DOCKETED	
Docket Number:	23-LMS-01
Project Title:	Load Management Standards Implementation
TN #:	262235
Document Title:	PG&E Revised LMS Compliance Plan
Description:	PG&E's Second Revised Load Management Standards Compliance Plan, current as of January 1, 2025, with minor grammatical revisions added on February 24, 2025.
Filer:	Jennifer Privett
Organization:	Pacific Gas and Electric Company
Submitter Role:	Applicant
Submission Date:	3/18/2025 10:12:32 AM
Docketed Date:	3/18/2025

Pacific Gas and Electric Company

Jennifer Privett
State Agency Relations
jennifer.privett@pge.com

1415 L Street, Suite 280
Sacramento, CA 95814
916-698-8033

January 9, 2025

California Energy Commission
Efficiency Division
517 P Street
Sacramento, CA 95814
ATTN: Executive Director Drew Bohan

PACIFIC GAS AND ELECTRIC COMPANY
***Second Revised* 2023 Compliance Plan for the Load Management Standards**[1]

Investor-Owned Utility:	Pacific Gas and Electric Company 300 Lakeside Drive Oakland, CA 94612
Original Submission:	October 2, 2023
***Revised* Submission via Email:**	May 16, 2024
***Revision 2* via Email:**	January 9, 2025
Regulatory Contact:	Jennifer Privett, State Agency Relations
Subject Matter Contact:	Emily Bartman, Chief Product Manager, Pricing Products
Subject Matter Contact:	Melanie McCutchan, Principal Product Manager, Pricing Products

On October 2, 2023, pursuant to the California Public Resources Code Sections 1621 and 1623.1, Pacific Gas and Electric Company submitted PG&E's 2023 Load Management Standards (LMS) Compliance Plan to the California Energy Commission (CEC) Docket Number 23-LMS-01. On April 15, 2024, PG&E received a Revision Notice from CEC staff and on May 16, 2024, PG&E provided Staff (via email) a *Revised* PG&E 2023 LMS Compliance Plan that incorporated guidance provided in the CEC Revision Notice. This revision was also updated to reflect PG&E's progress toward meeting the LMS compliance requirements as of May 1, 2024.

On December 10, 2024, PG&E received an additional revision request and this compliance plan, [*Second Revised* 2023 Compliance Plan for the Load Management Standards], submitted to Staff via email on January 9, 2025, reflects those revisions.

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

Should you have questions or request additional information, please reach out 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

Contents

List of Figures

List of Tables

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 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. This compliance plan has been revised based on feedback from CEC staff received in April 2024, with textual changes by PG&E that reflect conditions as of May 1, 2024. The plan has since been further refined based on additional staff feedback received in December 2024, with footnotes indicating any updates that reflect conditions as of January 1, 2025.

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 – including hourly marginal cost generation, distribution and transmission components – which we will refer to here as Real-Time Pricing (RTP) rates, – for all regulated customer classes.[5] Per the LMS, these RTP rates must be proposed to each utility's respective

---

[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.

[5] CCR, Title 20, §§ 1621(c)(6) defines customer class as "a broad group of customers used for rate design. Customer classes include but are not limited to residential, commercial, industrial, and agricultural, but does not include street lighting." Subsequently, CCR, Title 20, §§ 1623(a) requires that "each Large IOU apply to its rate-approving body for approval of at least one marginal cost-based rate for each customer class."

rate-approving bodies by January 1, 2025 and are to be made available to customers by January 1, 2027, contingent on approval of those rates and cost recovery by each utility's respective rate-approving body. **PG&E is on track to comply with this requirement to make LMS-Compliant RTP rates available to all electric customers in regulated customer classes by January 1, 2027.**[6]

Subject to CPUC approval, PG&E's proposal in its 2023 GRC II testimony will have RTP rates available for all its retail bundled customers to opt into by January 1, 2027. Although unbundled CCA and Direct Access (DA) customers do not take generation service from PG&E, PG&E will have a distribution and transmission RTP-only rate option for unbundled customers if the CPUC approves. PG&E's proposed RTP rates for January 1, 2027 potentially may use shadow billing until the billing modernization project is completed and implemented system-wide. Subject to their governing bodies, individual CCAs and energy service providers for DA will be responsible for providing RTP generation rates to their customers, which they might bill themselves. PG&E will also present a proposal to FERC in 2026 for the transmission RTP rate, to be effective January 1, 2027, if approved by FERC.

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 marginal cost-based hourly or sub-hourly distribution and transmission components.[7,8] As stated above, PG&E will make RTP rates with these price components available to customers by

[6] With the exception of Streetlighting customers which are exempt from the LMS-compliant RTP rate requirements 20 CCR § 1621 (c)(6).

[7] "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 Phase 2 of PG&E's VGI Pilots that provides an hourly distribution price based on grouping circuits of similar load profiles into clusters.

[8] 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.)

January 1, 2027. PG&E intends to propose the generation and distribution components in our 2023 General Rate Case II (GRC), which will be filed in September 2024.[9] PG&E plans to propose the hourly marginal cost transmission component at FERC by July 2026. This later date for proposing the transmission component is needed because the Federal Energy Regulatory Commission (FERC) – the regulatory body that must approve the Transmission rate – will not accept applications sooner than six months prior to the effective date of the rate.

The LMS standard indicates that if LMS-compliant RTP rates are not adopted by the rate-approving body in time to be available to each customer class by January 1, 2027, an alternative cost-effective load flexibility program must be available in place of the LMS-compliant RTP rates.[10] Because PG&E plans to comply with the requirement to make RTP rates available to customers by January 1, 2027, PG&E is submitting the list of LMS-Compliant RTP rates that will be available on January 1, 2027 as satisfying this requirement (see Section 5 below).

