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California Energy Commission

DRAFT STAFF REPORT

Analysis of Potential Amendments to the Load Management Standards

Load Management Rulemaking

Docket Number 19-OIR-01

Gavin Newsom, Governor
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California Energy Commission

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PREFACE

The Warren-Alquist Act codified in Public Resources Code § 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, end-use storage, automation, and other cost-effective measures, as authorized by the Warren-Alquist Act (PRC § 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 (CPUC), California Independent System Operator (California ISO), investor-owned utilities (IOUs) and publicly owned utilities (POUs) [collectively utilities], community choice aggregators (CCAs), automation service providers (ASPs), equipment manufacturers, and other stakeholders to refine the scope and approach necessary to achieve widespread load management.

This draft staff report presents CEC staff's proposed changes to the load management standards regulations for the consideration of stakeholders and policy makers. A public staff workshop will follow the publication of this draft staff report, and staff plans to subsequently develop and publish a final staff report prior to the start of formal rulemaking.

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 CEC's 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 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 2020 Load Management Rulemaking is to increase statewide demand flexibility through amendments to the existing load management regulations (California Code of Regulations (CCR) Title 20 §§ 1621-1625). Throughout 2020, staff worked with the CPUC, California ISO, utilities, CCAs, 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 agreed upon principles and technologies for demand flexibility. Once completed, customers and automation service providers will be able to link flexible loads to this database, enabling the automation of customer end-uses in real time.

Staff proposes the following requirements for the five largest electric utility service territories in California – Pacific Gas and Electric (PG&E), Southern California Edison (SCE), Los Angeles Department of Water and Power (LADWP), Sacramento Municipal Utility District (SMUD), and San Diego Gas and Electric (SDG&E) – and the CCAs operating within these service territories:

1. Maintain the accuracy of existing and future time-varying rates in the publicly available and machine-readable MIDAS rate database.
2. Develop a standard rate information access tool to support third-party services.
3. Develop locational rates that change at least hourly to reflect marginal wholesale costs and submit those rates to the utility's governing body for approval.
4. Integrate information about new time-varying 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 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.

Keywords: Electric grid, reliability, load management, load flexibility, demand flexibility, demand response, price response, automation, real-time pricing, electricity rates, electricity tariff

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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 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 herein will enable 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 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.

The Warren-Alquist Act[1] establishes the California Energy Commission (CEC) as California's primary energy policy and planning agency. Public Resources Code[2] 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 Section 25402 to set energy efficiency standards for buildings and appliances.

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." 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.[3] 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 their underlying time-varying tariffs for electric energy and demand services, which have their own time-varying 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

[1] The Warren-Alquist State Energy Resources Conservation and Development Act, Division 15 of the Public Resources Code, § 25000 et seq., available at (http://www.energy.ca.gov/2017publications/CEC-140-2017-001/CEC-140-2017-001.pdf).

[2] Unless otherwise noted, all references to code sections refer to the Public Resources Code.

[3] Unless otherwise noted, all references to utilities include IOUs, POUs, and CCAs.

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, 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 will be maintained by the CEC with help from participating California utilities. Once completed, customers and automation service providers will be able to link flexible loads to this machine-readable database of rates and other grid signals to automate real-time mass-market demand flexibility on the electric grid.

Through workshops, working groups, and extensive discussions, the CEC staff has developed a proposal to create a foundation for price and greenhouse gas responsive demand flexibility. This draft staff paper presents that proposal for stakeholder and policymaker consideration.

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

1. **Maintain the accuracy of existing and future time-varying rates in the CEC's publicly available and machine-readable rate database.** The CEC has developed a database of time-varying rates that can be accessed by third-party service providers for automated optimization by connected devices. The database is a key part of the CEC's plan for the statewide Market Informed Demand Automation Server (MIDAS), which will allow consumers to automate their response to price and GHG signals.
2. **Develop a standard rate information access tool to support third-party services.** This will help streamline rate data collection efforts by companies that help customers optimize consumption patterns.
3. **Develop locational rates that change at least hourly to reflect marginal wholesale costs and submit those rates to the utility's governing body for approval.** This will provide customers with options for responding to hourly or sub-hourly price and GHG emissions signals. Approval from the utility's governing body is required before new rates can go into effect.
4. **Integrate information about new time-varying rates and automation technologies into existing customer education and outreach programs.** Most customers are unaware of price-responsive automation technologies and services.

Through these amendments, California will begin to develop 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. Universally available load management can reduce greenhouse gas emissions by shifting flexible consumption, 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.

ACRONYMS AND DEFINITIONS

Acronyms

AB	Assembly Bill
API	Application Programming Interface
ASP	Automation Service Provider
BIP	Base Interruptible Program
BTM	Behind-the-Meter
CBP	Capacity Bidding Program
CPP	Critical-Peak Pricing
DACAG	Disadvantaged Communities Advisory Group
DER	Distributed energy resource
DLAP	Default Location Aggregation Point
DSM	Demand Side Management
EV	Electric vehicle
GHG	Greenhouse Gas
GWh	Gigawatt hour
IEPR	Integrated Energy Policy Report
JARP	Joint Advanced Rates Parties
LADWP	Los Angeles Department of Water and Power
LAP	Location Aggregation Point
LMS	Load Management Standards
LSE	Load Serving Entity
MIDAS	Market Informed Demand Automation System
PG&E	Pacific Gas & Electric Company
PURPA	Public Utility Regulatory Policies Act (Pub. L. 95–617, 92 Stat. 3117, 1978)
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
TOD	Time of Day
TOU	Time of Use
VPP	Variable-Peak Pricing

Definitions

AutoDR	Automated Demand Response. A generic term for the automation of electric end-use response to prices or other system signals.
Application Programming Interface	A set of definitions and protocols that allow technology products and services to communicate with each other via the internet. (RapidAPI)
Commercial	Building sector that includes a wide variety of non-residential 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 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, or 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 (LAP)	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 Building	Intentional increases in energy use, e.g., during times of high supply and/or low GHG emissions.
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 Shift	Load shed combined with a coordinated load building either before or after the load shed period.
Load Shed	Short term energy reductions or curtailments in response to prices or other grid signals.
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.
OpenADR	Open Automated Demand Response. An open source, secure, two-way information exchange demand response model standard.
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.

CHAPTER 1: Introduction

The burning of fossil fuels in the electricity generation, buildings, transportation, industrial, and agricultural sectors drive changes in the Earth's climate by releasing greenhouse gases (GHGs) such as carbon dioxide and methane. The State of California has set ambitious goals to reduce or eliminate GHG emissions in these sectors, in hopes of mitigating the increasingly observable 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.

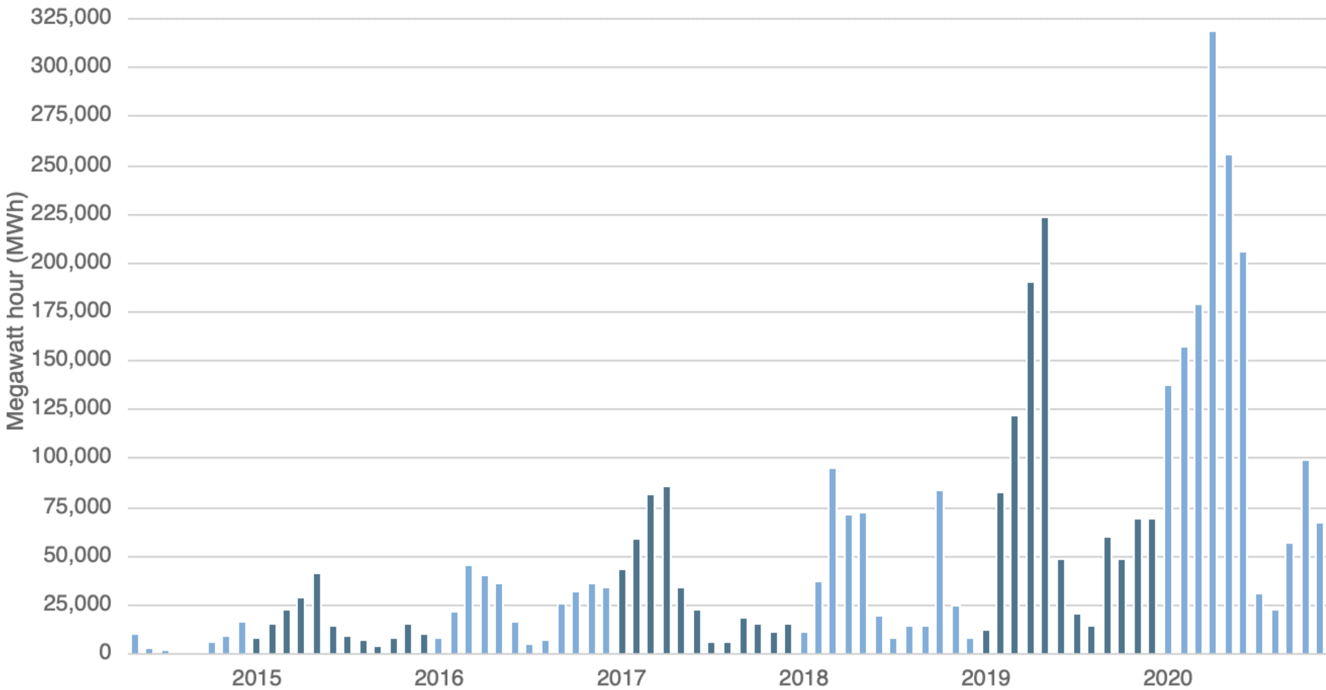
- SB 32 requires GHG emissions be reduced to 40 percent below 1990 levels by 2030.
- AB 3232 requires the CEC to assess strategies to achieve 40 percent GHG reductions in the California building sector by 2030.
- SB 100 requires 100 percent of retail sales of electricity to be from carbon-free resources 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 the natural course of daily rhythms. 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 is investigating 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 supplies are "curtailed" by reducing available solar generation or paying other markets to absorb the surplus. In the first half of 2020, the California ISO curtailed up to 320 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 12/9/2020)

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. Large commercial and industrial interruptible programs and residential air-conditioning (AC) 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-varying retail rates, storage, and automation. Since California's resources mix is increasingly made up of intermittent 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) 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." Immediately following this section, PRC section 25403.5 sets forth the CEC's authority and duty to adopt load management standards. Thus, the CEC explicitly interprets the load management standards authority to be part of a strategy for reducing greenhouse gas emissions.

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." 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 building refers to short-term energy increases.
- Load shifting or flexibility involves both load shedding and load building.
- Energy efficiency and strategic conservation are longer-term strategies for permanently reducing loads during hours of the year typically associated with low supply or high demand.

In 1979, the CEC's original load management regulations (CCR Title 20 §§ 1621-1625) compelled the implementation of marginal cost pricing, industrial time-of-use 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 pursuing the creation of new Flexible Demand Appliance Standards under the authority of the California Public Resources Code Sections 25210, 25213, 25218(e) and (f), 25402(f), and 25402.11; and Sections 1220-1225 of Title 20 of the California Code of Regulations.

