Load Management Standards Regulations

Updated Compliance Plan

Los Angeles Department of Water and Power

December 10, 2024

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1. Executive Summary

In 2019, the California Energy Commission (CEC) instituted a rulemaking proceeding (CEC Docket No. 19-OIR-01) to consider amendments to the load management regulations authorized under California Public Resources Code (PRC) Section 25403.5, which are Title 20, Sections 1621 to 1625. In 2021, a new docket (CEC Docket No. 21-OIR-03) was opened for this rulemaking. The rulemaking was initially directed at the three largest Investor Owned Utilities (IOUs) and two largest Publicly Owned Utilities (POUs), including the Los Angeles Department of Water and Power (LADWP), that provide retail electric service in the State of California (State). Ultimately, the rulemaking would also include Large Community Choice Aggregators (CCAs). Essentially, the rulemaking is based upon the premise that State electricity users will use smart devices to reduce or shift their electric loads in response to price or other signals. LADWP actively worked with the CEC, other utilities, and other stakeholders to provide input and comments on the various proposed regulations during the rulemaking and emphasized to the CEC the unique situation of LADWP, helping to shape the final approved load management regulations. The final regulations are set forth in California Code of Regulations Title 20 (CCR), Chapter 4, Article 5, §§ 1621, 1623, and 1623.1 (the Load Management Standards or LMS) and are provided as Appendix 1.

According to CCR § 1621, the Load Management Standards "establish cost-effective programs and rate structures which will encourage the use of electrical energy at off-peak hours and encourage the control of daily and seasonal peak loads to improve electric system equity, efficiency, and reliability, lessen or delay the need for new electrical capacity, and reduce fossil fuel consumption and greenhouse gas emissions, thereby lowering the long-term economic and environmental costs of meeting the State's electricity needs." A primary objective of the Load Management Standards is for the affected utilities and CCAs to implement marginal cost-based real-time (one hour or less) rates for each customer class or programs that enable automated response to marginal cost signal(s) for each customer class by April 1, 2026. The affected POUs are LADWP and the Sacramento Municipal Utility District (SMUD). The affected IOUs are Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). The IOUs have different applicable Load Management Standards than do the POUs and the CCAs, basically due to the CEC's recognition that the governing bodies of the POUs and the CCAs should play the central role in establishing those entities' compliance plans for the Load Management Standards.

Under the Load Management Standards, the initial compliance plan of a POU is required to be submitted to its rate-approving body by October 1, 2023, for adoption in a duly noted public meeting to be held within 60 days after the plan is submitted. The Board of Water and Power Commissioners is named as such a body for LADWP in the regulation. This document is prepared as LADWP's Load Management Standards compliance plan, based upon the CEC's compliance plan guide outline[1].

As this compliance plan indicates, LADWP remains fully committed to supporting the CEC's objective to promote California's leadership toward a 100 percent clean energy future and addressing climate change. In pursuing its renewable objectives, LADWP recognizes the opportunities as well as the unique challenges presented by the integration of renewable resources into its grid.

LADWP understands the CEC's goal as stated in CCR §§1623.1(a)(1): "… encouraging the use of electrical energy at off-peak hours, encouraging the control of daily and seasonal peak loads to improve electric system efficiency and reliability, lessening or delaying the need for new electrical capacity, and reducing fossil fuel consumption and greenhouse gas emissions." However, hourly rates are not standard for utility customers presently for a variety of reasons, including cost, technical difficulties to implement, and customers' avoidance of price risk. LADWP recognizes that someday, ideally, the use of time-based price signals could potentially prove to be invaluable in achieving this desired load management, particularly for customers who can automate management of their end-use consumption.

Enabling customers to automate end-use load management would require that LADWP offer a robust load management framework. As a POU, LADWP strives to develop its load management framework, subject to budgetary constraints, current and future rate-setting policies, infrastructure, and limitations on resources required to develop said framework. In doing so, LADWP assesses that implementing desired load management features within some of the specified timeframes required by CEC is not feasible.

LADWP's assessment of the feasibility of complying with the timeline set forth in the Load Management Standards is summarized as follows:

[1] CEC staff have outlined the form of a compliance plan in CEC document TN# 251054, "Compliance Assistance for Load Management Standards", 7/14/2023. LADWP's compliance plan is based upon this document, in particular the outline provided on pages 13-14.

Compliance Date	Load Management Standard	Requirement	Feasibility Yes or No
1-Apr-23		Effective Date of Load Management Standards.	NA
1-Apr-23	§ 1623.1(c)	Upload each time-dependent rate approved by the Board after this date to CEC's MIDAS database each time said rate is approved by the Board and each time said rate changes, prior to the effective date of said rate.	Yes
1-Jul-23	§ 1623.1(c)	Upload all existing time-dependent rates applicable to customers to CEC's MIDAS database.	Yes
1-Oct-23	§ 1623.1(a)(1)	Submit compliance plan to the Board for adoption in a duly noted public meeting to be held within 60 days after the plan is submitted.	Yes
1-Apr-24	§ 1623(c)(4)	Provide customers access to their Rate Identification Numbers (RINs) on customer billing statements and online accounts using both text and quick response (QR) or similar machine-readable digital code.	Yes
1-Oct-24	§ 1623(c)(2)	Develop single statewide RIN access tool with other utilities/CCAs. Submit RIN access tool to CEC for approval.	Yes
1-Oct-24	§ 1623.1(b)(3)	Submit list of load flexibility programs deemed cost-effective to CEC Executive Director.	NA
1-Apr-25	§ 1623.1(b)(2)	Apply to the Board for approval of at least one marginal cost-based rate.	No
1-Apr-26	§ 1623.1(b)(4)	Offer to each electricity customer voluntary participation in either a marginal cost-based rate or a cost-effective program.	No
Annually	§ 1623.1(a)(3)(C)	Submit annual report of plan implementation to CEC Executive Director, starting on the 1-year anniversary of the initial Board approval per §1623.1(a)(2).	Yes
Triennially	§ 1623.1(a)(1)(C)	Review the plan at least once every three years after the plan is adopted. Submit a plan update to the Board where there is a material change to the factors considered per §§1623.1(a)(1)(A)-(B).	Yes
Event-Triggered	§ 1623.1(a)(3)(A)	Within 30 days after plan adoption or material plan revision, submit the plan or material plan revision to the CEC Executive Director.	Yes
Event-Triggered	§ 1623.1(a)(3)(B)	Respond to requests or recommendations within 90 days of receipt from the CEC Executive Director.	Yes

Under §§ 1623.1(a)(2) of the CCR, the rate-approving body of a Large POU or a Large CCA may approve a compliance plan, or material revisions to a previously approved plan, that delays compliance or modifies compliance with the requirements of Subsections 1623.1 (b)-(c), if the rate-approving body determines that the plan demonstrates any of the following:

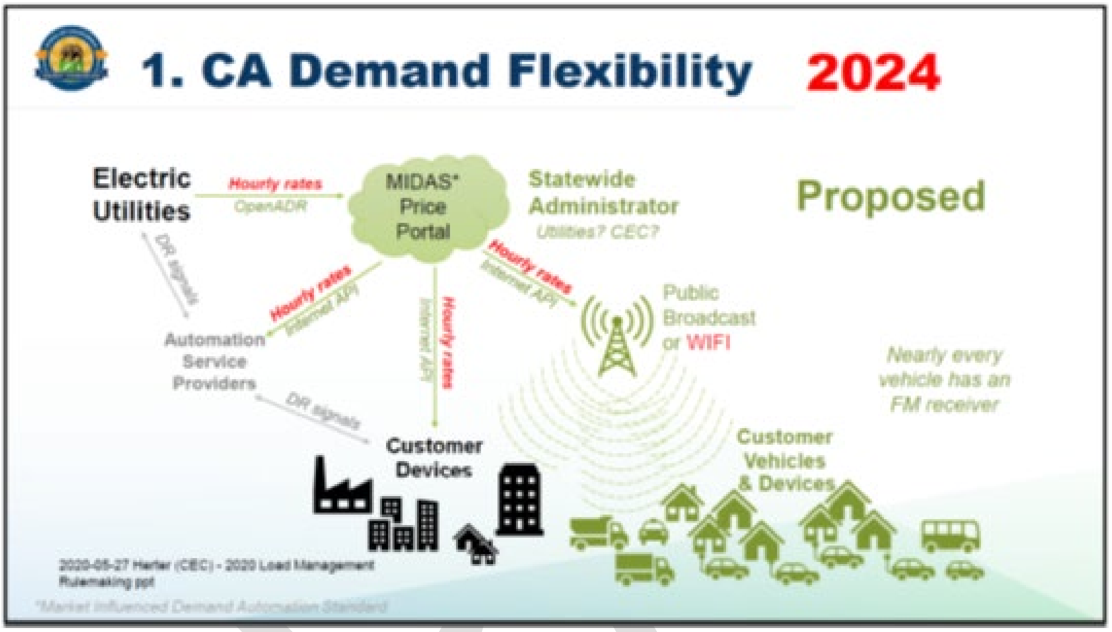
> (A) that despite a Large POU's or Large CCA's good faith efforts to comply, requiring timely compliance with the requirements of this article would result in extreme hardship to the Large POU or the Large CCA,
>
> (B) requiring timely compliance with the requirements of this article would result in reduced system reliability (e.g., equity or safety) or efficiency,
>
> (C) requiring timely compliance with the requirements of this article would not be technologically feasible or cost-effective for the Large POU to implement, or
>
> (D) that despite the Large POU's or the Large CCA's good faith efforts to implement its load management standard plan, the plan must be modified to provide a more technologically feasible, equitable, safe or cost-effective way to achieve the requirements of this article or the plan's goals.

