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October 2, 2023

California Energy Commission
Load Management Standards
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ATTN: Executive Director Drew Bohan

PACIFIC GAS AND ELECTRIC COMPANY E-FILING

2023 COMPLIANCE PLAN for the LOAD MANAGEMENT STANDARDS[1]
Docket 23-LMS-01

Investor-Owned Utility Name:	Pacific Gas and Electric Company 300 Lakeside Drive Oakland, CA 94612
Date submitted:	October 2, 2023
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Pursuant to the California Public Resources Code Sections 1621 and 1623.1, Pacific Gas and Electric Company submits the requested information to the California Energy Commission Docket Number 23-LMS-01.

Should you have questions or require additional information, please feel free to reach out to me anytime. For technical questions, kindly refer to subject matter experts Emily Bartman (emily.bartman@pge.com) and Melanie McCutchan (melanie.mccutchan@pge.com).

Sincerely,

Jennifer Privett
PG&E, State Agency Relations

[1] Pursuant to Title 20, California Code of Regulations Section 1623.1(a).

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0. Introduction

Pacific Gas and Electric Company (PG&E) respectfully submits this Load Management Standards (LMS) Compliance Plan to the California Energy Commission (CEC) Executive Director per the LMS requirement codified in Title 20, California Code of Regulations (CCR) Section 1621(d).[2] PG&E appreciates and supports the CEC's efforts to enable cost-effective load management through customer rates.

a. LMS load flexibility requirements and status

In April 2023, the CEC adopted amendments to the LMS[3] with the goal of establishing a foundation for a statewide system of granular time dependent signals that can be used by automation-enabled loads to provide real-time load flexibility on the electric grid.[4] The core of those amendments requires the Large Investor-Owned Utilities (IOUs), Community Choice Aggregators (CCAs), and Publicly Owned Utilities (POUs) to provide optional hourly marginal cost-based rates – which we will refer to here as Real-Time Pricing (RTP) rates – for all customer classes. Per the LMS, these RTP rates must be proposed to each utility's respective rate-approving bodies by January 2025 and are to be made available to customers by January 2027, contingent on approval of those rates and cost recovery by each utility's respective rate-approving body.

The LMS requires RTP rates to include a marginal cost-based hourly or sub-hourly generation energy and capacity (import only, i.e., delivered to the customer) component, as well as

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[2] 20 CCR § 1621 (d)(1) states, "Each Large IOU shall submit a plan to comply with Sections 1621 and 1623 of this article to the Executive Director no later than six (6) months after April 1, 2023."

[3] The LMS regulations are contained in 20 CCR §§ 1621-1625 and carry out the CEC's statutory mandate to establish electric load management standards for 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. The CEC proposed these amendments to the LMS to set standards for utility programs and rates to be better able to shift loads to periods of high renewable generation, in support of a carbon-free grid as envisioned by Senate Bill 100 (De León, 2018). Since adoption of the original LMS regulations many decades ago, technologies and markets have evolved substantially, creating significant opportunities for more advanced load management strategies. (Initial Statement of Reasons, Docket No. 21-OIR-03 Notice Published on December 24, 2021.)

[4] Herter, Karen and Gavin Situ. 2021. *Analysis of Potential Amendments to the Load Management Standards: Load Management Rulemaking, Docket Number 19-OIR-01.* California Energy Commission. Publication Number: CEC-400-2021-003-SF. (Dec. 22, 2021.) Available at: https://www.energy.ca.gov/publications/2021/analysis-potential-amendments-load-management-standards.

marginal cost-based hourly or sub-hourly distribution and transmission components.[5,6] If LMS-compliant RTP rates are not adopted by the rate-approving body in time to be available to each customer class by January 2027, an alternative cost-effective load flexibility program must be available in place of the LMS-compliant RTP rates.[7]

Along with requiring the development and availability of RTP rates, the April 2023 update to the LMS also included provisions for California's Load Serving Entities (LSEs) to implement tools to facilitate the delivery of RTP price signals to customers and their automated appliances or other end uses. These include the development of the CEC's Market Information Demand Automation Server (MIDAS), designed to be a machine-readable database of rates and other grid signals that can be used to automate demand flexibility.[8] The LMS also require that LSEs enable customer and third-party provider access to rate information through the development of Rate Identification Numbers (RINs) that capture the specific pricing for a customer premise, as well as develop a "Single Statewide RIN Access Tool" that would facilitate third parties' access to customer rate information.

Table 1 summarizes the requirements for PG&E that emerged from the April 2023 LMS amendments (in order of the compliance due date), as well as the status of PG&E's progress on meeting those requirements – as of the filing of this plan:

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[5] "Marginal cost" means the change in current and future electric system cost that is caused by a change in electricity supply and demand during a specified time interval. The LMS use the term "marginal cost-based rates," which appears to be synonymous with the CPUC's use of the term "demand flexibility rates" to refer to hourly or sub-hourly marginal cost-based RTP rates. For generation energy, hourly and sub-hourly marginal cost prices are available in California Independent System Operator markets. There are no markets that set marginal cost prices for generation capacity, distribution, and transmission. The inclusion of marginal cost-based hourly pricing components for distribution and transmission in RTP offerings in the U.S. has not been proven, but dynamic distribution as part of an RTP rate has been piloted by San Diego Gas & Electric for a limited number of circuits in their Power Your Drive VGI Integration pilot. Dynamic distribution is also currently being tested in SCE's Flexible Pricing Rate pilot and in Valley Clean Energy's AgFIT Pilot (on a limited number of circuits), and a version will be tested in PG&E's VGI Pilot that provides an hourly distribution price based on grouping circuits of similar load profiles into clusters.

[6] The LMS requirement to include a generation capacity component is intended to reflect the value of deferring the procurement of additional generation capacity. This capacity component was the subject of the Marginal Generation Capacity Costs (MGCC) Research Study performed by PG&E and other parties and is included in the optional and pilot Day-Ahead Hourly RTP (DAHRTP) rates to be launched in early 2024. (See PG&E MGCC Pricing Formula for PG&E's Day-Ahead Hourly Real Time Pricing (DAHRTP) Rates, Attachment 1. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M471/K485/471485737.PDF.)

[7] 20 CCR § 1621 and § 1623(d)(2).

[8] Herter, Karen and Gavin Situ. 2021. *Analysis of Potential Amendments to the Load Management Standards: Load Management Rulemaking, Docket Number 19-OIR-01.* California Energy Commission. Publication Number: CEC-400-2021-003-SF (Dec. 22, 2021), p.2. (Accessed Aug. 3, 2023.)

Table 1. PG&E Status on LMS Requirements.

Requirement	LMS Section	Compliance Due Date	Status	Compliance Plan Section
Time-dependent rate submission to MIDAS	§ 1623 (b)	October 1, 2023	Complete	Section 2
Rate Identification Numbers (RINs) on customer billing statements and online account	§ 1623 (c)(4)	April 1, 2024	In Process	Section 3
Single Statewide RIN Access Tool	§ 1623 (c)(1)-(3)	October 2024	In Process	Section 4
List of cost-effective load flexibility programs	§ 1623 (d)(1)-(2)	October 2024	In Process	Section 5
Marginal cost rate design and application (Generation, Distribution, Transmission)	§ 1623 (a)	January 1, 2025	On Track for Generation and Distribution signal; Transmission signal to follow 2026 FERC filing approval	Section 1
Marginal cost rate options for all customer classes	§ 1623 (d)(2)	January 1, 2027	In Process	Section 1
Public information program	§ 1623 (d)(3)	Not Specified	In Process	Section 6

b. Report structure

On July 14, 2023, the CEC provided Large IOUs, CCAs, and POUs *Compliance Assistance for LMS Compliance Plan Submittals* (Compliance Plan Guidance), which offered regulated parties additional information to assist in the development of the LMS Compliance Plans.[9,10] The Compliance Plan Guidance provides an outline to assist Large IOUs in submitting their respective Compliance Plan and to clarify the "good faith effort" determination outlined in the LMS.[11] The LMS state that 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."[12]

PG&E organized this LMS Compliance Plan Report to be consistent with the outline provided in the Compliance Plan Guidance, though some details the Compliance Plan Guidance suggests are not yet available and are not included. At times, PG&E provides additional information or adjusts organization of the report as needed. Sections 1-6 are numbered to mirror the outline provided in the Compliance Plan Guidance. Each section provides PG&E's plans for compliance with a given LMS requirement. The sections cover the following:

- Section 1 - Marginal cost rate design and application.
- Section 2 - Submission of time-dependent rates to MIDAS
- Section 3 - Rate Identification Codes (RINs) on customer bills and online accounts
- Section 4 - Single Statewide RIN access tool
- Section 5 - Provides a list of cost-effective load flexibility programs.
- Section 6 - Public information programs for RTP rates.

