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May 7, 2024

Mr. Drew Bohan
Executive Director
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Re: Peninsula Clean Energy's Load Management Standards Compliance Plan

Dear Mr. Bohan,

Pursuant to the California Code of Regulations, §1623.1(a)(3)(A), Peninsula Clean Energy (PCE) hereby submits its Load Management Standard (LMS) Compliance Plan to the California Energy Commission Docket Number 23-LMS-01.

PCE's LMS Compliance Plan was approved and authorized for submission by PCE's Board of Directors (Board) in a duly noticed public meeting held on April 25, 2024. Enclosed is PCE's LMS Compliance Plan and the Board's adopting resolution.

If you have any questions or if additional information is required, please contact Doug Karpa at dkarpa@peninsulacleanenergy.com.

Sincerely,

Jenna Sharp
Regulatory Analyst
jsharp@peninsulacleanenergy.com

Load Management Standard Compliance Plan

Peninsula Clean Energy Authority

Executive Summary

The California Energy Commission (CEC) established the Load Management Standard (LMS) regulation in April of 2023. The driving factors for the implementation of such standards are: (1) to encourage energy use at off-peak hours; (2) to encourage daily and seasonal peak load control to improve equity, efficiency, and reliability of the electric system; (3) to decrease or delay the need for new electrical capacity; and (4) to reduce greenhouse gas emissions and fossil fuel consumption. To ensure progress toward these goals, the CEC is requiring California's large Publicly Owned Utilities (POU), large Investor-Owned Utilities (IOU), and large Community Choice Aggregators (CCA) to submit an LMS Compliance Plan outlining how they will meet the LMS regulation requirements.

The LMS regulation requires each large utility or, as in this case, CCA to analyze an optional hourly marginal cost-based (MCB) rate for each customer class. The proposed rate should be evaluated based on five factors: (i) cost-effectiveness, (ii) equity, (iii) technical feasibility, (iv) benefits to the grid, and (v) benefits to customers. If adopted, the MCB rates must be available for customers to enroll in by July 1, 2027.

If the CCA deems the implementation of an MCB rate is not feasible based on one or more of the five factors listed above, then it must propose cost-effective marginal-cost responsive load flexibility programs for compliance and conduct an evaluation using the same five metrics. Compliance may be modified or delayed if the CCA can show that despite good faith effort, requiring timely compliance would result in reduced system efficiency or reliability, extreme hardship, technological infeasibility, or lack of cost-effectiveness to the CCA. If adopted these programs must be available for customer enrollment by the same date of July 1, 2027.

Peninsula Clean Energy Authority (PCE) supports the intent of the CEC's LMS regulation since load management is a key cost-containment strategy in achieving its goal of delivering 100% renewable energy on a high time-coincident basis in its 2020-2025 Strategic Plan. The load flexibility programs outlined in this LMS plan demonstrate how PCE's current efforts align with the CEC's priorities set forth via the LMS regulation.

Instead of developing its own MCB rates, PCE will explore participation in Pacific Gas and Electric Company's (PG&E) Real-Time Pricing (RTP) rate pilots. However, participation faces several preconditions that must be satisfied before participation will be feasible, including approval and implementation by the California Public Utilities Commission (CPUC), implementation of data access, billing requirements, and other requirements critical for CCA participation. Since the costs, benefits, and feasibility of participation in these pilots cannot be determined at this time, PCE lays out its approach to assessing these pilots as information becomes available.

In addition, PCE is also developing load flexibility programs in the coming years that can also serve to satisfy the CEC's goals. These programs include enhancements of existing load modification programs as well as the implementation of new programs. PCE anticipates using automated distributed energy resources to shift load in response to hourly signals, although significant technical prerequisites exist. These prerequisites include the availability of real-time transmission and distribution signals, integrating hourly and locational energy pricing, rules and processes for identifying and addressing dual enrollments, obtaining timely hourly billing quality data from PG&E, and other technical issues. Many of these requirements, and the markets that are required for automated distributed energy resources (DER) to significantly expand in the state, will depend on regulatory action by the CPUC and therefore have an uncertain timeline. Absent these prerequisites, PCE's programs will still be able to shift load in conformity with the goals of the LMS program, although perhaps not with the hourly specificity envisioned by the CEC.