This compliance plan includes the evaluation of cost effectiveness, equity, technological feasibility, benefits to the grid, and benefits to customers of implementing marginal cost-based rates. Consequently, LADWP finds that the implementation of marginal cost-based rates according to the timeline described in the Load Management Standards would result in extreme hardship to LADWP and is not technologically feasible. Therefore, in accordance with CCR § 1623.1(a)(2), compliance with the development of marginal-cost based rates for LADWP customers should be delayed until such a time as implementing such rates would be technologically feasible and equitable.

This compliance plan also includes the evaluation of cost effectiveness, equity, technological feasibility, benefits to the grid, and benefits to customers of implementing programs that depend on MIDAS signals. Consequently, LADWP finds that the implementation of programs that enable automated response to marginal cost signals or other MIDAS signals according to the timeline described in the Load Management Standards for all of LADWP's electricity customers would result in extreme hardship to LADWP and is not technologically feasible. Therefore, in accordance with CCR § 1623.1(a)(2), compliance with the development of programs that enable automated response to marginal cost signals or other MIDAS signals for all of LADWP's electricity customers should be delayed until such a time as implementing such programs would be technologically feasible, and, in the meantime, LADWP's compliance is proposed to be modified as follows: LADWP will continue to take steps to introduce residential and (commercial and industrial) C&I managed charging programs for EVs and a residential Smart Device Integration program in 2025 and to subsequently grow and adjust those programs in accordance with their merit and LADWP's capabilities.

Background

The below diagram demonstrates the CEC's vision for the Load Management Standards.



A key component of this vision is hourly rates. The hourly real-time prices would be transmitted to customers/customer smart Internet of Things (IoT) devices such that changes in the load in response to prices would decrease peak load through these devices acting by intelligent algorithm, termed demand flexibility by the CEC. "This … will help customers tailor their electricity use to save money, minimize greenhouse gas emissions from electricity production, improve the resilience of the electrical grid, and reduce the chance of planned and unplanned outages." [2] Thus, the stated timeline in the Load Management Standards in the CCR would require LADWP to implement hourly real-time prices tariffs in the next couple years.

The process of the Load Management Standards development started in 2019 with a rulemaking process. It ultimately resulted in amended CCR §§ 1621 and 1623 and a new § 1623.1. LADWP actively worked with the CEC, other utilities, and other stakeholders to provide input and comments on the various proposed regulations during the rulemaking and emphasized to the CEC the unique situation of LADWP, helping to shape the final approved load management regulations.

[2] CEC document TN# 251054, "Compliance Assistance for Load Management Standards", 7/14/2023, page 2.

From January 14, 2020, through CEC's adoption of the amended Load Management Standards during its October 12, 2022, Business Meeting, LADWP attended and participated in multiple meetings, including workshops, staff presentations and webinars, public hearings, and working group meetings.

In addition, from March 16, 2020, through September 27, 2022, LADWP contributed six comment letters to the CEC Load Management proceedings, expressing support for the intent of the proposed amendments, as well as conveying recommendations to alleviate potential concerns.

LADWP's comments expressed a wide range of concerns, including jurisdictional concerns regarding CEC's enforcement authority and its potential encroachment on the authority of local governing boards; implementation concerns relating to Advanced Metering Infrastructure (AMI) deployment, communication network expansion, and distribution system technology; and additional concerns regarding customer equity, cost effectiveness, and the POU business model.

The adopted Load Management Standards successfully allayed several of LADWP's significant concerns by: recognizing the distinct governance and circumstances of POUs as compared to IOUs through the creation of parallel but distinct requirements for POUs in § 1623.1; allowing for the consideration of various factors, including technological feasibility, equity, and cost effectiveness, in evaluating potential compliance plans; recognizing the authority of local governing boards in adopting POU compliance plans; and allowing for flexibility in compliance, including through use of programs in place of rates and through allowing governing boards to approve delays or modifications to compliance.

As a critical component of the Load Management Standards, a compliance plan is required by the CCR that will need to be submitted to LADWP's rate-approving body, the LADWP Board of Water and Power Commissioners, by October 1, 2023, for adoption in a duly noticed public meeting to be held within 60 days after the plan is submitted.

As demonstrated by the Load Management Standards implementation timeline, there are complex, technical components applicable to LADWP to meet the CEC's Load Management Standards vision. CEC staff have outlined the form of a compliance plan in CEC's document TN# 251054, "Compliance Assistance for Load Management Standards", 7/14/2023. A summary of the required components includes:

1. Time-dependent rate submission to MIDAS via the MIDAS API
2. Plan to provide RIN(s) on customer billing statements and online account using both text and QR code
3. Plans and current participation in the development of a Single Statewide RIN Access Tool

4. Marginal cost rates evaluation. If the marginal cost rates evaluation leads to proposal of marginal cost rates development: item 5; if not, consider item 6
5. Marginal costs rate design and application plan
6. Description of MIDAS-based hourly marginal signal programs

This document is LADWP's updated compliance plan (CP) prepared based on CEC's Compliance Assistance for Load Management Standards Compliance Plan Submittals.

2. Load Management Standards Timeline

The Load Management Standards set forth the timeline for compliance shown below:

- **1-Apr-2023**: Effective Date of Load Management Standards
- **1-Apr-2023:** § 1623.1(c): Upload each time-dependent rate approved by the Board after this date to CEC's MIDAS database each time said rate is approved by the Board and each time said rate changes, prior to the effective date of said rate.
- **1-Jul-2023:** § 1623.1(c): Upload all existing time-dependent rates applicable to customers to CEC's MIDAS database.
- **1-Oct-2023:** § 1623.1(a)(1): Submit compliance plan to the Board for adoption in a duly noted public meeting to be held within 60 days after the plan is submitted.
- **1-Apr-2024:** § 1623(c)(4): Provide customers access to their Rate Identification Numbers (RINs) on customer billing statements and online accounts using both text and quick response (QR) or similar machine-readable digital code.
- **1-Oct-2024**: § 1623(c)(2): Develop single statewide RIN access tool with other utilities/CCAs. Submit RIN access tool to CEC for approval.
- **1-Oct-2024:** § 1623.1(b)(3): Submit list of load flexibility programs deemed cost-effective to CEC Executive Director.
- **1-Apr-2025:** § 1623.1(b)(2): Apply to the Board for approval of at least one marginal cost-based rate.
- **1-Apr-2026:** § 1623.1(b)(4): Offer to each electricity customer voluntary participation in either a marginal cost-based rate or a cost-effective program.
- **Annually:** § 1623.1(a)(3)(C): Submit annual report of plan implementation to CEC Executive Director, starting on the 1-year anniversary of the initial Board approval per § 1623.1(a)(2).
- **Triennially:** § 1623.1(a)(1)(C): Review the plan at least once every three years after the plan is adopted. Submit a plan update to the Board where there is a material change to the factors considered per §§ 1623.1(a)(1)(A)-(B).
- **Event-Triggered**
    - § 1623.1(a)(3)(A): Within 30 days after plan adoption or material plan revision, submit the plan or material plan revision to the CEC Executive Director.
    - § 1623.1(a)(3)(B): Respond to requests or recommendations within 90 days of receipt from the CEC Executive Director.