Appendix A provides an expected timeline for PG&E's compliance with the LMS provisions. Each of these key activities and milestones are further detailed in the report section pertaining to a given LMS requirement. Appendix A also shows key milestones in the California Public Utilities Commission's (CPUC) Demand Flexibility Order Instituting Rulemaking (DFOIR) Proceeding, which will affect the development of PG&E's RTP rates. This timing represents PG&E's best estimates at this time and may change due to delays in regulatory milestones, operational constraints, or other unforeseen factors.

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[9] "Large Investor-Owned Utilities" and "Large IOUs" mean the San Diego Gas and Electric Company, the Southern California Edison Company, and the Pacific Gas and Electric Company (20 CCR § 1621(c)(8)).

[10] Wayland, Stephanie and Gavin Situ. 2023. *Compliance Assistance for Load Management Standards Compliance Plan Submittals*. California Energy Commission. Publication Number: CEC-400-2023-009.

[11] Ibid., p.7.

[12] 20 CCR 1621(d)(2).

1. Marginal cost rate design and application

a. RTP Rate design

PG&E has been steadily iterating on its preferred RTP rate design over the last several years, both through RTP rate pilots proposed in various proceedings and through the CPUC's DFOIR Track B (R.22-07-005). In the first half of 2023, PG&E participated in Working Group 1 sessions of the DFOIR Working Groups for Track B, which culminated in a Joint IOU Working Group 1 Report (DFOIR Joint IOU WG1 Report) drafted in August 2023.[13]

Through these proceedings and working group sessions, PG&E's RTP rate design has evolved over time from a simple generation-only rate to one that now includes dynamic distribution and other proposed enhancements such as subscription mitigations[14] and forward transactions.[15] The remainder of this section first describes the status of RTP pilots in PG&E's service area and then describes PG&E's proposed plan for achieving LMS-compliant rates.

i. PG&E's Pilot RTP rates

Pilots are in progress and proposed for PG&E's service area, which have made (or will make) RTP rates available to customers in the next few years. These pilots will continue to provide important learnings to inform RTP rate design. The Valley Clean Energy (VCE) AgFIT agricultural water pumping pilot is available to agricultural customers in VCE's service area and includes both marginal generation and distribution cost components.[16] Additionally, PG&E is in the process of implementing a Vehicle-to-Grid Integration RTP Pilot (VGI RTP Pilot) approved by CPUC Resolution E-5192 per directives in CPUC Decision (D.) D.20-12-029. The VGI RTP Pilot is targeted for rollout in 2024. In PG&E's 2020 General Rate Case (GRC) Phase II, RTP rate pilots

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[13] The DFOIR Joint IOU WG1 Report, "California Public Utilities Commission's Demand Flexibility Order Instituting Rulemaking (DFOIR) Track B Working Group 1 Report, Version for Working Group 1 Review" was submitted to the DFOIR Track B Working Group and the CPUC on Aug 14, 2023.

[14] The customer's "subscription" load assumed in the absence of RTP (in this case, last year's load) is charged the Otherwise Applicable Tariff (OAT) and only the difference between actual load and the subscription amount in any hour is charged the RTP price. Subscriptions are designed to recover costs that exceed the marginal costs recovered from RTP prices and also reduce the risk to customers of high bills resulting from extended high RTP prices, while still maintaining the RTP price incentive to shift load from high-priced hours to lower-priced hours.

[15] A full-featured transactive pricing platform allows customers to buy or sell energy at any time at prices set by the LSE for a specified time in the future, in PG&E's design up to seven days. In effect, customers can pre-schedule load to be on or off any time over the next seven days, with the price paid for the difference between pre-schedule and subscription set by the LSE. The customer thus ends up paying for subscription load at the OAT, transacted load (plus or minus) at the price set by the LSE at the time of the transaction(s), and the difference between actual load and subscription plus any transactions at the RTP.

[16] Valley Clean Energy is a CCA within PG&E's service area that serves the cities of Davis, Woodland, Winters, and the unincorporated areas of Yolo County. The VCE AgFIT Pilot was approved by CPUC Resolution E-5192.

were approved for Residential, Commercial, and Industrial customers.[17] However, these pilots were designed to include only dynamic generation price components and would not meet the LMS requirements to include hourly distribution and transmission marginal cost signals. On September 25, 2023, PG&E filed a proposal – in support of the CPUC Energy Division Staff's proposal in Track B of the CPUC's DFOIR proceeding[18] – to expand the VCE AgFIT Pilot (PG&E Expanded Pilots Proposal).[19] With this proposed pilot expansion, all PG&E-customer classes – except Commercial Electric Vehicle (CEV) and Street Lighting – would be able to enroll in an RTP rate with dynamic generation and dynamic distribution cost components by June 2024. This implementation timing is dependent, however, on PG&E receiving CPUC approvals for these pilots by November 30, 2023. If the PG&E Expanded Pilots Proposal is adopted and implemented on the schedule proposed by the CPUC (June 2024), PG&E will meet the requirements of the LMS to have marginal cost-based hourly rates available to all customer classes (except for CEV)[20] for the generation and distribution components of the RTP rates well ahead of the Jan 2027 CEC target.

If PG&E's proposal for including other customer classes (in addition to Agricultural) – as described in the PG&E Expanded Pilots Proposal – is adopted in the DFOIR proceeding, PG&E will be working with PG&E's GRC II RTP Track settling parties to pause PG&E's GRC II RTP pilot rates for the E-ELEC (Residential), B-6 (Small to Medium Commercial) and B-20 (Large Commercial and Industrial) rates. This will allow PG&E to replace those pilots with an RTP rate structure that includes not only marginal generation, but also marginal distribution cost components.

PG&E will provide an update on the plans to provide an LMS-compliant RTP rate for CEV customers by January 2027 in its next annual LMS Compliance Plan report. Although the VGI Pilot Dynamic Rate includes dynamic generation and distribution, eligibility is limited – in order for CEV customers to enroll in phase 2 of that pilot, they must be interconnected under Rule 21.[21] Interconnection under Rule 21 is required because the VGI Pilot's objective is to encourage export to the grid and testing of vehicle-to-grid use cases. The VGI Pilot is a short-term pilot and is unlikely to be open to customers all the way to 2027. However, eligibility and a timeframe for

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[17] PG&E A.20-12-011 approved in CPUC [D.22-08-002](D.22-08-002).
[18] CPUC *Administrative Law Judge's Ruling on Track B Staff Proposal to Expand Pilots* Aug 15, 2022. R.22-07-005.
[19] Submission of GridX, Inc., Polaris Energy Services, Gridtractor, Inc., and Pacific Gas and Electric Company's Comments and Responses to the Administrative Law Judge's Ruling on Track B Staff Proposal to Expand Existing Pilots. CPUC R. 22-07-005. September 25, 2023.
[20] Street Lighting customers are not required to be offered and LMS-compliant rate [20 CCR § 1621 (c)(6))].
[21] Rule 21 defines the interconnection process for facilities that export power to the electrical grid. Available at https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_21.pdf.

