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CleanPowerSF

Load Management Standards Plan

CleanPowerSF

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1. Executive Summary

On January 20, 2023, the California Energy Commission (CEC) adopted an update to the state's Load Management Standards, which took effect on April 1, 2023.[1] Load Management Standards (LMS) are defined as programs such as rate schedules, access to real time prices, or load modification programs that seek to reduce or shift electricity customers' demand away from periods of high electric system demand.

The LMS regulations direct Large Community Choice Aggregators (Large CCAs) to submit a compliance plan to their rate approving body that evaluates the cost-effectiveness, equity, technologically feasibility, grid benefits , and customer benefits of marginal cost-based rates that vary hourly or sub-hourly (also commonly referred to as real-time-pricing or RTP rates).[2] If, the Large CCA, despite its good faith efforts, does not propose to develop marginal cost-based rates finding that they do not meet the above criteria, the regulations direct the Large CCA to propose load flexibility programs that allow customers (as well as automated appliances and smart devices) to respond to marginal cost signals (qualifying load flexibility programs).[3] The same evaluation of "cost-effectiveness, equity, technologically feasibility, benefits [to] the grid, and benefits to customers" applies to these qualifying load flexibility programs.[4] Based on these criteria, a Large CCA may delay or modify how it will meet the LMS regulations.[5]

While CleanPowerSF strongly supports the CEC's goals of reducing peak electricity demand, reducing GHG emissions, and increasing grid reliability, CleanPowerSF's Load Management Standard Plan (Plan) concludes that CleanPowerSF should not implement real time pricing rates or qualifying load flexibility programs at this time, because they are not cost-effective, equitable, technologically feasible, beneficial to the grid, or beneficial to customers at this time. As a result, CleanPowerSF staff do not plan on proposing a marginal cost-based hourly or sub-hourly rate or rates for adoption by the San Francisco Public Utilities Commission (SFPUC) by July 1, 2025, for implementation by July 1, 2027. Consistent with the LMS regulations, CleanPowerSF will re-evaluate the cost-effectiveness, feasibility, equity, grid benefits, and customer benefits of implementing LMS qualifying real time rates and/or load flexibility programs within three years.

CleanPowerSF will also continue to offer other ways to reduce customer peak demand such as time-of-use rates and Peak-Day-Pricing (PDP) or similar demand response programs. CleanPowerSF will also consider participation in the real-time pricing pilot programs to reduce peak-demand recently authorized by the California Public Utilities Commission (CPUC). CleanPowerSF will continue to evaluate the cost and feasibility of real-time rates and programs as more market and customer experience with them is gained.

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[1] Title 20, Cal. Code of Regs (CCR) §§ 1621 – 1625 (2023).
[2] 20 CCR § 1623.1(a)(1)(A).
[3] 20 CCR § 1623.1(a)(1)(B).
[4] Ibid.
[5] 20 CCR § 1623.1(a)(2).

1.1 Goals of the LMS Regulations

The CEC states the intent of the new LMS regulations is "to form the foundation for a statewide system of granular time and location dependent signals that can be used by automation-enabled loads to provide real-time load flexibility on the electric grid."[6] The amendments to the CEC's LMS apply to the three large Investor-Owned Utilities (IOUs), the two largest Publicly Owned Utilities (POUs), and the largest CCAs, which includes CleanPowerSF.[7] In part, the goals of the LMS regulations are to: 1) encourage the use of electrical energy at off-peak hours; 2) encourage the control of daily and seasonal peak loads to improve electric system efficiency and reliability; 3) lessen or delay the need for new electrical capacity; and, 4) reduce fossil fuel consumption and greenhouse gas emissions.[8]

In support of hourly or sub-hourly rates, a critical component of the LMS is the creation of the Market Informed Demand Automation Server (MIDAS) database, a new CEC-developed platform that aims to provide ratepayers real-time access to their time-varying rates, GHG emission signals, and California Independent System Operator (CAISO) FlexAlert grid emergency alerts. The MIDAS system is designed to allow access to time-varying rates and signals to customers, third-party providers, and "smart" appliances (such as smart air conditioners) in order to adjust load operation to minimize cost and environmental impacts. A practical example could be a smart thermostat that pre-cools an office space when the price of electricity is low during the middle of the day and then shuts off for a few hours in the evening when prices are high. The smart thermostat would be receiving signals from the MIDAS system about the price of electricity every hour or a shorter time interval and adjust its use based on that price signal.

This Plan addresses each aspect of the LMS regulations related to Large CCAs, including analysis and evaluation of the cost-effectiveness, technological feasibility, equity, benefits to the grid, and benefits to customers of RTP rates and load flexibility programs relying on automated signals. Based on our evaluation, CleanPowerSF concludes that adopting marginal cost-based hourly or sub-hourly rates or MIDAS enabled load flexibility programs are not cost-effective, equitable, or technologically feasible, nor would they provide significant benefits to the grid or customers at this time. Additionally, CleanPowerSF concludes that, at present, implementing RTP rates and MIDAS enabled load flexibility programs would not materially reduce peak load beyond the reductions that can be achieved by CleanPowerSF's current time-of-use (TOU) rates and existing non-MIDAS enabled demand flexibility program. Implementing RTP rates or MIDAS enabled programs at this time would cause hardship to CleanPowerSF, reduce system reliability, equity, safety, and efficiency, and would not be cost-effective nor technologically feasible to implement.

While CleanPowerSF will not be developing RTP rates or MIDAS enabled programs at this time, it will continue to explore options in the future and will consider changes to this Plan if RTP rates or MIDAS

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[6] Herter, Karen and Situ, Gavin, "Analysis of Potential Amendments to the Load Management Standards: Load Management Rulemaking, Docket Number 19-OIR-01," California Energy Commission, 2021, iii. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=241067 (accessed: March 28, 2024).

[7] 20 CCR § 1621(c); The three large IOUs are Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric. The two POUs are Los Angeles Department of Water and Power and Sacramento Municipal Utilities District. The large CCAs include any CCA that provides more than 700 gigawatt-hours of electricity to customers within a calendar year.

[8] 20 CCR § 1623.1(a)(1).

enabled programs become more viable. CleanPowerSF is evaluating participation in new RTP pilots authorized by the CPUC that will allow for residential and commercial CCA customers to participate; these programs will begin to fill the data and experience gap necessary to further consider the benefits and feasibility of an RTP rate or automated LMS-qualifying load flexibility program.

CleanPowerSF strongly supports the CEC's goals of reducing peak electricity demand, reducing GHG emissions, and increasing grid reliability and is steadfast in its commitment to achieving 100% renewable energy. In fact, through the rates and programs CleanPowerSF currently offers, CleanPowerSF already supports these goals and has achieved success in encouraging peak-load reduction, reducing emissions, and improving grid reliability. CleanPowerSF has been engaged with the CEC and other stakeholders individually and through its industry association California Community Choice Association (CalCCA) throughout the development and passage of the CEC's LMS regulations.

2. Introduction

2.1 About CleanPowerSF

CleanPowerSF is San Francisco's Community Choice Aggregation (CCA) program operated by the San Francisco Public Utilities Commission (SFPUC).[9] CleanPowerSF began serving customers in 2016. CleanPowerSF now serves approximately 385,000 customer accounts across the City and County of San Francisco, offering renewable, affordable, and accessible energy to its community. Serving residential, commercial, and industrial customers,[10] CleanPowerSF empowers residents and businesses to choose a more sustainable future.

San Francisco, through its Climate Action Plan, has adopted a citywide goal of 100% renewable energy and/or GHG-free electricity supply by 2025, and CleanPowerSF is a critical part of that effort.[11] CleanPowerSF's power supply comes from renewable and/or GHG-free resources such as solar, wind, geothermal, and hydroelectric power, ensuring that San Franciscans have access to clean electricity to power their homes and businesses.[12]

In 2015, the California Public Utilities Commission (CPUC) voted to adopt Residential Rate Reform, which enacted a series of changes to residential rate structures to simplify electric rates for all customers. This effort culminated in the adoption of a Time-of-Use (TOU) rate plan as the default for most Pacific Gas and Electric Co. (PG&E) customers, where the price of electricity is lower during "off-peak" times during the middle of the day and at night and higher during "peak" times, typically between 4 – 9 p.m., when energy demand is high. As approved by the SFPUC Commission in Resolution No. 21-0085, most CleanPowerSF residential customers were automatically transitioned to CleanPowerSF's new default TOU rate plan in July 2021.[13] The transition to TOU rates is one example of many policies where CleanPowerSF encourages ratepayers to shift electricity usage from peak periods to off-peak periods, helping make the grid more resilient and reducing GHG emissions.

2.2 CEC Load Management Standards

On January 20, 2023, the California Energy Commission (CEC) adopted an update to the state's Load Management Standards, which took effect on April 1, 2023.[14] This update supports California's long-standing goal of improving energy efficiency and load or demand flexibility to reduce peak electricity demand by encouraging the development of real-time electricity rates or programs that provide price, GHG emissions, and grid stress signals that vary hourly or sub-hourly. The CEC states the intent of the new LMS regulations is "to form the foundation for a statewide system of granular time and location dependent signals that can be used by automation-enabled loads to provide real-time load flexibility on

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[9] 20 CCR § 1621(c); The SFPUC is the rate approving body for CleanPowerSF as defined in the LMS regulations.
[10] CleanPowerSF also has streetlight and agricultural rate tariffs with minimal load.
[11] San Francisco Environment Code, Chapter 9 § 902(b)(3); *San Francisco's Climate Action Plan*, San Francisco Department of the Environment, 2021. Available at: https://www.sfclimateplan.org/sites/default/files/2023-02/cap_fulldocument_wappendix_web_220124.pdf (accessed: February 7, 2024).
[12] See CleanPowerSF's Energy Sources available at: https://www.cleanpowersf.org/energysources
[13] See CleanPowerSF's Time-of-Use Transition webpage available at: https://www.cleanpowersf.org/tou
[14] 20 CCR §§ 1621 – 1625 (2023).

the electric grid."[15] The amendments to the CEC's LMS apply to the three large Investor-Owned Utilities (IOUs), the two largest Publicly Owned Utilities (POUs), and the largest CCAs.

Principal among the LMS regulations is the development of marginal cost-based rates that vary hourly or sub-hourly or load flexibility programs that allow automated response to marginal cost signals. Section 1623.1(b)(1) defines marginal cost as:

> "Total marginal cost shall be calculated as the sum of the marginal energy cost, the marginal capacity cost (generation, transmission, and distribution), and any other appropriate time and location dependent marginal costs, including the locational marginal cost of associated balancing authority, such as the Los Angeles Department of Water and Power, the Balancing Authority of Northern California, or other balancing authority. Marginal Capacity cost computations shall reflect the variations in the probability and value of system reliability of each component (generation, transmission, and distribution)."[16]

In addition to the development of marginal cost-based rates or programs, a critical component of the LMS is the creation of the MIDAS database, a new CEC-developed platform that aims to provide ratepayers real-time access to a machine-readable database of time-varying rates, GHG emission signals, and CAISO FlexAlert grid emergency alerts to help encourage changes in electricity usage away from peak times. The MIDAS system is designed to allow access to time-varying rates and signals to customers, third-party providers, and "smart" appliances (such as smart air conditioners) in order to adjust load operation to minimize cost and environmental impacts. These signals are enabled through Rate Identification Numbers (RINs) associated with the rates customers have selected. The CEC provided direction and instructions to Load Serving Entities (LSEs) on how to upload all applicable time-varying rates, and the attendant RIN to each rate, to the MIDAS system.[17]

The CEC's LMS is also part of a broader set of goals to which California has committed to with respect to climate change, renewable energy, and energy efficiency, among others. Significant legislation has been passed within the last 10 years setting bold goals for California's clean energy future, including Senate Bill (SB) 100 (De Leon, 2018) and Assembly Bill (AB) 3232 (Friedman, 2018). SB 100 established a target of 100% renewable energy by 2045 and AB 3232 established a target of a 40% reduction in GHG emissions in California's building stock by 2030.[18] The investment and work required to meet these targets will be significant and load flexibility will serve a role in achieving these goals.

In 2022, the legislature passed and the Governor signed SB 846 (Dodd, 2022) directing the CEC to establish goals laying out a framework to achieve significant load shifting to reduce California's peak electrical demand to support grid reliability and clean energy.[19] On May 26, 2023, the CEC adopted a

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[15] Herter, Karen and Situ, Gavin "Analysis of Potential Amendments to the Load Management Standards: Load Management Rulemaking, Docket Number 19-OIR-01," California Energy Commission, 2021. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=241067 (accessed: February 7, 2024).
[16] 20 CCR §1623.1(b)(1).
[17] See CEC MIDAS instructions available at: https://www.energy.ca.gov/proceedings/energy-commission-proceedings/inactive-proceedings/market-informed-demand-automation (accessed: March 28, 2024).
[18] Public Utilities Code (PUC) § 454.53 and Public Resources Code (PRC) § 25403.
[19] PRC § 25302.7.

goal of 7,000 MW of load flexibility by 2030 as part of its "Senate Bill 846 Load-Shift Goal Report."[20] The challenges California faces, as the CEC indicates in their report, are:

- The unprecedented buildout of variable renewable energy resources such as solar and wind to meet California's clean energy goals.
- Switching or substituting of energy uses such as transportation and heating from combustible fuels to electricity.
- Increase in variability of weather patterns and in climate-driven natural disasters, resulting in more challenges to grid reliability.[21]

In confronting these challenges, the CEC states that there are three main pathways to achieve the load flexibility goal:

- Load-Modifying, which includes time-of-use rates, dynamic pricing, and load modifying programs;
- Resource Planning and Procurement, which includes both economic and reliability supply-side demand response resources as well as POU demand response programs; and,
- Incremental and Emergency, which include incremental and emergency programs and back-up generators.[22]

The CEC finds that time of use rates, dynamic rates, and load-modifying programs can be developed and grown to help meet the 2030 goal of 7,000 MW of load flexibility capacity.[23] The CEC report sets a goal that load-modifying programs will account for 3,000 MW of the total load flexibility goal.[24]

CleanPowerSF strongly supports the CEC's goals of shifting peak electricity demand to off-peak periods, reducing GHG emissions, and improving grid reliability[25] and is steadfast in its commitment to achieving 100% renewable energy. CleanPowerSF has engaged with the CEC and other stakeholders individually and through its industry association California Community Choice Association (CalCCA) throughout the development and passage of the CEC's LMS.

2.2.1 CleanPowerSF LMS Implementation Roadmap

Section 1623.1(a)(1) of the LMS regulations directs a Large CCA to submit a plan to their rate approving body that is consistent with the LMS regulations. Below is a roadmap noting each section of this plan and the corresponding section of the LMS regulations it addresses.

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[20] Neumann, Ingrid and Erik Lyon, "Senate Bill 846 Load-Shift Goal Report," California Energy Commission, Publication Number: CEC-200-2023-008, May 2023. Available at: https://www.energy.ca.gov/publications/2023/senate-bill-846-load-shift-goal-report (accessed: March 28, 2024).
[21] Ibid, 1.
[22] Ibid, 5-8.
[23] Ibid, 4.
[24] Ibid.
[25] 20 CCR §§ 1621-1625.

Regulation Section	Regulatory Direction	Plan Section
§1623.1(a)(1)	Within one year of April 1, 2023, submit plan to rate approving body consistent with Section 1623.1. The plan is to be approved within 60 days of submission. The plan is to be reviewed at least once every three years and submit any material changes to the plan to the rate approving body.	2.3
§1623.1(a)(2)	The rate-approving body of the Large CCA may approve a plan, or material revisions to a previously approved plan, that delays or modifies compliance pursuant to Subsections 1623.1(a)(2)(A), (B), (C), and (D).	2.3, 3, 4, and 9
§1623.1(a)(3)	Within 30 days of plan approval, submit plan to California Energy Commission Executive Director.	2.3
§1623.1(a)(3)(C)	The Large CCA shall submit annual reports to the Executive Director of the CEC one year following approval of the plan and annually thereafter.	2.3
§1623.1(b)(2)	Within 27 months of April 1, 2023, the Large CCA shall apply to its rate-approving body for approval of at least one marginal cost-based rate for all customer classes for which the rate approving body determines such rate will materially reduce peak load.	3 and 9
§1623.1(b)(3)	Within 18 months after April 1, 2023, submit to the CEC Executive Director a list of load flexibility programs deemed to be cost-effective and able to materially reduce peak load.	4 and 9
§1623.1(b)(4)	Within 51 months of April 1, 2023, the Large CCA shall offer voluntary participation in either a marginal cost-based rate developed pursuant to Subsection 1623.1(b)(2), if such rate is approved by the Large CCA, or a cost-effective load flexibility program identified according to Subsection 1623.1(b)(3).	3, 4, and 9
§1623.1(b)(5)	Conduct public information program to inform and educate affected customers about real time pricing rates or load flexibility programs, automation needs, and how customers can save money.	8
§1623.1(c)	Within three months of April 1, 2023 (modified to August 1, 2023 and October 1, 2023 pursuant to Order No. 23-0531-10), the Large CCA will upload existing time dependent rates applicable to its customers to the MIDAS system.	5
§1623(c)(1)	Large IOUs, Large POUs, and Large CCAs shall develop a single statewide standard tool for authorized rate data access by third parties.	7
§1623(c)(2)	Large IOUs, Large POUs, and Large CCAs shall submit the single statewide standard to the CEC for approval within eighteen months of April 1, 2023.	7
§1623(c)(4)	Within one year of April 1, 2023, the Large IOUs, Large POUs, and Large CCAs shall provide customers access to their RIN(s) on customer billing statements and online accounts using both text and quick response (QR) or similar machine-readable digital code.	6

2.3 LMS Plan Development and Approval Process

Pursuant to Section 1623.1(a), each Large CCA shall submit a plan consistent with the applicable LMS regulations by April 1, 2024. The rate approving body of the Large CCA must review and consider for adoption the plan within 60 days of its submittal at a duly noticed public meeting.

CleanPowerSF submitted this Plan to the San Francisco Public Utilities Commission, its governing body. The Commission approved the Plan in a duly noticed public meeting on April 23, 2024.