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 uploading time-varying rates to 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.[11] 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 January 1, 2025:

[9] On September 30, 2024, PG&E proposed Hourly Real-Time Pricing (RTP) rates for Residential, Commercial, Industrial, Agricultural, and Business Electric Vehicle charging customers with generation and distribution price components for approval by the California Public Utilities Commission (CPUC) as part of Phase II of PG&E's General Rate Case Application (A.) 24-09-014 Exhibit 3, Chapter 10.
[10] 20 CCR § 1621 and § 1623(d)(2).
[11] 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 organized by Compliance Due Date.

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	Complete	Section 3
Single Statewide RIN Access Tool	§ 1623 (c)(1)-(3)	October 2024	PG&E has been working with the other load serving entities (LSEs) that are subject to the LMS on creating the statewide RIN tool pursuant to 20 CCR Section 1623(c). A proposed plan for the tool was submitted to the CEC for review on October 1, 2024. We will continue to work with the other LSEs and the CEC to implement and maintain the statewide RIN tool in a timely manner subject to the tool's approval by the Commission and subsequent funding approval by the CPUC and other responsible governance bodies and/or from non-ratepayer sources, for the Statewide Tool.	Section 4
List of cost-effective load flexibility programs	§ 1623 (d)(1)-(2)	October 2024	Complete	Section 5

Marginal cost rate design and application (Generation, Distribution, Transmission)	§ 1623 (a)	January 1, 2025	On Track. The Generation and Distribution components were proposed in PG&E's 2023 GRC II in September 2024 and will be subject to the outcome of that proceeding; the Transmission component will be submitted in July 2026 for FERC approval, as required by FERC.	Section 1
Marginal cost rate options for all customer classes	§ 1623 (d)(2)	January 1, 2027	On Track	Section 1
Public information program	§ 1623 (d)(3)	Not Specified	On Track	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.[12,13] 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.[14] 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."[15]

PG&E organized this LMS Compliance Plan Report to be consistent with the outline provided in the Compliance Plan Guidance, though some details that the Compliance Plan Guidance suggests are not yet available and are not included. At times, PG&E provides additional

[12] "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)).
[13] Wayland, Stefanie and Gavin Situ. 2023. *Compliance Assistance for Load Management Standards Compliance Plan Submittals*. California Energy Commission. Publication Number: CEC-400-2023-009.
[14] Ibid., p.7.
[15] 20 CCR 1621(d)(2).

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.

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.[16]

Through these proceedings and working group sessions, PG&E's RTP rate design has evolved over time from a simple dynamic generation-only rate to one that now includes dynamic distribution and other proposed enhancements such as subscription options[17] and forward

[16] 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.
[17] 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 load level in any

transactions.[18] 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 for PG&E's service area, which have made RTP rates available to all regulated customer classes in 2024. These pilots include:[19]

- **Valley Clean Energy (VCE) AgFIT Agricultural Water Pumping Pilot:** Approved by CPUC Resolution E-5192, is already available to agricultural customers in VCE's service area and includes both hourly marginal cost generation and distribution components.[20]
- **PG&E Expanded Pilots:** CPUC Decision D.24-01-032 adopted PG&E's Expanded Pilots, which is expected to be launched in June 2024, and includes hourly marginal cost generation and distribution components.[21]
- **Vehicle-to-Grid Integration (VGI) RTP Pilots**: Approved by CPUC Resolution E-5192 per directives in D.20-12-029, are available for Residential (VGI Pilot 1) and Commercial customers (VGI Pilot 2). Phase 2 of the VGI Pilots is targeted for rollout in September 2024 and requires participants to enroll in an RTP rate with hourly marginal cost generation and distribution components.[22]

---

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.

[18] Although not a part of LMS requirements, PG&E is considering a full-featured transactive pricing platform that would allow 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.

[19] The CPUC has also adopted RTP pilots for Residential, Commercial, and Industrial customers and an opt-in BEV RTP rate and non-NEM export pilot in D.21-11-017, D.22-08-002 and D.22-10-024. These RTP rates only include a marginal cost generation component and are currently approved to launch in February 2025. PG&E expects to propose an alternative path in order for the Expanded Pilots in D.24-01-032 and VGI Pilots, already adopted and scheduled to launch in 2024, to be able to meet the objective of providing RTP reflected in D.21-11-017, D.22-08-002 and D.22-10-024.

[20] 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 D.21-12-015 and Resolution E-5192.

[21] PG&E's Expanded Pilots launched in November 2024.

[22] Phase 3 of PG&E's VGI Pilots launched in October 2024.

As is discussed in Section 1.a.iii below, PG&E plans to implement the required transmission component of the RTP price signal by January 1, 2027, subject to FERC approval. This signal will be incorporated into the Expanded Pilot rates.

ii. Plan for hourly transmission rate components

PG&E recognizes that a dynamic transmission rate is an important component of the final RTP rate design. PG&E plans to propose an hourly marginal cost transmission rate component to FERC in July 2026. To be able to incorporate the signal into these rates by January 2027, FERC requires all proposals to be submitted no earlier than six months before implementation.

PG&E would like to explain that there are hurdles that must be overcome to develop a dynamic transmission rate that 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 previously been presented to FERC by the IOUs.

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. PG&E plans to keep the CPUC apprised on the development of the hourly marginal cost transmission rate and will file an Advice Letter with the CPUC to notify them of PG&E's application with FERC. This Advice Letter will be informational.