the VGI dynamic rates could potentially be expanded to non-Rule 21 CEV customers. Learnings from the Day-Ahead Real Time Pricing - Commercial Electric Vehicle (DAHRTP-CEV) opt-in rate, the CEV non-NEM export pilot[22] – planned to launch in February 2024 – and the VGI Pilots Dynamic Rate targeted for Q3 2024 would be used to inform the design of the LMS-compliant RTP rate for CEV customers.

ii. Plan for marginal energy cost, generation capacity, and distribution capacity

While still undergoing minor adjustments, PG&E's currently preferred rate design will likely be similar to the rate design of its VGI RTP Pilot and will satisfy all but one of the LMS requirements – hourly transmission costs. The VGI RTP Pilot rate design includes marginal energy costs, marginal generation capacity costs, and marginal distribution capacity costs, but does not include hourly transmission costs. Additional details of the rate design can be found in PG&E's Advice Letter 6694-E.[23] While the VGI RTP Pilot rate design does not include marginal transmission capacity costs, PG&E is developing a roadmap toward an LMS-compliant rate in 2027, as discussed in the next section.

iii. Plan for hourly transmission rate components

PG&E supports the CEC's goal to have effective price signals for load management, and RTP can be a tool for achieving this goal. While PG&E recognizes that a dynamic transmission rate will be an important component of the final RTP rate design, PG&E believes it is not a critical requirement to obtain load response in the near term, given that the dynamic transmission signal currently comprises only about 10 percent of the total time-varying marginal costs.[24] Nonetheless, PG&E will pursue a plan to have a dynamic transmission signal ready by January 2027 to be in full compliance with the LMS.

There are hurdles that must be overcome before a dynamic transmission rate can be added to the RTP rate price signal. For one, transmission marginal costs are not currently used to design transmission retail rates, and time-of-use (TOU) transmission retail rates have not yet been presented to the regulatory body presiding over transmission rates – the Federal Energy Regulatory Commission (FERC) – by the IOUs. This concept is entirely new and PG&E's

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[22] As authorized by CPUC D.21-11-017 and D.22-10-024.
[23] Available at ELEC_6694-E.pdf (pge.com) (https://www.pge.com/tariffs/advice-filing-index.page?xmldoc=sites-data/tariffs/data/advice-letters/2022/electric.xml).
[24] DFOIR Joint IOU WG 1 Proposal, p. 26. Figure 3 shows that the average time-varying marginal cost per kWh is approximately 7.9 cents for generation, 1.2 cents for distribution, and 1.1 cents for transmission.

benchmarking was unable to identify any active RTP rates in the United States that include a dynamic transmission element.[25]

Additionally, FERC holds exclusive authority over transmission rates and FERC approval is required to implement the dynamic transmission pricing component in PG&E's RTP rates. Upon FERC approval of PG&E's dynamic transmission pricing proposal, PG&E would file an Advice Letter with the CPUC to notify them when that new rate component would be incorporated into its RTP pilot rates (before January 1, 2027).

Furthermore, marginal transmission capacity costs warrant more detailed study. It is unknown what kind of capacity price signal would be best suited and what the appropriate geographic differentiator would be for transmission. Factors that contribute to the complexity of developing transmission price signals include: increased renewables capacity on the California grid; increased interstate import/export flows (with California transmission lines sometimes being used to move power from the Pacific Northwest or the Southwest to or from California, or even "wheeled" between the Pacific Northwest and the Southwest); transmission congestion; and the potential deferment of transmission upgrades. The most recent 2022-2023 Transmission Planning Process (TPP) indicated limited potential for deferment of transmission upgrades with 24 projects categorized as 'Reliability,' 21 characterized as 'Policy,' and no project that was identified as 'Economic-Driven.'[26]

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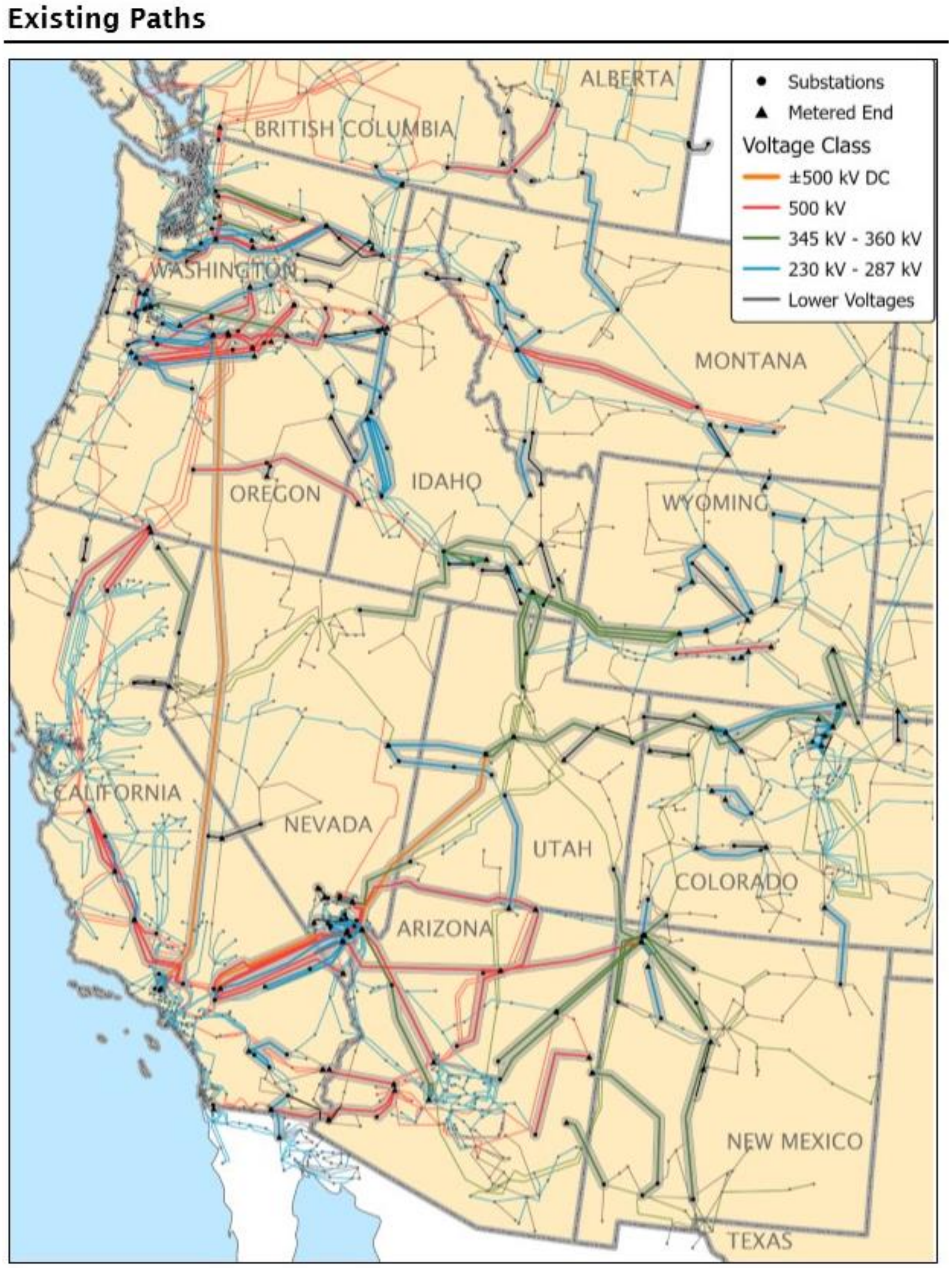
[25] In comments on the Joint IOU WG 1 Proposal, Utility Consumers' Action Network mentions that New Hampshire has an hourly rate that "passes through time-differentiated transmission rates (typically, in 3 to 6 price spikes that occur at different times each month)." PG&E was unable to locate any details regarding this transmission rate.
[26] CAISO 2022-2023 Transmission Plan, May 23, 2023. Available at: http://www.caiso.com/InitiativeDocuments/ISO-Board-Approved-2022-2023-Transmission-Plan.pdf.