As described below, it is not possible for LADWP to follow the stated timeline for some aspects of the Load Management Standards.

3. Load Management Standards Key State of California Regulations

CCR 1623.1(a)(1)(A):

> The [Load Management Standards compliance] plan must evaluate cost effectiveness, equity, technological feasibility, benefits to the grid, and benefits to customers of marginal cost-based rates for each customer class.

CCR 1623.1(a)(1)(B):

> If after consideration of the factors in Subsection 1623.1(a)(1)(A) the plan does not propose development of marginal cost-based rates, the plan shall propose programs that enable automated response to marginal cost signal(s) for each customer class and evaluate them based on their cost-effectiveness, equity, technological feasibility, benefits to the grid, and benefits to customers.

CCR 1623.1(b):

> Large POU and Large CCA Marginal Cost-Based Rates and Programs. Each Large POU and each Large CCA shall develop marginal cost-based rates or public programs structured according to the requirements of this article.
>
> (1) Total marginal cost shall be calculated as the sum of the marginal energy cost, the marginal capacity cost (generation, transmission, and distribution), and any other appropriate time and location dependent marginal costs, including the locational marginal cost of associated greenhouse gas emissions, on a time interval of no more than one hour. cost computations shall reflect locational marginal cost pricing as determined by the associated balancing authority, such as the Los Angeles Department of Water and Power, the Balancing Authority of Northern California, or other balancing authority. Marginal capacity cost computations shall reflect the variations in the probability and value of system reliability of each component (generation, transmission, and distribution).

CCR 1623.1(a)(2):

> The rate approving body of a Large POU or a Large CCA may approve a plan, or material revisions to a previously approved plan, that delays compliance or modifies compliance with the requirements of Subsections 1623.1 (b)-(c), if the rate approving body determines that the plan demonstrates any of the following:
>
> > (A) that despite a Large POU's or Large CCA's good faith efforts to comply, requiring timely compliance with the requirements of this article would result in extreme hardship to the Large POU or the Large CCA,

(B) requiring timely compliance with the requirements of this article would result in reduced system reliability (e.g., equity or safety) or efficiency,

(C) requiring timely compliance with the requirements of this article would not be technologically feasible or cost-effective for the Large POU to implement, or

(D) that despite the Large POU's or the Large CCA's good faith efforts to implement its load management standard plan, the plan must be modified to provide a more technologically feasible, equitable, safe or cost-effective way to achieve the requirements of this article or the plan's goals.

4. LADWP Load Management Standards Compliance Plan (CP)

As demonstrated by the above Load Management Standards implementation timeline, there are complex, technical components applicable to LADWP to meet the CEC's Load Management Standards vision.

§ 1623(b) Time-dependent rate submission to MIDAS via the MIDAS API

The Load Management Standards require California large utilities and CCAs, including LADWP, to upload all existing time-dependent rates applicable to customers to CEC's Market Informed Demand Automation Server (MIDAS) database by July 1, 2023.

In consultation with CEC staff, LADWP's Information Technology Services Division (ITSD) and Financial Services Organization (FSO) have reviewed LADWP's current electric rates and identified all applicable time-dependent rates. All rates were successfully uploaded, with exceptions noted, by July 1, 2023. Any rates with no customers have not been uploaded to MIDAS. LADWP will consider adding them to the upload if there are future sign-ups. Ultimately, with CEC staff input, LADWP uploaded time-dependent consumption-based rates, with the addition or subtraction of rate modifiers, such as adjustment factors to fund various projects and programs, discounts, and taxes.

As listed in the CEC staff compliance document TN# 251054:

1. a)

   i. 40 standard and 243 contract rate variations were uploaded in total by July 1, 2023. List of rate IDs is attached as Appendix 2. These were retrieved directly from the MIDAS API (https://midasapi.energy.ca.gov/api/ValueData?signaltype=0), and filtered for LADWP rates only (RIN prefix of 'USCA-LALA-').

   ii. The rate download file for the R1B0 standard rate is attached as an example as Appendix 3. The rate download file is retrieved directly from the MIDAS API (https://midasapi.energy.ca.gov/api/ValueData?ID=USCA-LALA-R1B0-0000&QueryType=alldata).

   iii. The composite rates for all 283 variations are calculated and provided in two CSV files used in the manual download process. Files are attached as Appendices 4 and 5 for reference. In general, the rate calculation is summarized as follows:

high peak/low peak/base period rate* + adjustment factors - discounts

*rate also depends on whether it is high low season

Applicable Rates

LADWP time-of-use (TOU) rates include the following rates shown below, as well as any corresponding rates from another LADWP electric rate ordinance.

Rate	Description	Determinants
R1B	Residential Time-of-Use	kWh
A1B	Small General Service (4.8 kV or 34.5 kV system , kW below 30)	kWh
A2B	Primary General Service (4.8 kV System , 30 kW demand or greater)	kWh, kW, kVarh
A3A	Subtransmission Service (34.5 kV system , 30 kW demand or greater)	kWh, kW, kVarh
AMP	Port of LA Alternative Maritime Power	kwh for unmetered kvarh customers
AMPB	Port of LA Alternative Maritime Power (7 MW demand or greater)	kwh for unmetered kvarh customers
XRT2	Experimental Real-Time Pricing Service, Primary Service 4.8 kV, 250 kW demand or greater	kWh, kW, kVarh
XRT3	Experimental Real-Time Pricing Service, Subtransmission Service 34.5 kV, 250 kW demand or greater	kWh, kW, kVarh
XCD2	Experimental Contract Demand Service, Primary Service 4.8 kV, avg kWh 500,000 or greater per month	kWh, kW, kVarh
XCD3	Experimental Contract Demand Service, Subtransmission Service 34.5kV, avg kWh 500,000 or greater per month	kWh, kW, kVarh
CG2A	Cogeneration, Primary Service 4.8 kV	kWh, kW, kVarh, Backup kWh
CG3A	Cogeneration, Subtransmission Service 34.5 kV	kWh, kW, kVarh, Backup kWh
XRT/XCD	Combo XRT and XCD. Avg kWh 10,000,000 or greater per month or for cold storage customers	kWh, kW, kVarh
EVA1	Electric Vehicle contract rate (4.8 kV or 34.5 kV system , kW below 30)	kWh
EVA2	Electric Vehicle contract rate (4.8 kV System , 30 kW demand or greater)	kWh
EVA3	Electric Vehicle contract rate (4.8 kV or 34.5 kV system , kW below 30)	kWh

Rate Calculations

CEC requires one number for kWh, kW, and kVarh for each TOU period. Adjustment factors must be added to each TOU base kWh rate factor as required.

LADWP's billing system, CC&B, has all of the factor tables for the base rates and adjustment factors for the standard rates: R1B, A1B, A2B, and A3A, which can be automatically extracted quarterly.

For PBS complex billing rates: AMP, XRT rates, XCD rates, all CG rates, XRT/XCD3, EVA rates, and EVB rates; the base rate numbers must be hard coded since these factors are not in CC&B; however, adjustment factors are the same as the standard rates and can be extracted automatically.

For R1B, the only residential rate included, the following adjustment factors must be added to kWh: ECA, ESA, RCA, IRCA kWh Residential, VEA, CRPSEA, and VRPSEA.

For all other rates, except the AMP rates, the following adjustment factors must be added to kWh: ECA, ESA, RCA, IRCA General Service, VEA, CRPSEA, and VRPSEA. No adjustment factors need to be added to the TOU kW and kVarh base rates.

For the CG rates, there is an additional Back-Up energy factor for kWh which CEC needs to add to their matrix. LADWP has communicated to CEC on this issue. No adjustment factors are added to this factor.

For the AMP and AMPB rates, only the unmetered kVarh rates are TOU, which is based on kWh determinants. No adjustment factors are added to this factor. All other factors are not time based for these two rates.

Upload to MIDAS will be performed on a quarterly basis due to some of the electric adjustment factors being adjusted on a quarterly basis.

The July 1, 2023, MIDAS upload was performed using a manual process.

After the July 1, 2023, MIDAS upload, there was a discussion between LADWP and CEC staff about whether taxes should be included in the upload. LADWP provided the relevant taxes information to CEC staff for review. On September 8, 2023, CEC staff clarified that these taxes should be included in the upload.

