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PG&E Comments on Potential Amendments to Load Managemet Standards

Additional submitted attachment is included below.

Pacific Gas and Electric Company

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California Energy Commission
Efficiency Division - Buildings Energy Efficiency Standards Program
Docket No 19-IOR-01
1516 9th Street
Sacramento, CA 95814

RE: Pacific Gas and Electric Company Comments on the California Energy Commission (CEC)'s Potential Amendments to the Load Management Standards within the Load Management Rulemaking (Docket Number 19-OIR-01)

On April 12, 2021, the California Energy Commission (CEC) staff conducted a workshop to receive public input on their report, Potential Amendments to the Load Management Standards (California Code of Regulation Title 20 § 1623) within the Load Management Rulemaking (19-OIR-01). The draft amendments include mandates for electric utilities to file and seek approval of changes to their rates. The mandatory rate and tariff updates would apply to Pacific Gas and Electric (PG&E), Southern California Edison (SCE), Los Angeles Department of Water and Power (LADWP), Sacramento Municipal Utility District (SMUD), and San Diego Gas and Electric (SDG&E) – and the Community Choice Aggregators (CCAs) operating within these service territories and require them to:

1. Maintain the accuracy of existing and future time-varying rates in the CEC's publicly available and machine-readable rate database.
2. Develop a standard rate information access tool to support third-party services.
3. Develop locational rates that change hourly or sub-hourly to reflect marginal wholesale costs by March 31, 2023, and submit those rates to the utility's governing body for approval.
4. Integrate information about new time-varying rates and automation program technologies into existing customer education and outreach programs by March 31, 2023, to enable customers to automate their response to marginal grid signals (i.e., marginal prices, marginal greenhouse gas emissions metrics or other Commission-approved marginal signals that enable automated end-use response).

PG&E supports the development of automated demand flexibility and more dynamic rates as a load management tool to help meet the state's climate goals. However, the load management tariff standards are premature at this time. The Standard should not take effect until the CEC and stakeholders have had the opportunity to conduct comprehensive pilot studies that fully assess the costs and benefits of real-time rates, including required infrastructure, manufacturer interest, automated load management enabled device availability, bill impacts, and customer impacts. In summary, PG&E recommends the CEC:

I. Remove the mandatory rate filing requirement and incorporate flexibility in the tariff language regarding consideration of the timeline, rate design, feasibility of customer classes, customer bill impacts, and cost-effectiveness of the Standard.

II. Work with the California Public Utilities Commission (CPUC) to coordinate and collaborate on consideration of the new load management standards, consistent with the CPUC's exclusive authority over the reasonableness, costs and customer impacts of various rates, utility rate design and demand response programs.
III. Update the cost effectiveness analysis to include scenarios and sensitivities, more accurate utility cost assumptions, and updated benefits.
IV. Utilize OpenADR 2.0 as the standard for sending rate signals.
V. Leverage the existing investor owned utilities (IOU) Share My Data (SMD) platform to provide the customer's Rate Identification Number (RIN) to an Automation Service Provider (ASP) in compliance with CPUC privacy rules rather than developing a new access tool.
VI. Evaluate and determine the proposed feasibility, cost-effectiveness and cost recovery mechanism for IOUs, SMUD, LADWP, and CCAs to comply with the CEC's load management standards authority and the CPUC's and other utility governing bodies' exclusive jurisdiction over rates and services to utility customers and clarify that Market Informed Demand Automation Server (MIDAS) database updates and maintenance commence when needed.

I. PG&E recommends that the CEC remove the mandatory rate filing requirement and incorporate flexibility in the tariff language regarding the timeline, rate design, feasibility of participation of customer classes, customer bill impacts, and cost effectiveness of the Standard.

Currently, the Standard requires utilities to apply for approval of at least one hourly or sub-hourly rate for all customer classes by March 31, 2023.[1] The Standard should not take effect until the CEC and stakeholders have had the opportunity to conduct and analyze comprehensive pilot studies and customer research that fully assess the costs and benefits of real-time rates, including required infrastructure, manufacturer interest, bill impacts, customer response and impacts, and load impacts. PG&E recommends the load management standard provide more flexibility regarding implementation timelines, participating customer classes and potential dynamic rate[2] designs, as explained further below.