Once the LMS Plan has been adopted, CleanPowerSF will establish a process to review the Plan once every three years. If any material changes are made to the Plan, CleanPowerSF will submit those to the SFPUC Commission. Further, upon adoption of the Plan by the Commission, CleanPowerSF will submit annual reports to the Executive Director of the CEC updating how CleanPowerSF’s Plan is proceeding.

By filing of this Plan, CleanPowerSF does not concede nor imply any jurisdictional authority of the CEC over CleanPowerSF’s rates and programs.

3. Marginal Cost-Based Hourly/RTP Rate Development

The CEC states the intent of the new LMS regulations is "to form the foundation for a statewide system of granular time and location dependent signals that can be used by automation-enabled loads to provide real-time load flexibility on the electric grid."[26] Principal among the LMS regulations is the development of marginal cost-based rates that vary hourly or sub-hourly. Section 1623.1(b)(2) directs Large CCAs to apply to its rate approving body for approval of at least one marginal cost-based rate for each customer class if determined to be cost-effective, equitable, technologically feasible, will benefit the grid, will benefit customers, and would materially reduce peak load. Further, CCAs may opt to apply for approval of the marginal cost-based rates that are offered by the Large IOUs in the CCA's service area. If marginal cost-based rates are approved, Large CCAs may then offer each customer class the opportunity to voluntarily participate in such rates.

Section 1623.1(a)(1) directs a Large CCA to, in its plan, evaluate the cost-effectiveness, equity, technological feasibility, benefits to the grid, and benefits to customers of marginal cost-based rates for each customer class. If, after this analysis, the Large CCA determines dynamic rates do not meet these criteria, the Large CCA may evaluate load flexibility programs that can respond to marginal cost-based MIDAS signals to determine if they meet these criteria and determine a path forward. Pursuant to Section 1623.1(a)(2), a Large CCA may delay or modify compliance with respect to dynamic rate or load flexibility adoption.

At this time, based on the analysis below and all information and data currently available, CleanPowerSF concludes adopting marginal cost-based hourly or sub-hourly rates would not be cost-effective, equitable, technologically feasible, provide significant benefits to the grid, nor benefit customers.

However, the CPUC has authorized PG&E to launch new dynamic rate pilots in partnership with CCAs for residential, commercial, and industrial customer classes. [27] These pilots will launch in June 2024 and are designed to be LMS compliant with respect to the generation component of the pilot RTP rate. CleanPowerSF is considering participation in those pilots to test the viability of adopting RTP rates; the pilots provide an opportunity to gather data and gain experience in offering dynamic rates while further analyzing the cost-effectiveness, equity, technological feasibility, and benefits to the grid and customers. Data and lessons from the pilots could be applied to determine whether to adopt dynamic rates at a future date.

3.1 CleanPowerSF Rate Development Process and Guidelines

The SFPUC conducts rate studies at least every five years for each of its enterprises, including CleanPowerSF. In 2022, CleanPowerSF conducted its first rates study, adopting cost of service (COS)

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[26] Herter, Karen and Situ, Gavin, "Analysis of Potential Amendments to the Load Management Standards: Load Management Rulemaking, Docket Number 19-OIR-01," California Energy Commission, 2021, iii. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=241067 (accessed: March 28, 2024).

[27] D. 24-01-032, Decision to Expand System Reliability Pilots of Pacific Gas and Electric Company and Southern California Edison Company, January 25, 2024. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M524/K176/524176497.PDF (accessed: March 28, 2024).

rates in May of that year. Prior to 2022, CleanPowerSF calculated its rates based on PG&E's generation rate, which led to rate instability and disconnection from the actual cost of delivery. COS rates ensure better financial sustainability by linking rates to CleanPowerSF's actual cost, while also providing more predictability and simplicity for the customer. CleanPowerSF also has flexibility in rate setting to prioritize customer needs, support San Francisco's climate actions goals, among other important goals.

The SFPUC has the flexibility to create rate structures that advance different policy goals. The SFPUC is committed to designing rates in a manner that prioritizes the needs of ratepayers and aligns with the mission and values of the agency.

Tradeoffs are inherent in the development of rates and financial planning; it is rarely possible to achieve all goals.[28] To ensure that decision-makers have properly assessed the impact of their recommendations, the SFPUC, as established in its Ratepayer Assurance Policy, has identified the following principles to consider during the development of all proposed rates and charges, which extend to CleanPowerSF electric rates, as quoted below:

> **Revenue Sufficiency**
>
> The Commission will aim to establish rates sufficient to cover the full cost of all SFPUC activities. Recovering sufficient revenue to fund the programs identified by the long-term plan is necessary to meet established level of service goals and comply with bond covenants, contract commitments, and adopted SFPUC and City policies.
>
> **Customer Equity**
>
> The Commission will establish rates based on cost of service in compliance with the San Francisco Charter and California Proposition 218. Cost of service based rates are an industry best practice to fairly allocate the cost of providing utility services between customer classes.
>
> **Environmental Sustainability**
>
> The Commission will aim to establish rates in a manner that values environmental sustainability and preserves the natural resources entrusted to the SFPUC's care. Rate structures that financially incentivize customers to conserve resources or reduce their demand on the SFPUC's system support this principle.
>
> **Affordability**
>
> The Commission will consider SFPUC service affordability for all its customers. Prudent operating and capital planning ties annual spending to system demand and intergenerational equity, enabling financial engineering and reducing costly emergency expenditures. Rate design should also consider the burden imposed by SFPUC bills on low-income customers.
>
> **Predictability**

[28] SFPUC's Ratepayer Assurance Policy, 3. Available at: https://sfpuc.org/sites/default/files/about-us/policies-reports/RatepayerAssurancePolicy_SEPT2017.pdf (accessed: March 28, 2024).

The Commission will aim to establish rates designed to minimize bill fluctuations, enabling ratepayers to plan ahead for their personal finances. Communicating to ratepayers well in advance of pending rate changes is important to prevent rate shock.

Simplicity

The Commission will aim to establish rates that are easy for ratepayers to understand. Simple rate structures also require fewer implementation and administration costs.

Tradeoffs

These principles sometimes compete with each other. For instance, customer equity may impede simplicity, environmental sustainability, or predictability. Rate structures that equitably distribute the cost of service often require more detail and complexity, which can hinder customers' ease of understanding, discourage measures to promote environmental sustainability, or inhibit the predictability of monthly bills. Some rate methodologies that promote conservation may be more challenging in meeting cost of service objectives, so the SFPUC will consider the principle of environmental sustainability alongside that of revenue sufficiency. The Commission endeavors to thoughtfully consider these inherent tradeoffs, and to transparently present the reasons for its decision-making.[29]

Any consideration of RTP rates in the future must take these principles into account and follow SFPUC rate design and rate setting processes, which is a comprehensive cross-agency effort. For example, RTP rates, by their very nature, are extremely complex and highly unpredictable, and thus any benefits that may be realized as a result of approving or offering RTP rates must be weighed against the downsides of other policy principles that CleanPowerSF must follow.

CleanPowerSF rates are subject to three levels of public oversight and are created with the input, guidance and review of the Rate Fairness Board, an advisory group of ratepayers and City financial officers to ensure rate stability, fairness and affordability. Any rate changes must be approved by the SFPUC at a noticed public meeting. Once approved, the Board of Supervisors has 30-days to disapprove the rates.

3.2 CleanPowerSF Time-of-Use Rates Overview

In 2015, the CPUC voted to adopt Residential Rate Reform, which enacted a series of changes to residential rate structures to simplify electric rates for all customers of Investor Owned Utilities. This effort culminated in the adoption of a TOU rate plan as the default for most Investor Owned Utility customers, where the price of electricity is lower during "off-peak" times during the middle of the day and at night and higher during "peak" times, typically between 4 – 9 p.m., when energy demand is high. As approved by the SFPUC Commission in Resolution No. 21-0085, most CleanPowerSF residential customers were automatically transitioned to the TOU rate plan in July 2021.[30] Since then,

[29] SFPUC's Ratepayer Assurance Policy, 3-4. Available at: https://sfpuc.org/sites/default/files/about-us/policies-reports/RatepayerAssurancePolicy_SEPT2017.pdf (accessed: February 7, 2024).

[30] See CleanPowerSF's Time-of-Use Transition webpage available at: https://www.cleanpowersf.org/tou

CleanPowerSF customers on a TOU rate comprise the vast majority of customers. The periods of both peak and off-peak vary based on customer class. While it depends on the rate schedule, commercial[31] customers typically have more TOU periods than residential customers; commercial TOU periods can include peak, part-peak, off-peak, and super off-peak, and may also incorporate demand charges with each peak period.

CleanPowerSF's current TOU rates for both residential and commercial customers encourage use of electrical energy at off-peak hours, encourage the control of daily and seasonal peak loads to improve electric system efficiency and reliability, lessen or delay the need for new electrical capacity, and reduce fossil fuel consumption and greenhouse gas emissions as noted in Section 1623.1(a)(1) of the LMS. [32] CleanPowerSF's default product for all customers is the "Green" product, which, for 2022, supplied 59.9% of energy from Renewable Portfolio Standard (RPS)-eligible resources including solar, geothermal and wind and an additional 37.2% from zero-GHG hydroelectric resources. The Green product had a low GHG-intensity of 47 lbs/MWh in 2022.

Further, CleanPowerSF offers a "SuperGreen" product option to all customers interested in having all their energy sourced from 100% RPS-eligible resources. CleanPowerSF's Green and SuperGreen options further lessen reliance on fossil fuels and reduce greenhouse gas emissions as compared to the statewide 2022 California power mix. The figure below shows the breakdown of CleanPowerSF's 2022 Power Content Label.

Figure 1: CleanPowerSF 2022 Power Content Label[33]

ENERGY RESOURCES	CleanPowerSF Green	CleanPowerSF SuperGreen	CleanPowerSF SuperGreen Saver	2022 CA Power Mix**
Eligible Renewable	59.9%	100.0%	100.0%	35.8%
Biomass & Biowaste	0.0%	0.0%	0.0%	2.1%
Geothermal	24.3%	0.0%	0.0%	4.7%
Eligible Hydroelectric	0.0%	0.0%	0.0%	1.1%
Solar	25.3%	50%	100%	17.0%
Wind	10.2%	50%	0.0%	10.8%
Coal	0.0%	0.0%	0.0%	2.1%
Large Hydroelectric	37.2%	0.0%	0.0%	9.2%
Natural Gas	0.0%	0.0%	0.0%	36.4%
Nuclear	0.0%	0.0%	0.0%	9.2%
Other	0.0%	0.0%	0.0%	0.1%
Unspecified sources of power*	2.9%	0.0%	0.0%	7.1%
TOTAL	100%	100%	100%	100%

[31] CleanPowerSF's commercial customer class also includes industrial and agricultural rates included in its commercial rate sheets available at: https://www.cleanpowersf.org/rates
[32] 20 CCR § 1623.1(a)(1).
[33] Further information on CleanPowerSF's 2022 Power Content Label available at: https://www.cleanpowersf.org/energysources

CleanPowerSF’s TOU rates have been successful at encouraging the reduction of peak load as compared to flat, non-time-dependent residential rates like E-1. By 2023, a year and a half after the residential transition to default TOU rates, approximately two thirds of all residential customers were on a TOU rate, with the remaining one third of customers remaining on E-1.

Figure 2 – Pre-Transition June 2021

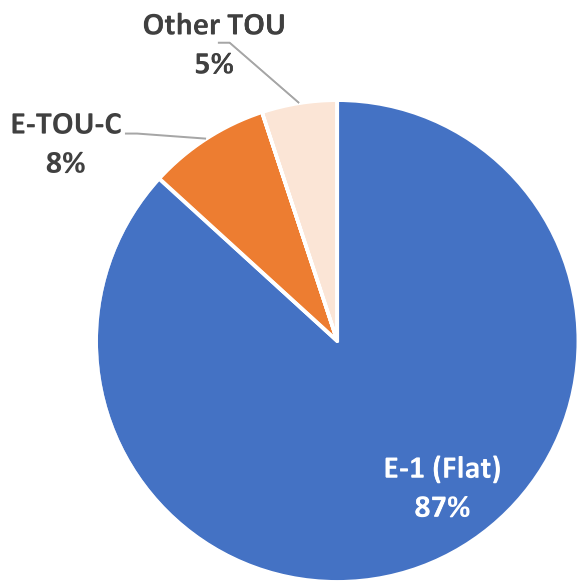
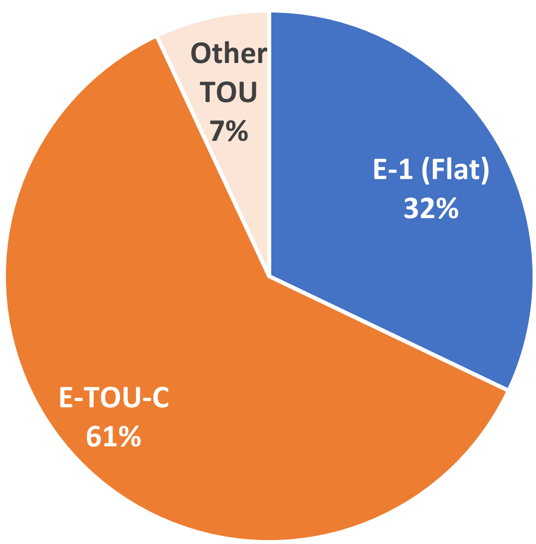
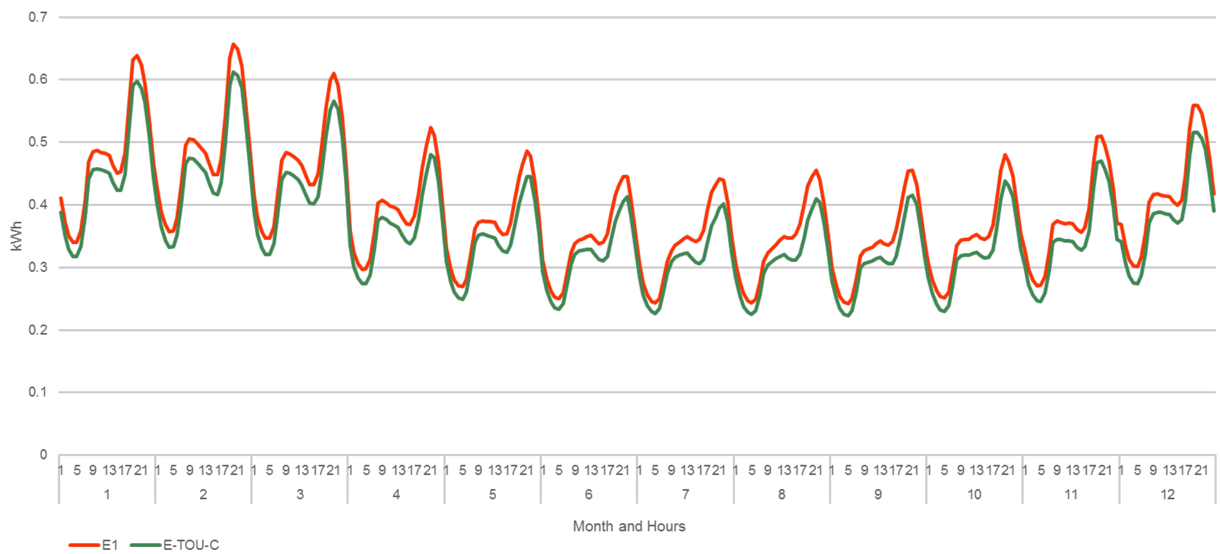


Figure 3 – Post-Transition August 2022



Comparing residential TOU customers to E1 customers, it is clear TOU customers showed significant load reduction during peak times as compared to E1 customers. Figure 4 below shows 2023 average weekday load profiles of E-TOU-C customers and E1 customers.

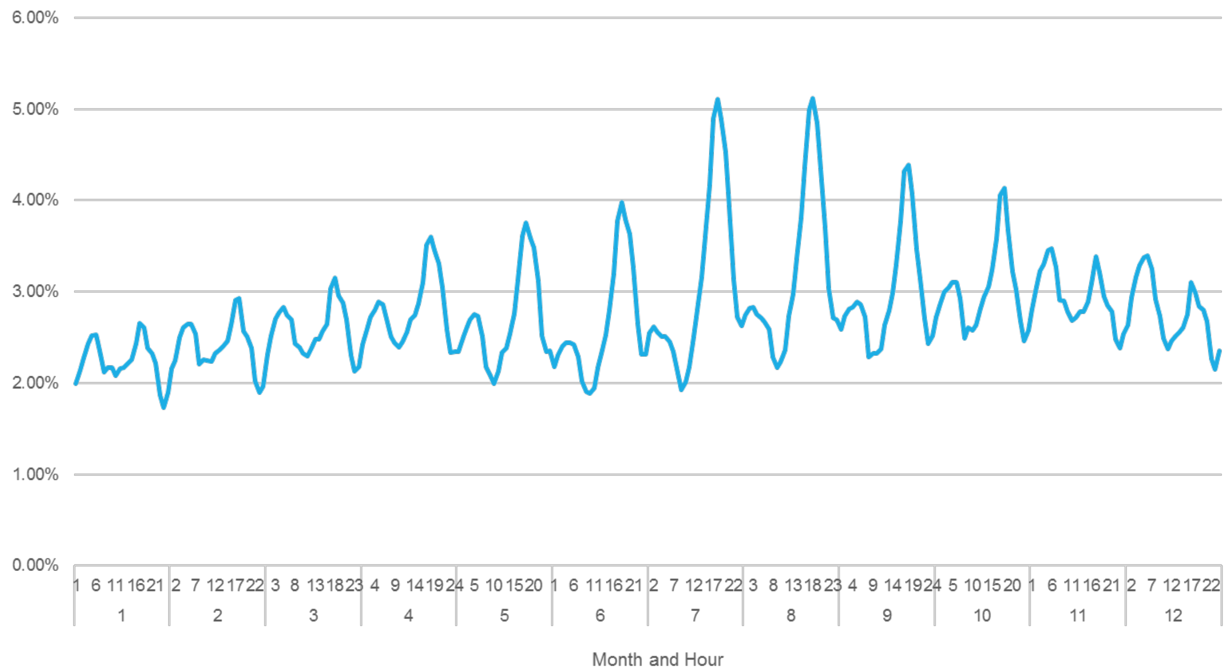
Figure 4 – 2023 Average Weekday Load Profile – E-TOU-C vs. E1



The magnitude of load reduction between E-TOU-C and E1 is consistently highest during 6PM in each month, and particularly so in the summer months, when electricity is most expensive throughout the year.