Current Status

Each of California's roughly 70 load serving entities offer their own version of load management program portfolios, largely populated by incentive programs that reward participants for load shed. 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 increase 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 off-peak load building to prevent renewable curtailment 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 CCAs has led to a substantial reduction in demand response (DR) program participation, as customers migrate from IOUs with mature program portfolios to CCAs, many of which are in the early stages of assessing potential for demand resources.

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 Boolean: 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 LED (light-emitting diode) lighting will have a smaller baseline than a customer with incandescent lights. As a result, if both customers turn off their lights, the inefficient customers will get paid more for turning off a larger load. Similarly, customers able to afford air conditioning 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 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 AC, battery charging, or process loads, so smaller and more efficient customers have less opportunity to benefit from participation. Utilities also target large loads like AC 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-varying rates have long been considered a more efficient alternative to incentive programs. The recent implementation of default time-of-use (TOU) rates at SMUD, PG&E, SCE, and SDG&E obligates regulators to consider statewide standards for technologies that support TOU cost savings. California's success in helping customers respond to time-varying rates hinges 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), including reasonable notice of the proposed regulations 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, the agency decides to change its proposal before adoption, it then must provide a period of at least 15 days for additional public comment. The proposed regulations will be placed on a CEC Business Meeting agenda for adoption. If adopted, a rulemaking package will be prepared and submitted to the Office of Administrative Law (OAL) for approval.

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

- Docket 19-OIR-01 for the Load Management Rulemaking[4] (October 21, 2019)
- Order Instituting Rulemaking Proceeding to Consider Updates to the Load Management Regulations[5] (November 13, 2019)

[4] 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).

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

- Draft Load Management Rulemaking Scoping Memo[6] (January 10, 2020)
- Agenda for Workshop on Scope of Load Management Rulemaking[7] (January 14, 2020)
- Proposed Amendments to the Load Management Tariff Standard[8] (February 21, 2020)
- Transcript of the Workshop on the Proposed Amendments to the Load Management Tariff Standard[9] (March 2, 2020)

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

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

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

[9] 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).

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. Update the MIDAS Rate Database whenever rates change.
B. Implement a standard RIN access tool to support third-party automation services.
C. Develop and submit locational retail electricity rates that change at least hourly to reflect marginal wholesale costs.
D. Integrate information about new time-varying rates and automation technologies into their existing customer education efforts.

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

A. MIDAS Rate Database Updates

The CEC developed and posted the MIDAS rate database in February 2021. To remain accurate, this database needs to be updated when retail rates are created or modified.

The benefits of an accurate MIDAS database include:

- End-users and their ASPs can use rate data to optimize load management for customer bill minimization.
- ASPs need not pay for subscriptions to rate information collected by companies that scrape utility websites and tariff sheets.
- Utilities, government, and researchers can take advantage of a standard format for transmission of rate data, reducing time and labor costs.

Staff conducted analyses of options for maintaining the accuracy of the MIDAS rate data and recommends that the utilities automate updates to the MIDAS Rate Database each time a new rate or rate modification is approved.

Utilities maintain current data for their own retail rates, so the process can readily be automated using the data upload tools available on the MIDAS website. A benefit of this option is that a direct transfer limits the possibility for errors in the data.

There are no known barriers to this alternative.

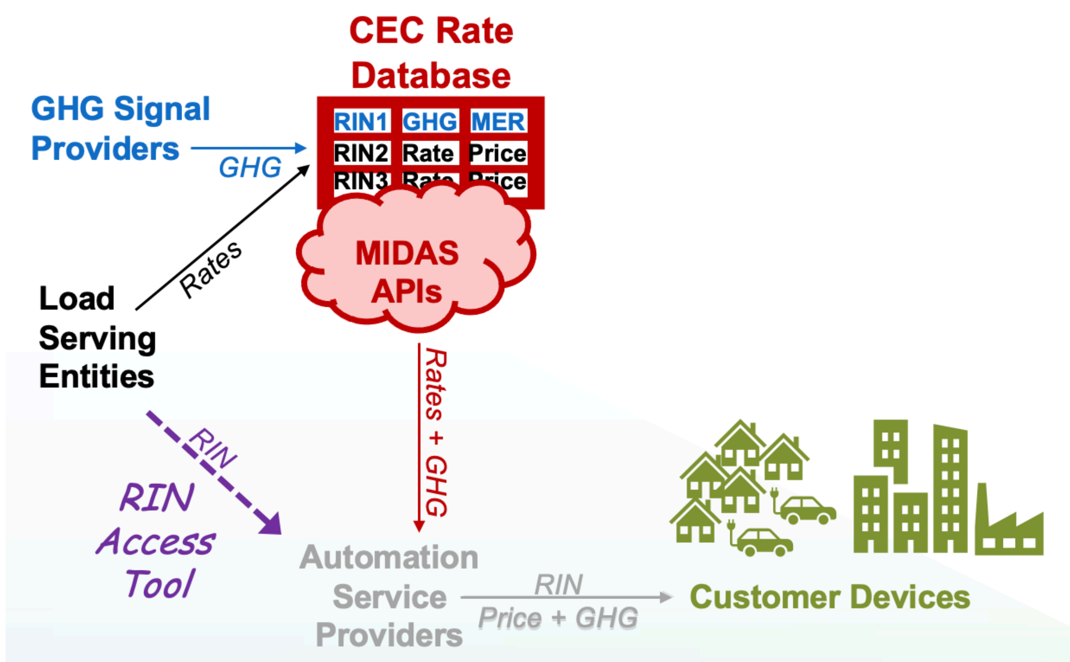
B. Third-Party Automation Services

Devices need to know the timing and prices of their assigned electricity rate to respond appropriately. There are several ways to accomplish this.

Motivated customers can initiate the link directly, for example, by typing the RIN into the end-use, control device, or an associated smartphone application. Less error-prone methods might involve a smartphone app that directs the customer to take a photo of the text, bar code, or a quick response (QR) code representing the RIN on the customer's electricity bill. Once the RIN is entered by the customer, the end-use can be optimized by a third-party service provider – or potentially the device itself – to avoid high-priced periods.

In addition to customer self-service approaches, utilities can support participation by less tech-savvy or hard to reach customers by coordinating with third-party ASPs to complete this process on the customer's behalf. To do this, utilities need a data service that receives requests and passes customer-specific rate information including the RIN to authorized ASPs. Once provided, the ASP can use the data to access the rate information in the MIDAS Rate Database and facilitate the automation of customer devices accordingly (Figure 2).

Figure 2: Rate Identification Number (RIN) Access Tool



Source: CEC Staff, 2021

After careful consideration of options for enabling third-party service providers to support customer participation in utilizing the MIDAS rate database, staff recommends that the utilities implement a standard RIN Access Tool. This will allow third-party vendors to implement a single process statewide for obtaining their customers' rate information.

Under this recommendation, utilities develop a standard statewide platform to facilitate sharing RINs between utilities, customers, and ASPs. Given access to individual customers' rate information, ASPs can help their registered customers install and program automation options to respond to the time-varying data in the MIDAS rate database, thus supporting mass-market automation in California.

C. Retail Rate Structures

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

The most common time-varying 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 this alternative include:

- Hourly, 15-minute, or 5-minute marginal pricing would improve system efficiency by aligning the rates customers see with the cost of supplying energy at that time.
- More frequent signals would enable the demand flexibility needed to offset the supply variations inherent in a carbon-free grid.
- Improvements in system efficiency through better alignment of retail rates with the cost of supplying energy at that location.

Some of the barriers to this alternative include:

- Some meters are unable to record energy use hourly or sub-hourly. Time-varying rates are not possible unless interval meters are present or installed.
- Billing system software may require updating prior to actual 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-varying rates such as TOU are common, upgrades are expected to be less resource intensive than upgrades from flat pricing to time-varying pricing.
- The number of rates would increase by a factor directly proportional to the number of distinct locations. However, an increase in the number of rates due to more categorization by location could ultimately be reduced through a reduction in categorization of customers by type. For example, a small business customer and a residential customer at the same location should, theoretically at least, pay the same price for each electron.

D. Educate Customers and Encourage Automation

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 recommends that utilities educate and encourage customers to use automation devices to respond to prices and GHG emissions.

Under this recommendation, 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-varying 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[10] found that residential customer willingness to sign up for a time-varying 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 FlexAlert campaigns.

Educational programs that help customers schedule the controls they already own is another low-cost option. Research shows that renters are less adept at programming thermostats than are homeowners (Herter 2015). 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.[11]

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.[12]

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 MIDAS signals 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 two. To gain the broadest possible effect of marginal signals, programs should provide customers with both marginal pricing and GHG signals.

Potential options for emissions signals include the California SGIP signal, Automated Emissions Reduction technology by WattTime, and Climate Trace, an Al Gore sponsored program[13] to monitor global climate emissions.

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[10] https://smartenergycc.org/rate-design-what-do-consumers-want-and-need/

[11] SMUD 2020

[12] https://sepapower.org/knowledge/designing-consumer-metrics-for-grid-connected-devices/

[13] 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/).

- **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[14] 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[15] is a real-time marginal GHG emissions API based on climate research completed at UC Berkeley.[16] This technology enables smart home devices including smart plugs, thermostats, and electric vehicles to automatically reduce emissions associated with their electricity use.

- **Global Climate Trace.** Former Vice President Al Gore in collaboration with a coalition of nine climate and technology organizations calling themselves Climate Trace[17] 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.

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[14] California Self-Generation Incentive Program GHG Signal, available at (http://sgipsignal.com/grid-regions).

[15] Automated Emissions Reduction (AER), available at (https://www.watttime.org/aer/what-is-aer/).

[16] *Location, Location, Location: The Variable Value of Renewable Energy and Demand-Side Efficiency Resources*, 2018. Available at (https://doi.org/10.1086/694179).

[17] Climate Trace website is available at (https://www.climatetrace.org/).

CHAPTER 3: Statutory Authority

The 1974 Warren-Alquist Act established the CEC as California's primary energy policy and planning agency. 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 to set building and appliance standards in section 25402.

Load management improves electric system efficiency and reliability by shifting electricity use to times with lower demand and more available energy. 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.

The load management standards authorization is a subsection of section 25403, which 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." Thus, the CEC explicitly interprets the load management standards authority to be part of a strategy for reducing greenhouse gas emissions.

Utility Applicability

Section 25403.5 (a) states that the CEC shall "adopt standards by regulation for a program of electrical load management for each utility service area."

Section 25118 defines "service area" as "any contiguous geographic area serviced by the same electric utility." Thus, investor and publicly owned utilities 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 on 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 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.[18]

Customer participation in CCAs is provided as the default service 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. Customers that do not opt-out are automatically enrolled in the

[18] CPUC decision D.12-12-036 is available at (https://www.cpuc.ca.gov/general.aspx?id=2567).