Implementation Timeline

PG&E believes the CEC's timeline for proposing consideration of a real-time pricing (RTP) rate for each customer class by March 31, 2023, is too aggressive. CEC and PG&E spending on RTP pilots and customer rate design preferences research is currently estimated to be between $28.1 and $33.7 million-without including other IOUs, CCAs, SMUD, or LADWP.[3] Proposing RTP rates for each customer class prior to the completion of these pilots would be a barrier to applying lessons learned to the RTP rates ultimately proposed as required by this load management rulemaking. PG&E urges the CEC to revise their proposed timeline to ensure pilots and customer research will inform the dynamic pricing rates proposed to comply with the load management standard.

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[1] CEC Load Management Tariff Amendments "on or prior to March 31, 2023, utilities shall apply for approval of at least one hourly or sub-hourly marginal cost rate for each customer class. Utilities shall provide the CEC with informational copies of tariff applications when they are submitted."
[2] Dynamic rate includes any time-varying rate such as time-of-use (TOU), Critical Peak Pricing (CPP), real-time pricing (RTP) rates.
[3] PG&E summarizes the cost of currently proposed pilots as: California Flexible Load Research and Development Hub – CalFlexHub ($16 million) + CEV ($3.9 million to $6.0 million) + C&I (incremental to CEV $7.8 million to $11 million) + residential and agricultural research ($400,000 and $700,000).

The CEC's California Flexible Load Research and Development Hub (CalFlexHub) is testing technologies and communication systems that will be critical to enable automated response to RTP. The learnings from these pilots will not be available until 2024, which is one year after the CEC's proposed timing for requiring load serving entities (LSE) to propose RTP rates for all customer classes. In addition, PG&E has also recently proposed two separate RTP pilots for commercial electric vehicles (CEVs) and commercial and industrial (C&I) customers to learn about the customer experience, test enablement systems, and evaluate load shift and if the CEV rate promotes transportation electrification. The results of these pilots will not be available until 2025 at the earliest – which is two years after the CEC's requirement that utilities propose RTP rates for all customer classes to their governing bodies. In its General Rate Case (GRC) Phase II (GRC II) proceeding, PG&E has also proposed customer research to examine the rate design preferences of residential and agricultural customers, which may result in additional pilots. PG&E urges the CEC to adopt a timeline that allows pilots and research to inform the proposed dynamic rates submitted to comply with the load management standard.

Customer Classes

PG&E believes flexibility is needed regarding which customer classes are to be included and the timeline for their inclusion. To support PG&E's recent proposed C&I RTP Pilot in its GRC II proceeding,[4] the Electric Power Research Institute performed a Benchmarking Study (EPRI Benchmarking Study) of RTP programs offered by regulated utilities in the United States.[5] The EPRI Benchmarking Study found 55 currently active RTP rate schedules offered by regulated utilities in the U.S. Two of those RTP rate schedules were specifically for residential customers, and two were for agricultural customers. The remaining 51 RTP rate schedules offered were for C&I customers. The EPRI Benchmarking Study concluded that the reason RTP generally has not been available to residential customers is primarily due to a lack of technology to automate response to price signals, while, conversely, larger C&I customers are more likely to have control systems in place to automate responses to RTP signals, and/or have dedicated energy managers and staff who actively manage their energy use.[6] Hence, there is very little, if any, evidence of residential or agricultural customer interest in or acceptance of RTP rates. PG&E's proposed rate design study for residential and agricultural customer classes seeks to evaluate preferences for different dynamic pricing rate structures, including RTP, and to evaluate the potential for dynamic pricing rate offerings to result in incremental load reduction versus what is being achieved by time-of-use (TOU) rates and potentially TOU rates with enabling technology.

