,335,806	$8,220,431	$29,556,237
Year 11	$21,762,522	$8,384,839	$30,147,361
Year 12	$22,197,772	$8,552,536	$30,750,308
Year 13	$22,641,728	$8,723,587	$31,365,315
Year 14	$23,094,562	$8,898,058	$31,992,620
Year 15	$23,556,454	$9,076,020	$32,632,474
15 Year NPV	$192,998,211	$74,359,900	$267,358,111

Source: CEC Staff

Alternative 1 Assumptions:

Expansion of DR incentive program reaches 3.64 percent of state residential households, same as the proposes amendments. 13 million households in California in 2019.[131]

Each participating household is assumed to receive a flat fee of $25 for participation.

Therefore, Incentive Program Flat Incentive Cost is:

$$3.64\% \times 13 \text{ million} \times \$25 = 11{,}830{,}000$$

Program Administration Costs are based on a review of past program costs data. It is estimated to be $500,000 in initial cost and $150,000 in annual cost per utility, which totals to 10,315,000 in NPV.

Alternative 2 Assumptions and Calculations:

As stated in Chapter 13, benefits would be projected to be delayed by 5 years. At a discount rate of 5%, cumulative reduction of net present value is $\frac{1}{(1+5\%)^5} = 78.3\%$

The benefits of advanced thermostats and residential BTM batteries are each reduced to 78.3%:

For advanced thermostat: $\$192{,}998{,}000 \times 78.3\% = \$151{,}218{,}000$

For residential BTM batteries: $\$74{,}359{,}000 \times 78.3\% = \$58{,}262{,}000$

131 US Census Bureau. July 2019. Quick Facts California webpage. Available at https://www.census.gov/quickfacts/CA.

APPENDIX F:
Automated Price Response Studies

Sacramento Municipal Utility District

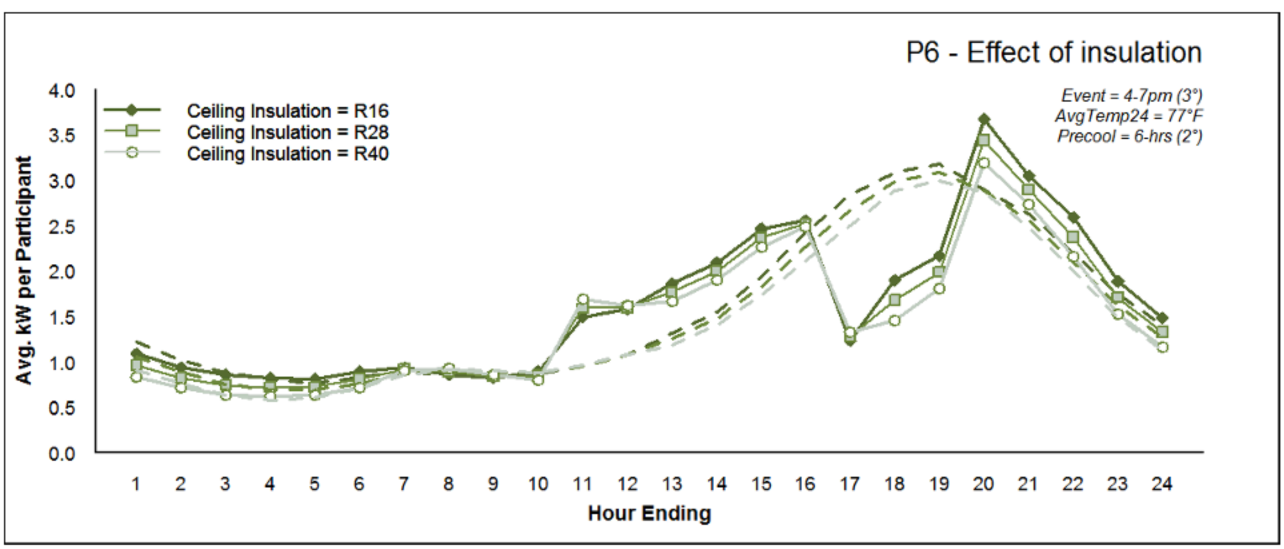
2008 Small Business Summer Solutions Study