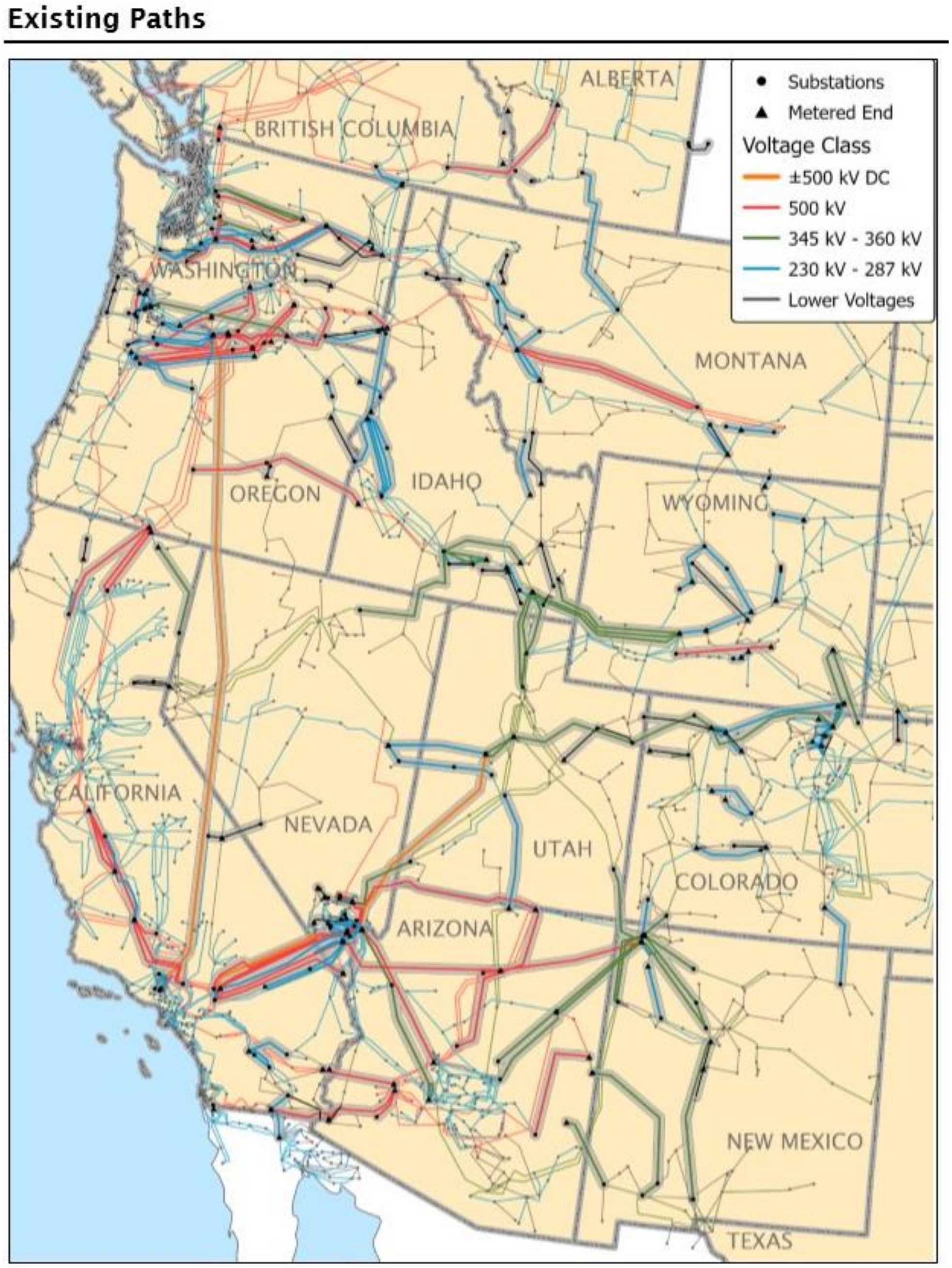
Over the next two years, PG&E will conduct a more detailed study of marginal transmission capacity costs. It is unknown what kind of capacity price signal would be best suited and what the appropriate geographic differentiator would be for transmission. Factors that contribute to the complexity of developing 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.'[23]

[23] 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[24]



[24] 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.

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. Further refined updates on timing will be provided to the CEC in PG&E's next annual report (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	Write dynamic transmission rate design application for FERC
2026 Q3	File transmission rate design application with FERC for implementation by January 1, 2027.[25] FERC approval generally takes 60 days unless hearings are requested. 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.
January 1, 2027	LMS compliant rates available to customers.

[25] 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 bill on the dynamic rate is better than their OAT bill on an annual basis.

b. RTP rate application

PG&E filed an application for LMS-compliant dynamic day-ahead hourly rates for each customer class in its GRC Phase II filing in September 2024. Some adjustments to these proposed rates may be needed once the CPUC issues directives in Track B of the DFOIR proceeding in R.22-07-005 and in PG&E's 2023 GRC II, A.24-09-024.[26] The rates PG&E filed in its GRC Phase II application in 2024 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. As explained in Section 1.a.iii., PG&E plans to submit a separate filing to FERC in July 2026 seeking approval for a dynamic transmission price signal to be included in PG&E's RTP rates.

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."[27]

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[28] with modifications.[29, 30]

ii. Frequency

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

---

[26] The April 24, 2024 ALJ Ruling, Attachment A, states that a proposed decision on DFOIR Track B, Working Group 1, will likely be issued in Q3/Q4 of 2024. This timing does not allow enough time to make any significant changes to the September 2024 GRC II proposal, however a supplemental filing can be made if necessary to include any CPUC requirements. A Final Decision has not yet been issued as of January 1, 2025 in Track B of the CPUC's DFOIR Proceeding.

[27] R.22-07-005, Joint IOU WG 1 Proposal, p. 11.

[28] 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.

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

[30] PG&E proposed this rate in its 2023 GRC II A. 24-09-014 Exhibit 3, Chapter 10 filed in September 2024.

iii. Proposed details about marginal capacity costs

The RTP rate will include the marginal generation capacity costs (MGCC) from PG&E's latest GRC Phase II, possibly modified by the proposal in PG&E's Advice Letter 7243-E or some other methodology that is later approved in the DFOIR or the GRC II decision. These costs will be allocated in the manner designed by a collaborative group of five parties,[31] 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, or as determined by the CPUC in the GRC II decision.[32]

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 from PG&E's latest GRC Phase II, possibly modified by the proposal in PG&E's Advice Letter 7243-E or some other methodology that is later approved in the DFOIR or PG&E's GRC II. The hourly prices will vary depending on the location of the customer and will utilize the scarcity pricing concept,[33] 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,[34] 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.