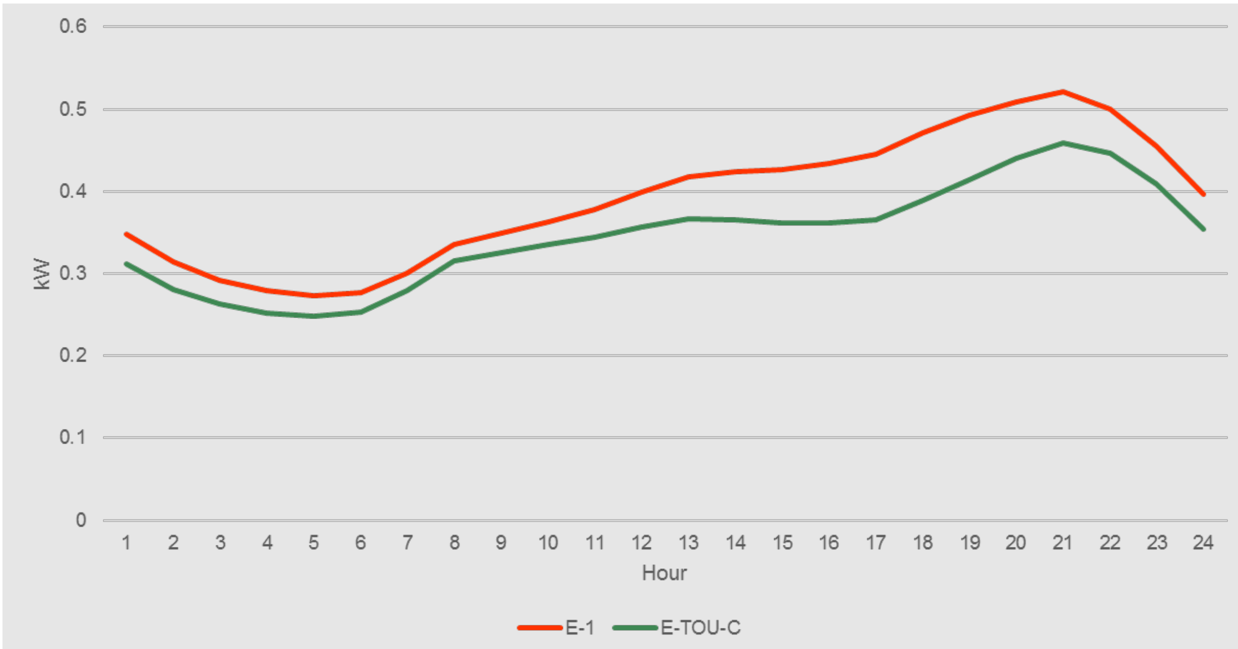
The difference in load is further illustrated in Figure 5 below, which shows the 2023 weekday average E-TOU-C load shift percentage relative to the simple average of both E-TOU-C and E1 customers. The magnitude of the load shift is highest during June, July, August, September, and October ranging between 1.88% and 5.12% and also highest (5.12% in August at 6PM) during the middle of CleanPowerSF's residential TOU peak period, around 6PM for weekdays.

Figure 5 – 2023 Weekday Average E-TOU-C Load Shift Percentage vs. Simple Average of E-TOU-C and E1 Load Profiles



Focusing on the effect of TOU rates to mitigate demand during extreme events, the load reduction impact from TOU-C customers remained significant during the September 2022 heat wave. Figure 6 below shows the load profile of E-1 vs E-TOU-C customers on September 6, 2022, which shows that E-TOU-C customers had much lower average load than E-1 customers, with the largest difference in load occurring between 4PM and 8PM. Thus, even on the hottest and most grid constrained days, CleanPowerSF's TOU customers had average peak usage 11.7% lower than customers on E-1.

Figure 6 – September 6th, 2022 Average Load of E-1 and E-TOU-C



The analysis of this data shows that TOU customers have lower peak loads than E-1 customers. While this analysis does not cover every variable that could drive differences between TOU and flat rate customers, CleanPowerSF's analysis shows that it is reasonable to conclude that shifting customers onto TOU rates would have an impact in reducing net peak load.[34] This conclusion is further supported by results from other TOU rate analyses. For example, Nexant's 2018 report, "California Statewide Opt-in Time-of-Use Pricing Pilot," showed PG&E load reduction varied between 3.5 percent and 6.1 percent depending on the type of TOU rate (peak period), the season, and the summer comparison year (2016 or 2017).[35] CleanPowerSF's reductions, as shown above, show similar results.

CleanPowerSF also sees similar distributions of E1 customers and TOU customers after the default transition occurred. In the Track B Working Group Report published in the CPUC's Demand Flexibility docket, the Joint IOUs noted that as of June 2023, "a significant portion of customers, primarily Residential, are not enrolled on TOU rates: 41% for PG&E; 42% for SCE; and 23% for SDG&E."[36] For CleanPowerSF, residential non-participation in TOU rates was 32% in 2022.

[34] Further analysis would be needed to determine all the driving factors for load reduction separate from any impact TOU rates have, especially isolating myriad variables that could impact load reduction during any specific time. The comparison between TOU and flat rates is indicative that TOU rates themselves have an impact on peak load reduction, but the degree of that impact relative to other variables is unknown.

[35] Nexant, Inc., "California Statewide Opt-in Time-of-Use Pricing Pilot: Final Report," March 30, 2018,. 4. Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/s/6442457172-statewide-opt-in-tou-evaluation-final-report.pdf (accessed: March 28, 2024).

[36] "Track B Working Group Report and Notice of Availability," Filed by Southern California Edison Company in CPUC R.22-07-005, October 11, 2023, 112. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K541/520541672.PDF (accessed: March 28, 2024).

Despite CleanPowerSF's transition to TOU rates as our default residential generation rate, customers are able to choose any rate, including a flat rate, thus customers may effectively opt-out of the TOU transition. Additionally, some customers were not included in the default transition including customers enrolled in CARE/FERA rates or on medical baseline. Thus, with so many customers still on a flat rate, there is significant potential to educate those customers about TOU rates and the benefits of load reduction or load shifting during peak periods. Moving customers on flat rates to TOU rates are part of the Joint IOU's "stepping-stones" approach to RTP in the Track B Working Group Report, with TOU as a first step along a path that ends in RTP after considerable preparation through pilots and studies of RTP and noting that other rates or pilots might take place before RTP, like Critical Peak Pricing or Variable Peak Pricing.

The potential peak load reductions of moving customers currently on flat rates onto TOU rates may provide significant load reductions even without additional RTP options. This load reduction may outweigh the potential incremental load reduction from moving any customers to RTP rates. While impacts to peak load reduction may be small, if done at significant scale, the aggregate impact could be orders of magnitude greater than significant peak load reduction at an individual level from a smaller group of customers.

The goal of RTP or similar rates, like shifting energy use from peak times to off-peak times to improve grid reliability, are something CleanPowerSF supports from a conceptual perspective, however RTP rates are complex to implement, challenging to communicate to customers, and could have problematic unintended side-effects. CleanPowerSF is reviewing RTP concepts and designs, including the necessary analysis of RTP rates and programs, but need more time and data to determine if RTP rates and programs are viable and, if so, would be done effectively. The sections below describe our research. Based on this research, CleanPowerSF concludes that developing RTP rates is premature. Developing an RTP rate or program now would: result in hardship to CleanPowerSF; reduce system reliability, equity, safety, and efficiency; not be cost-effective or technologically feasible to implement; or result in material peak load reduction. However, CleanPowerSF will continue to explore RTP rates and programs and will evaluate whether to participate in the expanded RTP pilots authorized in Decision D.24-01-032,[37] as a means to test the viability and gain experience in developing RTP rates.

3.3 Cost-Effectiveness Analysis

Cost-effectiveness is critical in evaluating the development of RTP rates for any customer class. The first challenge in addressing the potential cost-effectiveness (or not) of RTP rates is the lack of current data on RTP rates. CleanPowerSF does not currently have any data to support that RTP rates are cost-effective for any customer class in its territory. Few RTP programs exist around the country and only a few limited pilot programs have been run in California with little performance data.

[37] D. 24-01-032, Decision to Expand System Reliability Pilots of Pacific Gas and Electric Company and Southern California Edison Company, January 25, 2024. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M524/K176/524176497.PDF (accessed March 28, 2024).

With the issuance of Decision D.24-01-032 in R.22-07-005, expanding the AgFIT (Agricultural Flexible Irrigation Technology)[38] pilot to residential and commercial customers in PG&E's service territory, more data, experience, and research will become available to determine the cost-effectiveness of RTP rates and programs. CleanPowerSF is considering participation in those pilots depending on the final outcome and structure of the pilot programs.

3.3.1 Commonwealth Edison Company Study on RTP

Illinois's Commonwealth Edison Company (ComEd), a utility that has an RTP rate available to its customers, recently published its hourly pricing report for 2022.[39] In 2022, ComEd's hourly pricing rate had 43,455 accounts participate throughout the year, mainly for single-family residential customers but some multi-family residential customers as well. The 2022 report indicated that ComEd's hourly rate program cost $2,931,500.[40] The report stated that total benefits of the program were $9,240,510 for a total net benefit of $6,309,010.[41]

However, in reviewing the details of the benefits claimed in the ComEd report, most of the benefits claimed come from Demand Response Induced Price Effects[42] impacts across the entirety of the Pennsylvania-New Jersey-Maryland (PJM) interconnection, which comprises over 65 million people, and thus only a small fraction of those Demand Response Induced Price Effects benefits were realized by ComEd customers. The small portion of program benefits that were realized by ComEd customers were attributed to the net benefitting customers that participated in the hourly rate. In fact, the program resulted in net costs of $1,806,662 to non-participating residential ComEd customers, representing a significant cost-shift from participating to non-participating customers. When looking at impacts to ComEd across all its customers, the hourly pricing program for 2022 was not cost-effective, resulting in a total cost of $231,185.

Moreover, ComEd's hourly pricing program achieved similar load reduction impacts as TOU rates have shown, reducing load of hourly pricing participants by 3 percent in the summer of 2022. However, ComEd's hourly pricing rate increased usage in all other seasons.[43] ComEd also did not have a default TOU rate, so hourly pricing participants are compared to their pre-enrollment usage when on flat rates. ComEd has begun a limited TOU rate pilot program as an alternative to hourly pricing. Thus, any estimated ancillary Demand Response Induced Price Effects benefits across the PJM interconnection should also be viewed in this context. A TOU rate may have been more cost effective than ComEd's RTP

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[38] The AgFIT pilot was a RTP rate pilot administered by PGE&E and Valley Clean Energy for agricultural customers. In the CPUC proceeding R.22-07-005 using the AgFIT pilot as a foundation to extend RTP pilot rates to residential and commercial customers was considered. This resulted in the CPUC issuing Decision D.24-01-032 expanding new RTP pilots for residential and commercial customers.

[39] Elevate Energy. "Commonwealth Edison Company's Hourly Pricing: 2022 Annual Report," April 27, 2023. Available at: https://icc.illinois.gov/downloads/public/edocket/587138.PDF (accessed: February 7, 2024).

[40] Ibid.

[41] Ibid.

[42] Demand Response Induced Price Effects (DRIPE) is the theoretical impact of reducing the need for more expensive marginal generation assets due to a reduction in demand.

[43] Elevate Energy. "Commonwealth Edison Company's Hourly Pricing: 2022 Annual Report," April 27, 2023. Available at: https://icc.illinois.gov/downloads/public/edocket/587138.PDF (accessed: February 7, 2024).

rate and could have produced more Demand Response Induced Price Effects benefits with less cost and without a cost shift among customer classes and participants and non-participants.

3.3.2 Pacific Gas &Electric Company Real Time Pricing (RTP) Research

A critical component to the cost-effectiveness of RTP rates is also the level to which customers of each rate class would select an hourly or sub-hourly dynamic rate. Research by PG&E was included in Appendix 1 Party Proposal Attachments to the Track B Working Group Report submitted in the Demand Flexibility (Rulemaking (R.) 22-07-005) proceeding.[44] PG&E's "RTP Research Results" included in Appendix 1 of that report showed that the majority of both residential and non-residential customer classes have a preference to stay on their current rate and the preferred new rate is a TOU rate with variable grid stress charges,[45] with only a minority open to rate plans that vary hourly.[46] Further, PG&E's research showed that customers preferred less peaky rates, indicating a preference for more predictable bills and less volatility.

The research showed that residential customers were more concerned about RTP rates being too risky and could increase bills whereas non-residential customers were concerned with the inability to shift their demand in response to high RTP prices. Overall, only 10 percent of residential customers and 14 percent of non-residential customers included in PG&E's research survey indicated a preference to move to RTP rates.[47] PG&E's research was not concentrated on a specific geographic region; thus it is unclear how amenable CleanPowerSF customers would be to dynamic rates in comparison to PG&E's surveyed customers. Given San Francisco's temperate climate, winter peaking load, and geographic concentration, both CleanPowerSF's residential and commercial customer classes are likely to have less load shift potential than customers in hotter climates with greater air conditioning loads, particularly in the summertime during periods of high grid stress and high temperatures. This reduces the potential cost-effectiveness of developing an RTP rate for all customer classes in CleanPowerSF territory.

3.3.3 Cost-Effectiveness Conclusion

Even if significant peak load reduction could be achieved and the RTP rates were significantly subscribed to across customer classes, the impact on CleanPowerSF costs will also be contingent on CleanPowerSF's existing long-term contracts and open position. RTP signals should complement CleanPowerSF's contracted energy position such that the customer price signals being sent to reduce CleanPowerSF's energy supply costs are in line with CleanPowerSF's marginal cost of procurement, otherwise the price signals could reduce revenues but not costs, potentially creating a cost shift between RTP participants and non-participants. This uncertainty and risk is further compounded by lack of data on the potential

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[44] "Track B Working Group Report and Notice of Availability," Filed by Southern California Edison Company in CPUC R.22-07-005, October 11, 2023, Appendix 1 Party Proposal Attachments. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K541/520541778.PDF (accessed: April 8, 2024).
[45] Variable grid stress charges are charges that show up on customers' bills a few times a year when the grid is particularly strained.
[46] "Track B Working Group Report and Notice of Availability," Filed by Southern California Edison Company in CPUC R.22-07-005, October 11, 2023, Appendix 1 Party Proposal Attachments, 165. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K541/520541778.PDF (accessed: April 8, 2024).
[47] Ibid, 166.

uptake of RTP rates. Without data and experience with how many customers, what groups of customers within each rate class, and the degree to which customers would engage, it will be difficult to determine whether development of an RTP rate would be cost-effective.

CleanPowerSF does not have enough data, evidence, or experience to determine that developing RTP rates for all customer classes at this time would be cost-effective. CleanPowerSF will continue to gather data from reviewing the RTP programs of other load serving entities. The Staff Proposal on Existing Dynamic Rate Pilot Expansion, included in the CPUC Ruling on Track B Staff Proposal to Expand Existing Pilots on August 15, 2023, noted that one of the benefits of authorizing new expanded RTP pilots is "enabling utilities and CCAs to gain important operational experience in offering dynamic rates to customers across different applications and capabilities, which should help advance their technical and operational readiness and deployment timelines to offer widespread hourly, marginal-cost-based dynamic rates consistent with CEC's Load Management Standards."[48] The rates developed as part of these RTP pilots are expected to be consistent with the definition of marginal-cost-based rates in the LMS with respect to the generation and distribution component of a customer's rate, which includes the marginal energy cost, the marginal capacity cost, and associated marginal greenhouse gas emissions (marginal GHG emissions and costs are also included in the CEC's existing MIDAS system). Pilot programs like these will provide CleanPowerSF and other load serving entities with the experience needed to understand the cost-effectiveness of RTP rate offerings.

The CPUC approved new RTP pilots in Decision D.24-01-032 for residential and commercial customer classes, which provide LSEs an opportunity to test the cost-effectiveness of RTP rates.[49] The decision allows CCAs to participate in those pilots by filing a Tier 1 advice letter by March 1, 2025, indicating they will commence enrollment in the PG&E expanded pilots by June 1, 2025. Pursuant to D.24-01-032, PG&E filed a Tier 2 advice letter on March 25, 2024, proposing an implementation plan for the RTP pilots. CleanPowerSF is considering participation in those pilots in order to evaluate the cost-effectiveness of RTP rates.

3.4 Technological Feasibility Analysis

Technological feasibility is essential to the ability of CleanPowerSF, or any LSE, to develop and offer RTP rates. Without granular access to data at hourly or sub-hourly intervals (both forecasted and actual) and a billing system capable of billing at that level of granularity, developing dynamic rates is unviable. Advance Metering Infrastructure (AMI) or smart meters are critical in making dynamic billing possible. While almost all customers in CleanPowerSF territory have smart meters[50] the following further challenges must be addressed.

[48] R.22-07-005, "Attachment A: Staff Proposal on Existing Dynamic Rate Pilot Expansion," August 15, 2023, 2. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M517/K408/517408172.PDF (accessed: March 28, 2024).

[49] D. 24-01-032, Decision to Expand System Reliability Pilots of Pacific Gas and Electric Company and Southern California Edison Company, January 25, 2024.

[50] 98 percent of CleanPowerSF customers.

3.4.1 Load Forecasting and Determining Hourly/Sub-hourly Usage

Challenges pertaining to granular access to hourly and sub-hourly data and its effect on load forecasting has been detailed by Cal-CCA in the CPUC's Demand Flexibility proceeding R.22-07-005 Track B.