CCA. CCA customers continue to receive a single bill from the utility company. 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, however CCAs function within the service territory of IOUs. The load management standards apply to electric utility service territories, which include customers served by CCAs that operate within the service territory of IOUs. 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 increasing rapidly, any other interpretation would diminish the effectiveness of 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. Section 25403.5 (a) reads:

> 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.[19] As such, the proposed 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 CEC are focused on shaving energy demand during peak periods and increasing use in off-peak periods.

Statute 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, the statute further broadens the CEC's authority through use of the phrase "need-not-be-limited-to." 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.

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[19] 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.

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. (§ 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. (§ 25403.5 (b))

In addition to the six CPUC-regulated IOUs, California has 47 publicly owned utilities (POUs) and 22 CCAs operating in the state. POUs and CCAs maintain independent governing boards who approve retail electricity rates for their customers.[20]

Figure 3: 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 (LSEs) in California (https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-load-serving-entities-lses).

The 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 for contempt, and prescribe a uniform system of accounts for all public utilities subject to its jurisdiction."[21] 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.

[20] https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-load-serving-entities-lses

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

Public Utilities Code § 451 requires the CPUC to determine whether proposed rates, services, and charges are just and reasonable. The CPUC's Rate Design Principles,[22] 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 various other 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)[23] 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.
- Rate Design Window[24] 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

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[22] 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).

[23] More information about CPUC General Rate Case (GRC) proceedings can be found at (https://www.cpuc.ca.gov/general.aspx?id=2567).

[24] More information about CPUC rate design window optional filings can be found at (https://www.cpuc.ca.gov/General.aspx?id=12148).

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 that the CEC ensure that 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

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.

The Legislature included this provision to make sure that no utility would be unduly burdened given their unique circumstances. 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.

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[25] 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 California Energy Commission 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, the U.S. 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

[25] Elsewhere in the chapter the authors recognized that one-way communication is adequate.

energy agencies began requiring that utilities implement demand-side management programs where cost-effective.

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 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.[26]

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-varying pricing options, much less real-time pricing.

With this background, the CEC, in collaboration with the CPUC and the five largest California electric utilities,[27] undertook 26 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.

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[26] 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).

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

3. **Load Control.** Properly designed load control strategies achieved load and energy impacts throughout the targeted peak period and beyond but had many drawbacks.
    - Customers had limited ability to influence control of their own devices to address health, religious, or other special occasions.
    - 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 team 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 finalized four load management standards for the five largest electric utilities in the state: Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), Los Angeles Department of Water and Power (LADWP), and Sacramento Municipal Utility District (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[28] comprised of staff from the CEC, PUC, 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 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

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

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.

- 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-varying 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 (AB 1890), 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.

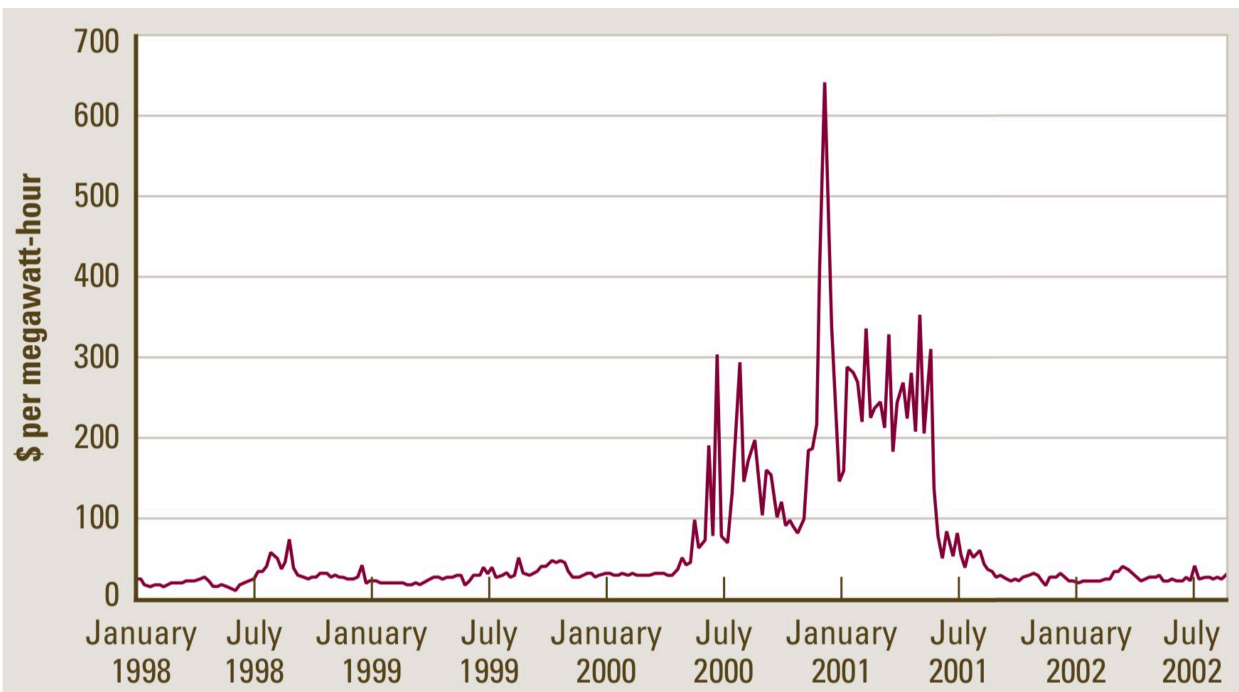
On March 31, 1998, AB 1890 went into effect. Utilities began to divest their power generation facilities while continuing to provide customers with distribution, metering, and billing services. Generators began selling their electricity on the new spot market.

2000s – The California Electricity Crisis and its Aftermath

In the summer of 2000, the California real-time electricity market began showing signs of considerable volatility. Peak spot prices increased an order of magnitude beyond those of previous years, from roughly $30 per MWh to over $300 per MWh (Figure 4).

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 to retail customers at a loss and the California ISO called nine emergency events initiating rolling blackouts that affected millions of customers. On September 20, 2001, the California Public Utilities Commission suspended retail access and energy prices normalized.

Figure 4. Weekly Average Peak Prices in West Coast Spot Markets, 1998–2002



Source: Pechman, 2007

When it was over, the estimated cost of the 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, demand-side management resurged as the best short-term solution. In 2001, 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 demand-side management programs aimed at reducing peak demand.[29] Together, these bills appropriated over $500 million dollars for demand-side management 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)[30] 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-varying rates for all customers, under the notion that price-responsive demand could prevent future wholesale market volatility.

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

- **Basic Interruptible Program**. Offered fixed rate discounts of about 15 percent in exchange for demand reductions requested by the utilities.
- **Voluntary Demand Reduction Program**. Compensated participants a fixed amount for each megawatt-hour of reduction.
- **Optional Binding Mandatory Curtailment Program**. Excused participants from rotating blackouts when they reduced their demand.
- **Air Conditioner Cycling Programs**. Issued participants an annual discount in exchange for allowing utilities to reduce the customer's air conditioning load during occasional peak periods.

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 aggregators per megawatt-hour to arrange curtailment of many smaller loads.
- **Ancillary Services Load Program**. Allowed participants to bid load reduction in the same way generators bid supply.

In 2003, the 1.5 gigawatts of demand response in California consisted largely of emergency programs that powered down commercial buildings, industrial operations, and residential air

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[29] 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).

[30] 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).

conditioners; however, a consensus was growing that time-varying rates must be part of the solution to California's electricity woes.

In an effort to redirect and align the state energy agencies on price-responsive demand resources, the Legislature declared in SB 1976 (Torlakson, Chapter 850, Statutes of 2002):[31]

- 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 (Figure 5) and recommended that the state deploy a system of advanced metering systems to enable dynamic pricing, provided favorable cost-effectiveness analysis (CEC 2003).[32]

Figure 5: Predicted Impacts of Dynamic Pricing

	Dynamic Rates as Default		**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).[33] In their Order Instituting Rulemaking, the CPUC observed the collaboration, writing: "As our first task in this proceeding, we will consider a strategic approach to the orderly development of demand-responsiveness capability in the California

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

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

[33] 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)

electricity market over the next 18 months. We are aware that the California Energy Commission (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*[34] was adopted by both the CEC and the CPUC. The Loading Order prioritizes investments in 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.[35] The main goal of the pilot and the accompanying impact evaluation was to develop an econometric model for predicting residential and small commercial demand response under alternative pricing plans.

Each of the experimental tariffs tested in the California Statewide Pricing Pilot consisted of a two-price TOU rate on normal days and a critical peak price (CPP) on event days, when peak demand was especially high. Twelve times each summer (May through October) and three times each winter (November through April), the critical price was charged over the five-hour event, from 2 p.m. to 7 p.m. on weekdays. Multiple rates were applied across the three utilities and climate zones. On average, depending on location, customers were charged around 10 cents per kWh during off-peak hours, 20 cents/kWh during peak hours, and 60 cents/kWh during CPP events. The average electricity price for the average non-participating California customer was about 13 cents/kWh.

Between July 2003 and September 2004, a total of 27 CPP events were called. Participants without responsive thermostats were notified by telephone of an impending event by 4 p.m. on the day before the event took place. Participants with responsive thermostats were notified four hours before the event was to take place, and their thermostats were signaled to automate response at the onset of the critical period. An analysis of meter data indicated that

[34] https://www.cpuc.ca.gov/eaps/

[35] 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).

homes with AC automation saved twice as much during critical peak events as did participants without responsive thermostats (Herter 2007).

2009-2013 – Deployment of Advanced 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)[36], 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 and 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:[37]

- 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 non-residential customers. By 2013, these four utilities had installed over 12 million electric interval meters, enabling TOU and dynamic rates for 100 percent of their customers. Of the utilities addressed by the load management standards, only LADWP has chosen not to install AMI. Despite this exception, roughly 90 percent of customers statewide now have the advanced metering required for time-varying rates (Figure 6).