To understand the implications from these projects, PG&E plans to partner with the following additional parties/entities to perform its detailed study:

- Experts in transmission planning and the transmission market.
- Other California IOUs – however, there may not be a one-size-fits-all approach as each IOU's transmission system is different and study parameters and results are likely to vary by IOU. Notably, a number of significant paths to external balancing authorities originate in Southern California, including paths to large grid-scale solar projects in Nevada and Arizona, as well as the Palo Verde (AZ) electricity trading hub. See Figure 1, below.
- The California Independent System Operator (CAISO) – as the transmission operator, CAISO is deeply involved in planning for transmission capacity additions on the grid.

Figure 1. Major Transmission Paths in the Western Electricity Coordinating Council[27]



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[27] Western Electricity Coordinating Council (WECC), "WECC 2022 Path Rating Catalog—Public Version," p. 7. Available at: https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/2022%20Path%20Rating%20Catalog%20Public.pdf&action=default&DefaultItemOpen=1.

PG&E's initial plan for developing dynamic transmission rates is summarized in Table 2.

The RTP rate design for transmission rates, as well as generation and distribution rates, would ideally be informed by learnings from the various pilots underway and those due to start over the course of the next year. However, PG&E recognizes that there is simply not enough time to gather the learnings from these pilots before an application must be submitted and approved by FERC prior to the CEC's January 2027 compliance date for making LMS-compliant rates available. PG&E will incorporate as many learnings from the RTP pilots as possible when designing the LMS-compliant rates.

To further complicate timing, the standard FERC application procedure requires applications to be filed between 30 and 180 days (about 6 months) before they go into effect. Consequently, PG&E cannot file an application with FERC before July 2026 in order to have a dynamic transmission price signal in place by January 2027. Thus, PG&E will likely have to ask the CEC for a waiver on the October 2025 LMS-compliant RTP rate design application for the transmission portion of the requirement. The timeline presented in Table 2 represents PG&E's best estimate as of the filing of this compliance plan. Further refined updates on timing will be provided to the CEC in the 2024 LMS Compliance Plan (submitted 12-months after the 2023 Compliance Plan is approved).

Table 2. PG&E's Plan for Developing Hourly Transmission Rates.

Time Period	Activity
2023 Q4 to 2024 Q1	Gather study requirements for dynamic transmission marginal cost study. Meet with transmission planners, operators, and market experts to understand CAISO operations and how load shifting could impact capacity needs.
2024 Q2 to 2024 Q4	Gather data and perform study to inform transmission marginal cost design.
2025 Q1 to 2025 Q2	Develop cost allocation models to inform dynamic transmission rate design.
2025 Q3 to 2026 Q1	Work with other IOUs and intervenor groups to discuss transmission marginal cost rate design options, coordinate design across the IOUs, and settle on a proposed rate design.
2026 Q2 to 2026 Q3	Write dynamic transmission rate design application and propose at FERC for implementation by January 1, 2027.[28]
2026 Q3 to 2026 Q4	File Advice Letter with the CPUC to notify the CPUC that a new Transmission rate component will be incorporated into PG&E's RTP pilot rates.

b. RTP rate application

PG&E plans to file an application for LMS-compliant dynamic day-ahead hourly rates for each customer class in its next GRC Phase II filing in the third quarter of 2024, incorporating guidance from the CPUC's DFOIR directives in R.22-07-005. This timing may need to adjust if different guidance is issued by the CPUC on where or when the application should be filed. The rates

[28] PG&E is undergoing a multi-year billing system upgrade project and does not expect to be able to build any new rates that are not already scheduled for implementation in the billing system before 2027. PG&E plans to "shadow bill" any new RTP rates that are introduced to meet the LMS-compliant RTP rate requirements for January 2027, until these rates can be built in the new billing system. PG&E will implement an ancillary billing platform that will operate in parallel to PG&E's existing billing system. A customer will continue to receive their regular bill on their otherwise applicable tariff and be responsible for its cost. The "shadow bill" will calculate customers' performance on the dynamic rate and provide a credit on the customer's actual PG&E bill if the customer's performance on the dynamic rate is better than on their OAT on an annual basis.

PG&E plans to file in its GRC Phase II application in 2024 will meet the LMS requirements for marginal cost rates for the components which capture marginal energy cost and marginal generation and distribution capacity cost. However, these rates will not include the marginal transmission capacity rate component. PG&E will submit a separate filing to FERC in the second half of 2026 seeking approval for a dynamic transmission price signal to be included in PG&E's RTP rates. This dynamic transmission signal will then need to be approved by the CPUC.

Another challenge related to timing is that any proposal for LMS-compliant RTP rates that PG&E submits in its next GRC Phase II will not be able to incorporate learnings from PG&E's existing and proposed RTP pilots. PG&E will provide an update in its next LMS Compliance Plan on how to best address this misalignment of timing.

c. Marginal cost-based rate design progress

i. Discussion of rate design intentions, considerations, and trade-offs

In the DFOIR Joint IOU WG 1 Proposal, the Joint IOUs put forth the following overall objective for dynamic rate design:

"Most effective demand flexibility at least cost with the best possible customer experience."[29]

In addition to this objective, PG&E also desires to be as consistent as possible in rate design across customer classes and to reflect marginal costs as accurately as possible. The RTP rate PG&E intends to propose in its next GRC Phase II application will use several elements from PG&E's RTP rates developed in its 2020 GRC Phase II, as well as from the CPUC's CalFUSE model[30] with modifications.[31]

ii. Frequency

The RTP rate will contain individual prices at the hourly level, updated on a day-ahead basis.

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[29] Joint IOU WG 1 Proposal, p. 11.

[30] CalFUSE stands for California Flexible Unified Signal for Energy. This dynamic rates framework is described in the CPUC white paper "Advanced Strategies for Demand Flexibility Management and Customer DER Compensation, Energy Division White Paper and Staff Proposal," June 22, 2022.

[31] Modifications include using clustering to group circuits with similar load profiles together for distribution pricing and potential modifications to the CalFUSE suggested subscription design.

iii. Proposed details about marginal capacity costs

The RTP rate will include the marginal generation capacity costs (MGCC) approved in D.21-11-016 and allocated in the manner designed by a collaborative group of five parties,[32] as approved in D.22-08-002.

iv. Proposed details about marginal energy costs

The RTP rate will include the marginal energy costs (MEC) approved in D.21-11-016, which are the CAISO energy prices at the PG&E Default Load Aggregation Point (DLAP), adjusted for line losses.[33]

v. Proposed details about marginal transmission and distribution costs

The RTP rate will include a dynamic distribution signal designed to recover the Primary Distribution Capacity Costs approved in CPUC D.21-11-016. The hourly prices will vary depending on the location of the customer and will utilize the scarcity pricing concept[34], with prices dependent on the forecasted load on a representative circuit with similar load characteristics to the customer's circuit. As described in the Joint IOU WG 1 Proposal,[35] hourly distribution prices will be set so that *average* prices are the same across all locations – prices on more constrained circuits will have more time differentiation, but annual average load-weighted prices will not vary geographically for equity reasons.

The design of the dynamic transmission rate is not yet known but will be developed in accordance with the roadmap outlined in section 1.a.ii above. More details should be available in PG&E's next annual LMS Compliance Plan.

vi. Proposed details about other marginal costs

In terms of electricity usage, no other rate component is truly marginal and therefore, there are no additional marginal costs to be incorporated into the RTP rate. Marginal Greenhouse Gas (GHG) costs are already in the MEC.

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[32] PG&E, Small Business Utility Advocates, Cal Advocates, California Large Energy Consumers Association, and Enel X.

[33] Line loss is a loss of electric energy during transmission and distribution of electricity across the electric grid.

[34] For explanation of scarcity pricing, see CPUC white paper "Advanced Strategies for Demand Flexibility Management and Customer DER Compensation, Energy Division White Paper and Staff Proposal," June 22, 2022.