According to the Track B Working Group Report addressing CalCCA's comments:

> CCAs in PG&E's service territory receive non-billing quality hourly interval data through PG&E's ShareMyData (SMD) platform. Load-serving entities such as CCAs need such data for load forecasting. Accurate forecasting (including day-ahead load forecast submissions to the CAISO) promotes load management and grid reliability especially during grid stress events. PG&E commits to providing data through ShareMyData within 48 hours of power flow, however the CCAs have experienced many instances of substantial delays in the data, as well as unplanned outages and certification issues with the platform. As described in a report provided to PG&E by East Bay Community Energy (EBCE) and Sacramento Municipal Utility District (SMUD) (EBCE's back-end billing provider (i.e., the interrogating agent)): (1) on at least 40 days in 2022, all usage data was missing until 72-96 hours after power flow; and (2) SMUD was unable to access any usage data on an additional 11 days due to outages or certification issues with the system. Therefore, the EBCE/SMUD report details a total of 51 days in 2022 in which EBCE did not have access to any usage data from PG&E's SMD within 48 hours. In addition, PG&E only allows one interrogating agent per CCA, resulting in CCAs having to wait for the SMD data payload to be processed and transferred by the CCA back-end billing provider, resulting in further delay. The CCAs have asserted, and their analysis demonstrates, that the hourly usage data in SMD often becomes available between 48-96 hours after usage. These delays render the data insufficient for short-term load forecasting in response to grid stress events, especially when incorporating time needed for processing and transfer from the interrogating agent.
>
> As pricing becomes more time-dependent (i.e., for both time-of-use and dynamic rates), the need for accurate data for load forecasting becomes heightened. Without such data, CCAs will incur additional costs for inaccurate scheduling, potentially resulting in inflated prices and further exacerbating grid reliability issues that both TOU and RTP are designed to improve.[51]

The need for non-billing quality hourly or sub-hourly interval data within 48 hours or less of power flow is critical in short-term load forecasting, particularly in response to grid stress events. Short-term load forecasting is necessary when developing RTP rates and how customers may react to price signals. CleanPowerSF will continue to engage with other CCAs and PG&E on the issue of the SMD platform in hopes of improving data transfer processes for non-billing quality data for load-forecasting within 48 hours or less of power flow. The timing needed to resolve these issues is unknown at this time.

[51] "Track B Working Group Report and Notice of Availability," Filed by Southern California Edison Company in CPUC R.22-07-005, October 11, 2023, 234-235. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K541/520541672.PDF (accessed: March 28, 2024);

3.4.2 Need for Data for Billing Purposes

In addition to load forecasting, hourly and sub-hourly data is critical for operation and billing processes for a RTP rate. Also noted in the Track B Working Group Report:

> CCAs in PG&E's service territory do not currently receive billing quality usage data at the hourly (or sub-hourly) interval. PG&E's billing transactions – the only reliable source of billing quality usage data – are presently aggregated down to PG&E's own pre-defined TOU periods. These data are provided at the end of each billing period. For example, a billing transaction will specify usage during "peak" and "off peak" only. For CCAs to bill customers on hourly (or sub-hourly) dynamic/RTP rates, or any other rates that differ from PG&E's defined TOU periods, CCAs must have access to billing quality hourly (or sub-hourly) interval usage data.[52]

PG&E is planning to improve its Electronic Data Interchange (EDI) data transfer system, which currently only supports billing quality interval data for a very limited number of Service Agreement IDs (SAID). PG&E plans to expand billing quality interval data across all SAIDs by 2027. However, the near-term plan to expand the number of SAIDs for billing quality interval data is mostly to address the new Net Billing Tariff (NBT) billing requirements under CPUC Decision (D.) 22-08-002.

As CleanPowerSF, and other CCAs are dependent on PG&E to provide this data, CleanPowerSF cannot accurately and predictably bill customers on a dynamic rate at hourly or sub-hourly intervals, then it cannot develop or offer those rates.

The 2027 timeline for PG&E's full-scale expansion of billing quality data at hourly or sub-hourly intervals does not allow CleanPowerSF to properly plan and develop RTP rates for all customer classes. After full expansion of PG&E's data transfer system, CleanPowerSF will need additional time to get familiar with and incorporate data transfer protocols into its processes for the successful implementation of RTP rates.

The expanded RTP pilots authorized by Decision D.24-01-032 would provide an opportunity to test technology platforms and gain experience in some aspects of hourly or sub-hourly billing. However, the expanded RTP pilots will utilize shadow billing where the customer is billed on their otherwise applicable tariff and shadow billed in parallel based on the dynamic California Flexible Unified Signal for Energy (CalFUSE) rate platform.[53] This will be administered by PG&E and customers will receive bill credits at the end of the year if they do better on the RTP rate than their otherwise applicable tariff. If the

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[52] "Track B Working Group Report and Notice of Availability," Filed by Southern California Edison Company in CPUC R.22-07-005, October 11, 2023, 233. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K541/520541672.PDF (accessed: March 28, 2024);,

[53] The CalFUSE platform or framework is: "a comprehensive policy roadmap, the centerpiece of which is a unified, universally accessible, dynamic, economic retail electricity price signal. The roadmap consists of a three-pillar structure addressing 1) the presentation of electricity prices to customers and smart devices, 2) electricity rate reform, and 3) customer options to optimize energy consumption and generation.";Achintya Madduri, Masoud Foudeh, Paul Phillips, and Aloke Gupta, "Advanced Strategies for Demand Flexibility Management and Customer DER Compensation: Energy Division White Paper and Staff Proposal," California Public Utilities Commission, June 22, 2024,3. Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/ed-white-paper---advanced-strategies-for-demand-flexibility-management.pdf (accessed: March 28, 2024).

customer does not see savings relative to their otherwise applicable tariff the customer would not receive any credits and their bill would be unaffected.

CleanPowerSF conducts its billing through a third-party provider and at this time does not have any rate structures in place that change at hourly and sub-hourly intervals. While experience could be gained from the expanded RTP pilots, additional analysis in collaboration with CleanPowerSF's third party billing provider will be necessary before developing any structures to accommodate RTP billing.

3.4.3 Customer Access to Smart Devices Capable of Interacting with MIDAS

Customer access to automated devices that are capable of interfacing with the MIDAS system directly, as designed, is also a technological barrier. Automated devices are still in early development nationwide. According to a 2022 Statista survey, only 13 percent of households in the United States own a major smart appliance.[54] Utility Dive published an article noting the Media Research Unit of S&P Global Market Intelligence concluded that while the number of smart thermostats would double in the next five years, smart thermostats would "still be installed in less than a third of homes equipped with broadband internet by the end of 2026."[55] The scale of expansion of smart and connected appliances is a significant barrier to the development of RTP rates.

3.3.4 Potential Sunk Costs of RTP Implementation

These barriers present further cost-effectiveness and scalability challenges for RTP rates as the development of these resources, billing systems, and data systems are, at least in the development stage, fixed administrative costs. With no data or pilot experience to determine the responsiveness of customers to RTP rates, incurring costs to develop these systems may become sunk costs if RTP rates have little impact on peak load reduction or cost reduction.

The data access barriers and potential costs present enough risks that CleanPowerSF cannot determine at this time that development of RTP rates would be technologically feasible. However, CleanPowerSF will continue to work with other CCAs and PG&E on data access issues, gain insight from results of the RTP pilots launching in June 2024 (whether CleanPowerSF participates or not) and evaluate possible paths forward with respect to technological feasibility.

[54] Statista Research Department, "Ownership rate of smart appliances in the United States in 2022," August 3, 2023. Available at: https://www.statista.com/statistics/1124257/smart-appliances-ownership-us-2020/ (accessed: March 28, 2024).
[55] Walton, Robert, "Slow adoption of smart thermostats in the US misses big potential energy savings: S&P," August 31, 2022. Available at: https://www.utilitydive.com/news/smart-thermostats-us-slow-adoption-misses-energy-savings/630901/ (accessed: February 7, 2024).

3.5 Equity Analysis

When considering developing RTP rates, equity is a key consideration. Access to automated and connected technologies, like smart appliances or thermostats, is critical to participate in RTP rates that leverage MIDAS signals. "Internet of Things" devices are still in their development stage with respect to end use energy infrastructure. As noted above, only 13 percent of households own a major smart appliance. Thus, the ability of customers to leverage the MIDAS system and take advantage of RTP rates is limited. This lack of access may be even more so for low-income ratepayers.

3.5.1 Inequitable Access to Smart Devices

In November 2022, Sensi, a smart thermostat company operating in the US, engaged TRUE Global Intelligence, a research arm of FleishmanHillard, to survey homeowners aged 18-76 and found that low-income households were far less likely to own a smart thermostat than higher-income households.[56] A study performed by the American Council for an Energy-Efficient Economy (ACEEE) in 2016 noted that "low-income households are less likely to have programmable thermostats. Only 24% of low-income households have programmable thermostats, while 47% of non-low-income households do."[57] The ACEEE study only touches on programmable thermostats, a simpler technology than smart thermostats, that just allows a customer to manually set times and temperatures for their heating and cooling needs and do not have the ability to react to real-time signals. Thus, inequitable access to smart devices and appliances presents a risk that only higher income customers would be able to take advantage of RTP rates.

3.5.2 Potential Cost-Shift from High- to Low-Income Ratepayers

The variability of access to Internet of Things technologies, appliances, and end-use energy infrastructure based on income presents significant equity concerns in the ability of ratepayers to take advantage of RTP rates with hourly or sub-hourly MIDAS signals. However, even more concerning, are possible cost-shifts as a result of inequitable utilization of RTP rates. If RTP rates are developed and scaled utilizing a MIDAS signal such that only households and businesses equipped with smart appliances and automated demands can participate, a cost shift may occur whereby low-income ratepayers that do not have these devices and are unable to take advantage of RTP rates would be subject to the cost of supporting CleanPowerSF costs to a greater degree than higher income ratepayers.

This challenge remains even if RTP rates were cost effective and had a positive impact on CleanPowerSF costs averaged across all ratepayers as the sum of that positive impact may be distributed unevenly

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[56] Sensi, "Smart Home Data Privacy Survey," October-November 2022. Available at: https://sensi.copeland.com/documents/sensi-data-privacy-survey-report-en-us-8744686.pdf (accessed: March 28, 2024).

[57] Cluett, Rachel, et al, "Building Better Energy Efficiency Programs for Low-Income Households," American Council for an Energy-Efficient Economy, March 2016, 4. Available at: https://www.southeastsdn.org/wp-content/uploads/2019/11/Building-Better-Efficiency-Programs-for-Low-Income-Households.pdf (accessed: March 28, 2024).

among income levels such that low-income ratepayers without access to a MIDAS signal could be subsidizing high-income ratepayers at a net cost to the low-income ratepayer population.

3.5.3 Price Volatility

Price volatility is also a significant equity concern with respect to RTP rates. Dynamic electricity prices are, by their very nature, more volatile than flat or TOU rates, and are extremely unpredictable. Price volatility can lead to significant utility bill volatility that may create financial hardships for low-income ratepayers. The negative impact of price volatility from RTP rates was evident in Texas during the 2021 winter storm that created price spikes up to the hard cap of $9,000 per megawatt-hour. In some cases, customers who had signed up for the dynamic rates experienced a monthly utility bill in excess of $15,000.[58]

An example cited in the New York Times was one customer who had a $16,752 utility bill.[59] The high bill was charged to the customer's credit card, which he had to pay, wiping out his savings account. For low-income customers, as well as businesses, this type of price and bill volatility could be financially devastating. Protections against this outcome are critical to ensure that if an RTP rate is adopted, both residential and commercial customer classes are protected from bill volatility and prices that could be an extreme financial burden. Subscription rate design, bill and price caps, or other consumer and business protections are critical. However, with more protections, the RTP rate itself becomes less connected to the marginal cost of energy, flattening out the peaks and valleys such that the rate may look similar to TOU rates. All of these factors are essential in further analyzing and testing to ensure that the rates CleanPowerSF develops follow the principles it has adopted when developing rates. RTP rates that create high bill volatility run against many of the rate design principles that the SFPUC uses as its guidelines, including customer equity, affordability, predictability, and simplicity.[60]

CleanPowerSF cannot conclude at this time that developing an RTP rate for each customer class would be equitable. In fact, the development of RTP rates could create significant equity concerns that may be difficult to assuage given market trends and without broader access to smart appliances and end loads.

3.6 Grid Benefits Analysis

As a CCA, CleanPowerSF is only responsible for providing generation services to its customers. PG&E is responsible for the transmission and distribution system. Thus, designing RTP rates that may produce grid benefits can be challenging in this dynamic, as marginal cost signals may not be aligned between CleanPowerSF from a generation side and PG&E from a transmission and distribution side.

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[58] Blumsack, Seth, "What's behind $15,000 electricity bills in Texas," The Conversation, February 24, 2021. Available at: https://theconversation.com/whats-behind-15-000-electricity-bills-in-texas-155822 (accessed: March 28, 2024).

[59] McDonnell Nieto del Rio, Giulia , Bogel-Burroughs, Nicholas, Penn, Ivan, "His Lights Stayed on During Texas' Storm. Now He Owes $16,752," The New York Times, February 20, 2021. Available at: https://www.nytimes.com/2021/02/20/us/texas-storm-electric-bills.html (accessed: March 28, 2024).

[60] Section 3.1 CleanPowerSF Rate Development Process and Guidelines.

Energy and Environmental Economics, Inc. (E3) published a white paper in March 2023[61] that highlights the avoidable costs that occur as a result of customer demand response, noting that avoided generation capacity costs are highly correlated with load reduction during specific times, but not necessarily specific locations. Transmission and distribution capacity cost reductions, on the other hand, are contingent upon both time and location. See below a table excerpt from E3's white paper detailing the degree to which time and location has on avoided fuel and GHG emissions and generation, transmission, and distribution capacity costs.

Figure 7 – E3 "Rate Design for the Energy Transition" Comparison of Avoidable Costs with Customer Response Table[62]

Comparison of Avoidable Costs with Customer Response

Cost Category	Degree to Which the Response Must:			Degree of Load Diversity	Avoidability Rating
	Occur in Specific Hours	Occur in Specific Locations	Be Predictable and Reliable		
Fuel and GHG Emissions	Mid	Low	Low	High	★★★★
Generation Capacity	High	Low	High	High	★★★
Transmission Capacity	High	Mid	High	High	★★
Distribution Capacity	High	High	High	Low	★

Cost categories that are easy to avoid · Cost categories that are somewhat easy to avoid · Cost categories that are difficult to avoid

The extent to which customer responses can avoid electricity system costs varies based on the type of cost. The colors in each cell indicate how each factor contributes to an "avoidability rating"—the lightest orange indicates factors that make the cost category easy to avoid, while the darkest orange indicates factors that make the cost category difficult to avoid, and the mid-colored orange cells fall somewhere in between. Avoiding generation capacity costs requires a targeted, predictable, and reliable response during specific hours, but a locationally specific response is not necessary and load diversity is high at the system level, which makes it relatively easy to avoid those costs. In contrast, avoiding transmission and distribution capacity costs requires locationally specific responses from a smaller and smaller pool of customers, and the load diversity decreases, making it harder to avoid those costs.

The two cost categories that CleanPowerSF can control are the fuel and GHG emissions and generation capacity costs, which are both more contingent on time of load reduction as opposed to location of load reduction. Thus, marginal cost signals in RTP rates could benefit the grid by reducing energy capacity strain and reducing GHG emissions, however the degree to which marginal generation cost signals can benefit the transmission and distribution system is limited.

A large number of customers responding with small adjustments to TOU rates may have a bigger impact than a few customers responding with big adjustments to RTP price signals. Any grid benefits from RTP rates are all dependent on the degree and scale in which those rates can induce incremental load shifts – and if those rates are more effective at shifting load than CleanPowerSF's current TOU rates. As shown

[61] Olson, Arne et al, "Rate Design for the Energy Transition: Getting the Most out of Flexible Loads on a Changing Grid," Energy and Environmental Economics, Inc. (E3), March 2023. Available at: https://www.esig.energy/rate-design-for-the-energy-transition-getting-the-most-out-of-flexible-load-on-a-changing-grid/ (accessed: March 28, 2024).

[62] Ibid, 14.

above, CleanPowerSF's TOU rates have been effective at encouraging reduction of peak load relative to flat rates at similar percentages as those seen in ComEd's RTP program. Given the results of some RTP studies that show RTP rates have a similar effect on peak load reduction as TOU rates there may not be any incremental load shift occurring as a result of the adoption of RTP as compared to TOU. Further, grid benefits are also highly contingent upon alignment between generation signals and transmission and distribution signals, which are controlled by two separate entities in CleanPowerSF and PG&E for CleanPowerSF's customer base.

Another important consideration with respect to grid benefits and system reliability is the possible unintended consequences of significant dispersed load responding to the same price signal at the same time. An April 2022 paper, "Collective effects and synchronization of demand in real-time demand response," highlighted the potential unintended consequences of load synchronization when loads respond to a single signal. [63] The paper notes:

> Without DR, the actions of single consumers, i.e., the switching of a single device, can be considered an independent stochastic event. In a large interconnected power system, demand fluctuations of individual households average out, and the total grid load varies rather smoothly. In the spirit of the central limit theorem, we can assume that the residual fluctuations of the total grid load around the smooth daily profile follow a normal distribution. This assumption is no longer valid for real-time DR, where the customer demands are adapted according to a common input signal, the electricity price, and thus are no longer independent. Collective effects may then fundamentally alter the statistics of the electricity demand.[64]

The collective effects of synchronized load may create quick and significant demand ramps that could increase grid stress rather than decrease grid stress. The research indicates that these demand spikes may also not take place during periods of low prices: "Instead, they may also occur if the price drops after a long period of high values. In such case, DR operation may be counter-productive for system stability, introducing demand peaks at time of limited generation."[65] These spikes in demand may also be concentrated in certain locations, further straining distribution infrastructure in addition to transmission and generation concerns. The research concludes that, "While load shifting itself is the desired effect of DR, a comprehensive roll-out of such systems may lead to undesired excessive effects."[66]

Based on the uncertainty with respect to grid benefits from CleanPowerSF developing an RTP rate, CleanPowerSF cannot conclude that developing such rate would benefit the grid – especially any incremental grid benefits beyond what CleanPowerSF is able to accomplish with its current TOU rate offerings for all customer classes. And, based on the cost-effectiveness, equity, and technological feasibility challenges, the ability to scale RTP rates with hourly or sub-hourly MIDAS signals limit any potential grid benefits as well.