The addition of the tax variations has multiplied LADWP rate variations from less than 300 RINs to 1,720 RINs. Therefore, LADWP worked with its vendor Oracle to find a better way to store this RIN information on the customer billing system, and a potential solution was found.

An automated process (INT072) was in development at the time of the upload on July 1, 2023, and was subsequently implemented on April 4, 2024. The automated process provides daily TOU rate updates to MIDAS. Additionally, all tax variations are now included and uploaded as part of the automated process implemented on April 4, 2024.

§ 1623(c)(4) Plan to provide RIN(s) on customer billing statements and online account using both text and QR code

The Load Management Standards require California's large utilities and CCAs to upload their time-dependent rates to the CEC's Market Informed Demand Automation Server (MIDAS), provide customers Rate Identification Access Numbers (RINs), and jointly develop a RIN access tool so third parties can assist customers in checking or changing the rate enrollment with the customers' authorization. Further, by April 1, 2024, they shall provide customers access to their RIN(s) on customer billing statements and online accounts using both text and quick response (QR) or similar machine-readable digital code.

LADWP Implementation Plan for Access to RINs

1.1. Objective

This implementation plan is to provide an overview of tasks and timelines required to place RINs on customer statements and online account using both text and QR code.

1.2. Implementation Outline

Major activities

1. Store RINs and Rate Variants in Billing System (CC&B)
2. Modify Billing Process to include the associated RINs when Customer Statements are generated.
3. Modify Customer Statements to include RINs in both text and QR code format.
4. Prepare Webpage to display RINs and rates information for customers' reference.

1.3. Timeline

The deadline for compliance is April 1, 2024. The RINs implementation requires engagement and coordination of various LADWP business units, including Information Technology Services Division, Customer Service Division, Financial Services Organization, and Customer Communication Group as there will be impacts in relation to customer bills change, display of rate information, organizational readiness, and other areas.

The table below presents the overall RINs implementation timeline. All tasks were completed as of March 28, 2024, by LADWP before the compliance deadline.

Task#	Task	Owner	Resource		2023			2024		
				Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	March
1	Gather functional requirements	ITSD	ITSD							
2	Finalize Technical Design	ITSD	ITSD							
3	Build and Store RINs and Rate Variants in Billing System (CC&B)	ITSD	ITSD							
4	Modify Billing Process to include the associated RINs when Customer Statements are generated.	ITSD	ITSD							
5	Modify Customer Statements to include RINs in both text and QR code format.	ITSD and Customer Service Division	ITSD and Customer Service Division							
6	Prepare Webpage to display RINs and rates information for customers' reference.	Customer Communications	Customer Communications, Customer Service Division, ITSD							
7	Testing and Organization Readiness	ITSD and Customer Service Division	ITSD and Customer Service Division							
8	Roll out and validation	Customer Communications, Customer Service Division, ITSD	Customer Communications, Customer Service Division, ITSD							

Potential Issues with Providing RINs to Customers

LADWP will be able to provide the RINs to customers on rates R1B, A1B, AMP, AMPB, and all EVA rates. However, for the rates that include kVarh factors, the kVarh rates are based on the power factor for each individual customer. Power factor must be calculated at the end of the billing period. If the customer calculates their power factor in the middle of the billing period, it may change by the end of the month, so the rates may not be accurate at the time the customer checks MIDAS. Power factor is calculated as the square root of (HP kwh/(HP kwh^2 + HP $kvarh^2$)). Because the power factor is calculated at the end of the billing period, it would be impossible to provide the RIN on the customer's bill. HP means High Peak.

The same is true for all XCD rates which are based on load factors for each individual customer. The load factor must be calculated at the end of the billing period. If the customer calculates their load factor in the middle of the billing period, it may change by the end of the month, so the rates may not be accurate at the time the customer checks MIDAS. Load factor is calculated as Total kwh/(HP kW * number of days in billing period * 24 hours). Because the load factor is calculated at the end of the billing period, it would be impossible to provide the RIN on the customer's bill.

§ 1623(c)(1)-(3) Plans and current participation in the development of Single Statewide RIN Access Tool

The Load Management Standards require IOUs, POUs, and CCAs (collectively, the parties) to jointly develop a single statewide rate tool (SST) for authorized rate data access by third parties that is compatible with each of those entities' systems, for submission to the CEC by October 1, 2024, for approval at a CEC Business Meeting.

SCE, PG&E, SDG&E, and California CCAs volunteered for the leadership team of the utility working group. LADWP participated in this process; representatives from ITSD and FSO were designated, and their names were provided to the CEC and utility leadership team.

On September 15, 2023, CEC staff opined that the public and CEC need transparency in the RIN tool development to be able to track progress and provide appropriate input on the design and implementation of the single statewide rate lookup tool. To further these goals, CEC staff requested the affected utilities and CCAs to post plans, schedules, and monthly status reports on the progress of the single statewide rate access tool design and development to the LMS implementation docket 23-LMS-01 until such time as the tool is fully implemented and publicly available. A single status report submission from multiple regulated parties is allowed.

Specifically, CCR § 1623(c) mandates that the parties develop an SST that enables a third party, authorized by a customer, to access that customer's rate information and other eligible rates, with the ability to modify the customer’s rate as necessary, reflecting those changes in the next billing cycle. Additionally, CCR §1623(c) instructs the parties to propose terms and conditions for third-party use of the SST.

The parties held nine workshops between July 12 and September 11, 2024, in an extensive collaborative process to create the SST concept design. John Lin, from PG&E, led the workshops with CEC personnel participating in two of the August meetings. The proposed design complies with CCR § 1623(c)(1) by directing third parties to individual load serving entities for necessary rate information instead of functioning as a centralized repository. While the parties generally agree on the overall SST concept, there are still differences regarding the roles and responsibilities of the Large IOUs, Large CCAs, and Large POUs in operating the SST once implemented. In addition, there are varying concerns and priorities related to the ultimate design, construction, functionality, costs, cost allocation, funding, maintenance, and oversight of the SST.

On October 1, 2024, the parties submitted the proposed SST framework, aiming to fulfill their obligations under CCR § 1623(c). This initiative is designed not only to meet regulatory requirements but also to establish a robust, ongoing collaborative process. The ultimate goal is to develop a fully operational and cost-effective SST that delivers tangible benefits to California's electric customers while enhancing the overall efficiency and reliability of the state's electricity grid. By fostering collaboration among stakeholders, the SST framework seeks to integrate innovative technologies and best practices, ensuring a sustainable energy future for California. LADWP anticipates creating a mechanism to interface with the SST that will provide other eligible RINs for its customers, until such time as LADWP has a rate or bill calculation tool.

§ 1623.1(a)(1)(A) Marginal cost rates evaluation

CEC Load Management Standards Marginal Cost Rates Requirement

According to CCR § 1623.1(b)(1), each Large POU and Large CCA shall develop marginal cost-based rates. The detailed description of the marginal cost-based rates and timeline are as follows:

"(1) Total marginal cost shall be calculated as the sum of the marginal energy cost, the marginal capacity cost (generation, transmission, and distribution), and any other appropriate time and location dependent marginal costs, including the locational marginal cost of associated greenhouse gas emissions, on a time interval of no more than one hour. Energy cost computations shall reflect locational marginal cost pricing as determined by the associated balancing authority, such as the Los Angeles Department of Water and Power, the Balancing Authority of Northern California, or other balancing authority. Marginal capacity cost computations shall reflect the variations in the probability and value of system reliability of each component (generation, transmission, and distribution)."

"(2) Within two (2) years of April 1, 2023, each Large POU, and within twenty-seven (27) months of April 1, 2023, each Large CCA, shall apply to its rate-approving body for approval of at least one marginal cost-based rate, that meets the requirements of Subsection 1623.1(b)(1). Large CCAs may apply for approval of marginal cost-based rates that are offered by the Large IOUs in whose service areas the Large CCAs exist in.

> (A) Large POUs and Large CCAs shall apply for approval of marginal cost-based rates only for those customer classes for which the rate-approving body determines such a rate will materially reduce peak load."

"(4) Within three (3) years of April 1, 2023, each Large POU, and within fifty-one (51) months of April 1, 2023, each Large CCA, shall offer to each of its electricity customers voluntary participation in either a marginal cost-based rate developed according to Subsection 1623.1(b)(2), if such rate is approved by the Large POU's or Large CCA's rate-approving body, or a cost-effective program identified according to Subsection 1623.1(b)(3)."