SMUD's Small Business Summer Solutions Study, which offered an experimental TOU-CPP rate paired with CPP-responsive thermostats, provided evidence that responsive thermostats can be a reliable tool for enhancing the ability of customers on dynamic rates to respond to intermittent price events. The load impact evaluation showed 20 percent average load impacts on a 100°F reference day for participating offices and retail buildings. Overall, participating offices, restaurants, and retail buildings achieved summer energy savings of 20 percent and bill savings of 25% percent. (Herter, Wayland, and Rasin, 2009)

2012 Residential Precooling Study

The Residential PowerStat Pilot solicited 180 residential participants with the primary objective of testing the effects of event-based precooling and peak temperature offsets on energy use, peak demand, and occupant comfort. Three different precooling treatments were tested 8 times during the summer of 2012. Treatment 1, the base case, had no precooling before the peak period. Treatment 2 was a 2-hour, 4-degree precool before the peak period. Treatment 3 was a 6-hour, 2-degree precool before the peak period. Participant survey responses and interval meter data were collected to enable comparison of the impacts of the three treatments to determine whether the different precooling strategies had different effects on hourly load shapes, daily energy use, and occupant comfort. As shown in Figure 11, insulation levels, included in the regression model, had a statistically significant effect on both peak load impacts and energy use. This indicates that the installation of increased insulation can improve the effectiveness of peak load reduction programs.

Figure 11: Residential PowerStat Pilot



Source: Herter and Okuneva, 2012

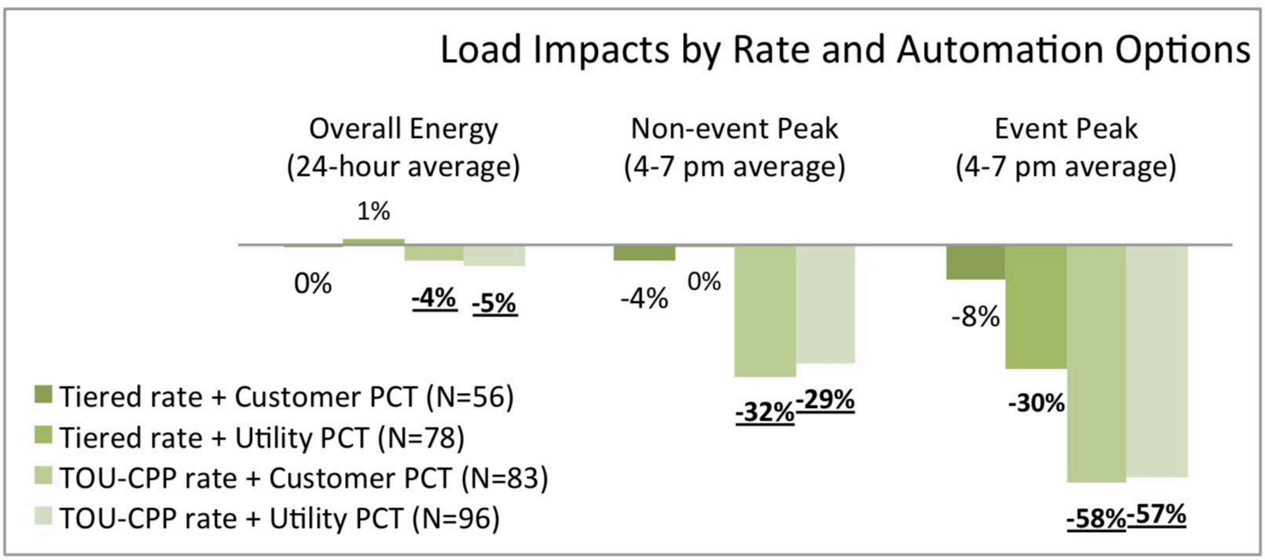
2011-2012 Residential Summer Solutions Study

The 2011-2012 Single Family Summer Solutions Study showed significant energy efficiency (~5 percent), weekday peak demand (~30 percent) and event load shed (~60 percent) impacts resulting from the implementation of responsive thermostats and time-varying rates.