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[63] Han, Chengyuan, et al, "Collective effects and synchronization of demand in real-time demand response," Journal of Physics: Complexity, April 28, 2022. Available at: https://iopscience.iop.org/article/10.1088/2632-072X/ac6477/pdf (accessed: March 28, 2024).
[64] Ibid, 1-2.
[65] Ibid, 9.
[66] Ibid, 10.

3.7 Customer Benefits Analysis

Reviewing the effect of both actual real-time pricing programs, as well as modeled results, shows that many customers are worse off under RTP, total utility costs may not be lower, and price volatility (i.e., exposure to high hourly energy prices) all limit the benefits of RTP programs to customers.

Reviewing ComEd's RTP program, its 2022 annual report showed that the median annual savings of its RTP participants was $50.28 or only 5.8 percent of their bill. There were 22,306 accounts that saved money out of the 43,445 total participants in 2022, which only constitutes 51 percent of participants. There were 21,139 accounts (49 percent of participants) that did not achieve any savings with the median annual loss at $47.34 or 8.1 percent, with losses ranging from $0.01 to $688.27. Thus, ComEd's program had nearly as many "losers" as "winners," with bill losses almost offsetting net bill savings.

The total net bill savings for 2022 hourly pricing participants was $729,306, which averages an annual bill savings across all participants of only $17, or $1.40 of bill savings per month. However, these minimal bill savings accrued to hourly pricing participants came at a cost to all non-participants. In fact, non-participants contributed $2,137,591 of the program costs but received only $330,929 in benefits for a total net loss of $1,806,662.

Overall, it appears ComEd's hourly pricing rate was not cost-effective for ComEd or ComEd customers. The lion's share of benefits in the report were due to claimed lower energy prices from Demand Response Induced Price Effects impacts across the entirety of the 65 million customer PJM interconnection, a contention difficult to verify.[67]

Another study out of the Lawrence Berkeley National Lab (LBNL) also showed that under an inelastic demand scenario (hypothetically re-billing customers on historical usage) there was considerable variation in benefits and costs with respect to customer bill impacts for both residential and commercial rate classes.[68] Under this LBNL study, residential and commercial customers' bills were billed under a "business-as-usual" (BAU) scenario (the customer's applicable tariff) and then customers were billed under a variety of dynamic tariffs (one fully dynamic and three others with some load subscription component) to estimate the impact of the dynamic tariff.

The LBNL study results showed that some residential customers did better (saved) under a fully dynamic rate with no subscription protections but did worse (did not save) on a dynamic rate with various subscription protections. Further, residential NEM customers did worse in all dynamic pricing scenarios. Small commercial customers bill impacts were similar to residential with some savings under fully dynamic pricing but some increases with dynamic pricing with subscription components. Medium and large commercial customers' bill impacts were worse on fully dynamic pricing with a few examples of bill

[67] The claimed benefits were calculated by comparing the 2022 PJM supply curve to the 2007 PJM supply curve. Given the miniscule size of ComEd's program relative to the size of the entire PJM system, it is hard to discern the actual positive impacts that would have occurred across the entirety of the PJM interconnection based on the ComEd hourly pricing program.

[68] Gerke, Brian F., et al, "Potential bill impacts of dynamic electricity pricing on California utility customers," Lawrence Berkeley National Laboratory, 2024. Available at: https://escholarship.org/uc/item/2wj199mq (accessed: February 7, 2024).

savings under dynamic pricing with subscription components. Commercial demand charges under dynamic pricing can cause increases in bills due to concentrated shifts in energy use to low energy price periods that create high demand during that period. While the energy cost may be low, the demand is high and thus may shift the total peak demand for that customer during the month. With demand charges accounting for a considerable amount of a commercial customer's bill, dynamic pricing can lead to bill increases for large commercial customers. Bill subscription protections can mitigate this impact, but not entirely.[69]

Some conclusions of the LBNL study include:

- The dynamic-only tariff (no load-shape subscription) would tend to reduce bills for residential, agricultural, and small C&I customers without [on-site solar]—while increasing bills for the corresponding customer classes with [on-site solar]—since they are compensated at a lower rate, on average, for exports to the grid.
- The dynamic-only tariff (no load-shape subscription) tends to increase bills for large C&I customers regardless of the presence of [on-site solar] generation.
- For all customer types without [on-site solar], the dynamic-only tariff (no load-shape subscription) leads to a significant increase in month-to-month bill volatility. Residential and small C&I customers with [on-site solar] see decreases in volatility due to the reduced occurrence of very low or negative bills.[70]

Finally, as expected, dynamic rates lead to significant bill volatility, which can lead to considerable negative effects to affordability. High volatility makes bills less predictable and thus harder for both residential and commercial customers to plan and budget their expenses.

As noted in Section 3.5.3 Price Volatility above, an extreme, but real example, of bill volatility from dynamic rates is what occurred in Texas in February 2021 when the state experienced a severe winter storm and extremely cold temperatures that drove wholesale energy costs up by orders of magnitude, which under certain dynamic pricing structures available in the state were passed on to customers.[71]

Even if RTP rates are able to provide some aggregate bill savings across many customers, those benefits may not outweigh the significant risk of bill volatility under a dynamic pricing structure that could lead to debilitating financial hardship when a customer is subject to wholesale electricity markets. Bill subscription protections, bill caps, and other measures could be important consumer protections for participating residential and commercial customers.

Any benefits to all CleanPowerSF customers as a result of reduced energy costs, reduced capacity needs, or other environmental benefits is contingent on customer participation in dynamic rates and the incremental peak load reduction that a set of customers can achieve. If residential and commercial customers are hesitant to participate in dynamic rates due to the financial risk, the incremental peak

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[69] Gerke, Brian F., et al, "Potential bill impacts of dynamic electricity pricing on California utility customers," Lawrence Berkeley National Laboratory, 2024, vii. Available at: https://escholarship.org/uc/item/2wj199mq (accessed: March 28, 2024).

[70] Ibid, viii – ix.

[71] Blumsack, Seth, "What's behind $15,000 electricity bills in Texas," The Conversation, February 24, 2021. Available at: https://theconversation.com/whats-behind-15-000-electricity-bills-in-texas-155822 (accessed: March 28, 2024).

load reduction as a result of developing a dynamic rate will be de minimis and not produce any benefits to CleanPowerSF or its customers. Further, the potential peak load reduction of dynamic rates also need to be viewed within the context of existing TOU rates offered by CleanPowerSF. Given research has shown that dynamic rates have a similar load reduction impact as TOU rates, there may be no incremental load reduction on a per customer basis from dynamic rates as compared to TOU rates. Based on the data and evidence above, CleanPowerSF cannot conclude that developing an RTP rate for each customer class would benefit CleanPowerSF customers. Rather, the development of RTP rates could increase costs to customers and create bill volatility that could result in significant economic risks to both residential and commercial customers.

3.8 D. 24-01-032 CPUC Expanded RTP Pilots Consideration

On January 25, 2024, the CPUC approved Decision (D.) 24-01-032, which authorized expanded system reliability pilots, informed by the CalFUSE platform, and an extension of the AgFIT pilot previously authorized in partnership with PG&E and Valley Clean Energy. The expanded RTP pilots would extend to select residential and commercial customers, in addition to agricultural customers the AgFIT program was originally designed for.

Two pilot tracks were authorized by D. 24-01-032. Pilot 1 is authorized for agricultural customers and has a target capacity enrollment of 50 MW across PG&E territory and available to all CCAs interested in participating. Pilot 1 would expand the eligible end use load from water pumping only to any demand from the agricultural customer.

Pilot 2 would be available to customers on the following PG&E rate schedules: B-6, B-10, B-19, B-20, E-ELEC, and EV2-A.[72] Pilot 2 is also available to any end use customer. Pilot 2 will use a shadow billing structure with little to no risk to the participating customer, whereby the customer is billed on their otherwise applicable tariff. Simultaneously, the customer's load is being tracked on the pilot RTP rate and if after the end of the year, the customer did better on the RTP rate than their otherwise applicable tariff, then the customer will receive a credit of the difference between the two. If the customer does worse on the RTP rate, then the customer is simply billed on their otherwise applicable tariff and would not receive any credits.

The expanded pilots will be administered by PG&E and CCAs may elect to participate. The CPUC authorized a budget of $15,200,000 for Pilot 2, which includes a $20 per kW-year incentive for enrolled CCA load up to a total budget of $1,800,000 to encourage CCAs to participate in the pilot and help offset some of the program operating costs.

PG&E must file a Tier 2 advice letter within sixty days of the effective date of the decision and propose an implementation plan for both Pilot 1 and Pilot 2 that would commence enrollment of customers by June 1, 2024. However, any CCA interested in participating in the expanded pilots may indicate their intention to do so by filing a Tier 1 advice letter by March 1, 2025 for participation any time before June 1, 2025. Thus, CCAs will have more time to consider the parameters of the implementation plan, develop processes and procedures for rolling out the RTP pilot in their territory and to their customers

[72] CleanPowerSF offers generation rate schedules that align with PG&E retail rate schedules.

and research how it will work within the CalFUSE rate structure to offer a dynamic hourly marginal cost-based rate to eligible customers. CleanPowerSF staff are engaged with PG&E, along with many other CCAs in PG&E territory, as part of a working group on the expanded RTP pilots to learn more about the implementation and rollout of the pilots. Staff will evaluate PG&E's implementation plans and program design to determine whether it would be in the interest of CleanPowerSF and its customers to participate.[73]

D. 24-01-032 also requires measurement and evaluation of the expanded pilots, which include assessment of the following:

- The response of customer loads to prices, to evaluate the efficacy of the dynamic pilot rate to shift customer exports into peak hours;
- The monthly bill impacts of the pilot dynamic rate in comparison to a customer's otherwise applicable tariff;
- The recovery of generation and resource adequacy costs for customers on the pilot tariff, including the impact of any under collection of generation and resource adequacy revenues against the impact of the shifted participant loads on marginal generation and resource adequacy costs, and on the avoided cost value, including using the Commission's Avoided Cost Calculator, where appropriate;
- The recovery of delivery costs for customers on the pilot tariff, including the impact of any under-collection of delivery revenues against the impact of the shifted participant loads on marginal delivery costs, and on the avoided cost value, including using the Commission's Avoided Cost Calculator, where appropriate;
- The number of participating customers and the number of kilowatts of shiftable load enrolled in [Environmental and Social Justice] communities;
- The total amount of shadow bill credits delivered to customers in in [Environmental and Social Justice] communities;
- The impact of the expanded pilot on greenhouse gas emissions and other emissions with particular consideration of [Environmental and Social Justice] communities; and
- Lessons learned about how dynamic rates and associated programs can be designed to provide benefits to [Environmental and Social Justice] communities.[74]

The evaluation of the pilots will provide valuable data, whether or not CleanPowerSF participates in them, to help determine the viability of dynamic rates and programs and their ability to help shift peak load to off-peak periods.

Given the alignment of these expanded pilots and the fact that the generation portion of the dynamic rate is expected to be LMS compliant, CleanPowerSF will be considering participation in Pilot 2 pending

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[73] Pilot 1 is not fit for CleanPowerSF given there are no true agricultural customers served by CleanPowerSF. Some customers are served on an AG rate, but these are legacy rates and CleanPowerSF would likely include those customers as commercial in any future RTP rates. Further, there are so few customers on an AG rate that it would not make sense to develop a program specifically for that customer base alone, but rather include them in any commercial RTP offering, if CleanPowerSF decides to develop one in the future.

[74] D. 24-01-032, Decision to Expand System Reliability Pilots of Pacific Gas and Electric Company and Southern California Edison Company, January 25, 2024, Attachment C, C1-C2. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M524/K176/524176497.PDF (accessed March 28, 2024).

further analysis of the implementation plans filed by PG&E in their Tier 2 advice letters along with other considerations.

3.9 RTP Development Conclusion

As a result of this analysis, and the cost effectiveness, technological feasibility, equity, grid and customer benefit concerns, CleanPowerSF is unable to conclude, at this time, that developing an RTP rate for each of its customer classes is viable. However, CleanPowerSF will continue to evaluate, analyze, and research dynamic rates and rate design to determine whether developing a RTP rate sometime in the future would be cost-effective, technologically feasible, equitable, benefit the grid, and benefit customers.

Further, CleanPowerSF is considering participation in the expanded pilots authorized under D. 24-01-032 to gain the data and experience to better test the viability of developing and offering RTP rates to all customer classes. CleanPowerSF staff will review the implementation plan filed by PG&E through their upcoming Tier 2 advice letter and following the rollout of the pilot itself to determine whether CleanPowerSF should participate prior to the March 1, 2025 deadline.

4. MIDAS Enabled Load Flexibility/Demand Response Programs

4.1 Overview of CleanPowerSF's Peak Day Pricing Program

In addition to CleanPowerSF's suite of TOU rates, CleanPowerSF also offers a load flexibility program to commercial and industrial customers on E-19, B-19, E20, and B-20 rate schedules called the Peak Day Pricing Program (PDP Program). The PDP Program offers commercial and industrial customers an opportunity to earn an incentive while helping to reduce GHG emissions and lower demand during periods of peak grid stress. Enrolled customers receive incentives for reducing electricity use between 4 P.M. and 9 P.M. on six to twelve PDP "Event Days" from July 1 – October 31. Typically, Event Days occur on the hottest days of the summer in Northern California. CleanPowerSF's event days only occur on weekdays; holidays and weekends are excluded. Enrolled customers remain on their current electric rate schedule with no difference in their monthly billing and there are no penalties or risks for participation. If a customer is not able to reduce their load during an Event Day, they do not pay any fees.

Customers enrolled in the 2022 PDP program received an incentive rate of $1.50/kilowatt hours (kWh) of load reduction on Event Days during applicable times. Customers that reduced their load during more than 75 percent of the PDP Program's Event Day-hours received a bonus incentive of $1.00/kWh for a total possible incentive rate of $2.50/kWh during Event Day-hours. PDP incentives were calculated at the end of the program season and then credited to the customer on their CleanPowerSF bill.

CleanPowerSF provides notice to participating customers via its website, along with email or text messages in the afternoon before an Event Day.

Below is an evaluation of CleanPowerSF's PDP Program and its suitability as a MIDAS enabled load flexibility program, which includes evaluation of any new MIDAS enabled load flexibility program viability.

4.1.1 Analysis of CleanPowerSF PDP Program

CleanPowerSF started offering a PDP Program in 2019. The 2022 PDP Program had:

- 36 participating customer accounts
- 11 Event Days, of which four were part of the 2022 Heat Event (September 6-9)
- 60.74 megawatt-hours (MWh) of load reduction
- $183,000 in end-of-season incentives distributed

The objectives of the 2022 PDP Program included, but were not limited to:

1. Continue to provide a demand response-type program that allows CleanPowerSF customers to contribute to grid reliability and curbing greenhouse gas emissions on peak days;
2. Continue evaluating the effectiveness of offering a tiered incentive model (bonus incentive) in promoting load shed; and
3. Explore strategies to facilitate scaling the program to a larger pool of customers.

To increase enrollment in the program, CleanPowerSF coordinated with its Customer Engagement Group to focus recruitment efforts on large commercial and industrial customers enrolled in either CleanPowerSF's SuperGreen rate and customers required to comply with San Francisco's 2019

Renewable Energy Ordinance.[75] This approach to outreach for the PDP Program was effective for the 2022 season and was more effective than broader outreach to a more general pool of commercial customers as was done in the prior year. Customers reported motivations for their initial enrollment were generally focused on sustainability and other societal issues, generally referred to as Environmental, Social, and Governance (ESG) goals.

Enrolled customers preferred text messages for Event Day notifications with email as a close second. Some customers expressed interest in website forecasts but were unaware that the PDP Program website provided notifications and forecasts. The fact that customers did not leverage web notifications and forecasts may be an indication that direct communication from the LSE to the customer is better at encouraging demand response than passive communication a customer is required to engage with proactively.

CleanPowerSF performed post program interviews with many enrolled customers who expressed satisfaction with the PDP Program and stated they had a positive experience and were likely to continue participating in the program. However, some challenges that were reported from customers were managing tenant concerns, staff turnover or buy-in from staff, limitations to building management systems, and the ability to respond on particularly hot days while still maintaining building comfort. The MIDAS system may not address any of these concerns for customers other than staff buy-in assuming the customer has automated devices capable of responding to a MIDAS signal without human action. However, without building management systems that are capable of interacting with the MIDAS system automatically, the potential of utilizing a MIDAS signal as the main communication mechanism for a demand response event is limited.

Customers were generally satisfied with the incentives provided in the PDP Program. At $1.50/kWh for the base incentive and a consistent performance bonus incentive of $1.00 kWh, the total incentive per kWh in the PDP Program is even greater than the CAISO maximum Energy Bid price that will clear the CAISO Market Processes at $2,000/MWh. Thus, incentive levels offered under the PDP Program in 2022 are potentially greater than what could be procured on the market.

In response to California's record-setting heat wave in September 2022 (Heat Event), CleanPowerSF implemented a combination of efforts to maximize load shedding during the key hours. CleanPowerSF increased communications to PDP participants, leveraged general awareness of the Heat Event, and increased incentive levels. Specifically, CleanPowerSF doubled the PDP Program incentive rate to $3.00/kWh (from a base of $1.50/kWh) during the Heat Event. In addition, PDP participants that reduced load more than 75 percent during the PDP Program event-hours the week of September 5, 2022, were eligible for a $1.00/kWh bonus, for a total possible payment of $4.00/kWh, twice the CAISO maximum Energy Bid price allowable. To alert PDP participants of the increased incentives,

[75] San Francisco Environment Code, Chapter 30, § 3003(a); San Francisco Ordinance 220-19 passed on September 24, 2019 and required commercial buildings to comply with 100% renewable electricity. Commercial buildings with greater than 500,000 square feet or greater must comply with 100% renewable energy by December 31; 2022, commercial buildings with 250,000 square feet or greater by December 31, 2024; and, commercial buildings with 50,000 square feet by December 31, 2030. Available at: https://www.sfenvironment.org/100-renewable-electricity-commercial-buildings-ordinance?repaired

CleanPowerSF sent specialized text alerts and emails with details of the increased incentives the day before each day of the Heat Event including on Labor Day (September 5, 2022).