As developments in these areas proceed, PCE will be moving forward aggressively to implement one or more load management strategies to accomplish the goals of the regulation.

Table of Contents

1. Introduction

Peninsula Clean Energy Authority (PCE) supports the overall objectives of the Load Management Standard (LMS) since these strategies are important for PCE's goal of serving its customers 100% renewable energy on a high time-coincident basis in coming years. Since this requires the matching of load to the generation of PCE's contracted variable energy generation resources, load shifting is a critical strategy for PCE to achieve this goal. PCE looks forward to working with the California Energy Commission (CEC) in the coming years to develop cutting-edge and cost-effective approaches to achieving the overall goals of the standard.

1.1. About PCE

PCE, a community choice aggregator (CCA), provides electricity service to residents and businesses in San Mateo County and the City of Los Banos in Merced County. Formed in February 2016, PCE is a joint powers authority, consisting of the County of San Mateo, all twenty of its towns and cities, and the City of Los Banos in Merced County. Following a comprehensive feasibility study, consistent with Assembly Bill (AB) 32 voluntary action pathways, elected officials from each member jurisdiction unanimously agreed to form PCE to meet their local climate action goals and for the benefit of San Mateo County. In 2020, following another comprehensive feasibility study, elected officials from the City of Los Banos voted to join PCE.

PCE provides cleaner electricity, and at lower rates, than the incumbent investor-owned utility (IOU), Pacific Gas and Electric Company (PG&E). PCE plans for and secures commitments from a diverse portfolio of energy-generating resources to reliably serve the electric energy requirements of its customers over the near-, mid-, and long-term planning horizons. PCE was assigned an investment-grade credit rating from Moody's in May 2019 and S&P in June 2023, the second of the three CCAs in California to obtain investment-grade credit ratings. PCE's programs include advancing the adoption of electric transportation and transitioning building fossil fuel uses to low-carbon electricity.

As part of its mission-driven, collaborative, not-for-profit, locally focused roots, PCE is committed to two key organizational priorities:

- Deliver 100% renewable energy on an annual basis and align renewable energy supply with customer demand each and every hour of the day in the coming years.
- Contribute to San Mateo County reaching the state's goal to be 100% free of greenhouse gasses (GHG).

PCE is also committed to the following several strategic goals:

- Secure sufficient, low-cost, clean sources of electricity that achieve PCE's priorities while ensuring reliability and meeting regulatory mandates.

- Strongly advocate for public policies that support PCE's organizational priorities.
- Implement robust energy programs that reduce GHG emissions, align energy supply and demand, and provide benefits to community stakeholder groups.
- Develop a strong brand reputation that drives participation in PCE's programs while ensuring customer satisfaction.
- Employ sound fiscal strategies to promote long-term organizational sustainability.
- Ensure organizational excellence by adhering to sustainable business practices and fostering a workplace culture of innovation, diversity, transparency, and integrity.

The importance of these goals for the communities of San Mateo County is underscored by the 2019 declaration of a climate emergency by the Board of Supervisors calling on local agencies and jurisdictions to work "to achieve carbon neutrality throughout San Mateo County and to implement other actions to address climate change."[1]

1.2. The Role of PCE's Board of Directors

PCE is governed by its Board of Directors (Board). Each member jurisdiction from San Mateo County, plus the city of Los Banos, has one seat on PCE's Board (except for San Mateo County, which has two) for a total of 23 elected officials acting as board members. In addition, the Board has two board member director emeritus selected from former directors who participate in board activities as non-voting members.

The Board is responsible for setting the overall strategy for PCE, including rate setting and energy procurement decisions.[2] The decisions of the Board are binding requirements for PCE.