Mandating RTP as the best dynamic pricing structure for residential and agricultural customer classes would be premature prior to the results of the proposed customer preferences research. Therefore, the Standards should have flexibility regarding the customer classes that should be provided with a dynamic rate, much less an RTP rate. In addition, this year's winter storm in Texas demonstrated that the risks of RTP for residential customers can be substantial. While the California regulatory context and the California Independent System Operator (CAISO) market are very different, specific consideration should be made for residential customers to mitigate the risk of market breakdown such as in Texas, the risk of user error, and the risk of technology or communication failure for customers with RTP.

Rate Design

PG&E recommends the CEC provide flexibility regarding consideration of a specific dynamic rate design that can be applied to each customer class. To elaborate, some rate designs may not meet the CEC's definition of RTP or an hourly or sub-hourly rate but may be more effective than an RTP rate and be more

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[4] A.19-11-019, Exh (RTP-1).
[5] A.19-11-019, Exh (RTP-1).
[6] A.19-11-019, Exh (RTP-1), AppA-7, Electric Power Research Institute (EPRI) Report, p. vii.

appropriate for certain customer classes. For example, Oklahoma Gas & Electric (OG&E)'s Variable Peak Pricing (VPP) residential SmartHours program has been in operation since 2012, with about 11% of residential customers enrolled. Although VPP applies only to peak period hours, it selects from a set of four prices (low, standard, high, and critical) based on a daily algorithm that evaluates the forecasted marginal prices for the next day. VPP can be considered an RTP hybrid. Average load reduction at system peak for SmartHours customers with the free OG&E-provided and installed programmable thermostat on a high-price day is 0.92 kilowatts (kW), and on a critical-price day is 1.31 kW.

PG&E considers that it is also premature to conclude that locational rates (with spatial granularity) should be included in dynamic pricing rate design, and more study is needed. EPRI's Benchmarking Study found that only four out of 55 RTP rates offered by regulated U.S. utilities had spatial granularity. Two of the main obstacles PG&E observes in creating a cost-based, real-time distribution rate is that distribution capacity constraints are much more localized and can be temporary. This makes the pricing for such a program highly variable year-to-year. It is not clear if targeted demand response programs or pricing programs are best able to address locational grid constraints.

II. The CEC should exercise its authority to require IOUs, SMUD, LADWP, and the CCAs in those territories to *consider* submitting hourly or sub-hourly rates to their regulatory bodies consistent with the Load Management Standards that comply with the CEC's statutory authority. However, the CEC may not *mandate* that utilities submit or file any particular rates or load management programs because the CPUC and other utility governing bodies have exclusive authority over rates and services to utility customers.

The Public Resources Code grants the CEC authority, by no later than 1978, to adopt load management standards. However, it does not grant the CEC authority to mandate that utilities submit or file specific rates or load management programs to their governing bodies, including the CPUC. The legislature has granted the CPUC with plenary and exclusive authority to regulate the rates, services, and programs of investor owned utilities, and the governing bodies of publicly owned utilities and CCAs have similar plenary, exclusive authority. The CEC's load management standards may require the utilities to consider the CEC's load management standards, but may not mandate that the utilities file and submit for approval specific rates or load management programs over which the CPUC and other utility governing bodies for CCAs or publicly owned utilities have exclusive, plenary authority.

III. In its cost-effectiveness analysis, the CEC should include scenarios and sensitivities, more accurate utility cost assumptions, and an update of its assessment of benefits.

Scenarios and Sensitivities

First, PG&E suggests the cost-effectiveness analysis performed for the load management standards incorporate a range of scenarios and sensitivities, including but not limited to:

- Forecasted market penetration (number of customers) participating in RTP with and without CCA participation,
- Average load response to dynamic rate for different customer classes, with and without enabling technology,
- Aggregate load response based on combinations of market penetration and average load response,
- Utility costs with and without CCA participation,
- A range of CEC costs,
- A range of ASPs costs,

- A similar comparison of cost/benefit for TOU rates with and without enabling technology (e.g., how many TOU customers would it take to get the same results as a 2% penetration of RTP customers), and
- Adoption of load flexibility controls and cost associated by manufacturers.