[35] Joint IOU WG 1 Proposal, p. 28.

vii. Proposed details about fixed costs

All fixed costs will be collected through the subscription mechanism outlined in the CalFUSE proposal.[36] The dynamic price signal will only contain marginal costs and there will be no scaling or adders to represent the collection of fixed costs.

viii. Customer class(es)

PG&E plans to have an optional dynamic rate available to all customer classes except Street Lighting. LMS requirements exempt Street Lighting from the LMS-compliant rates.[37]

d. Resource commitment to rate design and application

Table 3 below consolidates PG&E's current estimated resource needs to meet the rate design and application portions of the LMS requirements described in Section 1 of this report. PG&E's future commitments may change as CPUC regulatory requirements and timing are further specified or if PG&E's plan for RTP rate design and application need to be revised for other unforeseen reasons. PG&E has committed considerable effort to developing RTP rates as part of our 2020 GRC Phase II RTP Pilots and through participation and development of a report for the DFOIR Track B Working Group 1.

PG&E has also committed significant resources to RTP pilots that will inform RTP rate design. These combined pilots are estimated to cost roughly $25 million.[38] If PG&E's proposal to expand RTP rate pilots (described in Section 1.a.i of this report) is accepted, additional resources would be required to implement the expanded pilots.

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[36] CPUC white paper "Advanced Strategies for Demand Flexibility Management and Customer DER Compensation, Energy Division White Paper and Staff Proposal," June 22, 2022., p. 66-72.
[37] 20 CCR § 1621 (c)(6).
[38] These include the following pilots: Valley Clean Energy AgFIT Pilot (CPUC D.21-12-015); CEV/BEV Charging Compensation (CPUC D.21-11-017 and D.22-10-024); Res, SMB, and C&I RTP Pilot (CPUC D.22.08-002); Vehicle to Grid Integration Pilot (CPUC Res E-5192).

Table 3. PG&E Cost Estimates for RTP Rate Design and Applications.

	Time Period		PG&E Labor	Vendor Contract	Total
Incurred		Q1 2020- Q3 2023	$1,696,000	$800,000	$2,496,000
Projected	2023	Q4	$47,000	-	$47,000
	2024	Q1	$73,000	-	$73,000
		Q2	$95,000	-	$95,000
		Q3	$95,000	-	$95,000
		Q4	$47,000	-	$47,000
	2025	Q1	$47,000	-	$47,000
		Q2	$47,000	-	$47,000
		Q3	$47,000	-	$47,000
		Q4	$47,000	-	$47,000
	2026	Q1	$33,000	-	$33,000
		Q2	$33,000	-	$33,000
		Total	$2,307,000	$800,000	$3,107,000

e. Internal infrastructure in support of marginal cost rates adoption

i. Billing system compatibility review and improvement plan and resource commitment:

A. Software

PG&E is enhancing its billing capability to support hourly rates as part of its 2020 GRC Phase II Day-Ahead Hourly Real Time Price (DAHRTP) rate implementation.[39] These rates are scheduled to launch in the first quarter of 2024.[40] The enhancement will also allow CCAs in PG&E's service area to implement and bill customers on rates with hourly generation component rates.

B. Hardware

No additional hardware is required to support the billing of LMS-compliant rates.

C. Resource Commitment: funding and personnel

A total of $21 million has been authorized to implement and run the DAHRTP rates, and the estimated cost to implement the billing system enhancements and new billing process is approximately $8 million. No additional funding has been authorized at this time. PG&E currently has a team of three full time employees dedicated to the implementation and program management of the DAHRTP rates.

ii. Hourly marginal cost-based rates calculation system development plan and resource commitment:

The estimated cost to implement the approved pricing engine and its integration with downstream systems is approximately $2.4 million.[41]

A. Software

PG&E is developing a pricing engine as part of its DAHRTP rate implementation. The system will deploy in Q4 of 2023.

B. Hardware

No additional hardware is required to support the billing of LMS-compliant rates based on current information.

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[39] As explained in Section 1.a.i on page 6, PG&E will be working with the 2020 GRC II RTP Track settling parties to pause building the RTP pilot rates for the E-ELEC, B-6, and B-20 in PG&E's billing system if PG&E's proposal to include them in the expanded pilots is adopted in the DFOIR proceeding. If that proposal is adopted, implementation would be delayed until June 2024.

[40] Ibid.

[41] CPUC D.21-11-017, OP 6.

2. Time-dependent rate submission to MIDAS

a. Status of MIDAS submission for current time-dependent rates

i. List of current time-dependent rates and their RINs

Please see Appendix A.

ii. Proof of rates availability on MIDAS

PG&E's time-dependent rates are accessible by customers via the Market Informed Demand Automation Server (MIDAS) database, and instructions on how to access the prices are available on the CEC's MIDAS website. Attached to this Compliance Plan is an excel document *[List of PG&E RINs Uploaded to Midas]* that shows the 100 MIDAS rates and their underlying .JSON files. At this time, the CEC's E-filing system is unable to accept .JSON file formats. PG&E will work with the CEC to transmit the .JSON files to CEC staff.

iii. Composite rate calculation and submission solution

PG&E has uploaded its bundled generation rates and bundled rates minus the generation price for unbundled customers. PG&E does not plan to generate composite rates with CCA generation prices for upload to MIDAS.

iv. Plan for ensuring accuracy and maintenance of current time-dependent rates

PG&E is developing a process that will update the MIDAS database each time there is a price update concurrent with updating all other PG&E systems. The process will include testing and validation prior to submission to MIDAS.

b. Plan for LMS-compliant submission of time-dependent rates

PG&E is developing an IT process to automate the upload of rates with time-dependent prices to MIDAS whenever there is a price update. The project is scheduled to be completed at the end of November 2024.

3. RIN(s) on customer billing statements and online accounts

a. Implementation plan timeline

PG&E plans to add the RIN on customer bills and online accounts by April 2024 per the LMS requirements. PG&E has started compiling requirements and working with the CCAs in its territory on a solution that will support both bundled and unbundled services. Requirements will be finalized by the end of October followed by development and testing in Q4 2023 and Q1 2024.

b. Billing system update plan and current progress

The project to add RINs on customer bills and online has been initiated and PG&E is working through design architecture and requirements.

c. Proposed text design and QR code design and proposed placement on billing statements

PG&E plans to add the RIN and QR code on the electric service agreement details page of the bill. There is already a section of the bill that lists the rate schedule code, so it is likely that the RIN and QR code will be added to that section. This design will support both bundled and unbundled customers. A sample should be available in Q4 2023 after PG&E completes the design phase of the project.

d. QR Code linked webpage (if any)

PG&E does not plan to make a QR Code-linked webpage available.

4. Development of a Single Statewide RIN Access Tool

The LMS require Large IOUs, POUs, and CCAs to develop a single statewide tool. The tool would enable third parties to:

A. Obtain RINs for individual customers
B. Switch customers to other rates for which a customer is eligible
C. Provide average or annual bill amounts for eligible rates, and
D. Modify enrolled customer rate for the next billing cycle

This access is to be provided through cybersecure, digital methods with minimal adoption barriers. The "Statewide Tool" specification is to be presented at a CEC Business Meeting eighteen months (October 2024) from the effective date of the LMS. The Large IOUs, POUs, and CCAs are required to implement and maintain the Statewide Tool thereafter.

PG&E has committed resources to coordinate with other utilities and CCAs under the CEC's LMS Working Group 2 subgroup (Tool Working Group) on the Statewide Tool to develop a plan for such a tool to be developed for approval by the CEC. As of August 2023, the Tool Working Group plans to participate in regular meetings planned and coordinated by CEC staff, to determine tool specifications as agreed upon by the implementing utilities and CCAs. It is the intent of PG&E to advocate for a Statewide Tool system and specifications that maximize the use of existing webservices such that risks to project costs, complexity, delivery timeline, and cybersecurity can be mitigated.