LADWP Evaluation of Marginal Cost-Based Rates to Meet the Load Management Standards Requirements

Since the Load Management Standards development process started in 2019, LADWP actively worked with the CEC, other utilities, and other stakeholders to provide input and comments on the various proposed regulations during the rulemaking and emphasized to the CEC the unique situation of LADWP, helping to shape the final approved load management regulations.

LADWP submitted multiple comment letters to the CEC from March 2020 through September 2022, expressing support for the intent of the proposed load management regulations, as well as challenges that LADWP is facing. In particular, LADWP's March 16, 2020, comments on the draft load management regulations listed various challenges in implementing real-time marginal cost-based tariffs. Even though progress has been made in certain areas since the time of that submittal, some of the challenges remain for LADWP. LADWP's evaluations of marginal cost-based rates are summarized as follows.

A. Cost Effectiveness

In general, marginal cost-based real-time rates can offer various cost-effective benefits to both customers and utilities:

- Potential customer electric bill savings – by providing real-time rates, customers are incentivized to plan and manage energy usage, using more when rates are cheaper (for example, set up washer and dryer timer to off-peak period) and using less during the peak period when the rates are more expensive.
- Potential utility cost savings – by encouraging customers to shift energy usage from a peak to off-peak demand period, a utility can achieve cost savings by reducing investment on expensive peaking power plants and infrastructure, as well as associated labor costs. Utilities can also use the available resources and funding for the overall electric system effectively.
- Environmental and sustainability benefits – by encouraging customers to shift energy usage from a peak to off-peak demand period, when there is abundance of solar or wind renewable energy resources, it will lessen the reliance on fossil fuels and achieve greater sustainability benefits.

However, vertically integrated POUs, such as LADWP, own nearly all of their generation capacity, by design. LADWP's cost of service includes all pre-planned and established generation, and LADWP's rates and financial planning are designed to match these generation costs. Real-time pricing cannot match the LADWP's cost of generation exactly all the time, so there will be cost differences. An issue that arises is determining how these cost differences will be accounted for, and by whom. To resolve this, years ago, IOUs went through the transition to recover all of their generation costs, stranded costs over a period of ten years, and then implemented real-time pricing (direct access). For LADWP to allow its customers to participate in the real-time pricing market would require fee assessment onto all customers, which can be positive or negative depending on the costs, to rebalance the cost of service.

Implementing marginal cost-based real-time rates in accordance with the LMS could require LADWP to switch its business model dramatically, possibly with unintended consequences for customers.

LADWP also needs to evaluate the costs to support the implementation of the real-time rates that lead to the ultimate customer and utility benefits described above. Majority of LADWP's costs associated with real-time rates are expected to be related to Advanced Metering Infrastructure (AMI) and the accompanying infrastructure and technology. As mentioned below, the estimated cost for completing the integration of AMI (excluding smart meter procurement and mass deployment) is about $95 million. Additionally, the costs for a new cost of service study and dynamic marginal cost-based rate design are estimated to be $2.5 million.

LADWP will continue to evaluate the cost effectiveness as it works toward the implementation of the marginal cost-based real-time rates.

B. Equity

A misconception regarding load management standards is that the economic benefits might be limited to only customers who understand the standards and have the resources to obtain automation devices to participate in marginal cost-based real-time rates and/or programs. In reality, customers who are not participating in marginal cost-based real-time rates and/or programs will still benefit from the load management. Since the costs associated with providing electricity are distributed across all customers, as overall system peak demand decreases, the marginal and average costs of electricity also decrease, which consequently benefits all customers, including those that are not yet utilizing marginal cost-based real-time rates.

However, real-time marginal cost-based rates are best suited for customers who have flexibility in when they use energy and can adjust their energy usage in response to price signals, ideally through automated devices, such as smart thermostats, battery storage, and flexible electric vehicle (EV) charging, among other technologies. Marginal cost-based real-time rates will allow load shifting participants to gain additional benefits on top of success they may have with implementing energy efficiency and demand shedding. Customers can benefit financially commensurate with their contribution to the grid.

Further, electric services that deliver information on real-time marginal cost-based rates directly to customers will represent an entirely new type of service for LADWP customers, without precedent in terms of complexity and customer understanding. This may put customers not able to manage advanced technology, including some older generation customers, at a disadvantage. In addition, LADWP's service territory is highly urbanized with a high percentage of renters who may not have access to automated end devices that can respond to real-time rates. If customers are unable to adjust their usage, they may face unexpectedly high bills during peak hours. Additionally, operation of a new real-time marginal cost-based rate could be seen as biased against certain customer groups as access to these automated devices, technology, and information for load shifting may not be equitable, especially for low-income customers and others in disadvantaged communities that cannot afford to purchase these devices. Solar panels and other electric infrastructure upgrades, such as energy efficiency retrofits, to generally reduce a customer's utility bill can also be particularly relatively expensive for low-income customers and disadvantaged communities, adding to the inequity.

As LADWP continues to improve grid reliability and resiliency and move toward a clean energy future, and to prepare for the eventual implementation of Load Management Standards, LADWP continues to address equity challenges, including the above-mentioned issues, and takes equity concerns seriously. Among other things,

- LADWP has conducted a two-year LA100 Equity Strategies Study to begin exploring potential future rate design, programs, changes, and options.
- LADWP is currently in the process of working on the LA100 Equity Strategies Action Plan.
- LADWP is implementing programs with a focus on equity, such as energy efficiency programs, providing energy management education, and seeking federal and state grants to provide technology subsidies to low-income and disadvantaged communities.
- LADWP plans to engage communities, especially low-income and disadvantaged communities in the planning and future implementation of marginal cost-based real-time rates to get their input and ensure the needs of all customers are met equitably.

C. Technological Feasibility

Providing LADWP customers with marginal cost-based real-time rates as required by the LMS would require LADWP to first provide end users with a supportive framework, including, but not limited to:

- AMI meters, or "smart meters", which serve as the user-side endpoint of the interface between utilities and end users;
- Communications networks that enable two-way communications between AMI meters and utility computer networks;
- Data analytics tools; and
- System architecture and field devices to provide increased granular visibility into the electrical distribution system.

Based on the following evaluation, offering marginal cost-based rates for any LADWP customer class is not technologically feasible at this time.

Advanced Metering Infrastructure (AMI)

LADWP has completed a pilot project deploying a small sample of AMI meters across its service territory, as a means of testing the integrity of the AMI communication network. Currently, less than 1 percent of LADWP’s 1.5 million residential and business customers have smart meters. A significant challenge has been the inability to fully integrate these AMI meters with LADWP’s current billing system. Mass deployment is projected to begin in 2027, following the complete integration with LADWP’s upcoming Customer Cloud System (CCS). The CCS will deliver meter-to-cash solutions with the scale, agility, and security of a cloud-optimized customer platform and is expected to be completed by the end of 2026. The full deployment of AMI meters is anticipated to span five years, from 2027 to 2031. This integration is crucial for implementing advanced rate structures, such as marginal real-time rates.

Communications Network Expansion

The real-time granularity adopted in the LMS would consume significantly more bandwidth than LADWP’s current TOU rates program. LADWP has an AMI communication network that is about 85% complete. The communication network and back-office equipment have been designed to support 1.5 million endpoints and can be scaled beyond that, if needed. This project is still ongoing and would be a prerequisite to offering next-generation, future real-time rates as part of a long-term project.

The estimated cost for completing the integration of AMI (excluding smart meter procurement and mass deployment) is about $95 million. The communication network has progressed far enough to start meter deployment and is expected to be completed with the meter deployment in 2031.

Data Analytics Tools

To assist with the design of the marginal cost-based real-time rates, advanced data analytics tools will be needed to analyze demand forecast, consumption, and revenue requirements, to set up the pricing properly and effectively, and to reflect dynamic market conditions. LADWP currently uses SAS (previously called "Statistical Analysis System") statistical software for data analytics and bill comparisons, SAS Energy Forecasting for demand forecasting, and SAS Visual Analytics for creating dashboards to interpret complex data sets, making it easier to understand consumption trends and pricing changes. LADWP is also looking into other advanced data analytics tools; once AMI meter data is available, these software tools will be instrumental in monitoring usage patterns and developing marginal cost-based real-time rates.