PDP participants did respond to this effort and did increase their load shed with the frequency of achieving load shed during the Heat Event increasing to 71 percent as compared to 61 percent for the overall season. The average load shed also increased to 11 percent compared to seven percent for the season.

Table 1 – 2022 Peak Day Pricing Program Outcomes

Performance Metric	Results
Customer accounts enrolled	36
Total load shed	60.7 MWh
Median load shed per participant	625.9 kWh
Total GHG savings (metric tons CO2)	21.18 mTCO2
Average GHG savings per participant (metric tons CO2)	0.57 mTCO2
Frequency of event participation during Event Day hours	61 percent
Number of customer accounts that obtained the Season bonus	7 of 36
Number of customers accounts that obtained the Heat Event bonus	14 of 36
End-of-season incentives distributed	$183,000
Average incentive paid per kWh of load shed	$3.02
Estimated CleanPowerSF wholesale energy cost savings	$64,021

PDP Program staff conducted an analysis to understand if CleanPowerSF Heat Event-related efforts made a difference, and if so, which efforts mattered most. With the support of a program consultant, staff compared the load shed performance of PDP enrollees, who received CleanPowerSF and general awareness messaging, such as news reports about the Heat Event and statewide messaging to conserve as well as the increased incentives, to that of non-participants, who received only general messaging. The analysis also compared PDP's 2022 enrollees to PDP enrollees during a similar Heat Event in 2020. The 2020 Heat Event provided a comparison where CleanPowerSF PDP customers were not offered increased incentive levels for the week, but otherwise received similar increased communications from CleanPowerSF and from general awareness messaging.

This assessment found that PDP participants' increased performance seems strongly linked to increased communications, both by general media sources and by CleanPowerSF; but there was no clear indication that doubling incentives alone had a significant impact on increased performance.

- Non-participants received general awareness messaging but did not receive CleanPowerSF messaging or PDP incentives. They shed approximately 3 percent of load during the 2022 Heat Event compared to their baseline electricity use. (This compares to the 11% shed by 2022 PDP participants. during the Heat Event. It appears that some combination of PDP messaging, extra incentives, and other characteristics of PDP participants were responsible for the difference.
- During the 2020 Heat Event, PDP Participants shed an additional seven percent of load, going from seven percent load shed (on the season's other Event Days) to 14 percent on Heat Event Event-Days. Again, these participants received general awareness and CleanPowerSF messaging but did not receive increased PDP incentives.

When comparing the driving factors of customer action during the 2022 Heat Event, PDP participants shed only an additional 3.5 percent of load, despite being offered increased (double) PDP incentives. Therefore, this analysis does not find increased incentives *and* messaging materially improved load shed performance any more than increased messaging alone. Additionally, the scale and scope of impact was far greater given general customer awareness of a Heat Event than the existence of the PDP program itself, even though the general awareness produced a smaller percentage of load shed per customer.

Moreover, in reviewing load reduction contributions by customer, nearly 70 percent of the total kWh load reduction achieved through the program was attributable to the largest third of customers enrolled in the program. The smallest third of customers contributed less than one percent of the program's incremental load reduction. Load reduction was also concentrated between the hours of 6:00-7:00 P.M. with the rest of load reduction being relatively evenly distributed throughout the rest of the program hours.

4.2 Cost-Effectiveness Analysis

In 2022, CleanPowerSF's PDP Program, while successful in achieving load shed during peak grid events, was not cost effective from the standpoint of energy procurement avoided costs. Standard base and bonus incentives went up to $2.50/kWh and up to $4.00/kWh on Heat Event days in 2022. At the end of the 2022 season, a total of $183,000 in incentives were distributed to customers, representing an average of $3.02/kWh in incentives. However, during event hours, it is estimated that CleanPowerSF saved approximately $64,000 in wholesale energy costs (~$29,000 in CAISO Real-Time Market prices and ~$35,000 in CAISO Day-Ahead Market prices). Thus, without accounting for staff time, development costs, operational costs, and other program related costs, as well as other benefits beyond energy procurement avoided costs, the benefit-cost ratio of the 2022 PDP Program was ~0.35, well below a threshold of 1 to achieve a program result that is cost-effective.

In assessing the additional costs of integrating a MIDAS signal to CleanPowerSF's existing PDP Program, or developing entirely new MIDAS-enabled demand response programs, it is unlikely that such programs would perform cost-effectively. The potential incremental avoided energy and/or capacity costs as a result of integrating a MIDAS signal into CleanPowerSF's current PDP Program or developing new MIDAS enabled load flexibility programs is not estimated to be greater than the costs of the program itself. Further, when considering the expansion of the PDP Program including a MIDAS enabled signal to small commercial and residential customer classes, the cost to implement the program is anticipated to be even greater. As the analysis above shows, nearly 70% of all load reduction came from the largest third of enrolled customers. Larger customers were more responsive to load flexibility signals, suggesting there would be diminishing returns of load reduction from smaller customers when utilizing a MIDAS signal as opposed to broader education about grid stress, which is cheaper and easier to scale.

While some program operation efficiency efforts were implemented during the 2022 season, overall staff effort increased for 2022 due in part to extra efforts and outreach during the 2022 Heat Event. CleanPowerSF's PDP Program, in its current form, remains relatively labor intensive and difficult to scale for wider participation from an operational and technical perspective.

CleanPowerSF will continue to analyze its existing PDP Program and will consider how to improve it and whether integrating a MIDAS signal could improve program performance under the right circumstances, as well as explore expanding or developing new MIDAS enabled load flexibility programs to reach small commercial and residential customers. However, at this time, CleanPowerSF does not have enough evidence to conclude that MIDAS enabled load flexibility programs would be cost effective.

4.3 Technological Feasibility

CleanPowerSF also identified significant technological feasibility challenges in the analysis of its PDP program. These problems mirrored the same concerns, previously identified in Section 3.4 Technological Feasibility Analysis on the problems and timeliness of receiving hourly data. Compiling usage data for the PDP Program has been a major challenge. Compiling participants' usage data and conducting necessary quality assessments to produce mid-season feedback reports and perform incentive calculations continued to be a labor-intensive, "manual" undertaking due to gaps in the ShareMyData interval data for many customers.

CleanPowerSF's operation of the PDP Program also confirms (as discussed in Section 3.4 Technological Feasibility Analysis above) the need for non-billing quality hourly or sub-hourly interval data within 48 hours or less of power flow for short-term load forecasting, particularly in response to grid stress events. Until PG&E is able to improve its Electronic Data Interchange (EDI) data transfer system, which currently only supports billing quality interval data for a very limited number of Service Agreement IDs (SAID), operationalizing an RTP or other MIDAS-enabled program will not be possible. PG&E does not anticipate this full EDI functionality until 2027.

These results present further cost-effectiveness and scalability challenges for a MIDAS integrated demand response program, particularly with respect to small business and residential customers with smaller loads. Only certain customer classes may respond with any reliability and with enough load shed when incentives are increased and additional communication is provided. Small commercial and residential customers may respond better to general communication, which could produce better results from a cost-effectiveness perspective.

While implementing a MIDAS enabled load flexibility program is theoretically feasible from a purely technical perspective, the technological barriers of data access and proliferation of MIDAS enabled end-use devices presents challenges that make the *successful* implementation of a MIDAS enabled load flexibility program currently unlikely. However, CleanPowerSF is committed to continued participation and engagement with other CCAs and PG&E to improve hourly and sub-hourly data access. As progress is made on hourly and sub-hourly data access, CleanPowerSF will reevaluate the viability of MIDAS enabled load flexibility programs from a technological feasibility lens.

4.4 Equity Analysis

When considering modifying CleanPowerSF's existing PDP Program to be MIDAS enabled or developing new MIDAS enabled load flexibility programs, equity is a key consideration. Access to automated and connected technologies, like smart appliances or thermostats, is critical to participate in load flexibility programs that leverage MIDAS signals. As noted above, Internet of Things devices are still in a nascent stage of development with respect to end use energy infrastructure. As discussed in Section 3.5 Equity Analysis above, with only 13 percent of households owning a major smart appliance, the ability of customers to leverage the MIDAS system is limited, and this lack of access may be even more so for low-income ratepayers.

For example, as also noted in Section 3.5 Equity Analysis, "[o]nly 24 percent of low-income households have programmable thermostats, while 47 percent of non-low-income households do."[76] The variability of access based on income to internet connected technologies, appliances, and end-use energy infrastructure presents significant equity concerns in the ability of ratepayers to utilize a MIDAS enabled load flexibility program. However, even more concerning are possible cost-shifts as a result of inequitable utilization of MIDAS enabled programs. As shown above, CleanPowerSF's PDP currently costs CleanPowerSF more in incentive disbursements than wholesale energy cost savings. Like any nascent program, cost shifts are likely in the early stages and CleanPowerSF's PDP Program, given its relatively small size, does not present any significant equity concerns at this time. However, if scaled and utilizing a MIDAS signal such that only households and businesses equipped with smart appliances and end loads could use, a much more substantial cost shift may occur whereby low-income ratepayers that may be unable to participate in a MIDAS enabled load flexibility program would be subject to the cost of supporting the load flexibility program to a greater degree than higher income ratepayers.

This challenge is particularly concerning in a situation in which the load flexibility program is not cost effective. However, even if the load flexibility program were cost effective, the possibility of cost shift across income levels is still possible. If high-income ratepayers that have greater access to technologies that would allow automation with MIDAS reduced CleanPowerSF costs, that could have a positive impact on costs for all ratepayers. However, that positive impact may be distributed unevenly among income levels. Low-income ratepayers that cannot take advantage of a MIDAS enabled load flexibility program may subsidize high-income ratepayers such that the net impact would be negative for low-income ratepayers.

CleanPowerSF cannot conclude at this time that modifying its existing PDP Program to be MIDAS enabled or creating new MIDAS enabled load flexibility programs would be equitable. In fact, the expansion of MIDAS enabled programs could create significant equity concerns that may be difficult to assuage given market trends and the lack of broader access to smart appliances and end loads.

4.5 Grid Benefits Analysis

As a CCA, CleanPowerSF is only responsible for providing generation services to its customers. PG&E is responsible for the transmission and distribution system. Thus, designing MIDAS enabled programs that may produce grid benefits can be challenging in this dynamic, as marginal cost signals may not be aligned between CleanPowerSF from a generation side and PG&E from a transmission and distribution side.

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[76] Cluett, Rachel, et al, "Building Better Energy Efficiency Programs for Low-Income Households," American Council for an Energy-Efficient Economy, March 2016, 4. Available at: https://www.southeastsdn.org/wp-content/uploads/2019/11/Building-Better-Efficiency-Programs-for-Low-Income-Households.pdf (accessed: March 28, 2024).

As noted above in Figure 7, the E3 white paper "Rate Design for the Energy Transition: Getting the Most out of Flexible Loads" highlights the avoidable costs that occur as a result of customer demand response, noting that avoided generation capacity costs are highly correlated with load reduction during specific times, but not necessarily specific locations. Transmission and distribution capacity cost reductions, on the other hand, are contingent upon both time and location as noted in the E3 white paper in Figure 7 above.

The two cost categories that CleanPowerSF can control are the fuel and GHG emissions and generation capacity costs, which are both more contingent on time of load reduction as opposed to location of load reduction. Thus, marginal cost signals in a MIDAS enabled load flexibility program could benefit the grid by reducing energy capacity strain and reducing GHG emissions, the degree to which marginal generation cost signals can benefit the transmission and distribution system is limited.

However, any grid benefits from MIDAS enabled load flexibility programs are all dependent on the degree and scale in which those programs can create incremental load shifts and whether or not customers are interested in participating in those programs – and if those programs are more effective at shifting load than CleanPowerSF's current programs and rates. Further, grid benefits are also highly contingent upon alignment between generation signals and transmission and distribution signals, which are controlled by two separate entities, CleanPowerSF and PG&E, in CleanPowerSF's service area.

Based on results from CleanPowerSF's analysis of its PDP Program, the benefit to the grid is de minimis. And, based on the cost-effectiveness, equity, and technological feasibility challenges, the ability to scale a MIDAS enabled load flexibility program is a barrier to meaningful grid benefits at this time.

4.6 Customer Benefits Analysis

Benefits to customers can be broken into two segments comprising benefits to CleanPowerSF customers that participate in the MIDAS enabled load flexibility program and customers that do not. CleanPowerSF's PDP Program clearly shows that there are benefits to customers that participated. The PDP Program is a no risk incentive that rewards customers for reducing load during high grid stress periods. CleanPowerSF distributed $183,000 to PDP Program customers for the 2022 season, and assuming those customers made their own judgement that the load reduction was worthwhile given any possible negative business impact, they benefited financially from participation. However, when considering the cost-effectiveness analysis above, the overall impact on CleanPowerSF customers was a net negative from the standpoint of energy market cost avoidance, since the incentives provided were greater than CleanPowerSF's reduced wholesale energy costs during event day hours. As the costs of the PDP Program are distributed across all customers, those that did not participate in the PDP Program bore the cost of the incentives, which were greater than the benefit of the reduced wholesale energy purchased by CleanPowerSF.

A well-designed MIDAS enabled load flexibility program could benefit both participating and non-participating customers, however those benefits are highly contingent on the scale of program participation, the incentive and pricing structure of the programs, and how costs of implementation are shared among all CleanPowerSF customers. As noted above, the issue of cost shift is a significant concern with respect to the benefits, or lack thereof, to customers, which is further compounded by equity concerns regarding those cost shifts.

CleanPowerSF cannot conclude at this time that, based on the analysis of its PDP Program, a MIDAS enabled load flexibility program would produce customer benefits to both participating and non-participating customers. However, CleanPowerSF will continue to analyze its existing programs and research new MIDAS enabled load flexibility programs to better understand possible customer benefits across all CleanPowerSF customers.

4.7 MIDAS Enabled GHG and Flex Alert Proposal

CleanPowerSF has uploaded its applicable time-dependent rates into the MIDAS system. The MIDAS system also includes marginal GHG emissions RINs and CAISO Flex Alert RINs. As noted in the CEC's Staff Instructions "Market Informed Demand Automation Server (MIDAS) Documentation Version 1.2: Connecting to and Interacting with the MIDAS Database and Application Programming Interface," the MIDAS system leverages WattTime to monitor GHG emissions in eleven regions across California for real-time and forecasted GHG emission levels. [77] There are three GHG RINs (historic GHG, real-time GHG, and forecasted GHG) for each of the eleven regions for a total of thirty-three RINs. Those RINs exist in the MIDAS database and can be pulled to gather GHG emission data in real-time and forecasted. This data could be used to develop a load-modifying program based solely on reducing emissions independent of any price or cost signals. This type of load-modifying program could be more cost-effective and more technologically feasible for CleanPowerSF to implement given the public may access the MIDAS system, register for an account, and use the non-upload portion of the system to gather GHG emission data to help inform how a customer would manage their load. CleanPowerSF would not be needed to implement something like this as anyone can access the MIDAS system, but some form of educational program could help inform environmentally conscious customers of the capabilities of MIDAS and that those customers could leverage MIDAS to gather GHG emission data.

This would likely be unfeasible for residential customers since the MIDAS system requires some knowledge of coding to set up an account and access the MIDAS database, but more sophisticated commercial customers may have the resources to leverage MIDAS independently of anything CleanPowerSF administers.

Customers could also leverage the MIDAS database to pull CAISO Flex Alert RINs as a means to automate reactions to Flex Alerts. There are three Flex Alert RINs (historic, real-time, and forecasted), and thus customers could use the MIDAS database to shift their load in reaction to a Flex Alert. However, given CAISO already has a means by which to inform customers of Flex Alerts, the MIDAS Flex Alert RIN signal may not add any value above what already exists with the Flex Alert program.

CleanPowerSF may consider developing an education program to inform customers of MIDAS' capability with respect to GHG and Flex Alert RINs. However, more data, information, and analysis are needed to

[77] Sheperd, Morgan, et al, "Market Informed Demand Automation Server (MIDAS) Documentation Version 1.2: Connecting to and Interacting with the MIDAS Database and Application Programming Interface," CEC Staff Instructions, October 22, A-6. Available at: https://www.energy.ca.gov/publications/2021/market-informed-demand-automation-server-midas-documentation-version-12.

determine how this information would be gathered and communicated to customers as well as how customers might react to GHG and Flex Alert RINs alone. CleanPowerSF will explore these options in the future as it explores various ways to integrate MIDAS into its load-modifying programs.

4.8 MIDAS Enabled Load Flexibility Program Conclusion

After examining the cost effectiveness, technological feasibility, equity, grid and customer benefit concerns, CleanPowerSF is unable to conclude, at this time, that adopting new or modifying existing demand response programs that enable MIDAS signal interfacing viable. However, CleanPowerSF staff will continue to evaluate its existing PDP Program for modification to include MIDAS signal capability as well as evaluate new potential MIDAS enabled load flexibility programs in the future.

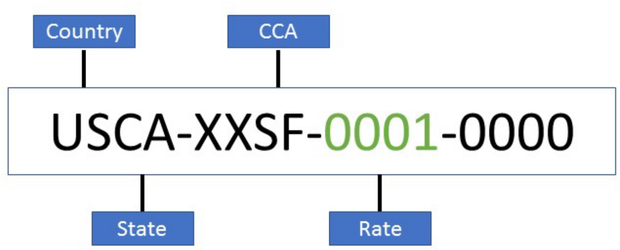
5. MIDAS Uploads and Maintenance

Section 1623.1(c) of the LMS regulations requires Large POUs and Large CCAs to upload their time-dependent rates to the MIDAS. The MIDAS platform provides a public and accessible database of time-dependent rates, greenhouse gas emission signals, and CAISO FlexAlerts to help ratepayers and automated service providers optimize electricity usage to shift load away from peak periods, reduce GHG emissions, reduce costs, and support grid reliability.