---

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

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

[33] 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.

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

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.

vii. Proposed details about fixed costs

All fixed costs will be collected through the subscription mechanism outlined in the CalFUSE proposal, subject to the CPUC decision in GRC II.[35] 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.[36]

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 already committed considerable effort to developing RTP rates as part of PG&E's RTP Pilots DFOIR Track B Working Group 1 and development of the Joint IOU Working Group 1 report.

[35] 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.
[36] 20 CCR § 1621 (c)(6).

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 will not be able to implement RTP rates in its production billing system until the completion of its Billing System Modernization project. PG&E plans to build these rates in the billing system once its multi-year billing system upgrade is completed. Upon implementation of the new billing system, enhancements will need to be made along various points of the billing process including but not limited to enrollment, interval data processing, validation, editing and estimation, billing segment calculation, financial reporting, CCA data integrations, and the billing statement.

In the interim, PG&E is licensing billing software for the Expanded Pilots and Phase 2 of the VGI pilots. The pilots will used "Shadow Billing", meaning customers will receive their regular bill for their Otherwise Applicable Tariff (OAT) and PG&E will send a monthly communication that explains to the customer how they have performed on the RTP rate.

The customer continues to pay the OAT bill for one year, and then the customer is paid a credit if their total annual bill calculated on the RTP rate is lower than the annual total on their OAT. PG&E will be able to modify the rate design (e.g., add a transmission component) once approved by FERC. PG&E plans to build these rates in the billing system once its multi-year billing system upgrade is completed.

B. Hardware

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

C. Resource Commitment: funding and personnel

PG&E has committed significant resources to pilots that will inform RTP rate design. The VCE AgFit Pilot, PG&E's Expanded Pilots, and the Phase 2 VGI Pilots discussed in Section 1.a.i are estimated to cost roughly $43 million[37] for incentives, technology, measurement and evaluation, and program administration. This cost is to enable a marginal generation and distribution rate design only. Furthermore, this funding does not include the cost to implement RTP rates in our future upgraded billing system rather than in PG&E's shadow billing system which is being used for the pilots.

[37] Cost breakdown: $3.9 M for the VCE AgFit Pilot, $36.7 M for the PG&E Expanded Pilots, $2.3 M for the VGI Pilots.

PG&E currently has a team of five employees dedicated to the implementation and program management of PG&E's RTP pilots.

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

The estimated cost to implement the marginal generation and distribution prices in a pricing engine and its integration with downstream systems is approximately $5 million.[38] PG&E does not have cost estimates to implement marginal transmission rates at this time.

A. Software

PG&E is developing a pricing engine as part of its DAHRTP and PG&E Expanded Pilots implementations.[39]

B. Hardware

No additional hardware is required to support the billing of LMS-compliant rates based on current information. PG&E's pricing engine is hosted on a cloud platform.

2. Time-dependent rate submission to MIDAS

a. Considerations for uploading non time-dependent rates[40]

PG&E, in collaboration with the CEC and other IOUs, established factors to consider in deciding which non time-dependent rate modifiers to upload to MIDAS in a technologically feasible, cost-effective way that complies with the regulations outlined in the LMS. These considerations and associated definitions are discussed below.

i. Definitions

Modifier / Price Modifier

A non-time-dependent volumetric adjustment to hourly electricity prices, that includes the following:

A. Additive Modifier

A modifier that adjusts prices by adding a fixed amount (monetary) that does not change for a given customer on a given day.

---

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

[39] The system was deployed in Q3 of 2024.

[40] Subsection (a) "Considerations for uploading non time-dependent rates" was provided to the CEC as an Addendum in October 2024 and is incorporated into this Second Revised Compliance Plan.

B. Ratio Modifier

A modifier that adjusts prices by multiplying by a ratio (or percentage) that does not change for a given customer on a given day.

C. Fixed Charge Modifier

A modifier that only affects the monthly fixed charge. These modifiers are not uploaded to MIDAS and need not be included in these considerations.

D. Tier Modifier

A modifier that only affects the allocation of electricity use into tiers. These modifiers are not uploaded to MIDAS and need not be included in these considerations.

ii. Considerations

Feasibility

The total number of RINs uploaded by a utility should be manageable and technologically feasible for both the utility and MIDAS. Non-time dependent rate modifiers may be excluded from being uploaded to MIDAS based on infeasibility and the other considerations discussed here.

User Communication

The CEC and regulated parties should communicate to MIDAS users at the time of sign-up, and on MIDAS informational webpages, that MIDAS electricity price data are closely representative, but not precisely accurate depictions of actual electricity rates. MIDAS electricity prices are designed to inform device operation decisions for the purposes of load flexibility, not to provide precisely accurate total energy cost calculations.

Modifier Exclusion

Non-time-dependent modifiers may be excluded from MIDAS uploads if:

- The additional RIN(s) that would be created by including the modifier represents less than 0.5% of the total number of customers served by the utility <u>and</u> less than 0.5% of total annual load as sales; or
- The change in price due to the modifier is less than $0.01 per kilowatt-hour for additive modifiers <u>or</u> 2% for ratio modifiers.

Modifier Review

Excluded modifiers should not cause problems with device operation or for certain groups of customers (e.g., medical baseline, large industrial, etc.), especially where exclusion of the modifier may eliminate the group's participation in MIDAS. Modifiers will be reviewed for inclusion in MIDAS every year as part of the annual compliance update, or when major issues are reported by third parties, customers, or CEC staff.

b. 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. PG&E is uploading RINs to MIDAS in .XML format and attached to this Compliance Plan is an excel document [*01.01.2025 PG&E Rate Modifier Exclusion Data*] that shows the 230 MIDAS rates/rate modifier combinations and their underlying .XML files, and also includes Modifiers, Base Rates, UUT factors, PCIA by vintage group and rate year, and modifier exclusion information.