Distribution System Technology

Locational pricing requires incorporating location into price signal calculations and poses challenges. While LADWP is currently implementing its distribution automation plan, which includes installing line monitoring sensors and technology to remotely control capacitor banks, additional technologies are necessary to achieve the distribution-level granularity required to fully comply with the LMS. These technologies include intelligent field devices, control systems, communication systems, modeling tools, and the construction of an advanced distribution control center, which LADWP currently lacks. As a result, LADWP is carefully exploring the best approach to deploy these technologies, considering the rate impact associated with such significant capital expenditures. Extending this level of visibility would require substantial time, far exceeding the timeframe set forth in the LMS. The estimated timeline for LADWP's technology upgrades is broken into phases:

1. Sensor Installation and Distribution Automation - Estimated at 2-4 years.
2. Additional Technologies Deployment - Involves hardware and system integrations, requiring 3-4 years.
3. Advanced Distribution Control Center Construction - Projected to take 6-8 years.
4. Achieving Granularity and Compliance - Full deployment of distribution system technology expected within 8-10 years, considering current limitations and iterative implementation.

The total estimate is 8-10 years, subject to project specifics, resources, and regulatory factors.

D. Benefits to the Grid

Implementing marginal cost-based electricity rates offers significant benefits to the electrical grid. Currently, LADWP's 1.3 million residential customers typically experience peak demand after work hours. By encouraging these customers to shift their energy usage to off-peak times, LADWP could likely enhance grid reliability and minimize the risk of outages. Reducing peak demand would also likely reduce the need for peaking power plants, which are often more costly to operate, which would lead to cost savings to the utilities, and ultimately savings to the customers. Marginal cost-based electricity pricing can also help balance the variability of renewable energy sources by encouraging consumption when renewable generation is high, such as during sunny or windy periods. Dynamic pricing sends the right signals to consumers, suggesting that they adjust their consumption patterns and encouraging them to shift energy usage away from peak periods to ultimately save on their electricity bills.

This is particularly crucial as electric vehicle (EV) adoption rises; many EV owners currently charge during peak hours, which adds significant stress to the grid. By analyzing usage patterns and implementing real-time rates, LADWP could incentivize off-peak charging, thereby alleviating the anticipated burden on the grid and lowering system peaks. If LADWP fails to adopt appropriate pricing strategies, the forecasted demand from EV adoption will place additional strain on the grid, but with the right signals, LADWP can shift usage patterns to maintain balance. Some of the analysis from a recent LADWP distribution planning load forecast shows:

1. Electric transportation is the single largest driver of load growth, expected to increase the distribution system demand by 927 MVA by 2035 according to the Moderate Scenario.
2. Electrification is also expected to shift LADWP's peak demand period from around 5 pm, to 7-8 pm, mainly driven by residential EV charging.
3. LADWP's analysis shows that, if residential EV charging shifts away from the 7-8 pm peak, then distribution system demand will be reduced by over 250 MW in year 2035.

    a. **Managing residential EV charging has a significant effect on reducing the capacity shortfall on the 4.8kV distribution system.**
        i. Shifting residential charging times for light-duty EVs from evening hours to early morning hours reduces the capacity shortfall of Distributing Stations and 4.8kV Feeders by 31% and 48%, respectively, by 2035.
        ii. Consequently, the distribution system demand is reduced by 262 MVA by 2035.

As more customers adopt and effectively utilize marginal cost-based rates, system peaks could gradually decrease, benefiting all users. By aligning energy consumption with available supply, these rates might not only help manage demand on the grid but also reduce the need for additional generation capacity, thus minimizing the risk of blackouts. Furthermore, this shift can lead to more efficient use of existing resources, lower overall energy costs, and a greater integration of renewable energy sources, contributing to a more sustainable energy future for the entire community. This collaborative approach fosters a resilient grid that can adapt to changing demands while supporting cleaner energy practices.

E. Benefits to the Customer

Providing customers with real-time marginal cost-based rates gives customers an opportunity to manage their electricity costs and potentially lower their electricity bills. Customers can save money by using electricity during times when energy is cheaper, generally during periods when electricity demand is lower and when solar energy is generating. Having information on real-time marginal cost-based rates, an unconstrained customer can better plan and manage energy usage and costs, pay lower rates than what that customer might normally pay, and save money if consumption is reduced during higher priced hours or shifted to lower priced hours.

Marginal cost-based real-time rates also encourage customers to reduce energy consumption and conserve during peak periods. Further, by reducing overall peak demand, the need to replace or procure expensive peaking power plants may be reduced. Since the costs associated with providing electricity are distributed across all customers, the cost savings will ultimately benefit all customers.

Still, the actual financial impacts to customers in LADWP's service territory from being placed onto marginal cost-based real-time rates are not yet known. Feasibility studies are necessary to assess the financial impact to customers' bills and to quantify the potential decrease in peak load in LADWP's service territory as a result of real-time rates. Furthermore, the impacts to low-usage, low-income, and Lifeline customers, in particular, need to be identified to ensure that LADWP can continue to provide fair and reasonable rates to all its customers. For example, significant infrastructure costs would be incurred to institute real-time rates, and those costs must be carefully assigned in the rate-design process.

An additional benefit of shifting away from the peak demand period is the need for lower peak energy generation, which can be expected to lower greenhouse gas emissions. Customers who are concerned about the environment would feel good about saving energy and increasing reliance upon renewable energy because these align with their values of sustainability and environmental stewardship. By engaging in behavior that increases reliance on renewable resources like solar, wind, and hydro, customers contribute to reducing greenhouse gas emissions and combating climate change, which fosters a sense of responsibility toward the planet. Overall, the positive impact on the environment, combined with the personal and community benefits, enhances customers' satisfaction and pride in their energy choices.

Conclusion of Evaluation of Marginal Cost-Based Rates

The foregoing evaluation discusses cost effectiveness, equity, technological feasibility, benefits to the grid, and benefits to customers of marginal cost-based rates. As mentioned above, LADWP recognizes that the marginal cost-based rates provide significant benefits to the grid and customers. However, due to the technological limitations of LADWP, the implementation of marginal cost-based rates according to the timeline described in the Load Management Standards would result in extreme hardship to LADWP and is not technologically feasible. Therefore, in accordance with CCR § 1623.1(a)(2), compliance with the development of marginal-cost based rates for LADWP customers should be delayed until such a time as implementing such rates would be technologically feasible and equitable. Even though LADWP has determined that implementation of marginal cost real-time rates under the stated Load Management Standards timeline is not feasible, LADWP will continue to address the challenges, actively look into options, and pursue Meter/IT/Billing infrastructure that can facilitate the Load Management Standards requirements.

LADWP will work with its Corporate Strategy and Communications Office to develop a public information program at such a time when it adopts the real-time marginal cost-based rates as contemplated by the Load Management Standards.

§ 1623.1(a)(1)(B) Evaluation of MIDAS-based Hourly Marginal Signal Programs

LADWP has existing load management programs, and new programs will continue to be developed. As described below, LADWP plans to develop three programs that could integrate MIDAS signals. However, extensive rollout of such programs will take time due to LADWP's current technological limitations.

Existing LADWP Demand Response (DR) Programs

LADWP currently provides a robust suite of DR programs that cater to both commercial and industrial (C&I) as well as residential customers.

- **DR Programs for C&I Customers**

  In June 2016, the Board, through Resolution No. 016-307, approved establishment of the LADWP Summer Shift Program. In addition, LADWP ramped up the Demand Response Pilot Program, which started in 2015 and is now called the C&I Demand Response Program, to provide financial incentives to participating large C&I customers who reduce electricity usage or shift their electricity use away from high energy use periods. The minimum required curtailment commitment is 100 kW to join the program. The C&I DR season starts on June 15 and ends on October 15. Incentives are calculated at the end of season based on performance data obtained from meter data.

- **DR Program for Residential Customers**

  In November 2019, the Board, through Resolution No. 020-102, approved an agreement with the Southern California Public Power Association (SCPPA) by which, in conjunction with EnergyHub, Inc., LADWP implemented the Power Savers Program (PSP), which is an innovative DR program that targets residential and small commercial customers. This program utilizes a bring-your-own-thermostat (BYOT) model to manage and reduce electricity load during peak demand times, from June 1 to October 31. Participants who enroll in the program agree to allow LADWP to remotely adjust their thermostats during peak load events, ensuring efficient energy use across the network. In return, participants receive incentives that not only include an initial sign-up bonus, but also a seasonal reward based on their participation rate. This program plays a pivotal role in enhancing LADWP's ability to manage energy consumption effectively during the summer months when demand is typically at its highest.