PG&E emphasizes that a well-defined and sustainable cost recovery mechanism is a prerequisite for developing the Statewide Tool. Given the overlapping functional requirements identified in the CPUC's DFOIR Proceeding for a third-party facilitated rate change service, PG&E intends to file for cost recovery for the features and functions of the CEC's LMS Statewide Tool through the CPUC DFOIR proceeding.[42] PG&E expects that it will be able to proceed with development of the Statewide Tool upon Tool Working Group stakeholder's and CEC staff's agreement on tool specifications and following cost recovery approval through the CPUC DFOIR filing. Such approval will allow PG&E to properly fund the resources needed for development of the Statewide Tool.

At the time of filing (October 2, 2023), PG&E has identified the following key considerations for a statewide tool:

A. The CEC's requirement for a **single** statewide tool could be met through the following two implementation pathways:
   1. A single tool platform that would include RINs from all utilities and CCAs, or alternatively,
   2. Individual utility or CCA platforms that have the same operating characteristics.

PG&E will seek to clarify which path should be pursued through the Tools Working Group process.

B. PG&E intends to fully leverage ShareMyData and/or other data access services that are currently available to associate RINs with individual customer service agreements and provide a process for delivering data to third-parties that is cybersecure and protects customer privacy.
C. PG&E intends to specify and build a rate comparison tool available to third parties for PG&E customer service agreements, such that upon customer authorization of the third party, third parties may facilitate customer enrollments that enable customer rate changes on the next billing cycle.

PG&E notes two challenges that must be addressed to successfully implement the Statewide Tool: (1) building consensus in the Tool Working Group may be a complex and time-consuming undertaking, given the number of POUs, CCAs, and IOUs that need to agree on specifications;

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[42] DFOIR Track B Working Group 2 – Joint IOU Proposal for Systems and Processes, August 14, 2023, p. 23, Section 8: Cost Recovery (Question 4e).

and (2) PG&E must secure cost recovery, most likely through the CPUC's DFOIR. PG&E will work to overcome these challenges and to the extent possible, meet the timeline outlined in the LMS.

a. Resource commitment

PG&E plans to commit personnel to participate in working group meetings to help define and plan for the Statewide Tool specifications. PG&E estimates this participation requires staff resourcing of approximately $650,000 over the next year. After CPUC approval, PG&E will dedicate resources to build and maintain the Statewide Tool specification, alongside POUs, CCAs and other IOUs. As stated above, however, resources to implement the statewide tool must be supported by an appropriate funding mechanism as determined by the CPUC.

5. List of cost-effective, LMS-compliant programs

Per the LMS, Large IOUs are required to submit to the CEC a list of load flexibility programs deemed cost-effective by a given Large IOU no later than eighteen (18) months after the effective date of the LMS. PG&E understands the compliance due date for the load flexibility programs list to be October 1, 2024. Availability of a load flexibility program or programs for each customer class would be an alternative if LMS-compliant rates have not been approved by the Large IOU's rate-approving body.[43]

Section 1623 (d)(1) states:

> *. . . The portfolio of identified programs shall provide any customer with at least one option for automating response to MIDAS signals indicating marginal cost-based rates, marginal prices, hourly or sub-hourly marginal greenhouse gas emissions, or other Commission-approved marginal signal(s) that enable automated end-use response.*

PG&E interprets a program that provides customers with "at least one option for automating response to MIDAS signals indicating marginal cost-based rates" as a program that facilitates adoption of a technology or technologies that enable customer end-use load to respond automatically to a CEC-approved MIDAS signal. PG&E runs existing programs – listed in Table 4 – which could be capable of responding to MIDAS-enabled signals, though currently, these programs respond only to TOU and Critical Peak Pricing (CPP) signals and not marginal cost rates as defined in the LMS § 1623 (a)(1). The programs include PG&E's Automated Demand

[43] 20 CCR § 1623(d)(2).

Response (ADR) program, the WatterSaver pilot program, and the Market Access Program (MAP).

The ADR Program is a CPUC-approved program that provides rebates and incentives to customers across all customer classes who invest in ADR-certified technologies[44] and are enrolled in demand response (DR) programs. The WatterSaver pilot is available to PG&E Residential customers who are on a TOU rate. The pilot optimizes customers' connected electric water heaters and heat pump water heaters usage based on their TOU rate. The water heaters receive signals and use automated controls to take advantage of lower electricity rates and heat water at the least expensive times of day. The MAP offers participants financial incentives to reduce energy use during high price periods. The program's goal is to avoid rotating outages while minimizing costs to customers. The MAP subprogram with a smart thermostat manufacturer offers TOU rate optimization for customers.

PG&E believes that technologies incentivized through these programs will be able to respond to hourly RTP price signals. This capability has been tested in a real-world setting for agricultural pumping control technologies,[45] which are eligible for ADR incentives. PG&E has also tested battery storage controls through its Demand Response Emerging Technology program, though battery storage control technologies are not eligible for the ADR program.

None of the above-mentioned pilots and programs were required to meet the CPUC Energy Efficiency or the Demand Response Cost Effectiveness Protocols. These types of technology incentive programs were instituted as market transformation programs, therefore cost effectiveness requirements were not applicable.

PG&E will continue to identify load flexibility programs that would be consistent with the LMS specifications. PG&E will explore – in coordination with the CEC, CPUC and key stakeholders – which cost-effectiveness assessment protocols would be appropriate for programs that encourage automated load response under dynamic rates. PG&E needs CPUC authorization to offer load flexibility programs. PG&E plans to submit an updated list of load flexibility programs by October 1, 2024 to the CEC Executive Director per the LMS requirement.

[44] ADR-certified technologies include Commercial Energy Management Systems and Automated Control Systems for Heating Ventilation and Air Conditioning (HVAC), Lighting, Industrial Processes, and Agricultural Pumping, among other end uses.
[45] Through the VCE AgFIT Pilot.

Table 4. Examples of PG&E Programs that could Enable Customer Response to MIDAS signals.

Program Name	Automated Demand Response (ADR)	WatterSaver Pilot	Market Access Program (MAP)
Program description:	Provides rebates and incentives to customers who invest in ADR-certified technologies and are enrolled in DR programs.	Optimizes customers' connected water heaters and heat pump water heaters based on their TOU rate. These water heaters receive control signals and automatically heat water at the least expensive times of day.	Offers participants financial incentives to reduce energy use during peak periods; the subprogram with a smart thermostat manufacturer offers TOU rate optimization for residential customers.
Types of price signals to which technologies can respond:	PG&E's SmartRate, PG&E's Peak Day Pricing and potentially RTP[46]	E-TOU-C, E-ELEC (Electric HOME)	E-TOU-C
Target customer class/end use:	Residential, Small to Medium Businesses, Agricultural, Large Commercial and Industrial/Multiple End Uses	Residential/Water Heating	Residential/Air Conditioning[47]
Equipment requirements:	For a list of OpenADR certified products (~250), please visit – www.openadr.org	Connected Heat Pump Water Heater and Electric Water Heater Control	Air Conditioning and Smart Thermostat
Participating third-party automation service providers:	For a list of ASPs that support the OpenADR standard, please visit - www.openadr.org	Virtual Peaker	Smart Thermostat Manufacturer(s)

[46] PG&E has proposed to add Real Time Pricing as an ADR-eligible program in PG&E's 2024-2027 Demand Response Application which is still pending CPUC approval.
[47] MAP also provides incentives to Non-Residential customers, but those incentives are not tied to the ability to respond to automated price signals.