Directions on accessing the MIDAS system and retrieving time-dependent rates applicable to LMS regulated LSEs, GHG emissions signals, and CAISO FlexAlerts are available on the CEC's MIDAS webpage.[78] The CEC notes users will be required to register with MIDAS and will need programming skills and software to query and use the system.

Under the LMS regulations, each Large CCA must assign a Rate Identification Number (RIN) applicable to each of its time-dependent rates. Following the CEC MIDAS workshop on June 20, 2023, the CEC and the regulated entities agreed to a protocol for the RIN format, where unbundled CCA rates would include an "XX" for the Utility Distribution Company (distribution) portion of the RIN and a two-letter code for the Large CCA generation portion of the RIN, which CleanPowerSF chose to be "SF." CleanPowerSF is only responsible for uploading its generation portion of the rate. The rate portion of the RIN format CleanPowerSF is utilizing follows a simple incremental numerical approach with only digits representing the rate portion of the RIN. See Figure 8 below for an example of a CleanPowerSF RIN.

Figure 8: RIN Example



Each of CleanPowerSF's applicable time-dependent rates have a unique RIN associated with the rate, and when provided that RIN, any user of the MIDAS system will be able access hourly interval information about that rate.

Section 1623.1(c), as modified by CEC Order No. 23-0531-10, required Large CCAs to upload their time-dependent "base" rates by August 1, 2023 and upload the remaining time-dependent rates with modifiers by October 1, 2023.

CleanPowerSF uploads its time-dependent rates to MIDAS using the following protocol:

- Rates are provided to CleanPowerSF's billing agent, which are moved into the billing system test and production environments following repeated testing and validation

[78] MIDAS webpage available at: https://www.energy.ca.gov/proceedings/energy-commission-proceedings/inactive-proceedings/market-informed-demand-automation

- To prepare for the MIDAS upload process, the rates are converted into a streaming format as required by MIDAS and reformatted in XML and pushed to MIDAS using the CEC published Application Programming Interface (API). Rates are tested to ensure consistency with these requirements.
- CleanPowerSF staff independently verify that all applicable RINs appear in the MIDAS system.

CleanPowerSF staff are working on a streamlined automated process to reduce staff time required to manually verify RINs in MIDAS.

As of July 27, 2023, CleanPowerSF has uploaded the first set of applicable time-dependent rates to MIDAS, comprising of 66 rate permutations. Following each upload, CleanPowerSF staff independently confirm the upload is successful. As of September 26, 2023, CleanPowerSF uploaded to MIDAS the remaining applicable time-dependent rates, comprising 132 rate permutations for a total 198 rate permutations. Following that upload, CleanPowerSF independently confirmed the upload of all 198 rates.

CleanPowerSF makes no warranty or guarantee that customers using the CEC's MIDAS system to control their energy usage will result in lower costs to the customer.

See Appendix A for a full list of all CleanPowerSF RINs and the associated rate.

5.1 Future Rate Upload Process

The SFPUC reviews CleanPowerSF rates every fiscal year and implements adopted rate changes on July 1 each year. CleanPowerSF plans to upload all future time-dependent rates and changes to time-dependent rates to MIDAS as described above as necessary and before those rates become effective as directed by Section 1623.1(c). Further, CleanPowerSF will work with its billing agent to make this process simpler and easier to perform.

6. Plan for Rate Identification Number (RIN) Access and Customer Communication

CleanPowerSF staff, working with its billing agent, and in collaboration with the other CCAs in PG&E's service territory, have been working with PG&E to establish a process for including the generation RIN and QR code on customers' bills and online accounts by April 1, 2024. As noted in PG&E's LMS Compliance Plan submitted to the 23-LMS-01 Docket on October 2, 2023:

> "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."[79]

PG&E continues with respect to the QR code:

> "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."[80]

PG&E has indicated that, for unbundled customers given there is a transmission and distribution RIN (I.e. PG&E) and a generation RIN (e.g. CleanPowerSF), that two RINs and two QR codes will appear on unbundled customers' bills and online accounts. CleanPowerSF is working with its billing agent and other CCAs to standardize a process by which CleanPowerSF would provide PG&E with the applicable RINs to customers with time-varying rates and PG&E would automatically generate the QR code and place both the RIN and the QR code on the bill and online accounts. Since PG&E manages the bills for CCA customers, CleanPowerSF is reliant on PG&E to place the RINs and QR codes on customers' bills and online accounts, thus CleanPowerSF is limited in what it can do with respect to the actual placing of RINs and QR codes on customer bills and online accounts. PG&E has indicated in its compliance plan that it does not plan to provide a QR code webpage.

CleanPowerSF expects to have its generation portion of the customer's RIN placed on bills by April 1, 2024 contingent on PG&E's ability to do so, thus meeting this direction is not fully within the control of CleanPowerSF.

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[79] Pacific Gas and Electric Company, "2023 Compliance Plan for the Load management Standards Docket 23-LMS-01," October 2, 2023, 18. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=252489&DocumentContentId=87506 (accessed: March 28, 2024).

[80] Ibid, 19.

7. Single Statewide Standard Tool

Section 1623(c) of the LMS directs the Large IOUs, Large POUs, and Large CCAs to develop a single statewide standard tool for authorized rate data access by third parties, stating the tool shall:

- Provide the RIN(s) applicable to the customer's premise(s) to third parties authorized and selected by the customer;
- Provide any RINs, to which the customer is eligible to be switched, to third parties authorized and selected by the customer;
- Provide estimated average or annual bill amount(s) based on the customer's current rate and any other eligible rate(s) if the Large IOU, Large POU or Large CCA has an existing rate calculation tool and the customer is eligible for multiple rates;
- Enable the authorized third party to, upon the direction and consent of the customer, modify the customer's applicable rate to be reflected in the next billing cycle according to the Large IOU's, Large POU's or Large CCA's standard procedures;
- Incorporate reasonable and applicable cybersecurity measures;
- Minimize enrollment barriers; and
- Be accessible in a digital, machine-readable format according to best practices and standards.[81]

CleanPowerSF has been working with CalCCA and the other CCAs in collaboration with the Large IOUs and Large POUs on the development of the single statewide standard tool. CleanPowerSF also attended the CEC hosted workshop, "Load Management Standards and Statewide Rate Roll Workshop," on January 17, 2024 and contributed to CalCCA's filed comments in the 23-LMS-01 Docket addressing the subject areas that can be addressed during future and ongoing workshops. Those subject areas include:

- How the Statewide Tool will integrate with the Market Informed Demand Automation Server (MIDAS) and the price machine being considered by the CPUC for integration of dynamic rates;
- Barriers and/or or open questions regarding the Statewide Tool's rate comparison and change features, including:
  - How to address different LSE's treatment of rate modifiers in MIDAS; and
  - How to integrate existing rate change processes and comparison tools.
- Cybersecurity measures and the treatment of personally identifiable information;
- Cost recovery for tool development, operation, and maintenance;
- Processes for vendor selection for tool development, operation, and maintenance; and
- How to ensure a seamless customer experience for both unbundled and bundled customers.[82]

CleanPowerSF will continue to work with stakeholders as part of the development of the statewide standard tool.

[81] 20 CCR § 1623(c)(1).

[82] California Community Choice Association, "California Community Choice Association's Comments on the Workshop on Load Management Standards Implementation," January 31, 2024, 2. Available at : https://efiling.energy.ca.gov/GetDocument.aspx?tn=254282&DocumentContentId=89643 (accessed: March 28, 2024).

8. Public Information Campaign on RTP

Any transition from one electricity rate structure to another requires robust and coordinated education and outreach between CleanPowerSF and its diverse customers and communities. The recent transition from flat rate structures to time-of-use is a good example of the significant need for comprehensive and far-reaching education and outreach campaigns to inform customers of their new rates and the impact those rates may have on their bills.

In July 2021, most CleanPowerSF residential customers were automatically transitioned to the TOU rate plan.[83] This transition was preceded and accompanied by a wide-reaching outreach and education campaign to inform and educate customers about the rate change. To adopt either a time-dependent marginal cost-based rate or a MIDAS enabled load flexibility program in the future, CleanPowerSF will most likely follow a similar approach to its TOU transition campaign. CleanPowerSF will maintain its commitment to community centric communication, outreach, and education that will focus on:

- Reaching the diverse communities represented across San Francisco and the unique customers CleanPowerSF serves, including tailoring education and outreach to low-income and disadvantaged communities.
- Utilizing a comprehensive suite of resources and tools to reach customers, including digital, print, and community led channels to ensure customers are aware of CleanPowerSF's rate decisions and changes.
- Customer centric, clear, and concise communication best practices to ensure customers can manage their bills and energy use effectively.

8.1 Time-of-Use Transition Campaign

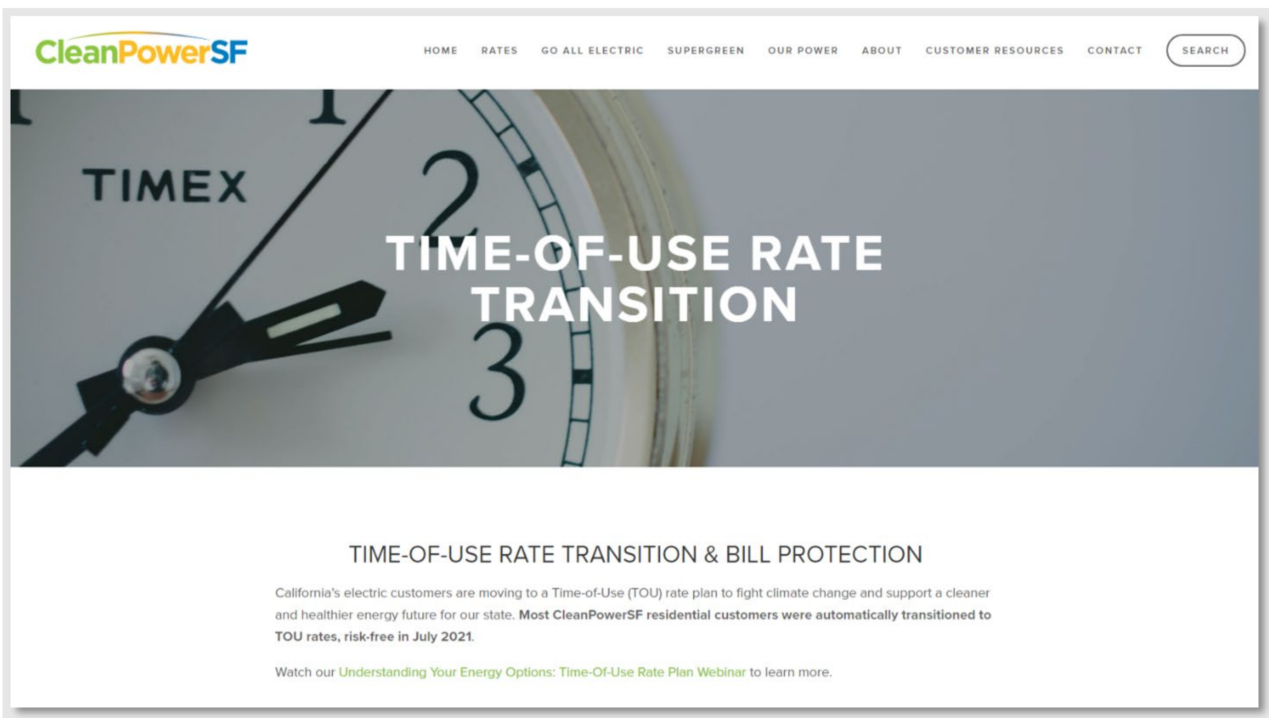
CleanPowerSF developed a multi-prong outreach and education campaign leveraging digital and online resources, factsheets, email blasts, webinars, websites, and other resources to educate and inform customers of the default transition to TOU rates.

CleanPowerSF's campaign was also deeply rooted in reaching the diverse communities that make up San Francisco as well as the different customer segments within CleanPowerSF. CleanPowerSF developed factsheets that were translated into multiple languages (Spanish, Tagalog, and Chinese) in addition to English. The factsheets explained in plain language what time-of-use is, how TOU rates work, peak and off-peak hours, and how to save money and reduce carbon emissions by shifting load from peak to off-peak periods.

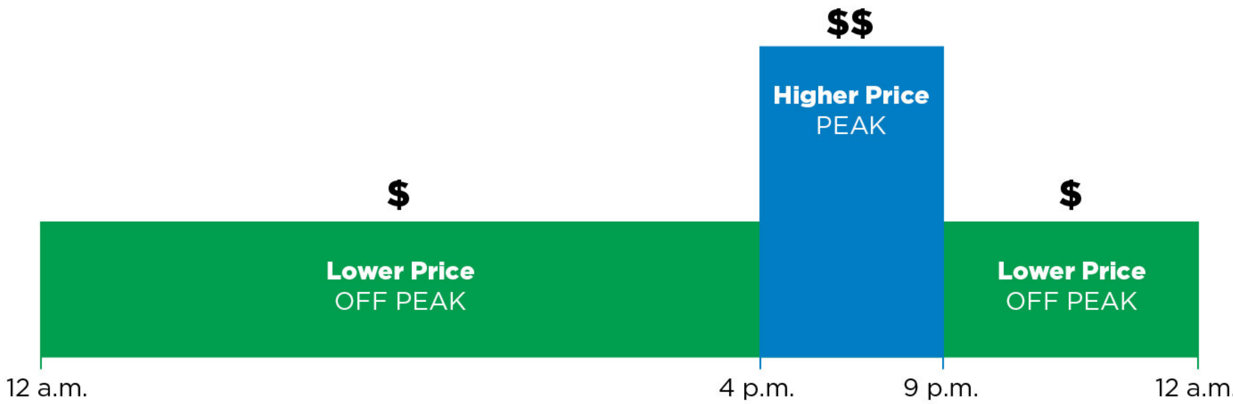
[83] See CleanPowerSF's Time-of-Use Transition webpage available at: https://www.cleanpowersf.org/tou

CleanPowerSF also provided mailers in collaboration with PG&E as part of the coordinated outreach and education plan between PG&E and CleanPowerSF (along with all other CCAs working on this launch of default TOU rates).

Continued education and outreach were also critical in ensuring customers understood the transition to TOU rates as well as understand bill impacts and rate structures over time and not just during the transition itself. Webpages and online communication were a crucial part of that goal. CleanPowerSF maintains a TOU webpage with resources to webinars, FAQ pages, cross-references to resources from other organizations, among many other resources for customers on an ongoing basis.



Included in CleanPowerSF's TOU webpage is an easy to understand graphic of how TOU rates work, showing the peak period with higher prices between 4 P.M. and 9 P.M. and the off-peak periods on either side of the peak period.



These communication techniques are helpful for a broad swath of customers, but as noted above in the PDP Program, CleanPowerSF also utilizes targeted outreach to specific customer segments that may be most responsive to certain programs or messaging. In the event CleanPowerSF adopts a marginal cost-based rate or MIDAS enabled program in the future, employing both broad and narrow outreach and education strategies will be paramount in communicating something as complicated as real-time-pricing.

CleanPowerSF will continue to educate customers on the potential benefits of TOU rates and how customers can save money and reduce carbon emissions by shifting load to cheaper and less carbon intense times of the day. Further, CleanPowerSF will continue to market its PDP Program and is considering expanding that program to more customer classes, which will require new outreach and education efforts. As all of these efforts are pursued, CleanPowerSF will assess applicability of these strategies to a potential future public information campaign around marginal cost-based rates and/or MIDAS enabled load flexibility programs.

CleanPowerSF will look to its experience in both the rollout of TOU rates and its PDP Program in developing any messaging around potential future RTP rates and MIDAS enabled programs. CleanPowerSF can also leverage the experience of other load serving entities as they roll-out their public information campaigns for any RTP or MIDAS enabled programs they will be offering.

8.2 D.24-01-032 CPUC Expanded RTP Pilots Information Campaign Consideration

CleanPowerSF staff will review the implementation plans filed by PG&E in their Tier 2 advice letters pursuant to D. 24-01-032 and determine whether CleanPowerSF will participate in the expanded RTP pilots. If CleanPowerSF does participate in the expanded RTP Pilot 2, CleanPowerSF will work closely with PG&E, along with other participating CCAs, to develop a public information, education, and enrollment campaign to inform customers of the availability of the RTP pilots and how the programs will work. The details of such a campaign will be determined as part of the implementation plan for the RTP pilots when filed by PG&E in their Tier 2 advice letter within sixty days of the effective date of D. 24-01-032. CleanPowerSF staff are currently engaged with PG&E and other interested CCAs in preliminary discussions of the expanded pilots and will be participating in the dual enrollment workshops ordered by Decision D. 24-01-032 as well.

9. Conclusion and Need for Modification and Delay of LMS Requirements

The LMS regulations provide direction pursuant to Section 1623.1(a)(2) where a Large CCA may approve a plan that delays or modifies compliance with the LMS regulations. Section 1623.1(a)(2) provides direction that, despite a Large CCA's good faith effort to comply with the regulations, the Large CCA may modify or delay compliance with the regulations.

Pursuant to Section 1623.1(a)(2), and as detailed in this compliance plan, despite CleanPowerSF's good faith efforts CleanPowerSF has concluded to delay implementation of MIDAS-enabled RTP rates and load flexibility programs as doing so on the schedule proposed in the LMS regulations would result in hardship to CleanPowerSF and its ratepayers. Further, based on CleanPowerSF's analysis, it is unclear if implementing LMS will improve system reliability, safety or efficiency. CleanPowerSF is particularly concerned about the potential for these programs to exacerbate energy inequities, and concludes that they are not technologically feasible or cost-effective to implement at this time.