The study recruited from a sample of over sixteen thousand eligible customers. Participants were given the option to keep their existing tiered rate or volunteer for an experimental TOU rate with CPP events, i.e., a TOU-CPP rate. Participants also chose between two types of responsive thermostats: one programmed by the customer to respond to the CPP events as desired to save money, and one controlled by the utility during events in exchange for an incentive payment designed to mimic the expected CPP bill savings of the other thermostat.

These options created a total of four treatment groups. The average impacts of these treatments on whole-house energy, peak demand, and event load shed are illustrated in Figure 12.

Figure 12: Results of SMUD's Residential Summer Solutions Study



*Impacts significantly different from the "Tiered rate + Customer PCT" group are marked in **bold**.*
Impacts significantly different from the "Tiered rate + Utility PCT" group are underlined.

Source: Herter and Okuneva, 2014

The study provided strong evidence that a dynamic rate with automation could be expected to elicit significant energy, peak demand, and event savings relative to a tiered rate. While participants on the tiered rate saved 190 kWh during the summer months, those on the TOU-CPP rate saved 460 kWh over the same period – well over twice as much. In parallel, those on the TOU-CPP rate benefited from double the bill savings of those on the standard tiered rate and more than twice as many TOU-CPP participants (44 percent) exceeded $100 in summer savings.

SMUD's Load Impact Calculator (SLIC)

SMUD's Load Impact Calculator combined the statistical load impacts of 9 separate rate and automation pilots, involving tens of thousands of residential and small commercial customers. The SLIC enabled cross-pilot examination of load impacts by temperature, program variables, and demographics for 7 of the pilots as shown in Figure 13.

Figure 13: SMUD Residential Smart Grid Pilots included in the SLIC

Pilot	Year(s)	Conservation Day Events	Dynamic Pricing	Automation Technology	Enhanced Information
Single-family Summer Solutions	2011-2012	✓	✓	✓	✓
Smart Pricing Options	2012-2013	✓	✓		✓
PowerStat Pricing	2013	✓	✓	✓	
Smart Thermostats	2013	✓	✓	✓*	
Low-Income Weatherization & Energy Management	2013			✓*	✓
In-Home Display Checkout	2013				✓
Multifamily Summer Solutions	2013	✓	✓	✓	✓