Utility Costs

PG&E is concerned that the cost-effectiveness analysis, and costs to "utilities" from chapter eight, table three of the CEC's potential amendments to the load management standards, significantly underestimate the costs of enabling dynamic rate which include: 1.) billing system modifications, 2.) customer enablement pricing platforms, 3.) reporting, 4.) marketing, education and outreach, and 4.) ASP authorization. In the CEC's workshop, CEC staff commented that the costs were based on demand response budgets and estimated personnel hours. PG&E does not believe the method or final results reflects actual costs and would like to work with the CEC on updating its cost estimates for utilities.

In the CEC's estimate, the costs for all utilities amounts to $4.8 million in development and implementation and $0.6 million in annual maintenance. In contrast, the cost for development and implementation of two of PG&E's pilots for a limited number of participants for just three rate classes (BEV, B-19, and B-20)[7] is estimated to be between $11.7 million – $17 million.[8]

PG&E does not believe the statewide marketing costs identified in table three of the CEC's potential amendments to the load management standards are enough to cover this requirement based on PG&E's experience when marketing new rates to customers, especially since the new hourly rate is a new concept to many customers. In contrast to the CEC's estimated $750,000 for development and implementation and $375,000 annually, PG&E's experience with pilots for three customer classes is even larger. The costs for the C&I RTP marketing, education, and outreach (ME&O) is estimated at $550,000. Of this total cost, it is estimated that $272,000 would be dedicated to customer acquisition, while $278,000 would be dedicated to customer retention and support.[9] The costs for the CEV RTP ME&O[10] is estimated at $153,000 to $443,000. It is estimated that $33,000 to $218,000 of these costs will be dedicated to customer acquisition including developing sales support tools and one-to-one outreach, while $20,000 to $25,000 of the total costs is dedicated to maintenance for acquired customers and will include vendor support tools. Lastly, $100,000 to $200,000 is forecasted for customer experience and customer insights research. This research will cover qualitative and quantitative research with program participants and research with prospective customers. The primary variance in these estimates is due to the number of pilot participants and the scope executed for the research.

Similarly, PG&E does not believe the billing system costs identified in table three of the CEC's potential amendments to the load management standards are sufficient to cover this requirement based on PG&E's experience and costs. The CEC estimates $3,750,000 for development and implementation and $75,000 annually for its whole proposed load management standard. On the other hand, PG&E has estimated the following cost estimates, first for implementing the new non-residential TOU periods pursuant to D.18-08-013, and second just for its RTP pilot proposals in A.20-11-011 and A.19-11-019: 1.) the cost to implement new TOU periods in the billing system for non-residential customers alone has been more than $2 million; and, 2.) the cost to modify the billing system for the CEV RTP Pilot was estimated as ranging

[7] BEV (Business Electric Vehicle) B-19 (medium general demand-metered TOU Service); B-20 (Service to customers with maximum demands of 1000 kilowatts or more)
[8] The range in costs reflects the variability of implementing technology projects as the details will not be apparent until the business rules are fully defined.
[9] CPUC. A. 19-11-019. Ch. 5. pp. 16.
[10] CPUC. A. 20-10-011. Ch. 3. pp 11-16.

from $300,000 to $550,000,[11] and the incremental cost for expanding the CEV RTP pilot customer enablement pricing platform for the C&I RTP pilot is estimated to range from $1 million to $1.3 million. The C&I RTP pilot incremental cost estimate includes a one-time cost (ranging from $50,000 to $100,000) to expand the CEV RTP pilot technology platform and an additional $40,000 to $50,000 per month in operations and maintenance costs.[12]

Benefits

PG&E suggests that the cost-effectiveness analysis be re-run for benefits, which underestimates the cost to charge, does not accurately represent how load settles, and ignores other market pathways. The CEC's potential amendments to the load management standards states, "assuming zero cost for charging from otherwise curtailed renewables, and night-time charging at the California ISO's 2019 locational marginal prices, the net financial value of this shifted battery resource is $34.60 per megawatt hour (MWh). This per MWh value translates to a net present value over 15 years of roughly $81 million." This ignores three key items:

- The CEC assumes that all batteries will charge at a zero price, which due to retail rates or the activities of the energy imbalance market, may not be accurate.
- The CEC assumes EV charging is at the 2019 CAISO locational marginal prices (LMP), but because this load resource would not be directly participating in the market, it would settle at the default load aggregation point price for each participating transmission operator's service territory, rather than at the LMP.
- The CEC omits some load management programs or market pathways which enable aggregated behind-the-meter (BTM) resources to charge at a negative or zero price in their cost-effectiveness analysis and in "table two: summary of demand response programs in California," The CEC should update their analysis and the tables to reflect the following two models available to price-responsive load, although currently there are no CPUC-approved retail tariffs for BTM use:
    - The proxy demand response-load shift resource (PDR-LSR) model is a CAISO market model that allows for behind-the-meter batteries to bid zero or negative prices to increase load and is settled using a baseline methodology.
    - The distributed energy resource provider (DERP) model allows for an aggregation of distributed energy resource (DER) to provide energy and ancillary services to the CAISO wholesale market, including charging at a zero or negative price.

IV. The CEC should utilize OpenADR 2.0 on formalized communication of rates.

PG&E supports CEC to use a "light version" of the OpenADR standard for the LMS price signal on dynamic rate but adds that CEC should clearly define the associated use cases for the applicability of such a "light" version. As PG&E pointed out on several occasions during the LMS proceeding, PG&E strongly recommends using OpenADR 2.0 on formalized communication of rates for the following reasons:

- OpenADR is an internationally standard adopted by multiple countries and many manufacturers
- OpenADR was developed by many industry experts (OpenADR Alliance members, Lawrence Berkeley National Laboratory (LBNL), the National Institute of Standards and Technology (NIST), the Department of Energy (DOE), OASIS, etc.) and has gone through multiple edits based on real-world implementation and best practices,
- The OpenADR Alliance has committed to developing a simpler profile for price signals that can be readily applied to this initiative,

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[11] CPUC. A. 20-10-011. Ch. 3. pp. 3

[12] CPUC. A. 19-11-019. Ch. 5. pp. 19.

- DOE and NIST smart grid roadmap process recommend all stakeholders to use standards in the catalog of smart grid standards such as OpenADR,
- Developing a new standard would take a long time (two-three years minimum) and does not match CEC LMS timeline.

V. The CEC should leverage Green Button Connect [referred to at PG&E as Share My Data (SMD)] platform to provide the customer's RIN to an ASP rather than developing a new access tool.

PG&E recommends leveraging the existing Share My Data (or more generally, Green Button Connect - GBC) platform to provide a customer's RIN to an ASP rather than developing a new access tool as CEC proposed in the CEC's potential amendments to the load management standards. This position also aligns with third-party vendors such as agricultural technology vendor Polaris represented by David Meyers during the CEC workshop on April 12th. All three IOUs provide GBC as a way for customers to authorize and provide to a third party their information in a secure manner. Developing another system for the same purpose would not only duplicate the function of GBC but would also be time-consuming and costly.

- To provide a true cost to customers, PG&E recommends CEC to consider only including rates with no tiers and no demand charge in CEC's MIDAS database. The existing MIDAS proposed by CEC may not provide the actual customer's rate since it does not incorporate customers' actual energy usage and is therefore not able to provide an accurate price to the customer. If the rate sent does not reflect the actual rate due to the tiers, it could be misleading for customers or the ASPs and cause confusion or bad customer experience.
- The CEC should clarify the cost recovery mechanism expectations for IOUs, SMUD, LADWP, and CCAs for implementing the LMS requirements, although the CEC has no authority to authorize approval of cost recovery mechanisms to collect costs that will be charged to the utilities' customers.

VI. The CEC should clarify what the cost recovery mechanism will be for IOUs, SMUD, LADWP, and CCAs to comply with the CEC's requirements.