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.

c. 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.[41]

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

a. Implementation plan timeline

PG&E added RINs on customer bills and online accounts by April 2024 per the LMS requirements.

[41] This project was completed in September 2024.

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

PG&E added the RIN and QR code on the electric service agreement details page of the bill in April 2024. This design supports both bundled and unbundled residential & non-residential customers. When customers point their smartphone camera at the QR code on their bill, they will see their RIN displayed on the screen. The RIN is also printed below the QR code for customers who do not use a smartphone. Once the customer gets the RIN from their bill, they can follow their devices' on-screen instructions to optimize energy consumption. A sample bill is available in PG&E's Advice Letter 7136-E-B.

c. 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 on development of the Statewide Tool with utilities,[42] CCAs, and other stakeholders under the CEC's LMS Working Group 2 subgroup (Tool Working Group). Since August 2023, the Tool Working Group has held several meetings that were coordinated by CEC staff as planning sessions to determine tool specifications. PG&E will continue 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.

[42] Utilities here refers to both investor-owned and publicly owned utilities that are subject to LMS requirements.

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.[43] 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.

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 gives access to RINs from all utilities and CCAs that are subject to LMS, or alternatively,
    2. Individual utility implementation that gives access to associated customer RINs and provides similar operating characteristics across the IOUs, POUs, CCAs.

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

B. PG&E intends to fully leverage existing data access services that are currently available within PG&E's technology infrastructure 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 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 rate comparison and 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 (at

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

least 17 different Load Serving Entities)[44]; 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. PG&E has been working with the other load serving entities (LSEs) that are subject to the LMS on creating the statewide RIN tool pursuant to 20 CCR Section 1623(c). A proposed plan for the tool was submitted to the CEC for review on October 1, 2024. We will continue to work with the other LSEs and the CEC to implement and maintain the statewide RIN tool in a timely manner subject to the tool's approval by the Commission and subsequent funding approval by the CPUC and other responsible governance bodies, and/or from non-ratepayer sources, for the Statewide Tool.

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 and maintain 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 are not available to customers by the January 1, 2027 deadline.[45]

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.*

[44] 20 CCR § 1621 (c)(8),(9),(10).
[45] 20 CCR § 1623(d)(2).

Based on further guidance from CEC staff on Section 1623 (d)(1), PG&E understands that a rate can be a program that provides customers with "at least one option for automating response to MIDAS signals indicating marginal cost-based rates." Prior to implementation of the RTP rates in January 2027, PG&E will provide the CEC with a list of RTP rates that PG&E plans to make available to customers. Assuming that the MIDAS platform is capable of making these rates available through the platform, PG&E plans to upload these rates to MIDAS. This will enable customers to leverage automated devices to respond to marginal cost-based price signals available in MIDAS by the January 1, 2027 deadline.

For informational purposes only, PG&E is providing an overview of which RTP rates (with hourly generation and distribution price signals) will be available to customers through PG&E's Expanded RTP Pilots approved by CPUC D.24-01-032 and Phase 2 of the VGI Pilots approved by CPUC Resolution E-5192 described in Section 1.a.i of this Compliance Plan.[46]

Table 4 lists the rates and associated customer classes that will be available through these pilots.

[46] These pilot RTP rates will not be available in MIDAS, as they are experimental rates that will be billed outside of PG&E's billing system through Shadow Billing by a separate 3rd party-administered process.

Table 4. List of rates that will be available through PG&E's planned RTP Rate Pilots

Pilot	Rate	Rate Description	Customer Class
PG&E Expanded Pilot per D.24-01-032. Agricultural	AG-A1	Maximum Demand < 35 kW Low Usage	Agricultural
	AG-A2	Maximum Demand < 35 kW High Usage	Agricultural
	AG-B	Maximum Demand > 35 kW Medium Usage	Agricultural
	AG-C	Maximum Demand > 35 kW High Usage	Agricultural
PG&E Expanded Pilot per D.24-01-032. Residential	E-ELEC	Electrification rate: qualifying technologies: electric vehicle charging, energy storage, or electric heat pump	Residential
	EV2A	Electric Vehicle Rate: qualifying technologies: electric vehicle or storage	Residential
PG&E Expanded Pilot per D.24-01-032. Commercial and Industrial	B6	Commercial Maximum demand of 75 kilowatts (kW)	Small Business
	B10	Commercial/Industrial Maximum demand of 75-499 kW	Medium Business
	B19	Commercial/Industrial Maximum demand of 500-999 kilowatts (kW)	Large Commercial and Industrial

Pilot	Rate	Rate Description	Customer Class
	B20	Commercial/Industrial maximum demand greater than 1000 kW	Large Commercial and Industrial
Phase 2 of VGI Pilot 1	E-ELEC	Electrification rate - qualifying technologies: electric vehicle charging, energy storage, or electric heat pump for water heating or climate control.	Residential
	EV2A	Electric Vehicle Rate: qualifying technologies: electric vehicle or storage	Residential
Phase 2 of VGI Pilot 2	B6	Commercial Maximum demand < 75 kilowatts (kW)	Small Business
	B10	Commercial/Industrial Maximum demand of 75-499 kW	Medium Business
	B19	Commercial/Industrial Maximum demand of 500-999 kilowatts (kW)	Large Commercial and Industrial
	B20	Commercial/Industrial maximum demand greater than 1000 kW	Large Commercial and Industrial
	BEV-1	Business Electric Vehicle Rate Low Use	Business EV
	BEV-2	Business Electric Vehicle Rate High Use	Business EV

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 PG&E Expanded Pilots and Phase II of the VGI Pilots. The public information program for LMS-compliant rates will rely on evaluating outreach efforts and results from PG&E's Expanded Pilots, which are expected to have mid-term evaluations completed by 2026. PG&E expects insights garnered throughout the implementation of all PG&E Expanded Pilots, as well as Phase II of the VGI Pilots 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[47] 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.