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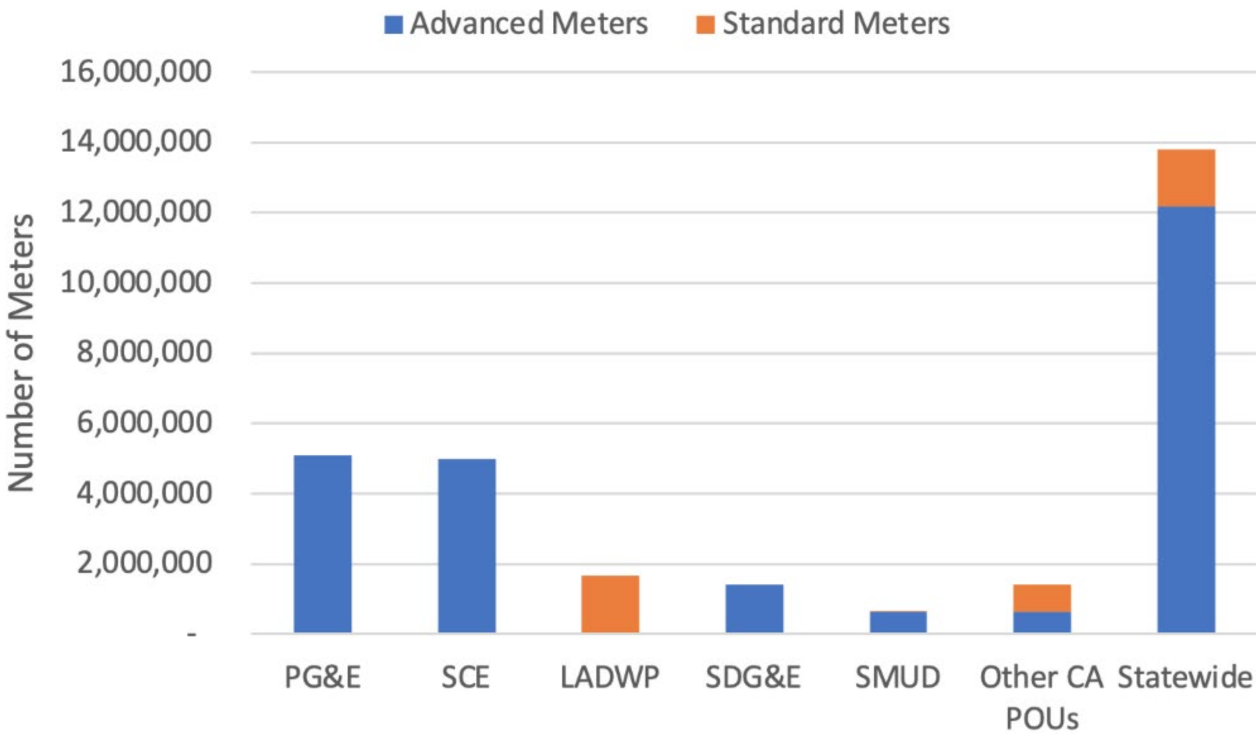
[36] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report

[37] California Public Utilities Commission, Decision #08-07-045. July 31, 2008.

Figure 6: Advanced Metering at California Utilities



Source: CEC Staff, 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.[38]

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:

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

- SCE Summer Discount Plan[39]
- SCE Agricultural & Pumping Interruptible Program[40]
- SDG&E Residential AC Saver[41] and AC Saver Thermostat[42]
- SDG&E Commercial AC Saver[43] and Smart Thermostat Program[44]
- SMUD Peak Corps[45]

Base Interruptible Program (BIP, TOU-BIP)

The BIP provides short-term load reductions on the day of California ISO emergency curtailments. BIP is integrated into the CAISO market as a Reliability Demand Response Resource. Non-residential 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. (See PG&E BIP, SCE BIP, SDG&E BIP).[46]

Capacity Bidding Program (CBP)

The 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 non-residential customers have the option to qualify for self-aggregation. CBP is integrated into the California ISO as a Proxy Demand

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[39] SCE Summer Discount Plan, available at (https://www.sce.com/sites/default/files/inline-files/135650_DR%20Programs%20Fact%20Sheet%200520%20FINAL%20WCAG.pdf).

[40] SCE Agricultural & Pumping Interruptible Program, available at (https://www.sce.com/sites/default/files/inline-files/135650_DR%20Programs%20Fact%20Sheet%200520%20FINAL%20WCAG.pdf).

[41] SDG&E Residential AC Saver, available at (https://www.sdge.com/residential/savings-center/rebates/your-heating-cooling-systems/summer-saver-program).

[42] SDG&E AC Saver Thermostat, available at (https://www.sdge.com/residential/savings-center/energy-saving-programs/reduce-your-use/reduce-your-use-thermostat).

[43] SDG&E Commercial AC Saver, available at (https://www.sdge.com/businesses/savings-center/energy-management-programs/demand-response/summer-saver-program).

[44] SDG&E Smart Thermostat Program, available at (https://www.sdge.com/business-thermostat).

[45] SMUD Peak Corps,
available at (https://www.smud.org/en/In-Our-Community/Help-your-Community/Peak-Corps).

[46] 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).

Resource and so must comply with California ISO tariff requirements. (See PG&E CBP, SCE CBP, SDG&E CBP)[47]

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 Self-Generation Incentive Program,[48] sets aside over $700 million dollars for California IOU programs that install responsive energy storage, including batteries and heat pump water heaters.[49]

Proxy Demand Resource Pilots

The Excess Supply Demand Response Pilot (XSP)[50] 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[51] is 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 non-residential 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

DRPs 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-Varying Rates

Time-varying 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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[47] 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).

[48] CPUC's Self-Generation Incentive Program, available at (https://www.selfgenca.com/).

[49] Self-Generation Incentive Program Handbook, March 2020, available at (https://www.selfgenca.com/).

[50] Excess Supply Demand Response Pilot (XSP), available at (https://olivineinc.com/services/our-work/xsp/).

[51] Supply Side II Demand Response Pilot, available at (https://olivineinc.com/services/our-work/ssp/).

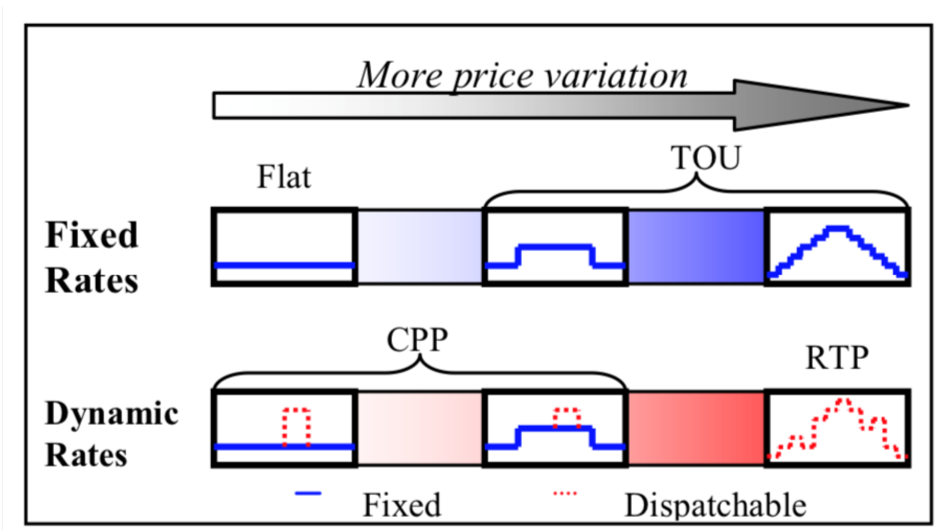
enabling further development of carbon-free supply resources and improving system efficiency.

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

Common time-varying rate designs can be categorized into three basic groups: time-of-use (TOU), critical peak pricing (CPP), and real-time pricing (RTP).[52] By the end of 2020, more than half of California customers were on a time-varying rates, and dynamic rates accounted for over 900 MW of load flexibility at the California IOUs.

Figure 7: Rate Designs in Order of Increasing Variation and Precision



Source: Herter, McAuliffe, and Rosenfeld, 2003

The following sections address each rate design type in more detail.

Time-of-Use Pricing (TOU)

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

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

for both the utility and customers. Automation devices programmed with TOU periods have been shown 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 months or 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 LADWP, PG&E, SCE, SDG&E, and SMUD in the 1980s following the first Load Management Standards. Smaller non-residential 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 monumental decision was based on the successful results of their Smart Pricing Options pilot, which showed a 6 percent peak load savings from default residential TOU rates (SMUD 2014).

Following SMUD's lead, 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[53] indicated statistically significant 4-9 PM peak impacts of 2-4 percent in the winter and 4-6 percent in the second summer of study (Table 1). 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 1: California IOU Weekday 4-9 PM Load Reductions Under TOU Pricing

IOU 4-9 PM TOU Rate	Winter 2016/2017	Summer 2017
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.

[53] https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457172.

Links to utility time of use sites:

- PG&E: Residential TOU, Commercial TOU[54]
- SCE: Residential TOU, Commercial TOU[55]
- SDG&E: Residential TOU Pricing Plans, EV pricing plans, Commercial TOU[56]
- SMUD: Residential TOU[57]

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, 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 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.

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[54] PG&E Residential TOU rates are 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 are available at (https://www.pge.com/en_US/small-medium-business/your-account/rates-and-rate-options/compare-rates.page).

[55] SCE Residential TOU rates are available at (https://www.sce.com/residential/rates/Time-Of-Use-Residential-Rate-Plans). SCE Commercial TOU rates are available at (https://www.sce.com/business/rates/time-of-use).

[56] SDG&E Residential TOU pricing plans are available at (https://www.sdge.com/whenmatters). SDG&E Electric Vehicle pricing plans are available at (https://www.sdge.com/residential/pricing-plans/about-our-pricing-plans/electric-vehicle-plans). SDG&E Commercial TOU rates are available at (https://www.sdge.com/businesses/pricing-plans/time-use-tou-pricing-plans-business).

[57] SMUD Residential TOU rates are available at (https://www.smud.org/en/Rate-Information/Residential-rates).

Status. In February 2010, the CPUC approved CPP for PG&E customers in Application 09-02-022.[58] PG&E refers to its commercial CPP offerings as Peak Day Pricing,[59] and its residential CPP as SmartRate.[60] In March 2013, the CPUC approved CPP for SCE customers in Application 11-06-007.[61] CPP is the default option for all of SCE's non-residential 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.[62] This proceeding was reopened and consolidated with Application 19-03-002[63] in June 2019. CPP is the default option for all of SDG&E's large non-residential customers (Rate Schedule CPP-D Time of Use Plus).[64]

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 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 United States 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

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58 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).

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

60 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).

61 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).

62 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).

63 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).

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

baseline. When a customer consumes less than their baseline amount, the utility pays the customer the spot price for the difference.

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[65] 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.
> - 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.

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[65] SCE's large commercial and industrial RTP rate plan is available at (https://www.sce.com/sites/default/files/inline-files/RTP%20Fact%20Sheet%200918_WCAG_3.pdf).

In Decision 17-01-006, the CPUC again indicated support for dynamic rates, including real-time pricing.[66] 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.[67] However, later that same year, the CPUC hosted a workshop on dynamic rates and real-time pricing as part of San Diego Gas & Electric'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.[68]

On April 6, 2020, the California Solar and Storage Association, OhmConnect, Inc., and California Energy Storage Alliance filed joint testimony[69] as the Joint Advanced Rates Parties (JARP) under CPUC proceeding A.19-03-002.[70] 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 extension of the statutory deadline[71] to allow time for evidentiary hearings and briefs prior to the issuance and review of a final decision, expected by May 4, 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).[72]

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

[67] See finding of fact 12 in adopted CPUC Decision D.19-03-002, available at (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M273/K643/273643295.PDF).

[68] https://www.cpuc.ca.gov/General.aspx?id=6442462894

[69] Prepared testimony of California Solar and Storage Association, OhmConnect, Inc., and California Energy Storage Alliance ("Joint Advanced Rate Parties") to CPUC A.19-03-002. April 6, 2020. 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).