  In addition to PSP, LADWP also developed and launched a program aligning with CEC's Demand Side Grid Support Program for battery energy storage at residential homes in LADWP's service territory. As of October 25, 2024, Tesla had registered 119 batteries into the program.

DR RFP for Technology, Integration, and Program Services Expected to Yield Three Programs that Will Eventually Enable Automated Response to MIDAS signals

Over the past two years, LADWP has undertaken significant steps to further enhance its DR capabilities through a comprehensive Request for Proposal (RFP) process. This initiative is aimed at implementing an advanced Demand Response Management System (DRMS), which will not only expand LADWP's existing programs but also facilitate the launch of new, innovative DR programs. Specifically, in April 2024, LADWP initiated an RFP to enhance its technological infrastructure and expand its DR capabilities. The solicitation process concluded with the proposal submission deadline at the end of June 2024.

The RFP is currently in the evaluation phase. The LADWP team is reviewing the proposals to ensure that the selected contracts align with LADWP's strategic goals and adhere to the highest standards of efficiency and effectiveness. This process is crucial as it will determine the partners and technologies that will help LADWP advance toward a more responsive and sustainable energy management system.

LADWP anticipates awarding contracts by the first quarter of 2025, potentially earlier, marking a significant advancement in integrating a comprehensive DRMS system. This RFP is designed not only to bolster existing DR programs but also to facilitate the development and launch of three innovative DR initiatives in 2025. These initiatives are tailored to meet the diverse needs of LADWP's customer base:

1. **Residential Managed Charging Program**: This program will implement a managed charging approach for electric vehicles (EVs) and EV supply equipment (EVSE), enabling more efficient energy use during peak demand periods.
2. **Commercial and Industrial (C&I) Managed Charging Program**: Specifically designed for C&I customers, this program shifts daily energy consumption from peak hours to off-peak hours via the use of EV telematics and/or EVSE.
3. **Smart Device Integration**: The third program will focus on integrating smart devices in residential settings, including smart plugs, appliances, water heaters, pool pumps, internet-connected window air conditioners, and battery energy storage systems. This initiative will leverage advanced technology to optimize household energy consumption and contribute to grid stability.

Collectively, these programs are projected to augment LADWP's DR capacity to approximately 338 MW by the end of 2029, significantly enhancing the utility's ability to manage load and support the grid effectively.

Proposed Program Details

LADWP intends to work with the CEC to ensure the current DR efforts align with the LMS. Since the managed charging programs are still in the process of development, LADWP proposes the design of both the C&I Managed Charging and Residential Managed Charging Programs (actual names of these programs are to be determined) to comply with the LMS.

It is planned that these proposed programs will allow the customer to respond to a signal from MIDAS. For this signal, LADWP intends to use a grid operator's index, such as the forecasted reserve capacity or net power for load (NPL). The reserve capacity describes the extra power that is theoretically available to meet demand if there is a disruption to the supply in the grid. NPL is the total amount of instantaneous electricity generated and imported from other regions to meet the demand of customers in a given area. Both datasets are currently developed by the LADWP's Energy Control Center (ECC) team. As a part of this compliance plan, LADWP will upload hourly forecasts of the agreed index to MIDAS for the DR service providers and the program participants to view and schedule their EV charging accordingly.

LADWP will calculate the monthly incentives for the program participants, who elect to respond to the MIDAS signal during their program participation, based on the index value, at which they charge their EVs, and the predetermined incentive tier, which will correspond to different ranges of the index. An example of the potential incentive tier is described in the table below. The exact values and ranges will be determined during the program design phase. LADWP projects an initial enrollment of approximately 1,000 EVs and EVSEs in the first year of the program, with expectations to expand to around 15,000 by the fifth year for both Residential and Commercial programs.

Reserve Capacity (MW)	Incentives or Penalties
800 MW or more	$0.05 per kWh
600 MW through 799 MW	$0.04 per kWh
400 MW through 599 MW	$0.03 per kWh
200 MW through 399 MW	$0.02 per kWh
100 MW through 199 MW	$0.01 per kWh
50 MW through 99 MW	$0.00 per kWh
49 MW or less	-$0.05 per kWh

A. Cost Effectiveness and Strategic Financial Planning

LADWP utilizes the LA100 study, developed by the National Renewable Energy Laboratory (NREL), as a critical benchmark to measure the cost-effectiveness of its renewable energy and DR programs. The study sets a benchmark of $150/kW-year to gauge the economic viability of these initiatives compared to traditional energy resources, providing a framework for a transition to a carbon-free grid by 2045.

Currently, LADWP's costs for the managed charging programs are projected in ongoing RFP processes and contract negotiations at approximately $620/kW-year, which is notably above the LA100 benchmark. These costs incorporate all associated fees and incentives for the initial five-year term of the contracts. While LADWP acknowledges that its current expenses exceed the recommended benchmark, this discrepancy underscores the early-stage investment required to establish robust and effective DR programs and is not currently viewed as a deterrence.

Acknowledging this initial high cost, LADWP commits to a systematic annual review of the planned programs to assess and enhance their cost-effectiveness. Each year, the LADWP team will critically evaluate program performance, costs, and technological advancements to identify opportunities for cost reduction and efficiency improvements. The aim is to progressively lower costs through operational efficiencies, increased program participation, and the strategic application of emerging technologies.

This ongoing evaluation will ensure that the planned programs continue to progress toward meeting the LA100 benchmark. The expectation is that, as these programs mature and scale, combined with advancements in DR technologies and management practices, the costs will gradually align with or even fall below the benchmark. Additionally, LADWP will continue to explore and secure diverse funding sources, including federal grants and public-private partnerships, to support the financial sustainability of these programs. Therefore, LADWP believes that the planned programs can be cost-effective.

B. Equity and Inclusivity in Program Access

LADWP is committed to ensuring equitable access to its DR and renewable energy programs. Its current programs include the Residential Customer Electric Vehicle Home Charger Rebate Program launched in 2011 and the EVSE Residential and Commercial Rebate Program expanded in 2013, which included publicly accessible locations, workplaces, and multi-unit residential dwellings. These programs are designed to support participation from a broad range of customers, including those with newer, telematics-enabled EVs and older models without such capabilities.

To facilitate this inclusivity, especially for customers using older EV models, LADWP coordinates with EVSE providers to collect necessary charging data for accurate incentive calculations. Furthermore, during the ongoing RFP process, LADWP requires all vendors to submit detailed equity engagement plans. These plans must outline strategies to ensure all programs are accessible to every LADWP customer, including those from disadvantaged communities, and describe how potential participation barriers will be mitigated.

These equity engagement plans are thoroughly reviewed and scored during the proposal evaluation phase. LADWP's goal is to select vendors who are not only technically proficient but also deeply committed to providing equitable benefits to all its customers.

As described above, the managed EV charging programs that integrate MIDAS signals are being developed for both residential and C&I customers who have EVs. Further, the

Smart Device Integration program would be available to residential customers of varying income levels and situations. Thus, even though LADWP does not anticipate being able to offer each of its electricity customers voluntary participation in a program that integrates MIDAS signals by the timeline specified in the LMS, LADWP believes that its planned program offerings sufficiently extend equitable access to its customers under the circumstances.

C. Technological Feasibility

LADWP's Demand Response and Electric Transportation teams collaborated with other utilities and potential vendors to explore managed EV charging programs aiming to gain insights into existing initiatives. As part of this effort, LADWP reviewed Sacramento Municipal Utility District's Managed EV Charging, San Diego Gas and Electric's Power Your EV Drivers, and Pacific Gas and Electric's EV Charge Manager. This engagement allowed LADWP to develop a comprehensive understanding of diverse program structures and the varied functionalities of different vendor platforms for EV managed charging.