In addition to operating the CCA program, PCE also implements a range of customer programs to facilitate decarbonization and access to electrification, especially for disadvantaged customers. Generally, PCE does not receive cost recovery from the California Public Utilities Commission (CPUC) for these programs but funds them through rates or grants from outside sources.

1.3. The CEC LMS

In 1974, the California State Legislature passed the Warren-Alquist Act establishing the CEC. At its inception, the CEC was granted specific authority including but not limited to implementing load management standards.[3] The CEC updated these standards in 2022 to

[1] County of San Mateo Board of Supervisors, Resolution No. 19-847: Adopt a resolution endorsing the declaration of a climate emergency in San Mateo County that demands accelerated actions on the climate crisis and calls on local jurisdictions and agencies to join together to address climate change (2019).
[2] Public Utilities Code § 366.2.
[3] California Energy Commission, *2022 Load Management Standards Rulemaking Fact Sheet*, 1 (2022), https://www.energy.ca.gov/sites/default/files/2022-10/Load_Management_Fact_Sheet_ADA.pdf

enhance statewide demand flexibility, and the new amendments effective as of April 2023 are what this plan addresses.[4]

The CEC established its LMS regulation based on the definition of load management as "any utility program or activity that is intended to reshape deliberately a utility's load duration curve."[5] The primary objectives of the regulation are to:

- Encourage energy use at off-peak hours.
- Encourage daily and seasonal peak load control to improve equity, efficiency, and reliability of the electric system.
- Decrease or delay the need for new electrical capacity.
- Reduce GHG emissions and fossil fuel consumption.

To ensure progress toward these goals, the CEC is requiring California's large Publicly Owned Utilities (POU), large IOUs, and large CCAs to submit an LMS Compliance Plan outlining how they will meet the LMS regulation requirements.

The LMS regulation requires each large POU, IOU, and CCA to analyze an optional hourly marginal cost-based (MCB) rate for each customer class. The proposed rate should be evaluated based on five factors: (i) cost-effectiveness, (ii) equity, (iii) technical feasibility, (iv) benefits to the grid, and (v) benefits to customers. If the CCA deems the implementation of an MCB rate is not feasible based on one or more of the five factors, then it must propose cost-effective load flexibility programs for compliance and conduct an evaluation using the same five metrics. Compliance may be modified or delayed if the CCA can show that despite good faith effort, requiring timely compliance would result in reduced system efficiency or reliability, extreme hardship, technological infeasibility, or lack of cost-effectiveness to the CCA.

[4] 20 Cal. Code Regs. §§ 1621-1625.
[5] Public Resources Code § 25132.

Table 1 outlines the goals set forth in the LMS regulation, along with the expected completion date identified by the CEC and PCE's progress status toward meeting that deadline.

Table 1. Progress Toward LMS Goals

LMS Section	Description	Deadline	PCE Status
§1623.1(c)	Upload existing time-dependent rates to the Market Informed Demand Automation Server (MIDAS) database.	October 1, 2023	Completed with ongoing updates
§1623(c)	Provide customers access to their Rate Identification Numbers (RIN) on billing statements and in online accounts using both text and quick-response (QR) code.	March 31, 2024	Awaiting PG&E billing changes
§1623.1(a)(1)	Develop and submit to PCE's Board an LMS plan.	April 1, 2024	Submitted to the Board March 22, 2024
§1623.1(a)(3)(A)	Submit to the CEC the Board-approved LMS plan.	May 31, 2024	
§1623(c)	Develop and submit to the CEC, in conjunction with the other obligated utilities, a single statewide RIN access tool.	Oct. 1, 2024	Ongoing, through CalCCA participation
§1623.1(b)(3)	Submit to the CEC a list of load flexibility programs deemed cost effective by PCE.	Oct. 1, 2024	
§1623.1(a)(3)(C)	Submit annual reports to the CEC demonstrating implementation of plan, as approved by the PCE Board.	Annually	
§1623.1(b)(2)	Submit to the PCE Board for approval at least one MCB rate for the customer class(es) for which it will materially reduce peak load	July 1, 2025	
§1623.1(b)(2)	Offer customers voluntary participation in either an MCB rate, if approved by the Board, or a cost-effective load flexibility program.	July 1, 2027	
§1623.1(b)(5)	Conduct a public information program to inform and educate affected customers why MCB rates or load flexibility programs and automation are needed, how they will be used, and how these rates and programs can save customers money.	Goal date not specified	Ongoing currently
§1623.1(a)(1)(C)	Review the plan at least once every 3 years after it is adopted and submit an update to the PCE Board if there is a material change.	Triennially	