[70] 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).

[71] CPUC Decision 20-08-052, available at (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M346/K098/346098820.PDF).

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

Summary of California Load Management Programs

Table 2 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.[73]

Table 2: 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

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

[73] See for example SMUD Summer Solutions and OG&E SmartHours.

CHAPTER 6: Load Management Efforts at the CEC

PRC § 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 kickstart early load management efforts through regulation. Since then, the CEC has continued internal efforts to address load management, through standards, research and development projects, data analysis, and reporting. More recently, as a foundation for the currently proposed load management standard amendments, the CEC has also begun to develop a 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 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)[74] 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 (§ 25402(f)(1)). This is separate and distinct from the CEC's traditional authority to prescribe energy efficiency standards and labeling requirements "for minimum levels of operating efficiency" of appliances to reduce their energy consumption (§ 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" (§ 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 its Integrated Energy Policy Report (§ 25402(f)(6)).

[74] SB 49 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).[75] This proceeding is being conducted in coordination with existing Building Standards and proposed Load Management standards efforts. More information on this effort can be found on the Flexible Demand Appliances website.[76]

Building Standards Related to Load Management

PRC § 25402(a)(1) authorized 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." Many sections of the Building Energy Code are related to or address load management, including the following Joint Appendices (JA):

- JA-3 Time Dependent Valuation[77]
- JA-5 Technical Specifications for Occupant Controlled Smart Thermostats[78]
- JA-11 Qualification Requirements for Photovoltaic System[79]
- JA-12 Qualification Requirements for Battery System[80]
- JA-13 Qualification Requirements for Heat Pump Water Heater Demand Management System[81]

More information on this effort can be found on the Building Energy Efficiency Standards website.[82]

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[75] CEC Docket 20-FDAS-01, Flexible Demand Appliance Standards, available at (https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=20-FDAS-01).

[76] Flexible Demand Appliances website, available at (https://www.energy.ca.gov/proceedings/energy-commission-proceedings/flexible-demand-appliances).

[77] California Building Energy Code, JA-3 Time Dependent Valuation, available at (https://efiling.energy.ca.gov/GetDocument.aspx?tn=223245-4).

[78] 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).

[79] California Building Energy Code, JA-11 Qualification Requirements for Photovoltaic System, available at (https://efiling.energy.ca.gov/GetDocument.aspx?tn=223245-6).

[80] California Building Energy Code, JA-12 Qualification Requirements for Battery System, available at (https://efiling.energy.ca.gov/GetDocument.aspx?tn=223245-13).

[81] 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).

[82] CEC Building Energy Efficiency Standards website, available at (https://www.energy.ca.gov/programs-and-topics/programs/building-energy-efficiency-standards).

Load Management Standards

Pursuant to 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."[83] 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, §§ 1621-1625, as listed below:

- § 1621. General Provisions.[84]
- § 1622. Residential Load Management Standard.[85]
- § 1623. Load Management Tariff Standard.[86]
- § 1624. Swimming Pool Filter Pump Load Management Standard.[87]
- § 1625. Non-Residential Load Management Standard.[88]

More information on this proceeding can be found on the Load Management Standards website.[89]

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[83] The pertinent statutory language is as follows:

Section 25403.5 (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 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 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.

[84] California Code of Regulations, § 1621. General Provisions. Available at (https://govt.westlaw.com/calregs/Document/I927F2FC0D44E11DEA95CA4428EC25FA0).

[85] California Code of Regulations, § 1622. Residential Load Management Standard. Available at (https://govt.westlaw.com/calregs/Document/I74822F10FB3911DEB55BEB7A3F18BAB6).

[86] California Code of Regulations, § 1623. Load Management Tariff Standard. Available at (https://govt.westlaw.com/calregs/Document/I74B5E940FB3911DEB55BEB7A3F18BAB6).

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

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

[89] Load Management Standards website at (https://www.energy.ca.gov/proceedings/energy-commission-proceedings/2020-load-management-rulemaking).

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 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[90] at innovation.energy.ca.gov, and a full list of completed research reports is available on the Energy Research and Development Reports and Publications website.[91]

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. 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.[92]

More information on this effort can be found on the California Flexible Load Research and Deployment Hub website.[93]

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 (Núñez, Chapter

[90] CEC's Energy Innovation Showcase, available at (http://innovation.energy.ca.gov/).

[91] Energy Research and Development Reports and Publications website, available at (https://www.energy.ca.gov/energy-rd-reports-n-publications).

[92] 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).

[93] 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).

750, Statutes of 2007),[94] which took effect January 1 2008, and was extended through January 1, 2024, by Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013).[95] 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.[96]

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. 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.[97]

Interval Meter Database

The CEC warehouses hourly meter data for all bundled electricity customers served by the five largest utilities in the state — LADWP, PG&E, SCE, SDG&E, 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 strategies. More information on this effort can be found on the Energy Data Collection Rulemaking website[98] and Docket[99] (18-OIR-01).

MIDAS Rate Database

The CEC has developed the Market Informed Demand Automation Server (MIDAS) Rate Database at http://MIDASTest. The web-based service provides access to time-varying rates in

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[94] AB 118, available at (http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200720080AB118).

[95] AB 8, available at (https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB8).

[96] CEC Clean Transportation Program website, available at (https://www.energy.ca.gov/programs-and-topics/programs/clean-transportation-program).

[97] The IEPR Docket is at (https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-03).

[98] The Energy Data Collection Rulemaking website is 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).

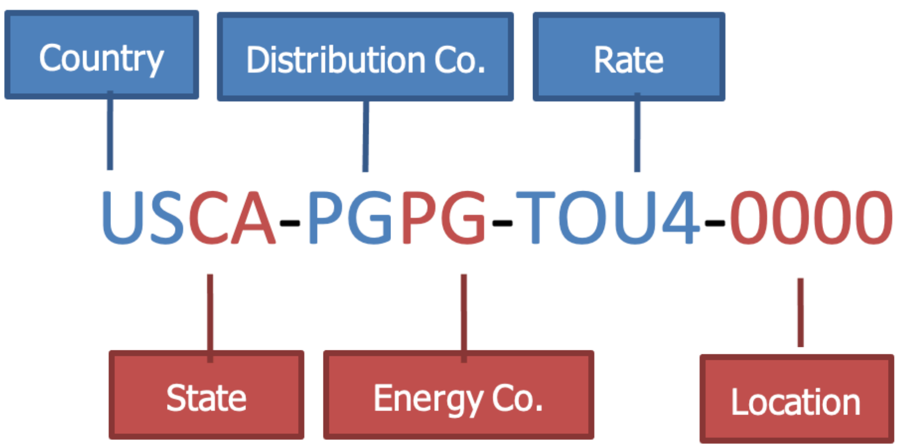
[99] The Energy Data Collection Rulemaking Docket is available at (https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=18-OIR-01).

a standard machine-readable format using an application programming interface (API). This allows device manufacturers and California customers to automatically access customer rate information for use in automating price responsive load shifting.

The CEC's MIDAS platform was created to enable demand automation through time-varying rates and marginal grid signals. Once fully developed, the MIDAS platform will receive, aggregate, and distribute 5-minute locational price and greenhouse gas emissions data from multiple sources. The system will use APIs to enable statewide access to electricity rates using standard Rate Identification Numbers or RINs. The goal of this effort is to facilitate mass-market load flexibility to lower customer bills and/or greenhouse gas emissions. The MIDAS system is being designed to be scalable to the national or international level.

RINs use standardized codes for country and state; distribution and energy company (co.); rate; and location (Figure 8), so every rate has its own unique RIN. With the use of RINs, customers, utilities, ASPs, and others can match automation devices to the relevant electricity prices or GHG signals, ensuring appropriate load management for the customer at that site.

Figure 8: MIDAS Rate Identification Number Format



Source: CEC Staff, 2020

The CEC's preliminary rate database will contain existing time-varying electricity prices from LADWP, PG&E, SCE, SDG&E, SMUD. Future iterations of the database will facilitate the publication of all time-varying and dynamic utility electricity rates, greenhouse gas signals, and other time-varying grid signals in a machine-readable format.

The publication of the MIDAS rate 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.

The rate database 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 California Energy Commission to prepare a biennial integrated energy policy report 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), 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).

More information on this effort can be found on the IEPR website.[100]

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 California PRC § 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 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.[101]

Building Decarbonization Assessment (AB 3232)

AB 3232, codified in PRC § 25403, 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

[100] CEC Integrated Energy Policy Report (IEPR) website, available at (https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report).

[101] CEC Energy Efficiency in Existing Buildings website, available at (https://www.energy.ca.gov/programs-and-topics/programs/energy-efficiency-existing-buildings).

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."

More information on this effort can be found on the Building Decarbonization Assessment website or in the Building Decarbonization Docket (Docket 19-DECARB-01).[102]

SB 100 Joint Agency Report

Senate Bill 100 (SB 100, De Leon, Chapter 312, Statutes of 2018) established 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 (CARB) 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.[103] 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.

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).[104]

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[102] AB 3232 Building Decarbonization Assessment website, 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).

[103] The 2021 Senate Bill 100 Joint Agency Report is available at (https://www.energy.ca.gov/sb100).

[104] SB 100 Joint Agency Report website, available at (https://www.energy.ca.gov/sb100). SB 100 docket, 19-SB-100, available at (https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-SB-100).

CHAPTER 7: Proposed Amendments

The CEC staff has considered all public comments received and developed proposed language appropriately. The proposed regulations advance the following four requirements on specified utilities to:

1. Maintain the accuracy of existing and future time-varying rates in the publicly available and machine-readable MIDAS rate database.
2. Develop a standard rate information access tool to support third-party services.
3. Develop and submit locational rates that change at least hourly to reflect marginal wholesale costs.
4. Integrate information about new time-varying rates and automation technologies into existing customer education and outreach programs.

The intended outcome of these regulation amendments is to form the foundation for a statewide demand automation system that aggregates and publishes time-varying 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 new language appears as underline and deletions appear as strikeout. Existing language appears as plain text.

§ 1621 General Provisions

(a) Purpose. This article establishes electric load management standards pursuant to Section 25403.5 of the Public Resources Code. These standards establish cost-effective programs which will <u>encourage the use of electrical energy at off-peak hours and encourage the control of daily and seasonal peak loads to </u>~~result in~~ improve~~d~~ ~~utility~~ <u>electric</u> system efficiency<u> and reliability</u>, ~~will~~ lessen or delay the need for new electrical capacity, and reduce fossil fuel consumption and greenhouse gas emissions, ~~and will~~ thereby lowering the long-term economic and environmental costs of meeting the State's electricity needs.

(b) Application. Each of the standards in this article applies to the following electric utilities: Los Angeles Department of Water and Power, San Diego Gas and Electric Company, Southern California Edison Company, Pacific Gas and Electric Company, and Sacramento Municipal Utility District, as well as any Community Choice Aggregator (CCA) operating within the service area and receiving distribution services from the foregoing electric utilities. The California Energy Commission has found these standards to be technologically feasible and cost effective when compared with the costs for new electrical capacity for the above-named electric utilities, including any customers of CCAs operating within the service area of such electric utilities.