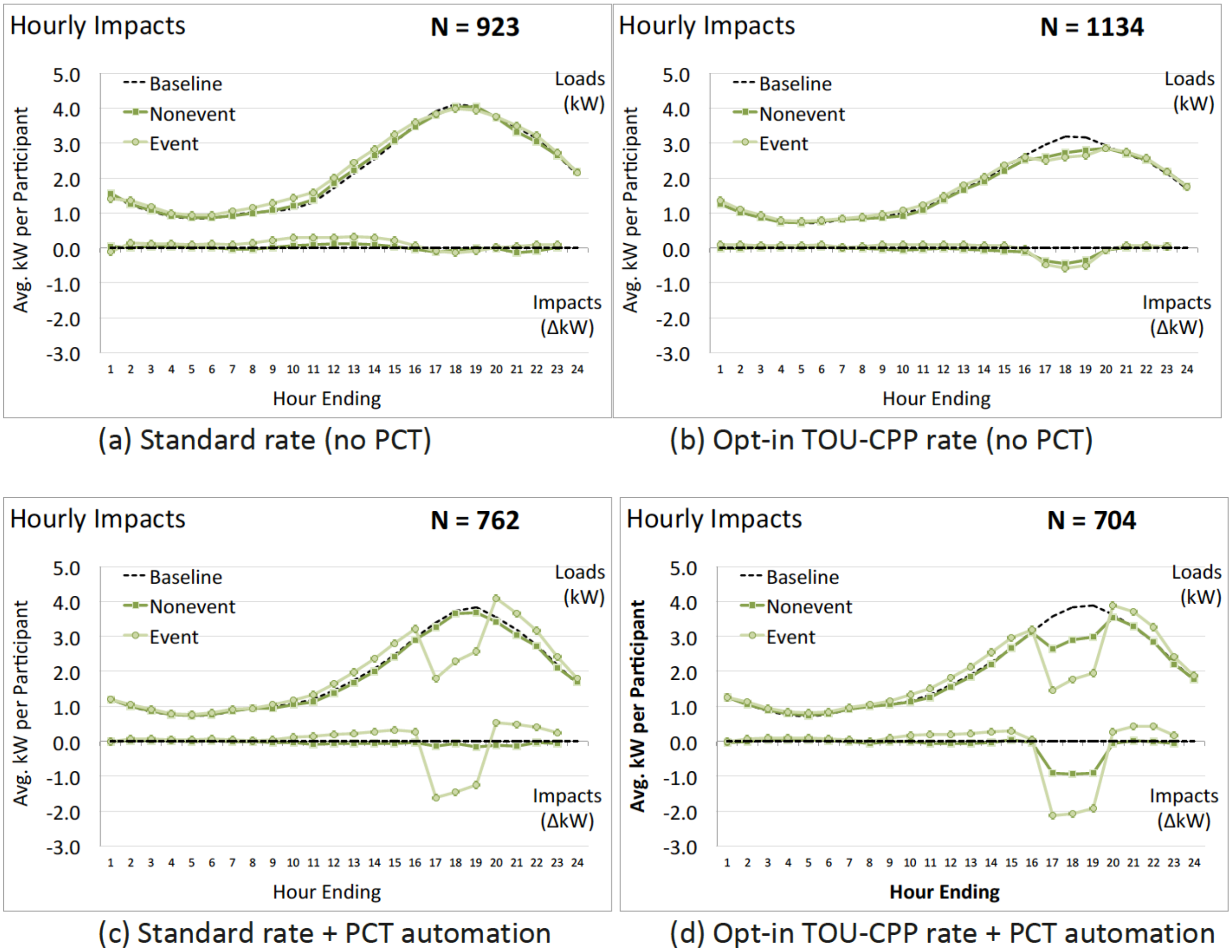
** Automation technology was not linked to Conservation Day or CPP event signals*

Source: Herter and Okuneva, 2014

In all cases, "Automation Technology" refers to smart thermostats.

Figure 14 shows some example results derived from the SLIC, in this case, the four sets of load impacts for customers on a tiered or TOU-CPP rate, both with and without automated price response via thermostat.

Figure 14: Example Results Derived from the SLIC



(a) Standard rate (no PCT)

(b) Opt-in TOU-CPP rate (no PCT)

(c) Standard rate + PCT automation

(d) Opt-in TOU-CPP rate + PCT automation

Source: Herter and Okuneva, 2015

U.S. Consumer Behavior Studies

The Smart Grid Investment Grant (SGIG) program, authorized by Title XIII of the Energy Independence and Security Act of 2007 (EISA) and later modified by the American Recovery and Reinvestment Act of 2009 (ARRA), provided the DOE with funding to conduct statistically rigorous studies of the effects of time-varying rates and automation on customer electricity use across the country. Of the ten Consumer Behavior Studies, three involved both dynamic rates and price-responsive automation. DTE Energy and NV Energy both piloted CPP rates with responsive thermostats, and Oklahoma Gas and Electric piloted both CPP and VPP rates with responsive thermostats.