9.1 Providing RINs and QR codes on Customer Bills

CleanPowerSF, in collaboration with PG&E and other CCAs operating in PG&E territory, does not currently expect any modification or delay in placing RINs and QR codes on applicable customer bills and online accounts by April 1, 2024. However, CleanPowerSF is almost entirely dependent on PG&E to ensure RINs and QR codes are placed on the applicable customer bills as PG&E controls the customers' bills and online accounts. CleanPowerSF, working with its billing agent, is developing a process with PG&E to allow PG&E to place the RIN and an automatically generated QR code on each customer's bill as detailed in Section 6 above.

9.2 Statewide Standard Tool Development

CleanPowerSF has been and will continue to be engaged with the Large IOUs, Large POUs, and other Large CCAs to develop by October 1, 2024 a plan for the development of the statewide standard tool pursuant to Section 1623(c). The development of this tool is contingent on many factors and as CleanPowerSF is just one of many entities working on the tool, delays or modifications beyond the control of CleanPowerSF may occur. CleanPowerSF looks forward to working with CEC staff and other stakeholders in developing this tool and encourages the CEC to hold more workshops to facilitate further development.

9.3 Marginal Cost-Based Rate Development

As detailed above in Section 3 Marginal Cost-Based Hourly/RTP Rate Development, CleanPowerSF, based on its analysis, evidence, and research, cannot conclude that developing a marginal cost-based rate that varies hourly or sub-hourly would be cost-effective, technologically feasible, equitable, provide benefits to the grid, or provide benefits to customers at this time. Thus, doing so in spite of these issues would create hardship and reduce system reliability, equity, safety, and efficiency. CleanPowerSF staff do not plan on proposing a marginal cost-based hourly or sub-hourly rate or rates for adoption by the SFPUC Commission by July 1, 2025 for implementation by July 1, 2027.

CleanPowerSF supports the goals of the LMS regulations of encouraging the use of electrical energy at off-peak hours, encouraging the control of daily and seasonal peak loads to improve electric system efficiency and reliability, lessening or delaying the need for new electrical capacity, and reducing fossil fuel consumption and greenhouse gas emissions. However, CleanPowerSF believes its current rates and programs satisfy these goals at present and is committed to furthering these goals as we explore new rate designs and demand flexibility programs.

CleanPowerSF will consider participation in the expanded RTP pilots authorized in D. 24-01-032, after reviewing the implementation plan PG&E files. If CleanPowerSF decides to participate, it will leverage the experience, data, and knowledge gained to help inform future iterations of this LMS Plan.

9.4 MIDAS Enabled Load Flexibility/Demand Response Programs

As detailed above in Section 4 MIDAS Enabled Load Flexibility/Demand Response Programs, CleanPowerSF, based on its analysis, evidence, and research, cannot conclude that modifying its existing load flexibility programs to be MIDAS enabled or developing new MIDAS enabled load flexibility programs would be cost-effective, technologically feasible, equitable, provide benefits to the grid, or provide benefits to customers. Doing so in spite of these issues would create hardship and reduce system reliability, equity, safety, and efficiency. CleanPowerSF will continue to evaluate new program options or modifications to existing programs in the future that may leverage MIDAS signals. In particular CleanPowerSF will be evaluating the possibility of educating customers about using the MIDAS system's GHG and Flex Alert RINs to better respond to grid stress events through Flex Alerts. More analysis is needed to determine the viability and use of that program as currently any member of the public can already use the MIDAS system for these features. Thus, pursuant to Section 1623.1(b)(3) of the LMS regulations, CleanPowerSF will submit a list of load flexibility programs by October 1, 2024. However, since CleanPowerSF will not be developing any MIDAS enabled load flexibility programs at this time, the list of those programs will not include a MIDAS enabled load flexibility program.

Appendix A: RIN List

Below are the CleanPowerSF rates and associated RINs that have been uploaded to MIDAS.

MIDAS Rate Name	RIN
A-1-B	USCA-XXSF-0001-0000
A-10-B	USCA-XXSF-0002-0000
A-10-B-P	USCA-XXSF-0003-0000
A-10-B-T	USCA-XXSF-0004-0000
A-6	USCA-XXSF-0005-0000
A-ST-S	USCA-XXSF-0006-0000
AG-4-A	USCA-XXSF-0007-0000
AG-4-B	USCA-XXSF-0008-0000
AG-5-A	USCA-XXSF-0009-0000
AG-5-B	USCA-XXSF-0010-0000
AG-5-C	USCA-XXSF-0011-0000
AG-A1-A	USCA-XXSF-0012-0000
AG-A2-A	USCA-XXSF-0013-0000
AG-B-A	USCA-XXSF-0014-0000
AG-C-A	USCA-XXSF-0015-0000
AG-F-A1	USCA-XXSF-0016-0000
AG-F-A2	USCA-XXSF-0017-0000
AG-F-A3	USCA-XXSF-0018-0000
AG-F-B1	USCA-XXSF-0019-0000
AG-F-B2	USCA-XXSF-0020-0000
AG-F-B3	USCA-XXSF-0021-0000
AG-F-C1	USCA-XXSF-0022-0000
AG-F-C2	USCA-XXSF-0023-0000
AG-F-C3	USCA-XXSF-0024-0000
B-1	USCA-XXSF-0025-0000
B-1-ST	USCA-XXSF-0026-0000
B-10-P	USCA-XXSF-0027-0000
B-10-S	USCA-XXSF-0028-0000
B-10-T	USCA-XXSF-0029-0000
B-19-P	USCA-XXSF-0030-0000
B-19-R-P	USCA-XXSF-0031-0000
B-19-R-S	USCA-XXSF-0032-0000
B-19-R-T	USCA-XXSF-0033-0000
B-19-S	USCA-XXSF-0034-0000
B-19-S-P	USCA-XXSF-0035-0000
B-19-S-S	USCA-XXSF-0036-0000
B-19-S-T	USCA-XXSF-0037-0000

MIDAS Rate Name	RIN
B-19-T	USCA-XXSF-0038-0000
B-20-P	USCA-XXSF-0039-0000
B-20-R-P	USCA-XXSF-0040-0000
B-20-R-S	USCA-XXSF-0041-0000
B-20-R-T	USCA-XXSF-0042-0000
B-20-S	USCA-XXSF-0043-0000
B-20-S-P	USCA-XXSF-0044-0000
B-20-S-S	USCA-XXSF-0045-0000
B-20-S-T	USCA-XXSF-0046-0000
B-20-T	USCA-XXSF-0047-0000
B-6	USCA-XXSF-0048-0000
B-EV-1	USCA-XXSF-0049-0000
B-EV-2-P	USCA-XXSF-0050-0000
B-EV-2-S	USCA-XXSF-0051-0000
E-19-P	USCA-XXSF-0052-0000
E-19-S	USCA-XXSF-0053-0000
E-19-T	USCA-XXSF-0054-0000
E-20-P	USCA-XXSF-0055-0000
E-20-S	USCA-XXSF-0056-0000
E-6	USCA-XXSF-0057-0000
E-ELEC	USCA-XXSF-0058-0000
E-EV	USCA-XXSF-0059-0000
E-EV2-A	USCA-XXSF-0060-0000
E-TOU-B	USCA-XXSF-0061-0000
E-TOU-C3	USCA-XXSF-0062-0000
E-TOU-D	USCA-XXSF-0063-0000
S-B-P	USCA-XXSF-0064-0000
S-B-S	USCA-XXSF-0065-0000
S-B-T	USCA-XXSF-0066-0000
A-1-B-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0067-0000
A-1-B-RESIDENTIAL SuperGreen	USCA-XXSF-0068-0000
A-10-B-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0069-0000
A-10-B-RESIDENTIAL SuperGreen	USCA-XXSF-0070-0000
A-10-B-P-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0071-0000
A-10-B-P-RESIDENTIAL SuperGreen	USCA-XXSF-0072-0000
A-10-B-T-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0073-0000
A-10-B-T-RESIDENTIAL SuperGreen	USCA-XXSF-0074-0000
A-6-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0075-0000
A-6-RESIDENTIAL SuperGreen	USCA-XXSF-0076-0000
A-ST-S-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0077-0000

MIDAS Rate Name	RIN
A-ST-S-RESIDENTIAL SuperGreen	USCA-XXSF-0078-0000
AG-4-A-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0079-0000
AG-4-A-RESIDENTIAL SuperGreen	USCA-XXSF-0080-0000
AG-4-B-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0081-0000
AG-4-B-RESIDENTIAL SuperGreen	USCA-XXSF-0082-0000
AG-5-A-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0083-0000
AG-5-A-RESIDENTIAL SuperGreen	USCA-XXSF-0084-0000
AG-5-B-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0085-0000
AG-5-B-RESIDENTIAL SuperGreen	USCA-XXSF-0086-0000
AG-5-C-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0087-0000
AG-5-C-RESIDENTIAL SuperGreen	USCA-XXSF-0088-0000
AG-A1-A-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0089-0000
AG-A1-A-RESIDENTIAL SuperGreen	USCA-XXSF-0090-0000
AG-A2-A-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0091-0000
AG-A2-A-RESIDENTIAL SuperGreen	USCA-XXSF-0092-0000
AG-B-A-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0093-0000
AG-B-A-RESIDENTIAL SuperGreen	USCA-XXSF-0094-0000
AG-C-A-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0095-0000
AG-C-A-RESIDENTIAL SuperGreen	USCA-XXSF-0096-0000
AG-F-A1-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0097-0000
AG-F-A1-RESIDENTIAL SuperGreen	USCA-XXSF-0098-0000
AG-F-A2-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0099-0000
AG-F-A2-RESIDENTIAL SuperGreen	USCA-XXSF-0100-0000
AG-F-A3-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0101-0000
AG-F-A3-RESIDENTIAL SuperGreen	USCA-XXSF-0102-0000
AG-F-B1-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0103-0000
AG-F-B1-RESIDENTIAL SuperGreen	USCA-XXSF-0104-0000
AG-F-B2-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0105-0000
AG-F-B2-RESIDENTIAL SuperGreen	USCA-XXSF-0106-0000
AG-F-B3-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0107-0000
AG-F-B3-RESIDENTIAL SuperGreen	USCA-XXSF-0108-0000
AG-F-C1-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0109-0000
AG-F-C1-RESIDENTIAL SuperGreen	USCA-XXSF-0110-0000
AG-F-C2-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0111-0000
AG-F-C2-RESIDENTIAL SuperGreen	USCA-XXSF-0112-0000
AG-F-C3-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0113-0000
AG-F-C3-RESIDENTIAL SuperGreen	USCA-XXSF-0114-0000
B-1-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0115-0000
B-1-RESIDENTIAL SuperGreen	USCA-XXSF-0116-0000
B-1-ST-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0117-0000

MIDAS Rate Name	RIN
B-1-ST-RESIDENTIAL SuperGreen	USCA-XXSF-0118-0000
B-10-P-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0119-0000
B-10-P-RESIDENTIAL SuperGreen	USCA-XXSF-0120-0000
B-10-S-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0121-0000
B-10-S-RESIDENTIAL SuperGreen	USCA-XXSF-0122-0000
B-10-T-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0123-0000
B-10-T-RESIDENTIAL SuperGreen	USCA-XXSF-0124-0000
B-19-P-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0125-0000
B-19-P-RESIDENTIAL SuperGreen	USCA-XXSF-0126-0000
B-19-R-P-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0127-0000
B-19-R-P-RESIDENTIAL SuperGreen	USCA-XXSF-0128-0000
B-19-R-S-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0129-0000
B-19-R-S-RESIDENTIAL SuperGreen	USCA-XXSF-0130-0000
B-19-R-T-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0131-0000
B-19-R-T-RESIDENTIAL SuperGreen	USCA-XXSF-0132-0000
B-19-S-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0133-0000
B-19-S-RESIDENTIAL SuperGreen	USCA-XXSF-0134-0000
B-19-S-P-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0135-0000
B-19-S-P-RESIDENTIAL SuperGreen	USCA-XXSF-0136-0000
B-19-S-S-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0137-0000
B-19-S-S-RESIDENTIAL SuperGreen	USCA-XXSF-0138-0000
B-19-S-T-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0139-0000
B-19-S-T-RESIDENTIAL SuperGreen	USCA-XXSF-0140-0000
B-19-T-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0141-0000
B-19-T-RESIDENTIAL SuperGreen	USCA-XXSF-0142-0000
B-20-P-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0143-0000
B-20-P-RESIDENTIAL SuperGreen	USCA-XXSF-0144-0000
B-20-R-P-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0145-0000
B-20-R-P-RESIDENTIAL SuperGreen	USCA-XXSF-0146-0000
B-20-R-S-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0147-0000
B-20-R-S-RESIDENTIAL SuperGreen	USCA-XXSF-0148-0000
B-20-R-T-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0149-0000
B-20-R-T-RESIDENTIAL SuperGreen	USCA-XXSF-0150-0000
B-20-S-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0151-0000
B-20-S-RESIDENTIAL SuperGreen	USCA-XXSF-0152-0000
B-20-S-P-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0153-0000
B-20-S-P-RESIDENTIAL SuperGreen	USCA-XXSF-0154-0000
B-20-S-S-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0155-0000
B-20-S-S-RESIDENTIAL SuperGreen	USCA-XXSF-0156-0000
B-20-S-T-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0157-0000

MIDAS Rate Name	RIN
B-20-S-T-RESIDENTIAL SuperGreen	USCA-XXSF-0158-0000
B-20-T-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0159-0000
B-20-T-RESIDENTIAL SuperGreen	USCA-XXSF-0160-0000
B-6-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0161-0000
B-6-RESIDENTIAL SuperGreen	USCA-XXSF-0162-0000
B-EV-1-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0163-0000
B-EV-1-RESIDENTIAL SuperGreen	USCA-XXSF-0164-0000
B-EV-2-P-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0165-0000
B-EV-2-P-RESIDENTIAL SuperGreen	USCA-XXSF-0166-0000
B-EV-2-S-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0167-0000
B-EV-2-S-RESIDENTIAL SuperGreen	USCA-XXSF-0168-0000
E-19-P-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0169-0000
E-19-P-RESIDENTIAL SuperGreen	USCA-XXSF-0170-0000
E-19-S-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0171-0000
E-19-S-RESIDENTIAL SuperGreen	USCA-XXSF-0172-0000
E-19-T-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0173-0000
E-19-T-RESIDENTIAL SuperGreen	USCA-XXSF-0174-0000
E-20-P-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0175-0000
E-20-P-RESIDENTIAL SuperGreen	USCA-XXSF-0176-0000
E-20-S-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0177-0000
E-20-S-RESIDENTIAL SuperGreen	USCA-XXSF-0178-0000
E-6-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0179-0000
E-6-RESIDENTIAL SuperGreen	USCA-XXSF-0180-0000
E-ELEC-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0181-0000
E-ELEC-RESIDENTIAL SuperGreen	USCA-XXSF-0182-0000
E-EV-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0183-0000
E-EV-RESIDENTIAL SuperGreen	USCA-XXSF-0184-0000
E-EV2-A-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0185-0000
E-EV2-A-RESIDENTIAL SuperGreen	USCA-XXSF-0186-0000
E-TOU-B-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0187-0000
E-TOU-B-RESIDENTIAL SuperGreen	USCA-XXSF-0188-0000
E-TOU-C3-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0189-0000
E-TOU-C3-RESIDENTIAL SuperGreen	USCA-XXSF-0190-0000
E-TOU-D-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0191-0000
E-TOU-D-RESIDENTIAL SuperGreen	USCA-XXSF-0192-0000
S-B-P-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0193-0000
S-B-P-RESIDENTIAL SuperGreen	USCA-XXSF-0194-0000
S-B-S-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0195-0000
S-B-S-RESIDENTIAL SuperGreen	USCA-XXSF-0196-0000
S-B-T-NON-RESIDENTIAL SuperGreen	USCA-XXSF-0197-0000

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MIDAS Rate Name	RIN
S-B-T-RESIDENTIAL SuperGreen	USCA-XXSF-0198-0000
A-1-B-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0199-0000
A-10-B-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0200-0000
A-10-B-P-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0201-0000
A-10-B-T-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0202-0000
A-6-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0203-0000
A-ST-S-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0204-0000
AG-4-A-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0205-0000
AG-4-B-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0206-0000
AG-5-A-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0207-0000
AG-5-B-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0208-0000
AG-5-C-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0209-0000
AG-A1-A-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0210-0000
AG-A2-A-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0211-0000
AG-B-A-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0212-0000
AG-C-A-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0213-0000
AG-F-A1-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0214-0000
AG-F-A2-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0215-0000
AG-F-A3-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0216-0000
AG-F-B1-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0217-0000
AG-F-B2-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0218-0000
AG-F-B3-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0219-0000
AG-F-C1-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0220-0000
AG-F-C2-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0221-0000
AG-F-C3-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0222-0000
B-1-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0223-0000
B-1-ST-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0224-0000
B-10-P-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0225-0000
B-10-S-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0226-0000
B-10-T-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0227-0000
B-19-P-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0228-0000
B-19-R-P-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0229-0000
B-19-R-S-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0230-0000
B-19-R-T-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0231-0000
B-19-S-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0232-0000
B-19-S-P-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0233-0000
B-19-S-S-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0234-0000
B-19-S-T-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0235-0000
B-19-T-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0236-0000
B-20-P-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0237-0000

MIDAS Rate Name	RIN
B-20-R-P-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0238-0000
B-20-R-S-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0239-0000
B-20-R-T-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0240-0000
B-20-S-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0241-0000
B-20-S-P-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0242-0000
B-20-S-S-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0243-0000
B-20-S-T-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0244-0000
B-20-T-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0245-0000
B-6-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0246-0000
B-EV-1-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0247-0000
B-EV-2-P-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0248-0000
B-EV-2-S-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0249-0000
E-19-P-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0250-0000
E-19-S-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0251-0000
E-19-T-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0252-0000
E-20-P-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0253-0000
E-20-S-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0254-0000
E-ELEC-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0255-0000
E-EV-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0256-0000
E-EV2-A-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0257-0000
E-TOU-B-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0258-0000
E-TOU-C3-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0259-0000
E-TOU-D-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0260-0000
S-B-P-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0261-0000
S-B-S-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0262-0000
S-B-T-NON-RESIDENTIAL-MLC SuperGreen	USCA-XXSF-0263-0000