(c) Definitions. In this article, the following definitions apply:

(1) "Utility" means those electric utilities including CCAs serving customers within a utility service area, to which the sections of this article apply, as specified in subsection (b).

~~(2)~~ "Service area" means ~~is~~ the geographic area serviced by the same electric utility or utility.~~in which the utility supplies electricity to retail customers.~~

(3) "Rate-approving body" means the California Public Utilities Commission in the case of investor-owned utilities, such as the San Diego Gas and Electric Company, the Southern California Edison Company, and the Pacific Gas and Electric Company. It means the governing body of a publicly owned utilities~~:~~ such as the Los Angeles City Council for the Los Angeles Department of Water and Power, and the Boards of Directors for the Sacramento Municipal Utility District and CCAs.

(4) "Residential" means any family dwelling within the utility's service area which uses electricity for noncommercial purposes as defined in the utility's terms and conditions of service.

(5) "Water heater" means any residential electric water heater except those which provide hot water to heat space or those which operate within electric dishwashers.

(6) "Central air conditioner" means any residential electric air conditioner which delivers cooled air through ducts to rooms.

(7) "Marginal cost" ~~is~~ means the change in current and ~~committed~~ future electric system ~~utility~~ cost that is caused by a ~~customer-initiated~~ change in electricity usage during a specified time interval at a specified location. Total marginal cost ~~may be divided into~~ shall be calculated as the sum of ~~the commonly known categories of marginal~~ energy, ~~marginal~~ capacity (generation, transmission, and distribution), and ~~marginal customer costs, or~~ any other appropriate time and location dependent costs ~~categories~~, on a time interval of no more than one hour to inform the development of marginal cost rate structures.

(A) Energy cost computations shall reflect locational marginal pricing as determined by the associated balancing authority, such as the California Independent System Operator, the Balancing Authority of Northern California, or other balancing authority.

(B) Capacity cost computations shall reflect the variations in the probability and value of system reliability.

(8) "Commercial customers" means those customers of a utility who run any business described in Standard Industrial Classification Groups 40 through 86, and 89 through 99, and which do not treat sewage or manufacture goods or provide other process-oriented services.
   (A) "Large commercial customers" are those businesses whose demand for electricity equals or exceeds 500 kilowatts.
   (B) "Small commercial customers" are those businesses whose demand for electricity is less than 500 kilowatts.
(9) "Building type" means the classification of a non-residential building in accordance with ~~the following table:~~ California Code of Regulations, Title 24, Part 2, Chapter 3 of the California Building Code.

~~Building Type~~	~~Description~~
~~1~~	~~Office~~
~~1.1~~	~~Small (0-30,000 sq. ft.)~~
~~1.2~~	~~Med (30,000-200,000 sq. ft.)~~
~~1.3~~	~~Large (200,000 + sq. ft.)~~
~~1.3.1~~	~~Low rise (two or less stories)~~
~~1.3.2~~	~~Highrise (three or more stories)~~
~~2~~	~~Retail~~
~~2.1~~	~~Retail -General~~
~~2.1.1~~	~~Small (1-9,000 sq. ft.), detached~~
~~2.1.2~~	~~Small (1-9,000 sq. ft.), attached~~
~~2.1.3~~	~~Med (9,000-20,000 sq. ft.), detached~~
~~2.1.4~~	~~Med (9,000-20,000 sq. ft.), attached~~
~~2.1.5~~	~~Med (9,000-20,000 sq. ft.), enclosed mall~~
~~2.1.6~~	~~Large (20,000 + sq. ft.), detached~~
~~2.1.7~~	~~Large (20,000 + sq. ft.), attached~~
~~2.1.8~~	~~Large (20,000 + sq. ft.), enclosed mall~~
~~2.1.9~~	~~Highrise department store (three or more stories)~~
~~2.2~~	~~Retail -Food~~
~~2.2.1~~	~~Small (1-5,000 sq. ft.)~~
~~2.2.2~~	~~Large (5,000 + sq. ft.)~~
~~3~~	~~Restaurants~~
~~3.1~~	~~Fast Food~~
~~3.2~~	~~Sit-down~~
~~4~~	~~Storage Buildings~~
~~4.1~~	~~Conditioned~~
~~4.2~~	~~Unconditioned~~

~~5~~	~~Hotels and Motels~~
~~5.1~~	~~Large (50,000 + sq. ft.)~~
~~5.2~~	~~Small (less than 50,000 sq. ft.)~~
~~6~~	~~Schools~~
~~6.1~~	~~Elementary/pre-schools~~
~~6.2~~	~~Jr. high/high schools~~
~~6.3~~	~~Jr. colleges/trade schools~~
~~6.4~~	~~Colleges/universities~~
~~7~~	~~Public assembly buildings~~
~~7.1~~	~~Auditoriums~~
~~7.2~~	~~Theaters~~
~~7.3~~	~~Sports arenas~~
~~8~~	~~Health care facilities~~
~~8.1~~	~~General hospitals~~
~~8.2~~	~~Research hospitals~~
~~8.3~~	~~Mental hospitals~~
~~8.4~~	~~Convalescent hospitals/homes~~
~~9~~	~~Computer facilities~~
~~10~~	~~Auto repair and service stations~~
~~11~~	~~Miscellaneous~~

(10) "Conditioned Space" means the space, within a building which is provided with a positive heat supply or positive method of cooling.

(11) "Time-of-use rate" means a rate with predefined prices that vary according to the time of day, the season, and/or the day type (weekday, weekend, or holiday).

(12) "Hourly rate" means a rate with prices that vary hourly.

(13) "Sub-hourly rate" means a rate that varies sub-hourly. Sub-hourly frequencies for electricity rates include, but are not limited to, 15-minute and 5-minute rates.

(14) "Time-varying rate" means a rate that varies according to the time of day to encourage off-peak electricity use and reductions in peak electricity use. Time-of-use, hourly, and sub-hourly rates are time-varying rates.

(15) "Tariff" means the contract between the utility and customer that specifies the components of the customer's electricity bill.

(16) "Load management tariff" means a tariff with time-dependent values that vary according to the time of day to encourage off-peak electricity use and reductions in peak electricity use.

(17) "Rate Identification Number" or "RIN" means the unique identifier for an electricity rate established by the Commission.

(d) Review and Approval of Utility Submittals. These load management standards require utilities to submit various plans, information, and documents to the Executive Director. All such submittals shall be reviewed by the Executive Director and shall be subject to approval by the full Commission. The Executive Director shall complete ~~his~~ review of such submittals and shall report to the Commission within thirty calendar days after receipt as to whether the submittal is consistent with the provisions of this article. Within thirty calendar days after the Executive Director renders this report, the Commission shall, following a public hearing, approve or disapprove the submittal. The Commission may also approve a submittal on condition that the utility make specified changes or additions to the submittal, within a reasonable period of time set by the Commission. A conditional approval shall not take effect until the utility makes the specified changes or additions to the submittal under review. The Commission shall approve submittals which are consistent with these regulations and which show a good faith effort to plan to meet program goals for the standards. The Commission may delegate approval of these documents to the Executive Director.

If the Commission disapproves a submittal, the utility shall be notified of the specific reasons for such disapproval, and the utility shall submit a revised submittal for review by the Executive Director in accordance with the provisions of this subsection.

(e) Information Requests. In order to facilitate ~~his~~ review of a utility's compliance with the provisions of this article, the Executive Director may request a utility to furnish copies of any information in the utility's possession which is relevant to its implementation of these standards, including any tariff proposals and associated information which it submits to its rate-approving body. The Executive Director may set a reasonable period of time within which the utility must supply the requested information.

If any document ~~which is~~ requested by the Executive Director contains information that the utility believes is confidential proprietary information or trade secrets, the utility ~~shall~~ may submit a request, consistent with section 2505 of title 20 of the California Code of Regulations, to designate such information as confidential. ~~only be required to furnish the document to the Executive Director, if the Commission has established procedures, after a public hearing, for the protection of such proprietary information or trade secrets.~~

(f) Revisions of Approved Plans. Each time a utility significantly revises any plan or part of a plan required by this article, that was previously approved by the Commission, it shall submit this revised plan for review and approval pursuant to subsection (d) above. Such revised plan shall not be valid until it is approved by the Commission. If the Executive Director believes that new technologies, the state of the economy or other new information warrant revisions to plans which have already been approved, ~~he~~ the Executive Director shall request the utilities to make the appropriate revisions as part of their next annual report or within 90 days, whichever comes later. If the Executive Director issues such a request, the utility shall submit a revised plan for review and approval pursuant to subsection (d) above.

(g) Modifications to Program Goals. If, during the planning or execution of any program required by this article, a utility, despite its best good faith efforts, believes that it cannot achieve one or more of the program goals set forth in the various sections of this article or that a program is not cost-effective, the utility may submit a report to the Commission explaining the reasons therefore, and indicating when the utility believes that it could achieve the program goal or goals, or suggesting alternative goals. If based upon the utility report, or its own studies, the Commission finds that there are good and sufficient reasons for the utility not being able to achieve the goal or goals, the Commission shall modify any previously approved goal for that utility to one that is feasible and cost-effective for the utility to achieve.

(h) Utility Request for Exemptions.

(1) A utility may, at any time after the effective date of this article, apply to the Commission for an exemption from the obligation to comply with any or all of these standards. Any such application shall set forth in detail the reasons why a denial of the application by the Commission would result in extreme hardship to the utility, or in reduced system reliability and efficiency, or why the standard or standards from which the exemption is sought would not be technologically feasible or cost-effective for the utility to implement. The application shall also set forth the period of time during which the exemption would apply and shall indicate when the utility reasonably believes the exemption will no longer be needed.

(2) Within 30 days after receipt of any such application, the Commission ~~shall~~ may hold a hearing to consider whether there is sufficient information contained in the application to justify further hearings on the merits. If the Commission finds that the application does not contain sufficient information, it shall dismiss the application, and notify the utility of the specific reasons for the dismissal. The utility may thereafter submit a revised application in good faith.

(3) If the Commission finds that the application does contain sufficient information, it shall schedule such further hearings as may be necessary to fully evaluate the application.

(4) If, after holding hearings, the Commission decides to grant an exemption to a utility, the Commission shall issue an order granting exemption. The order shall set forth findings and specific reasons why the exemption is being granted.

(i) Noncompliance. The Executive Director may, after a review of the matter with the utility, file a complaint with the Commission, alleging that the utility is not in compliance with the provisions of this article:

(1) If the utility is not conducting a program in conformance with the provisions of its approved plan.

(2) If the utility fails to provide a required submittal in a timely manner.

(3) If the utility fails to make requested changes or additions to any such submittal within a reasonable time.

(j) Recovery of Program Costs. In its rate applications, each utility shall seek to recover the full costs associated with conducting each program required by this article from the class of customers which the program most directly affects. The utility shall not be required to commence implementation of any program required by this article until the utility's rate-approving body has approved the tariffs which are a part of any such program and a method for recovering the costs of the program.