[47] 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-1 PG&E LMS Compliance Plan – Timeline of Key Activities (in dark blue) and Milestones (in green)*

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[48]																			
DFOIR Track B Final Decision Anticipated[49]																			
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 (estimated)[50]																			
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																			

[48] As of January 1, 2025: A Final Decision has not yet been issued in Track B of the CPUC's DFOIR Proceeding on dynamic rate guidance.
[49] Ibid.
[50] As of January 1, 2025.

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
FERC Approval																			
CPUC Tier 1 Advice Filing																			
Implementation (factor update as T component will already be configured)																			
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 or Providing RTP (Marginal Cost) Rates to all Customer Classes																			
PG&E to make RTP Rates available to all Customer Classes																			
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 January 1, 2025, and may change due to delays in regulatory milestones, operational constraints, or other unforeseen factors.

Appendix B– Revised List of Current Time-Dependent Rates and their RINs[51]

Row	RIN	Rate Name
1	USCA-PGPG-0100-0000	E-TOU-C
2	USCA-PGPG-0101-0000	E-TOU-C-Smart Rate
3	USCA-PGPG-0102-0000	E-TOU-C-CARE
4	USCA-PGPG-0103-0000	E-TOU-C-FERA
5	USCA-PGPG-0106-0000	E-TOU-C-Smart Rate-CARE
6	USCA-PGPG-0107-0000	E-TOU-C-Smart Rate-FERA
7	USCA-PGPG-0200-0000	E-TOU-D
8	USCA-PGPG-0201-0000	E-TOU-D-Smart Rate
9	USCA-PGPG-0202-0000	E-TOU-D-CARE
10	USCA-PGPG-0203-0000	E-TOU-D-FERA
11	USCA-PGPG-0204-0000	E-TOU-D-Medical Baseline
12	USCA-PGPG-0205-0000	E-TOU-D-Smart Rate-Medical Baseline
13	USCA-PGPG-0206-0000	E-TOU-D-Smart Rate-CARE
14	USCA-PGPG-0207-0000	E-TOU-D-Smart Rate-FERA
15	USCA-PGPG-0208-0000	E-TOU-D-Smart Rate-CARE-Medical Baseline
16	USCA-PGPG-0209-0000	E-TOU-D-Smart Rate-FERA-Medical Baseline
17	USCA-PGPG-0210-0000	E-TOU-D-Medical Baseline-CARE
18	USCA-PGPG-0211-0000	E-TOU-D-Medical Baseline-FERA
19	USCA-PGPG-0300-0000	EV-B
20	USCA-PGPG-0301-0000	EV-B-Smart Rate
21	USCA-PGPG-0302-0000	EV-B-CARE
22	USCA-PGPG-0303-0000	EV-B-FERA
23	USCA-PGPG-0306-0000	EV-B-Smart Rate-CARE
24	USCA-PGPG-0307-0000	EV-B-Smart Rate-FERA
25	USCA-PGPG-0400-0000	EV2-A
26	USCA-PGPG-0401-0000	EV2-A-Smart Rate
27	USCA-PGPG-0402-0000	EV2-A-CARE
28	USCA-PGPG-0403-0000	EV2-A-FERA
29	USCA-PGPG-0406-0000	EV2-A-Smart Rate-CARE
30	USCA-PGPG-0407-0000	EV2-A-Smart Rate-FERA
31	USCA-PGPG-0500-0000	E-ELEC
32	USCA-PGPG-0501-0000	E-ELEC-Smart Rate

[51] As of January 1, 2025.

Row	RIN	Rate Name
33	USCA-PGPG-0502-0000	E-ELEC-CARE
34	USCA-PGPG-0503-0000	E-ELEC-FERA
35	USCA-PGPG-0504-0000	E-ELEC-Medical Baseline
36	USCA-PGPG-0505-0000	E-ELEC-Smart Rate-Medical Baseline
37	USCA-PGPG-0506-0000	E-ELEC-Smart Rate-CARE
38	USCA-PGPG-0507-0000	E-ELEC-Smart Rate-FERA
39	USCA-PGPG-0508-0000	E-ELEC-Smart Rate-Medical Baseline-CARE
40	USCA-PGPG-0509-0000	E-ELEC-Smart Rate-Medical Baseline-FERA
41	USCA-PGPG-0510-0000	E-ELEC-Medical Baseline-CARE
42	USCA-PGPG-0511-0000	E-ELEC-Medical Baseline-FERA
43	USCA-PGPG-0600-0000	B-1
44	USCA-PGPG-0612-0000	B-1-PDP
45	USCA-PGPG-0613-0000	B-1-CARE
46	USCA-PGPG-0614-0000	B-1-CARE-PDP
47	USCA-PGPG-0700-0000	B-6
48	USCA-PGPG-0712-0000	B-6-PDP
49	USCA-PGPG-0713-0000	B-6-CARE
50	USCA-PGPG-0714-0000	B-6-CARE-PDP
51	USCA-PGPG-0800-0000	B-10S
52	USCA-PGPG-0812-0000	B-10S-PDP
53	USCA-PGPG-0813-0000	B-10S-CARE
54	USCA-PGPG-0814-0000	B-10S-CARE-PDP
55	USCA-PGPG-0900-0000	B-10P
56	USCA-PGPG-0912-0000	B-10P-PDP
57	USCA-PGPG-0913-0000	B-10P-CARE
58	USCA-PGPG-0914-0000	B-10P-CARE-PDP
59	USCA-PGPG-1000-0000	B-10T
60	USCA-PGPG-1012-0000	B-10T-PDP
61	USCA-PGPG-1013-0000	B-10T-CARE
62	USCA-PGPG-1014-0000	B-10T-CARE-PDP
63	USCA-PGPG-1100-0000	B-19S
64	USCA-PGPG-1112-0000	B-19S-PDP
65	USCA-PGPG-1113-0000	B-19S-CARE
66	USCA-PGPG-1114-0000	B-19S-CARE-PDP
67	USCA-PGPG-1200-0000	B-19P
68	USCA-PGPG-1212-0000	B-19P-PDP
69	USCA-PGPG-1213-0000	B-19P-CARE
70	USCA-PGPG-1214-0000	B-19P-CARE-PDP