2. PCE LMS Plan

2.1. Overview

PCE does not view designing and implementing its own MCB rates as likely to be cost-effective or technically feasible as an approach to meeting the goals of the LMS, as discussed below. However, PCE is exploring participation in PG&E's Real-Time Pricing (RTP) rate pilots as a more effective approach to LMS-compliant rate offerings. PG&E filed its Expanded Pilots Proposal with the CPUC on September 25, 2023, requesting to make LMS-compliant modifications to the Agricultural Flexible Irrigation Technology (AgFIT) program. PCE is exploring participation in PG&E's Expanded Pilots, Business Electric Vehicle (BEV), and Vehicle to Grid Integration (VGI) RTP pilots to fully comply with the LMS. PCE will provide an update on the expansion of the pilots in its next LMS Compliance Plan report.

2.2. RTP Pilots

The status of PG&E's RTP pilots is in flux as the IOU is awaiting feedback from the CPUC regarding its expansion requests. PG&E details how the expanded pilots will comply with LMS in its LMS Compliance Plan submitted October 2, 2023.

> *Pilots are in progress and proposed for PG&E's service area, which have made (or will make) RTP rates available to customers in the next few years. These pilots will continue to provide important learnings to inform RTP rate design. The Valley Clean Energy (VCE) AgFIT agricultural water pumping pilot is available to agricultural customers in VCE's service area and includes both marginal generation and distribution cost components. Additionally, PG&E is in the process of implementing a Vehicle-to-Grid Integration RTP Pilot (VGI RTP Pilot) approved by CPUC Resolution E-5192 per directives in CPUC Decision (D.) D.20-12-029. The VGI RTP Pilot is targeted for rollout in 2024. In PG&E's 2020 General Rate Case (GRC) Phase II, RTP rate pilots were approved for Residential, Commercial, and Industrial customers. However, these pilots were designed to include only dynamic generation price components and would not meet the LMS requirements to include hourly distribution and transmission marginal cost signals. On September 25, 2023, PG&E filed a proposal – in support of the CPUC Energy Division Staff's proposal in Track B of the CPUC's DFOIR proceeding – to expand the VCE AgFIT Pilot (PG&E Expanded Pilots Proposal). With this proposed pilot expansion, all PG&E-customer classes – except Commercial Electric Vehicle (CEV) and Street Lighting – would be able to enroll in an RTP rate with dynamic generation and dynamic distribution cost components by June 2024. This implementation timing is dependent, however, on PG&E receiving CPUC approvals for these pilots by November 30, 2023. If the PG&E Expanded Pilots Proposal is adopted and implemented on the schedule proposed by the CPUC (June 2024), PG&E will meet the requirements of the LMS to have marginal cost-based hourly rates available to all customer classes (except for CEV)*

for the generation and distribution components of the RTP rates well ahead of the Jan 2027 CEC target.

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

PG&E will provide an update on the plans to provide an LMS-compliant RTP rate for CEV customers by January 2027 in its next annual LMS Compliance Plan report. Although the VGI Pilot Dynamic Rate includes dynamic generation and distribution, eligibility is limited – in order for CEV customers to enroll in phase 2 of that pilot, they must be interconnected under Rule 21. Interconnection under Rule 21 is required because the VGI Pilot's objective is to encourage export to the grid and testing of vehicle-to-grid use cases. The VGI Pilot is a short-term pilot and is unlikely to be open to customers all the way to 2027. However, eligibility and a timeframe for the VGI dynamic rates could potentially be expanded to non-Rule 21 CEV customers. Learnings from the Day-Ahead Real Time Pricing - Commercial Electric Vehicle (DAHRTP-CEV) opt-in rate, the CEV non-NEM export pilot – planned to launch in February 2024 – and the VGI Pilots Dynamic Rate targeted for Q3 2024 would be used to inform the design of the LMS-compliant RTP rate for CEV customers.[6]