(k) ~~Notwithstanding Section 2231 of the Revenue and Taxation Code, there~~ There shall be no reimbursement to local government entities (i.e., the Los Angeles Department of Water and Power and the Sacramento Municipal Utility District) for the costs of carrying out the programs mandated by these standards, because the Commission has found these standards to be cost-effective. The savings which these entities will realize as a result of carrying out these programs will outweigh the costs associated with implementing these programs.

§ 1623 Load Management Tariff Standard

(a) This standard requires that a utility develop marginal cost rates~~, using a recommended methodology or the methodology approved by its rate-approving body, when it prepares rate applications for retail services,~~ and that the utility submit such rates to its rate-approving body.

(b) Marginal Cost Methodologies and Rates. ~~Within six months after the Marginal Cost Pricing Project Task Force (which is jointly sponsored by the CEC and CPUC under an agreement with the Federal Department of Energy) makes its final report available to the public, and the Commission approves it by resolution, a utility submitting a general rate filing to its rate-approving body shall include marginal cost based rates in such filing which have been developed by using at least one methodology recommended by the Task Force, except that if a utility's rate-approving body has approved a marginal cost methodology, a utility may substitute the approved methodology for one recommended by the Task Force.~~

~~If at any time subsequent to the Commission's approval of the Task Force report, the utility's rate-approving body approves a marginal cost methodology which is substantially different from any of the methodologies recommended by the Task Force, the utility shall so inform the Commission, and shall explain the nature of and the reasons for these differences.~~

~~In addition to marginal cost-based rates which it develops using a methodology recommended by the Task Force report for that utility or approved by its rate-approving body, the utility may also submit marginal cost-based rates which it develops using any alternative methodology that it deems appropriate.~~

~~The utility may also submit other rates or tariffs which it deems appropriate.~~

~~Nothing in this section shall prevent the Commission from recommending the approval of marginal cost methodologies different from those used by a utility to any rate-approving body.~~

(1) Tariff Applications. On or prior to March 31, 2023, utilities shall apply for approval of at least one hourly or sub-hourly marginal cost rate for each customer class. Utilities shall provide the CEC with informational copies of tariff applications when they are submitted.

(2) Program Implementation. On or prior to March 31, 2023, utilities shall offer to electricity customers voluntary participation in a tariff or program that enables customers to automate response to marginal grid signals. The signals may indicate marginal prices, marginal greenhouse gas emissions metrics, or other Commission-approved marginal signals that enable automated end-use response.

(c) Public Information Program. ~~As soon as a utility's rate-approving body has adopted a tariff in accordance with a recommended or approved marginal cost methodology, the utility shall conduct a public information program which shall inform the affected customers why marginal cost based tariffs are needed, exactly how they will be used and how these tariffs can save the customer money.~~ Utilities shall encourage mass-market automation of load management by ensuring that time-dependent electricity rates are accessible to customers, devices, and service providers.

(1) Rate Data. On or prior to [date TBD] and each time a rate is approved by the rate-approving body, each Utility shall upload all of their time-dependent rates to the Commission's MIDAS database.

(2) Automation System. Beginning [date TBD], the Commission shall offer access to the Rate Database using an Application Programming Interface (API) that returns information sufficient to enable automated response to marginal grid signals such as price and GHG emissions.

(3) Customer Education. Beginning [date TBD], Utilities shall conduct a public information program ~~which~~ that shall inform and educate ~~the affected~~ customers why marginal cost-based tariffs and automation are needed~~, exactly how they will be used~~ and how these tariffs can save the customer money.

~~(d) Compliance. A utility shall be in compliance with this standard if all of the utility's rate applications are prepared in accordance with the provisions of subsection (b) above, and the utility provides informational copies of its applications to the Commission.~~

(d) Rate Identification Number (RIN) Access Tool. On or prior to [date TBD] utilities shall implement a statewide standard API for authorized rate access by third parties. The API responses shall be immediate and follow modern and established best practices. The API shall provide authorized parties with the following:

(1) The RIN applicable to the premise(s) selected by the customer;

(2) The RINs for which the customer is eligible to be switched, if any;

(3) If the utility has an existing rate calculation tool and the customer is eligible for multiple rate structures, average bill amount(s) based on the customer's current rate and any other eligible rate(s); and

(4) The ability for the authorized third party to, upon the direction of the customer, modify the customer's applicable rate, to be reflected in the next billing cycle according to the Utility's standard procedures.

CHAPTER 8: Cost Effectiveness

The goal of this analysis is to show that the levelized cost of the proposed load management system is less than the levelized cost of new electrical capacity. 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.

The current standard for new electrical capacity in California is utility-scale battery storage. 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 ranges between $80 and $140 per MWh in 2020 (Lazard 2020).[105] Lawrence Berkeley Lab's annual Utility-Scale Solar 2020 Update also contains limited information on the 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. After adjusting for difference in project timeline, battery roundtrip efficiency and other factors, these two studies' results are consistent. For this analysis, we use $110 per MWh as the midpoint of this range. Therefore, the goal of this analysis is to show that the levelized cost of the equivalent storage capacity created by the proposed load management standard amendments ($/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:

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

Where:

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

B = The Net Present Value of the cost reduction achieved by end-use 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:

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

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[105] 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).

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.

A. Cost of Proposed Amendments: $14 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 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 and CCAs 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 3: Estimated Cost of proposed Load Management Standard amendments

Item / Activity	Entity	Development & Implementation	Annual Maintenance	15-Year NPV†
Automation Server	CEC	$ 30,000	$ 15,000	$210,000
Billing System	Utilities	$ 3,750,000	$ 75,000	$4,630,000
Rates Reporting	Utilities	$ 150,000	$ 75,000	$1,030,000
Customer Education	Utilities	$ 750,000	$ 375,000	$5,160,000
ASP Authorization	Utilities	$ 150,000	$ 75,000	$1,030,000
ASP Software Upgrades	ASPs	$ 300,000	$ 150,000	$2,060,000
Total		**$ 5,130,000**	**$ 765,000**	**$ 14,120,000**

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

Source: CEC

B. The Value of Optimizing Behind the Meter Battery Charging: $81 million

The next step is to identify the benefits of the proposed load management amendments that utility-scale battery systems cannot achieve. One of the largest potential benefits is the optimization of Behind-the-Meter (BTM) battery charging. For this analysis, staff assumes the time-varying rates made available statewide through the MIDAS platform will enable batteries to optimize the timing of charging, i.e., avoid peak charging and maximize charging by daytime renewables that would otherwise have been curtailed.

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. These rate designs do not incentivize 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 in the winter. While federal investment tax credits (ITC) do encourage charging during daytime by requiring tax credit claimers to charge their battery with 75 percent or more renewable energy, as battery cost reduces over time and tax credit reduces to 10 percent 2022 onward, the resulting diminishing financial benefit of ITC might not be able to overcome the conflicting financial signals from these rate designs.

The MIDAS platform will be able to sustainably optimize the timing of the charging of residential BTM with intelligent price signals that eliminates conflicting financial signals and encourages charging whenever excess renewables occurs.

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. 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 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. This per MWh value translates to a net present value over 15 years of roughly $81 million.

C. Load Shifting Benefits using Existing Control Technologies

The first end-use considered 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 when appropriate, 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 AC 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

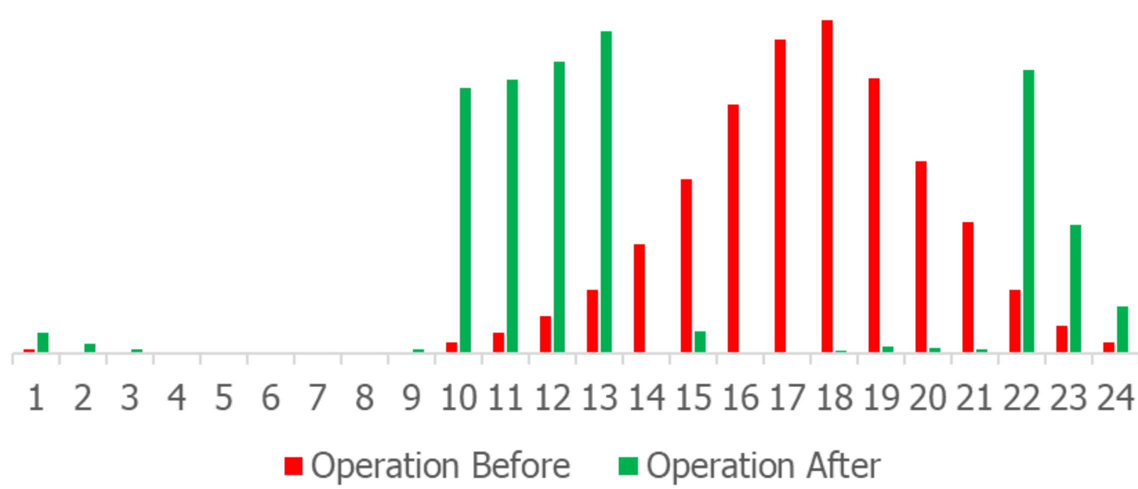
m = Advanced Thermostat market share in California

p = percentage of Advanced Thermostat participating

Over the past eight years, multiple studies conducted in the State of California have successfully demonstrated the effectiveness of advanced thermostats in reducing peak period cooling load by employing this intelligent control strategy.

In addition, 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. The energy modeling results largely agreed with the results of field studies. As can be seen in Figure 9, pre-cooling uses energy from 10 am to 1 pm, when cheap renewable energy supplies are plentiful, enabling a cooling load near zero during the peak period from 2 pm to 9 pm.

Figure 9: CBECC model results for AC load shifting



Source: CEC Staff, 2020

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. Therefore, we set $r = 0.90$.

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

- Homogeneous advanced thermostat ownership of 13.8 percent across CA (Source: ecobee/Statista)
- 26 percent of smart thermostat owners participate in MIDAS optimization (Source: ecobee)
    - 40 percent participation in hot summer areas with 30 percent of the state population
    - 20 percent participation in mild summer areas with 70 percent of the state population
- Daily load shifting in summer months (June-September)
    - Intelligent pre-cooling during near-zero LMP and carbon emissions

- 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

Results of this analysis indicate the following:

- Each year, 120 GWh of peak energy consumption could be shifted off peak.
- Over 15 years, 1,800 GWh of peak energy could be shifted off peak.
- Summer peak load reduction potential for AC 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.

$$LCOS\ of\ LMS = \frac{Cost\ of\ LMS(\$)}{Energy\ Shifted(MWh)} = \frac{\$\ 14\ million - \$81\ million}{1800\ GWh} = -\$37/MWh$$

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

1. Halve the cost avoidance of battery optimization: -$14 LMS < $110 Battery
2. In addition to #1, increase LMS cost by 50%: -$ 7 LMS < $110 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 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. 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.