Program Name	Automated Demand Response (ADR)	WatterSaver Pilot	Market Access Program (MAP)
Control algorithms:	For a list of control algorithms and use cases, please visit - [www.openadr.org.](http://www.openadr.org)	A control vendor sends daily control signals to pre-heat the water heaters before peak time (4pm to 9pm) and reduce water heater set point temperature during peak time.	Smart Thermostat manufacturer(s) send daily control signals to pre-cool customers' air conditioners before peak time (4pm to 9pm) and increase thermostat set point temperature during peak time.
Enrollment – current and projections:	Since 2013-2022: # of customers - 96 # of service accounts - 910 Projection for 2024-2027: # of customers -10 per year on average # of service accounts - 100 per year on average	# of customers as of August 2023: 167 Projection for 2023 to 2024: 1,000	# of customers in 2022: 770 Projection for 2023: 2,000
Total Load impact estimates and projections:	Since 2013-2022: 60 MW Projection for 2024-2027: ~5-7 per year MW	Based on 167 customers: ~30kW Based on 1,000 customers from 2023-2024: ~234kW	Load shift in 2022: ~154 kW Load shift forecast in 2023: ~400 kW
Program authorization:	CPUC D.19-07-009	CPUC Resolution E-5073	CPUC D.21-12-011

6. Public information program

a. Public information program messaging

PG&E intends to implement a public information program and conduct targeted outreach to customers who can benefit from RTP rates and automation. As part of this program, PG&E will educate customers about how RTP rates may be able to save them money.

i. Why marginal cost-based rates and automation are needed

California's dynamic pricing rates provide customers an opportunity to shift their usage to lower priced hours, potentially reducing customers' bills while improving grid reliability and supporting California's progress toward 100% clean carbon-free energy. Shifting usage to lower-priced hours helps reduce peak electricity demand, which eases stress on the electric system, making service more reliable for customers and their communities. Shifting electricity use away from peak hours can also help reduce the need to build or operate additional fossil-fuel power plants, contributing to a healthier environment and meeting California's climate change risk-reduction goals.

ii. How the rates will be used

RTP rates are best suited for customers who have flexibility in when they use energy and can adjust their energy usage in response to higher price signals – ideally through automated devices such as smart thermostats, battery storage, and flexible electric vehicle charging, among other technologies. Rates will be set on a day-ahead basis based on weather and other variables that affect electricity demand and prices. Rates will reflect the estimated electric system prices for the next day and prices will let customers know when they should use, or avoid using, electricity during the following day.

iii. How these rates can save the customer money

Customers can save money by using electricity during times when energy is plentiful and cheaper, generally during the night when electricity demand is lower and during the day when solar energy is generating. During these time periods, prices can be lower than what a customer would normally pay on a non-RTP rate. If a customer can reduce usage during periods of high electricity demand and prices—especially between 5-9 pm on hot summer days— then customers can save money relative to what they would pay on a non-RTP rate.

b. Public information program details

i. Dissemination medium and outreach targets and scale

PG&E's public information program for RTP rates will be based on rates that are still to be determined but will utilize insights and learnings gained from outreach conducted for upcoming RTP pilots and the CEV RTP rate. The public information program for LMS-compliant rates will rely on evaluating outreach efforts and results from PG&E's proposed expanded RTP pilots (if approved by the CPUC), which are expected to have mid-term evaluations completed by 2026. Learnings from the CEV RTP rate, scheduled to open in February 2024, will also be leveraged. PG&E expects insights garnered throughout the implementation of both the RTP pilots and the CEV RTP rate plan, as well as the VGI Pilot dynamic rate will help inform and finalize development of this public information program. In advance of having all the necessary information to create a full public information program, PG&E can provide the following information regarding how the public information program will be implemented.

The public information plan will be designed to help customers understand RTP rates and how retail electricity rates change at hourly intervals to reflect marginal costs. Customers will be educated on how automated response to hourly price signals works, and how customers might leverage these rates to their advantage. Based on the results of RTP customer research commissioned by PG&E that demonstrates cost reduction is the highest driver of interest in trying an RTP rate, a key focus of the public information program messaging will be on potential cost savings. This research[48] found that 74% of Residential customers and 76% of Non-Residential customers (not in a CCA) ranked "saving money" as their top reason they would try an RTP Rate, with grid reliability and environmental benefits as secondary drivers.

PG&E plans to utilize a multi-touch, multi-channel strategy that combines a mix of high touch, direct-to-customer communications and broader general education provided through PG&E-owned channels. The public information program will also seek to include community partnerships to assist with disseminating information on marginal cost-based rates.

[48] See Appendix B of Joint IOU DFOIR WG 1 Report "PG&E Dynamic Pricing Customer Research."

PG&E's strategy will likely include a combination of:

Strategy	Outreach Tactics
Direct-to-customer communications	A mix of education (the what) and acquisition (the why) via direct mail and email.
General education	Message integration into existing outreach efforts (such as Business Energy Reports, Home Energy Reports) and PG&E-owned channels such as its digital newsletter and pge.com to educate on marginal cost-based rates and offer rate choices.
Partnerships	Partner with Business Associations, Community Based Organizations (CBOs) and third-party technology partners to help disseminate information regarding marginal cost-based rates.

PG&E will determine the target audience and scale based on analysis of the final RTP rates. PG&E will segment the potential audience to create tailored messaging that resonates and helps increase awareness and motivates customers who can benefit from RTP rates to take action and change rate plans.

ii. Partnerships

In advance of the final RTP rate implementation, PG&E will reach out to third-party technology partners and automation service providers – who assist customers with automating load response – for interest in partnering with PG&E to help educate and acquire customers to enroll on RTP rates.

PG&E will reach out to business associations such as the Farm Bureau, restaurant associations, and others to determine support for additional customer education through trusted sources and ultimately, to encourage RTP rate adoption by customers who can benefit from RTP rates.

PG&E will also evaluate and determine if there are CBOs that have constituents who would be good candidates for the RTP rates.

iii. Resources to design and implement the public information programs

PG&E cannot determine the funding necessary for the public information program until all the factors surrounding the program are known. To determine appropriate resourcing for the public information program, PG&E must have a full understanding of the approved rates, which customers are good candidates for the rates, the overall size of the target audience, and if any research is necessary to better target and engage customers. PG&E plans to use inputs from PG&E's recent RTP customer preference research, market potential estimates for load flexible end uses, as well as early results from PG&E's RTP pilots to estimate the potential size of the target audience.

While much of PG&E's rate education and outreach work is done by in-house marketing experts, PG&E may contract with marketing agencies to assist with some components of the work such as creative development, research, and other tasks. Any contracts utilized for work on this program will be billed and tracked through the appropriate funding mechanism.

PG&E will need to allocate additional resources to provide the necessary marketing staff to develop, implement, track, and evaluate the public information program outreach. Time necessary for the development, implementation, tracking and evaluation will also be tracked through the appropriate funding mechanism.

7. Appendices

Appendix A – PG&E's LMS Compliance Plan Timeline

Appendix B – List of PG&E Rate Identification Numbers

Appendix A – PG&E LMS Compliance Plan Timeline

Figure A 2 PG&E LMS Compliance Plan – Timeline of Key Activities and Milestones*

Key CEC LMS Deadlines, PG&E LMS and Related CPUC DFOIR Activities Workstreams (in Blue) and Milestones (in Green)	2023			2024				2025				2026				2027			
	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1) CEC LMS Requirement: Offer Dynamic Marginal Cost Rates to all Customer Classes																			
CEC Deadline - Application to CPUC for LMS Compliant Rates (Jan 1, 2025)																			
CEC Deadline - LMS Compliant Rates Available to all Customer Classes (Jan 1, 2027)																			
CPUC DFOIR Proceeding Track B - Guidance for Demand Flexibility Rates																			
Working Group 1 (Rate Design) and 2 (Systems and Processes) Meetings																			
CPUC Expanded Pilots Proposal and PG&E Response																			
Working Group 1 and 2 Final Reports Issued, Public Workshops on RTP Rates																			
DFOIR Track B Proposed Decision Anticipated																			
DFOIR Track B Final Decision Anticipated																			
PG&E GRC Phase II - Energy (Generation), Capacity (Generation and Distribution)																			
Write and Submit Application																			
CPUC Standard GRC Phase II Regulatory Proceeding Process																			
CPUC GRC Phase II Approval																			
Implementation																			
PG&E Application to FERC for Time-Varying Transmission Rate																			
Perform Study and Modeling for Hourly Time-Varying Transmission Rates																			
Engage Key Stakeholders, Coordinate across IOUs on Transmission Rate Design																			
Write and Submit Application																			
FERC Approval																			
CPUC Tier 1 Advice Filing and Approval																			
Implementation (factor update as T component will already be configured)																			