PCE has participated in the proceeding developing these pilots and has expressed interest in participating in PG&E's Expanded Pilots and BEV and VGI RTP pilots. Should PG&E receive approval from the CPUC to make the pilots LMS compliant, PCE will further evaluate engagement in the pilots as a means to achieve its own LMS goals, based on the details of the final implementation of these programs.

2.2.1. Rate Design

PG&E states the following regarding its plan for an LMS-compliant rate.

While still undergoing minor adjustments, PG&E's currently preferred rate design will likely be similar to the rate design of its VGI RTP Pilot and will satisfy all but one of the LMS requirements – hourly transmission costs. The VGI RTP Pilot rate design includes marginal energy costs, marginal generation capacity costs, and marginal distribution capacity costs, but does not include hourly transmission costs … While

[6] Pacific Gas and Electric Company, 2023 LMS Compliance Plan (2023).

the VGI RTP Pilot rate design does not include marginal transmission capacity costs, PG&E is developing a roadmap toward an LMS-compliant rate in 2027.[7]

PG&E has outlined the details of its RTP rate and proposed the following for inclusion.

- **Frequency.** Individual hourly prices updated on a day-ahead basis.
- **Marginal Capacity Costs.** Marginal generation capacity costs as approved in D.21-11-016 and allocation as specified in D.22-08-002.
- **Marginal Energy Costs.** Marginal energy costs as approved in D.21-11-016. These "are the CAISO energy prices at the PG&E Default Load Aggregation Point (DLAP), adjusted for line losses."[8]
- **Marginal Transmission and Distribution Costs.** Dynamic distribution signal created "to recover the Primary Distribution Capacity Costs approved in CPUC D.21-11-016. The hourly prices will vary depending on the location of the customer and will utilize the scarcity pricing concept, with prices dependent on the forecasted load on a representative circuit with similar load characteristics to the customer's circuit. As described in the Joint IOU WG 1 Proposal, hourly distribution prices will be set so that average prices are the same across all locations – prices on more constrained circuits will have more time differentiation, but annual average load-weighted prices will not vary geographically for equity reasons."[9]
- **Fixed Costs.** Fixed cost collection subscription mechanism as outlined in the California Flexible Unified Signal for Energy (CalFUSE) proposal, with no scalers or adders to denote the collection.

As previously stated, PCE will explore whether to adopt similar rates if PG&E implements an RTP rate in the future.

2.3. Evaluation

2.3.1. Cost-Effectiveness

PCE's strategy of participation in the CPUC-sponsored pilots is informed by some of the cost and feasibility considerations of designing and implementing its own separate MCB rates. The cost-effectiveness of any MCB rate offering depends on whether the value of any load shift to the customer and PCE exceeds the costs of implementation of the proposal. Since CCAs are excluded from cost recovery for expenditures in support of wider grid benefits, the analysis of cost-effectiveness is necessarily narrower than it would be for either IOUs or POUs.

[7] *Id.*
[8] *Id.*
[9] *Id.*

The costs of implementing an MCB rate include a variety of fixed and per-customer costs. Fixed costs include, but are not limited to:

- Personnel costs for staff to design and maintain MCB rates.
- Management costs to obtain data from the California Independent System Operator (CAISO) and PG&E to calculate hourly costs.
- Software and system costs for design, maintenance, and operations.
- Contractor costs to implement MCB rates, including customer education and support.
- Software and upload costs associated with the MIDAS database interface.