Row	RIN	Rate Name
71	USCA-PGPG-1300-0000	B-19T
72	USCA-PGPG-1312-0000	B-19T-PDP
73	USCA-PGPG-1313-0000	B-19T-CARE
74	USCA-PGPG-1314-0000	B-19T-CARE-PDP
75	USCA-PGPG-1400-0000	B-20S
76	USCA-PGPG-1412-0000	B-20S-PDP
77	USCA-PGPG-1413-0000	B-20S-CARE
78	USCA-PGPG-1414-0000	B-20S-CARE-PDP
79	USCA-PGPG-1500-0000	B-20P
80	USCA-PGPG-1512-0000	B-20P-PDP
81	USCA-PGPG-1513-0000	B-20P-CARE
82	USCA-PGPG-1514-0000	B-20P-CARE-PDP
83	USCA-PGPG-1600-0000	B-20T
84	USCA-PGPG-1612-0000	B-20T-PDP
85	USCA-PGPG-1613-0000	B-20T-CARE
86	USCA-PGPG-1614-0000	B-20T-CARE-PDP
87	USCA-PGPG-1700-0000	AG-A1
88	USCA-PGPG-1712-0000	AG-A1-PDP
89	USCA-PGPG-1800-0000	AG-A2
90	USCA-PGPG-1812-0000	AG-A2-PDP
91	USCA-PGPG-1900-0000	AG-BS
92	USCA-PGPG-1912-0000	AG-BS-PDP
93	USCA-PGPG-2000-0000	AG-BP
94	USCA-PGPG-2012-0000	AG-BP-PDP
95	USCA-PGPG-2100-0000	AG-BT
96	USCA-PGPG-2112-0000	AG-BT-PDP
97	USCA-PGPG-2200-0000	AG-CS
98	USCA-PGPG-2212-0000	AG-CS-PDP
99	USCA-PGPG-2300-0000	AG-CP
100	USCA-PGPG-2312-0000	AG-CP-PDP
101	USCA-PGPG-2400-0000	AG-CT
102	USCA-PGPG-2412-0000	AG-CT-PDP
103	USCA-PGPG-2500-0000	AG-FAS
104	USCA-PGPG-2512-0000	AG-FAS-PDP
105	USCA-PGPG-2600-0000	AG-FBS
106	USCA-PGPG-2612-0000	AG-FBS-PDP
107	USCA-PGPG-2700-0000	AG-FBP
108	USCA-PGPG-2712-0000	AG-FBP-PDP

Row	RIN	Rate Name
109	USCA-PGPG-2800-0000	AG-FBT
110	USCA-PGPG-2812-0000	AG-FBT-PDP
111	USCA-PGPG-2900-0000	AG-FCS
112	USCA-PGPG-2912-0000	AG-FCS-PDP
113	USCA-PGPG-3000-0000	AG-FCP
114	USCA-PGPG-3012-0000	AG-FCP-PDP
115	USCA-PGPG-3100-0000	AG-FCT
116	USCA-PGPG-3112-0000	AG-FCT-PDP
117	USCA-PGPG-3200-0000	BEV-1
118	USCA-PGPG-3212-0000	BEV-1-PDP
119	USCA-PGPG-3300-0000	BEV-2-S
120	USCA-PGPG-3312-0000	BEV-2-S-PDP
121	USCA-PGPG-3400-0000	BEV-2-P
122	USCA-PGPG-3412-0000	BEV-2-P-PDP
123	USCA-PGPG-3500-0000	NBT23
124	USCA-PGPG-3501-0000	NBT23-Smart Rate
125	USCA-PGPG-3502-0000	NBT23-CARE
126	USCA-PGPG-3503-0000	NBT23-FERA
127	USCA-PGPG-3504-0000	NBT23-Medical Baseline
128	USCA-PGPG-3505-0000	NBT23-Smart Rate-Medical Baseline
129	USCA-PGPG-3506-0000	NBT23-Smart Rate-CARE
130	USCA-PGPG-3507-0000	NBT23-Smart Rate-FERA
131	USCA-PGPG-3508-0000	NBT23-Smart Rate-Medical Baseline-CARE
132	USCA-PGPG-3509-0000	NBT23-Smart Rate-Medical Baseline-FERA
133	USCA-PGPG-3510-0000	NBT23-Medical Baseline-CARE
134	USCA-PGPG-3511-0000	NBT23-Medical Baseline-FERA
135	USCA-PGPG-3600-0000	NBT24
136	USCA-PGPG-3601-0000	NBT24-Smart Rate
137	USCA-PGPG-3602-0000	NBT24-CARE
138	USCA-PGPG-3603-0000	NBT24-FERA
139	USCA-PGPG-3604-0000	NBT24-Medical Baseline
140	USCA-PGPG-3605-0000	NBT24-Smart Rate-Medical Baseline
141	USCA-PGPG-3606-0000	NBT24-Smart Rate-CARE
142	USCA-PGPG-3607-0000	NBT24-Smart Rate-FERA
143	USCA-PGPG-3608-0000	NBT24-Smart Rate-Medical Baseline-CARE
144	USCA-PGPG-3609-0000	NBT24-Smart Rate-Medical Baseline-FERA
145	USCA-PGPG-3610-0000	NBT24-Medical Baseline-CARE
146	USCA-PGPG-3611-0000	NBT24-Medical Baseline-FERA