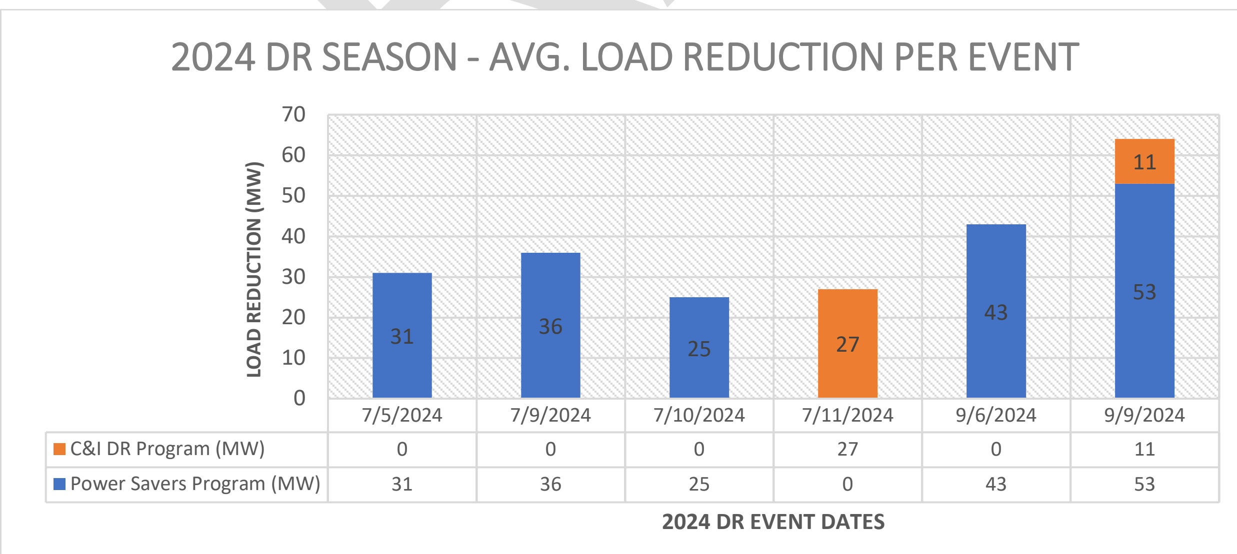
The industry's current approach to managed EV charging is based on a reward-based incentive model. In this setup, customers participate by plugging in their EVs and informing their automaker or a third-party provider of their desired charging completion time. An optimized charging schedule is then created, leveraging low-demand utility periods to reduce grid strain and increase renewable energy usage. This schedule is sent directly to the EV or EVSE, meaning customers simply plug in and receive rewards. These financial incentives may include gift cards, PayPal payments, rate discounts, or checks, depending on their previous month's charging behavior and rewards earned.

For LADWP, the primary goal is to shift energy consumption from peak hours to off-peak hours, using EV telematics and/or EVSE signals. Crucial to this approach is customer participation; LADWP can gauge how well EV owners respond to charging incentives that encourage off-peak charging and discourage peak-period charging. By analyzing participation and response patterns, LADWP can further refine these programs to maximize grid efficiency and enhance customer savings. Additionally, sustained customer engagement in off-peak charging not only helps to stabilize the grid but also supports LADWP's broader commitment to incorporating renewable energy sources and ultimately reducing the environmental impact of increased EV adoption. Currently, LADWP has not found any comparable managed charging program that respond to a direct signal, such as from MIDAS. Unlike standard customer-engagement models, the contemplated managed charging programs using MIDAS involve an automated process in which the utility, not the customer, controls charging decisions. This adds complexity as LADWP works to launch both Residential and Commercial Managed Charging Programs, with no baseline for such a program yet. LADWP aims to incorporate the MIDAS signal option in these programs, giving customers the choice to participate. In addition, LADWP currently lacks a managed charging vendor and remains uncertain about potential platform flexibility. Implementing MIDAS will rely heavily on a vendor's ability to support this functionality. LADWP's program team will continue engaging with the CEC during the design phase to ensure a practical and implementable program.

In addition, growth of the three planned DR programs depends upon the degree of AMI available. As described above in the evaluation of marginal cost-based rates, LADWP has been making progress toward the integration of AMI, but significantly more time and funding will be needed to achieve mass deployment of AMI. LADWP concludes that, while a fully automated program based on MIDAS is not yet technologically feasible at this time, it is committed to developing pilot projects that can guide future large-scale implementation strategies. The Residential EV Managed Charging Program and C&I Program could be technologically feasible to implement on a smaller scale, and the programs can provide LADWP valuable results from a sample of its customer base. This initial step toward enhancing load flexibility will provide critical insights needed to evaluate the effectiveness of these programs and inform the potential planning of future large-scale deployments. In other words, LADWP's technological limitations will prevent LADWP from offering each of its electricity customers voluntary participation in a program that integrates MIDAS signals by the timeline specified in the LMS, but LADWP intends to offer a measured rollout of the three planned DR programs in the next several years.

D. Benefits to the Grid

DR has become a reliable resource for LADWP's Grid Operations team at the ECC in the recent years. For example, the Grid Operations team issued the DR events on five consecutive days during September 2022 heat wave. ECC utilized the DR programs to relieve high demand during summer 2024.



Similar to the existing DR programs, LADWP expects the managed charging programs to provide additional resources for the Grid Operations team during peak demand periods as Angelenos adopt more and more EVs for their daily commute. LADWP expects the managed charging programs to benefit the grid by:

- **Reducing Peak Load**: By shifting EV charging to off-peak hours, LADWP can flatten peak demand curves, which helps in managing grid load more efficiently and prevents overburdening the power system.
- **Increasing Grid Stability**: Managed charging can help stabilize the grid by ensuring that the increase in electricity demand from EVs does not coincide with other high-demand periods, thus maintaining a balanced and stable energy supply.
- **Optimizing Energy Resource Use**: Through smart charging strategies, LADWP can maximize the utilization of renewable energy sources by scheduling EV charging times when renewable energy production is high, such as during the day when solar power generation peaks.

E. Benefits to the Customers

LADWP's DR programs have been delivering significant benefits to both residential and commercial customers since 2015. As of October 25, 2024, the Power Savers Program (PSP) has successfully enrolled 51,206 customers, demonstrating the program's widespread acceptance and effectiveness.

Since 2020, LADWP has distributed a total of $15,743,350 in incentives to PSP participants. These incentives not only reward customers for their active participation but also encourage continued engagement in energy-saving practices.

The upcoming managed charging programs introduce an incentive structure tailored especially for EV owners. These programs leverage the MIDAS system, allowing participants to identify optimal times for EV charging during low demand periods, thereby reducing their electricity costs. Both the Residential Managed Charging Program and the Commercial & Industrial (C&I) program would offer significant cost savings by incentivizing participants to adjust their energy use to off-peak hours. This not only aids in managing the grid more effectively but also equips customers with the tools necessary for efficient energy management.

Following the close of each month, LADWP will review the charging history of participants to accurately calculate and process incentives. With the introduction of a tiered incentive system, customers could maximize their rewards by strategically avoiding charging during peak demand periods.

Similarly, the Smart Device Integration program would offer significant cost savings by incentivizing participants to adjust their energy use to off-peak hours. It would optimize household energy consumption while also contributing to grid stability.

By continuously enhancing these programs and incentives, LADWP aims to foster a collaborative relationship with its customers, where every program participant could contribute to and benefit from a more resilient and sustainable grid.

Conclusion of Evaluation of MIDAS-based Hourly Marginal Signal Programs

The foregoing analysis includes evaluation of programs' cost effectiveness, equity, technological feasibility, benefits to the grid, and benefits to the customer. As described in the foregoing analysis, the implementation of programs that enable automated response to marginal cost signals or other MIDAS signals according to the timeline described in the Load Management Standards for all of LADWP's electricity customers is not technologically feasible. Therefore, in accordance with CCR § 1623.1(a)(2), compliance with the development of programs that enable automated response to marginal cost signals or other MIDAS signals should be delayed until such a time as implementing such programs would be technologically feasible, and, in the meantime, LADWP's compliance is proposed to be modified as follows: LADWP will continue to take steps to introduce the Residential Managed Charging Program, the C&I Managed Charging Program, and the Smart Device Integration Program in 2025 and to subsequently grow and adjust those programs in accordance with their merit and LADWP's capabilities. LADWP will work with its Corporate Strategy and Communications Office to develop a public information program to accompany the three load flexibility programs planned for 2025.

APPENDIX 1

LOAD MANAGEMENT STANDARDS

APPENDIX 2

LIST OF RINS

APPENDIX 3

PROOF OF RATE AVAILABILITY ON MIDAS FOR THE R1B0 STANDARD RATE

APPENDIX 4

COMPOSITE RATE CALCULATION AND SUBMISSION SOLUTION
FOR CONTRACT RATES

APPENDIX 5

COMPOSITE RATE CALCULATION AND SUBMISSION SOLUTION

FOR STANDARD RATES