Figure 15: Automation and Control Options for Load Flexibility

Table 2. Scope of the Consumer Behavior Studies

	CEIC	DTE	GMP	LE	MMLD	MP	NVE	OG&E	SMUD	VEC
Rate Treatments										
CPP		●	●		●	●	●	●	●	
TOU Pricing		●		●		●	●	●	●	
VPP								●		●
CPR	●		●							
Non-Rate Treatments										
IHD	●	●	●					●	●	
PCT	●	●					●	●		
Education							●			
Recruitment Approaches										
Opt-In	●	●	●	●	●	●	●	●	●	●
Opt-Out				●					●	

Utility Abbreviations: Cleveland Electric Illuminating Company (CEIC), DTE Energy (DTE), Green Mountain Power (GMP), Lakeland Electric (LE), Marblehead Municipal Light Department (MMLD), Minnesota Power (MP), NV Energy (NVE), Oklahoma Gas and Electric (OG&E), Sacramento Municipal Utility District (SMUD), Vermont Electric Cooperative (VEC)

Source: U.S. Department of Energy, 2016

APPENDIX G: Data Sources for Greenhouse Gas Emissions

Potential options for emissions signals include the California SGIP signal, Automated Emissions Reduction technology by WattTime and Climate Trace[132] to monitor global climate emissions.

- **California Self-Generation Incentive Program.** California's Self Generation Incentive Program (SGIP) allots over 800 million dollars in financial incentives through 2024 for the installation of clean, efficient, onsite distributed generation. The objectives of the SGIP are to reduce demand, GHG emissions, and electricity bills.

  The SGIP signal provides marginal GHG emission rates via API to storage systems, identifying when to charge (during low-GHG emission periods) and when to discharge (during high-GHG emission periods). The signal provides marginal GHG emissions factors for each of eleven California ISO sub-regions[133] at five-minute intervals in units of kilograms of carbon dioxide per kilowatt-hour (kgCO2/kWh). The GHG emissions factors are calculated using the same basic methodology as California's Avoided Cost Calculator, but with updated parameters and data sources more suitable for real-time.

  In addition to the real-time GHG emissions provided every five minutes, the following forecasting tools are available:

  - Fifteen-minute forecast, with 5-minute granularity, updated every fifteen minutes
  - One hour-ahead forecast, with 5-minute granularity, updated every fifteen minutes
  - Day-ahead forecast, with five-minute granularity, updated every fifteen minutes
  - Longer Term Forecasts: 72-Hour Ahead, Month-Ahead and Year-Ahead

  The GHG signal and forecasting tools are available online at (http://selfgenca.com/).

- **Automated Emissions Reduction (AER).** AER[134] is a real-time marginal GHG emissions API based on climate research completed at UC Berkeley.[135] This technology enables smart home devices including smart plugs, thermostats, and electric vehicles to automatically reduce emissions associated with their electricity use.

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132 Time magazine. July 2020. *How a New Effort to Trace Emissions, Led by Al Gore, Could Reshape Climate Talks.* Available at https://time.com/5866881/al-gore-climate-trace-emissions/.

133 California Self-Generation Incentive Program GHG Signal. Available at http://sgipsignal.com/grid-regions.

134 WattTime. Automated Emissions Reduction (AER) webpage. Available at https://www.watttime.org/aer/what-is-aer/.

135 Callaway, Duncan S., Meredith Fowlie, and Gavin McCormick. Journal of the Association of Environmental and Resource Economists. Volume 5, Number 1. January 2018. *Location, Location, Location: The Variable Value of Renewable Energy and Demand-Side Efficiency Resources*. Available at https://doi.org/10.1086/694179.

- **Global Climate Trace.** Former Vice President Al Gore in collaboration with a coalition of nine climate and technology organizations calling themselves Climate Trace[136] are using satellite data, artificial intelligence, and other technology to track worldwide marginal GHG emissions down to the level of individual factories, ships, and power plants. The team hopes to release the first version of the tool in summer 2021.

Since marginal GHG emissions are highly correlated with real-time electricity prices and grid congestion, GHG emissions are a reasonable signal option for introducing customers to load flexibility programs and automating their end-uses. Programs might offer retrofit communications for control of electric water heating, communicating thermostats for load shifting, or incentives for connected battery loads. Utilities could offer additional voluntary signals, such as price or congestion costs, under these programs as well.

136 Climate Trace website. Available at https://www.climatetrace.org/.