Key CEC LMS Deadlines, PG&E LMS and Related CPUC DFOIR Activities Workstreams (in Blue) and Milestones (in Green)	2023			2024				2025				2026				2027			
	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
2) CEC LMS Requirement: Time-Dependent Rate Submission to MIDAS																			
CEC Deadline for Uploading Time-Dependent Rate Components to MIDAS (Oct 1, 2023)																			
Time-Dependent Rate Components Upload																			
3) CEC LMS Requirement: Participate in Provision of Single Statewide RIN Access Tool																			
CEC Deadline for Submittal of Plan for Statewide RIN Tool																			
Working Group Development of Tool Requirements and Identification of Funding																			
4) Plan to provide Rate Identification Numbers-RIN(s) on Customer Billing Statements and Online Accounts																			
CEC Deadline for RINs on Billing Statements and Online Accounts																			
Product Requirements Analysis																			
Implementation																			
5) CEC LMS Requirement: List of Cost-Effective, LMS-Compliant Programs																			
Deadline for Providing List of Cost-Effective LMS Compliance Programs to CEC																			
Evaluate CEC Feedback on Proposed Programs																			
Determine Appropriate Cost-Effectiveness Protocol																			
Develop List of LMS-Compliant Programs by October 2024																			
6) CEC LMS Requirement: Public Information Program																			
Develop Direct-to-Customer Communications, General Education Messaging & Creative																			
Develop Creative for PG&E Assets (website)																			
Partnership Development (third party tech, business associations, CBOs)																			
Conduct Customer Communications and PG&E Assets/Website live																			

* This timing represents PG&E's best estimates of timing as of October 2023 and may change due to delays in regulatory milestones, operational constraints, or other unforeseen factors.

Appendix B– List of Current Time-Dependent Rates and their RINs

RIN	Rate Name
USCA-PGPG-0001-0000	TOUC
USCA-PGPG-0002-0000	TOUD
USCA-PGPG-0003-0000	EV2A
USCA-PGPG-0004-0000	EVB
USCA-PGPG-0005-0000	EELEC
USCA-PGPG-0006-0000	B1
USCA-PGPG-0007-0000	B1ST
USCA-PGPG-0008-0000	B6
USCA-PGPG-0009-0000	B10S
USCA-PGPG-0010-0000	B10P
USCA-PGPG-0011-0000	B10T
USCA-PGPG-0012-0000	B19S
USCA-PGPG-0013-0000	B19P
USCA-PGPG-0014-0000	B19T
USCA-PGPG-0015-0000	B20S
USCA-PGPG-0016-0000	B20P
USCA-PGPG-0017-0000	B20T
USCA-PGPG-0018-0000	AGA1
USCA-PGPG-0019-0000	AGA2
USCA-PGPG-0020-0000	AGB

RIN	Rate Name
USCA-PGPG-0021-0000	AGC
USCA-PGPG-0022-0000	BEV1
USCA-PGPG-0023-0000	BEV2
USCA-PGPG-0024-0000	EVA
USCA-PGPG-0025-0000	TOUB
USCA-PGPG-0027-0000	A1
USCA-PGPG-0028-0000	A6
USCA-PGPG-0029-0000	A10S
USCA-PGPG-0030-0000	A10P
USCA-PGPG-0031-0000	A10T
USCA-PGPG-0032-0000	E19S
USCA-PGPG-0033-0000	E19P
USCA-PGPG-0034-0000	E19T
USCA-PGPG-0035-0000	E20S
USCA-PGPG-0036-0000	E20P
USCA-PGPG-0037-0000	E20T
USCA-PGPG-0038-0000	AG4A
USCA-PGPG-0039-0000	AG4B
USCA-PGPG-0040-0000	AG4C
USCA-PGPG-0041-0000	AG5A
USCA-PGPG-0042-0000	AG5B
USCA-PGPG-0043-0000	AG5C

RIN	Rate Name
USCA-PGPG-0044-0000	AGFA1
USCA-PGPG-0045-0000	AGFA2
USCA-PGPG-0046-0000	AGFA3
USCA-PGPG-0047-0000	AGFB1
USCA-PGPG-0048-0000	AGFB2
USCA-PGPG-0049-0000	AGFB3
USCA-PGPG-0050-0000	AGFC1
USCA-PGPG-0051-0000	AGFC2
USCA-PGPG-0052-0000	AGFC3
USCA-PGPG-0053-0000	TOUCSR
USCA-PGPG-0054-0000	TOUDSR
USCA-PGPG-0055-0000	EV2ASR
USCA-PGPG-0056-0000	EELECSR
USCA-PGPG-0057-0000	B6PDP
USCA-PGPG-0058-0000	B10SPDP
USCA-PGPG-0059-0000	B10PPDP
USCA-PGPG-0060-0000	B10TPDP
USCA-PGPG-0061-0000	B19SPDP
USCA-PGPG-0062-0000	B19PPDP
USCA-PGPG-0063-0000	B19TPDP
USCA-PGPG-0064-0000	B20SPDP
USCA-PGPG-0065-0000	B20PPDP

RIN	Rate Name
USCA-PGPG-0066-0000	B20TPDP
USCA-PGPG-0067-0000	AGA1PDP
USCA-PGPG-0068-0000	AGA2PDP
USCA-PGPG-0069-0000	AGBPDP
USCA-PGPG-0070-0000	AGCPDP
USCA-PGXX-0001-0000	TOUC
USCA-PGXX-0002-0000	TOUD
USCA-PGXX-0003-0000	EV2A
USCA-PGXX-0004-0000	EVB
USCA-PGXX-0005-0000	EELEC
USCA-PGXX-0006-0000	B1
USCA-PGXX-0007-0000	B1ST
USCA-PGXX-0008-0000	B6
USCA-PGXX-0009-0000	B10S
USCA-PGXX-0010-0000	B10P
USCA-PGXX-0011-0000	B10T
USCA-PGXX-0012-0000	B19S
USCA-PGXX-0013-0000	B19P
USCA-PGXX-0014-0000	B19T
USCA-PGXX-0015-0000	B20S
USCA-PGXX-0016-0000	B20P
USCA-PGXX-0017-0000	B20T

RIN	Rate Name
USCA-PGXX-0018-0000	AGA1
USCA-PGXX-0019-0000	AGA2
USCA-PGXX-0020-0000	AGB
USCA-PGXX-0021-0000	AGC
USCA-PGXX-0022-0000	BEV1
USCA-PGXX-0023-0000	BEV2
USCA-PGXX-0024-0000	EVA
USCA-PGXX-0025-0000	TOUB
USCA-PGXX-0027-0000	A1
USCA-PGXX-0028-0000	A6
USCA-PGXX-0029-0000	A10S
USCA-PGXX-0030-0000	A10P
USCA-PGXX-0031-0000	A10T
USCA-PGXX-0032-0000	E19S
USCA-PGXX-0033-0000	E19P
USCA-PGXX-0034-0000	E19T
USCA-PGXX-0035-0000	E20S
USCA-PGXX-0036-0000	E20P
USCA-PGXX-0037-0000	E20T
USCA-PGXX-0038-0000	AG4A
USCA-PGXX-0039-0000	AG4B
USCA-PGXX-0040-0000	AG4C

RIN	Rate Name
USCA-PGXX-0041-0000	AG5A
USCA-PGXX-0042-0000	AG5B
USCA-PGXX-0043-0000	AG5C
USCA-PGXX-0044-0000	AGFA1
USCA-PGXX-0045-0000	AGFA2
USCA-PGXX-0046-0000	AGFA3
USCA-PGXX-0047-0000	AGFB1
USCA-PGXX-0048-0000	AGFB2
USCA-PGXX-0049-0000	AGFB3
USCA-PGXX-0050-0000	AGFC1
USCA-PGXX-0051-0000	AGFC2
USCA-PGXX-0052-0000	AGFC3