Row	RIN	Rate Name
147	USCA-PGPG-3700-0000	NBT00
148	USCA-PGPG-3701-0000	NBT00-Smart Rate
149	USCA-PGPG-3702-0000	NBT00-CARE
150	USCA-PGPG-3703-0000	NBT00-FERA
151	USCA-PGPG-3704-0000	NBT00-Medical Baseline
152	USCA-PGPG-3705-0000	NBT00-Smart Rate-Medical Baseline
153	USCA-PGPG-3706-0000	NBT00-Smart Rate-CARE
154	USCA-PGPG-3707-0000	NBT00-Smart Rate-FERA
155	USCA-PGPG-3708-0000	NBT00-Smart Rate-Medical Baseline-CARE
156	USCA-PGPG-3709-0000	NBT00-Smart Rate-Medical Baseline-FERA
157	USCA-PGPG-3710-0000	NBT00-Medical Baseline-CARE
158	USCA-PGPG-3711-0000	NBT00-Medical Baseline-FERA
159	USCA-PGXX-0100-0000	E-TOU-C-CCA
160	USCA-PGXX-0102-0000	E-TOU-C-CCA-CARE
161	USCA-PGXX-0103-0000	E-TOU-C-CCA-FERA
162	USCA-PGXX-0200-0000	E-TOU-D-CCA
163	USCA-PGXX-0202-0000	E-TOU-D-CCA-CARE
164	USCA-PGXX-0203-0000	E-TOU-D-CCA-FERA
165	USCA-PGXX-0204-0000	E-TOU-D-CCA-Medical Baseline
166	USCA-PGXX-0210-0000	E-TOU-D-CCA-Medical Baseline-CARE
167	USCA-PGXX-0211-0000	E-TOU-D-CCA-Medical Baseline-FERA
168	USCA-PGXX-0300-0000	EV-B-CCA
169	USCA-PGXX-0313-0000	EV-B-CCA-CARE
170	USCA-PGXX-0400-0000	EV2-A-CCA
171	USCA-PGXX-0402-0000	EV2-A-CCA-CARE
172	USCA-PGXX-0403-0000	EV2-A-CCA-FERA
173	USCA-PGXX-0500-0000	E-ELEC-CCA
174	USCA-PGXX-0502-0000	E-ELEC-CCA-CARE
175	USCA-PGXX-0503-0000	E-ELEC-CCA-FERA
176	USCA-PGXX-0504-0000	E-ELEC-CCA-Medical Baseline
177	USCA-PGXX-0600-0000	B-1-CCA
178	USCA-PGXX-0613-0000	B-1-CCA-CARE
179	USCA-PGXX-0700-0000	B-6-CCA
180	USCA-PGXX-0713-0000	B-6-CCA-CARE
181	USCA-PGXX-0800-0000	B-10S-CCA
182	USCA-PGXX-0813-0000	B-10S-CCA-CARE
183	USCA-PGXX-0900-0000	B-10P-CCA
184	USCA-PGXX-0913-0000	B-10P-CCA-CARE

Row	RIN	Rate Name
185	USCA-PGXX-1000-0000	B-10T-CCA
186	USCA-PGXX-1013-0000	B-10T-CCA-CARE
187	USCA-PGXX-1100-0000	B-19S-CCA
188	USCA-PGXX-1113-0000	B-19S-CCA-CARE
189	USCA-PGXX-1200-0000	B-19P-CCA
190	USCA-PGXX-1213-0000	B-19P-CCA-CARE
191	USCA-PGXX-1300-0000	B-19T-CCA
192	USCA-PGXX-1313-0000	B-19T-CCA-CARE
193	USCA-PGXX-1400-0000	B-20S-CCA
194	USCA-PGXX-1413-0000	B-20S-CCA-CARE
195	USCA-PGXX-1500-0000	B-20P-CCA
196	USCA-PGXX-1513-0000	B-20P-CCA-CARE
197	USCA-PGXX-1600-0000	B-20T-CCA
198	USCA-PGXX-1613-0000	B-20T-CCA-CARE
199	USCA-PGXX-1700-0000	AG-A1-CCA
200	USCA-PGXX-1800-0000	AG-A2-CCA
201	USCA-PGXX-1900-0000	AG-BS-CCA
202	USCA-PGXX-2000-0000	AG-BP-CCA
203	USCA-PGXX-2100-0000	AG-BT-CCA
204	USCA-PGXX-2200-0000	AG-CS-CCA
205	USCA-PGXX-2300-0000	AG-CP-CCA
206	USCA-PGXX-2400-0000	AG-CT-CCA
207	USCA-PGXX-2500-0000	AG-FAS-CCA
208	USCA-PGXX-2600-0000	AG-FBS-CCA
209	USCA-PGXX-2700-0000	AG-FBP-CCA
210	USCA-PGXX-2800-0000	AG-FBT-CCA
211	USCA-PGXX-2900-0000	AG-FCS-CCA
212	USCA-PGXX-3000-0000	AG-FCP-CCA
213	USCA-PGXX-3100-0000	AG-FCT-CCA
214	USCA-PGXX-3200-0000	BEV-1-CCA
215	USCA-PGXX-3300-0000	BEV-2-S-CCA
216	USCA-PGXX-3400-0000	BEV-2-P-CCA
217	USCA-PGXX-3500-0000	NBT23-CCA
218	USCA-PGXX-3502-0000	NBT23-CCA-CARE
219	USCA-PGXX-3503-0000	NBT23-CCA-FERA
220	USCA-PGXX-3504-0000	NBT23-CCA-Medical Baseline
221	USCA-PGXX-3600-0000	NBT24-CCA
222	USCA-PGXX-3602-0000	NBT24-CCA-CARE

Row	RIN	Rate Name
223	USCA-PGXX-3603-0000	NBT24-CCA-FERA
224	USCA-PGXX-3604-0000	NBT24-CCA-Medical Baseline
225	USCA-PGXX-3700-0000	NBT00-CCA
226	USCA-PGXX-3702-0000	NBT00-CCA-CARE
227	USCA-PGXX-3703-0000	NBT00-CCA-FERA
228	USCA-PGXX-3704-0000	NBT00-CCA-Medical Baseline
229	USCA-PGPG-0408-0000	EV2-A-Medical Baseline
230	USCA-PGXX-0408-0000	EV2-A-Medical Baseline