CHAPTER 9: Feasibility

Historically, the dual implementation of time-varying price signals linked to automation has been hindered by a chicken and egg problem. Policymakers have been hesitant to institute time-varying pricing without price-responsive technologies to help customers respond. At the same time, vendors have had little reason to develop price-responsive technologies until time-varying rates become widely available.

The recent overhaul of residential rates at PG&E, SCE, SDG&E, and SMUD means that the majority of customers, from the largest industrial factory to the smallest mobile home, will be charged time-of-use rates by the end of 2020.[106] This provides the state with a massive opportunity to tap into customer efforts to lower their electricity bills through automated price responsive load management at these utilities. This effort is particularly important to pursue in the residential sector now that a large portion of the workforce is working from home. In addition, residential devices tend to be less expensive and have shorter lifetimes, so have higher turnover rates and more immediate potential for flexibility benefits.

Enable Automated Response to Time-varying Rates

The first step in enabling automated response to time-varying rates is populating the MIDAS Rate Database. The proposed load management standard amendments require LADWP, PG&E, SCE, SDG&E, SMUD, and the current 22 (and future) CCAs located within these utilities' service areas to aggregate and upload their time-varying rate data using the data upload tool. The proposed Load Management Standards amendments would require utilities to regularly transmit their current time-varying rate data to the MIDAS Rate Database using the CEC's Upload Manager. Thus, this step is feasible.

The second step in enabling widespread automation is to enable third-party service providers access to their customers' standard RIN. The proposed load management standard amendments require utilities to develop a statewide method for use by all California utilities and CCAs, enabling more efficient customer outreach, and simplifying third-party efforts to coordinate with multiple utilities. The communication of customer RINs from utilities to authorized energy service providers can be accomplished using existing technology such as the GBC platform. The IOUs have had several years of experience with GBC, and their associated CCAs can take advantage of this experience and technology. The system is not currently in use at SMUD or LADWP, however, it can be implemented.

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.

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

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 or subsets of the customer population. Examples of such rates in California include:

- SCE's experimental RTP for the Retail Automated Transactive Energy System project[107]
- SCE's proposed two-part RTP
- SDG&E's Power Your Drive hourly rate[108]

Locational signals are also feasible. The IOUs SGIP delivers separate marginal GHG emissions signals for each of eleven California ISO sub-regions [109] at five-minute intervals. Discussions with stakeholders suggest that a similar approach can be used to deliver locational pricing.

[107] Cazalet, E. 2020

[108] SDG&E's Power Your Drive, available at (https://www.sdge.com/residential/electric-vehicles/power-your-drive/power-your-drive-ev-drivers).

[109] California Self-Generation Incentive Program GHG Signal, available at (http://sgipsignal.com/grid-regions).

CHAPTER 10:
Considered Alternatives

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

A. Update the MIDAS Rate Database whenever rates change.

B. Implement a standard RIN access tool to support third-party automation services.

C. Develop and submit locational retail electricity rates that change at least hourly to reflect marginal wholesale costs.

D. Integrate information about new time-varying rates and automation technologies into their existing customer education efforts.

The following are the considered alternatives to the CEC staff recommendations.

A. MIDAS Rate Database Updates - Alternatives

A1. No Updates (Do Nothing)

Under this alternative, the Rate Database would not be regularly updated, meaning the rate data in the MIDAS Rate Database would become irrelevant over time.

If the MIDAS Rate Database is not accurate and up to date, customers cannot take advantage of automation technologies and services to improve demand flexibility, reduce bills, and support a carbon-free grid. Allowing the MIDAS Rate Database to deteriorate is not recommended.

A2. CEC Regularly Updates the MIDAS Rate Database

Under this alternative, the CEC updates the MIDAS Rate Database by manually retrieving data from utility tariff sheets.

A minor benefit of this alternative is that the responsibility for aggregation, maintenance, and hosting of the data would reside with a single entity.

A serious barrier to this alternative is that manual data entry is an extremely inefficient use of staff resources compared to automated data transfer from utilities. In addition, manual collection of data is likely to result in errors and delays, which could translate to risk and liability.

A3. Third Parties Regularly Update the MIDAS Rate Database

Under this alternative, the CEC contracts with a vendor to provide rate data retrieved from utility tariff sheets.

A benefit of this alternative is that this option is readily available today.

Barriers to this alternative include the cost of the rate data subscription, the costs of contract administration, and issues regarding liability for errors in the data transmitted to the Rate Database.

B. Third-Party Automation Services - Alternatives

B1. Do Not Implement a Standard RIN Access Tool (Do Nothing)

More customers will be aware of and capable of participating with the help of ASPs. Under this alternative, utilities would be allowed to develop their own method for providing rate information to ASPs – meaning each ASP would need to develop a different data transaction process for each of the more than 70 utilities and CCAs in California.

C. Retail Rate Structures - Alternatives

C1. Do Not Offer Finer Rate Structures (Do Nothing)

Under this alternative, California would continue to operate the grid under the current paradigm of TOU rates and incentive programs. Utilities and system operators would continue to pay or otherwise incentivize aggregators and customers for load control and other forms of demand response, while response to time-varying rates such as TOU would continue largely unsupported by automation.

Some of the shortcomings of the existing demand response paradigm include:[110]

- Higher Cost
  - Utilities must market programs, contract with participants, and maintain administrative and control systems, all of which is more expensive than using time-varying rates and automation for demand response. (See Chapter 8)
  - Programs are prone to being particularly cost-ineffective in non-curtailment, zero-benefit years.
- Limited Demand Resources
  - Load shed is generally limited to certain hours of the day.
  - Off-peak load building to prevent renewable curtailment is not supported.
  - Customer time commitment cost is high, and value is low, so participation is low.
  - Only the largest customers are targeted in existing programs, so only a fraction of cost-effective demand resources are available.
- 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.

[110] Derived in part from Herter et al. 2003

    - Limited involvement impedes customer interest in and understanding of peak reduction opportunities, so transfer of strategies to non-event day TOU peak periods is less likely.
    - Direct incentives for participation 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.
    - Automation manufacturers are incentivized to withhold energy efficiency and load flexibility performance to sell peak resources into the energy markets or highest bidding aggregators.
- 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 loads, such as AC 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.

TOU price signals do not change frequently enough to stimulate the demand flexibility needed for real-time load management on a carbon-free grid. Some of the major benefits of finer time-varying price response over traditional demand response programs include:

- Customers of any size can participate with any end-use and control technology
- Customers can choose their own level of response according to their valuation of electricity services
- Customer demand for automation encourages innovation in technology markets
- Mass-market penetration possible
- Low prices encourage off-peak energy use, reducing renewable curtailment
- Utilities need not maintain separate participant databases
- Utilities can focus their efforts on marketing technologies instead of programs
- Utilities can reduce or replace more expensive demand response programs

D. Encourage Automation - Alternatives

D1. Do Not Encourage Price- and GHG-Responsive Automation (Do Nothing)

Under this alternative, utilities do not increase their efforts to encourage customers to purchase, install, and use price- and GHG-responsive automation.

The full benefits of time-varying rates like TOU will not be realized without end-use automation. Thus, this alternative is not recommended.

D2. Incentive Programs

Under this alternative, utilities would offer programs to incentivize demand flexible controls.

Prior to approval of marginal rates, utilities could offer incentive-based programs that make use of existing marginal signals, such as locational marginal pricing. Utilities can provide technology assistance, rebates, or incentives to encourage customers to install automation that shifts energy use away from peaks and ramps, and toward times of excess renewable power.

Research shows that customers are much more willing to sign up for time-varying rates if they are provided automation technology that they can set and forget. Utilities could increase flexible rate participation by offering free, low-cost, or amortized equipment, such as price-responsive thermostats, EV supply equipment, and water heater controls.

Where TOU rates are standard, community-wide installation of automated TOU response could be a cost-effective option. Appropriate automation technologies for low-income customers might include timers, thermostats, smart plugs and power strips, water heater controls, and home battery systems.

An incentive-based program could also involve rewarding customers on their bills for actual savings from automated response to California ISO locational marginal prices. The California ISO provides an API[111] for accessing wholesale market prices including day-ahead and real-time Locational Marginal Prices (LMP), including the Competitive Congestion, Non-Competitive Congestion, Loss and Energy Components that make up the LMP. While these values could be used to enable load management automation, a motivation for the customer to participate in such an effort is unclear.

Staff recommends that utilities develop a list of cost-effective load flex incentives that could move forward given funding.

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[111] Interface Specification for OASIS. Fall 2018 Release, Version: 5.1.5, available at (http://www.caiso.com/Documents/OASIS-InterfaceSpecification_v5_1_5Clean_Fall2018Release.pdf).

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APPENDIX A: Public Resources Code 25403.5

(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 and Electric Company
PacifiCorp
San Diego Gas and 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: Tariffs with Time-Varying Rates

Table 4 summarizes the time-varying rates included in the first MIDAS database.

Table 4: 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*
SMUD	Time-of-Day 5-8PM	GS-TOU1 GS-TOU2 GS-TOU3 Small C&I Primary GS-TOU3 Small C&I Secondary	
LADWP	R-1B	A-1B	

*approved for the SGIP program

Source: CEC

APPENDIX D:
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 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	SCE PG&E
Voltus, Inc. CPUC-DRP-0022 https://www.voltus.co/	NO	SCE PG&E

APPENDIX E:
Staff Assumptions and Calculation Methods

Table 5: Statewide Average Savings

Res Sector	Annual Peak 4-9 Cooling Energy (GWh)	Summer Peak 4-9 Cooling Load Average (GW)	Annual Peak 4-9 Cooling Cost ($)
State Total	3122	4.5	$ 156,871,345
Smart Thermostat Installation Base	14%	14%	14%
Participation Percentage	26%	26%	26%
Peak Cooling Load saving percentage	90%	90%	90%
Annual Savings	100.8	0.144	$ 5,065,689

Source: CEC

Table 6: Hot Summer Area Savings (Forecast Zones 3, 5, 9, 10, 11, 13, 17)

Res Sector	Annual Peak 4-9 Cooling Energy (GWh)	Summer Peak 4-9 Cooling Load Average (GW)	Annual Peak 4-9 Cooling Cost ($)
State Total	1776	2.6	$ 89,837,975
Smart Thermostat Installation Base	14%	14%	14%
Participation Percentage	40%	40%	40%
Peak Cooling Load saving percentage	90%	90%	90%
Annual Savings	88.210	0.129	$ 4,463,151

Source: CEC

Table 7: Mild Summer Area Savings (Forecast Zones 1, 2, 6, 7, 8, 12, 14, 16)

Res Sector	Annual Peak 4-9 Cooling Energy (GWh)	Summer Peak 4-9 Cooling Load Average (GW)	Annual Peak 4-9 Cooling Cost ($)
State Total	1347	1.9	$ 67,033,370
Smart Thermostat Installation Base	14%	14%	14%
Participation Percentage	20%	20%	20%
Peak Cooling Load saving percentage	90%	90%	90%
Annual Savings	33	0.046	$ 1,665,109

Source: CEC