The Load Management Standard requires the utilities to perform the following tasks:

- **Update the MIDAS Rate Database whenever rates change.**

  This task required the utility to develop a rate table for each of the utility's time-varying electricity rates. In December 2020, the CPUC requested each IOU to review a CEC template to correct existing data and add missing data for all the utility's time-varying electricity rates. The purpose of this template was to beta test a standard data format for machine-readable electricity rates in California. The template includes distinct tables to be imported into a database that will be made available for public use. In response, PG&E provided prices for a limited number of time-varying electricity rates that span the range of rate attributes required for testing and further refinement of MIDAS, as follows:
  - AG-C (time-of-use agricultural for demand >35kW)
  - BEV-1 (business electric vehicle with subscription charge)
  - B-6 (small business time-of-use), B-19 (medium business time-of-use with demand charges)
  - TOU-C (residential tiered, time-of-use)
  - TOU-D (the residential untiered time-of-use)
  - EV-2A (home charging, for electric vehicles and storage)

For each of these rate plans, PG&E spent approximately six to eight hours to create the table in the CEC format for the MIDAS system. In addition to the initial development and the addition of the remainder of PG&E's time-varying electricity rates, PG&E would incur ongoing costs for updating the MIDAS database whenever there are changes to these rates.

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

  PG&E proposes to leverage the existing Share My Data (SMD) platform to provide the customer's RIN to an ASP rather than developing a new access tool as proposed in the CEC's potential amendments to the load management standards. PG&E believes leveraging SMD would be the most cost-effective way to achieve this objective. Nevertheless, in a production PG&E system, when the features of MIDAS and RIN are finally settled, those features may require appropriate funding for PG&E to increase function and capacity of SMD.

  In the case that CEC disagree with this approach, the utilities should have the ability to recover the likely greater costs required to develop a new tool to support this requirement instead of a feature addition to SMD. That cost recovery will require approval from the CPUC.

- **Integrate information about new time-varying rates and automation technologies into existing customer education and outreach programs.**

  PG&E believes the statewide marketing costs identified in table three of the CEC's potential amendments to the load management standards ($750,000 for development and implementation and $375,000 for annual maintenance) were not enough to cover this requirement based on PG&E's experience when marketing new rates to customers, especially given the new hourly rate is a new concept to many customers.

  Furthermore, while PG&E believes that there will be some benefits, there is general lack of quantifiable evidence of CEC's proposed system of MIDAS and RIN to be adopted by various ASPs for RTP, much less dynamic rates, to effectively manage energy through automated systems. The adoption by ASPs, and their resultant overall effectiveness of utilizing the MIDAS and RIN-derived rate information for automated load management are not based on demonstrated pilots, and therefore PG&E finds it difficult to design convincing marketing efforts. The CEC's potential amendments to the load management standards also point out this data scarcity when it states that "options for customer automation are generally limited or non-existent. Successful automated price-response pilots and programs in California and elsewhere may hold clues to effective future implementations."

In conclusion, it is unclear what the mechanism is for utilities and CCAs to recover the funds for LMS requirements, including but not limited to, those identified above. PG&E also recommends that the requirement to provide the rate tables for remainder of its time-varying electricity rates for the MIDAS database, and the ongoing maintenance, does not commence until needed (e.g., ASPs are accessing the data for actual bill calculations).

VII. Conclusion

PG&E thanks the CEC for the consideration of the above comments and looks forward to continued partnership with stakeholders in the Load Management Rulemaking (19- OIR-01). PG&E supports the development of automated demand flexibility. However, for the reasons described above, PG&E requests that the CEC modify the proposed amendments to the load management standard to remove the mandatory rate filing requirement and incorporate flexibility in the tariff language regarding timeline, rate design, feasibility of participation of customer classes, customer bill impacts, cost effectiveness of the

Standard, and the requirement to provide and maintain time-varying electricity rate data for the MIDAS database. To highlight the comments PG&E made with the joint utilities in March of 2020, PG&E requests that the load management tariff standards do not take effect until the CEC and stakeholders have had the opportunity to conduct comprehensive pilot studies that fully assess the costs and benefits of real-time rates, including required infrastructure, manufacturer interest, and customer impacts.

PG&E appreciates the CEC for its close coordination with stakeholders and analysis of the potential amendments to the load management standards and looks forward to continued collaboration on this important topic.

Sincerely,

/s/

Mark Krausse
Director, State Agency Relations