In addition, per-customer costs include, but are not limited to:

- Data charges
- Vendor charges

At this time, the costs associated with the creation, implementation, and maintenance of the MCB rates are difficult to ascertain because many elements are still unknown. In addition to the implementation costs, it is unknown whether and how the CPUC will require PG&E to provide real-time billing quality customer data, the costs associated with obtaining these data, and any required technical or data handling costs. However, for comparison, the Sacramento Municipal Utility District (SMUD) anticipates these fixed costs would be larger than the value of the marginal improvement in load over existing time-of-use (TOU) rates.[10] Since PCE would be spreading comparable fixed costs across a customer base that is approximately a fifth the size of SMUD's customer base, it is far less likely that the value of the marginal improvement in load shifting over PCE's existing TOU rates would be enough to justify these fixed costs. PCE's comparable fixed costs would be recovered from a smaller rate base, resulting in higher per-customer costs.

By the same token that the costs of implementation are difficult to determine, the value of any load shift that might result from an MCB rate is also difficult or impossible to assess at this time. The value of the load shift depends on participation rate, how much load is shifted, in what hours, and the value of that load shift. In principle, the amount of load shift could be determined for each hour if the elasticity of electricity demand in each hour were known; however, evaluating these elasticities would require considerable data for all hours and would have significant uncertainties. In addition, it would be necessary to know how the MCB rate values would differ from existing TOU rates in each of these hours.

Currently, several components of the marginal costs would be difficult to ascertain at this time. While hourly energy costs are currently generated in the CAISO market, the hourly

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[10] Sacramento Municipal Utility District, Sacramento Municipal Utility District Comments - SMUD's Load Management Standard (LMS) Compliance Plan (Attachment A) (2023).

capacity values are unclear. The resource adequacy (RA) program is shifting to a 24-hour slice-of-day framework, which would theoretically generate differential values of capacity in different hours. However, until the slice-of-day framework has been in place for some years, it will be impossible to assess what the capacity value of energy use in one hour might be relative to the energy use in a different hour. In addition, there are no currently accepted methodologies in use for the assessment of the hourly value of transmission and distribution costs. As discussed below in the context of technical feasibility, several components of hourly costs are not currently available, making the evaluation of the value of load shift difficult or meaningless to calculate.

Determining the net value of any load shift would also require offsetting the cost of serving new load in the hour to which electricity use is shifted. This in turn would require an understanding of whether reduced load in various hours would result in overall load reductions (load shed) or a shift to other hours (load shift), and if so, to which hours. Furthermore, the value of a given shift (e.g., from 8 p.m. to 11 p.m.) is likely to vary by day of the week. Even if only within-day shifts are assessed, this constitutes nearly 50,000 pairwise shifts between hours across the year, even assuming that a single week can be representative of all hours in the month. This calculation would require extremely large quantities of data that are not available at this time. Thus, a full cost-effectiveness assessment is currently difficult or infeasible.

Given the difficulties in evaluating the cost-effectiveness of an MCB rate today, PCE is interested in participating in CPUC-sponsored IOU pilots. Such pilot programs with robust participation from all customer classes could provide some data on the sensitivity of electricity use to MCB rates. This is one contributing factor to PCE's interest in participating in PG&E's rate pilots to generate such information.

2.3.2. Equity

Significant equity concerns are raised by MCB rates because any error from the true cost raises the prospect of unrecovered costs. If any kind of adder is required to cover these unrecovered costs, this is likely to represent a cost shift onto non-participating customers. PCE anticipates that participation in any MCB rate offering is likely to be primarily by wealthier and more sophisticated customers able to afford the technology required to truly take advantage of such a rate. Non-participating customers should not bear increased costs because of such rate structures. However, since the actual costs that would be realized are difficult to determine a priori, costs recovered through MCB rates are likely to be highly variable, as customers are almost guaranteed not to respond as forecast in every billing period. Thus, the MCB rates would need to incorporate conservative assumptions about cost recovered through these rates and err on recovering more costs from participating customers. However, if these rates are intentionally conservative to ensure adequate cost recovery in all billing periods, then the economic benefits of participating would be blunted. As such, ensuring equity impacts are avoided likely limits the utility of MCB rates in the first place.

A second major point of concern is possible exposure of low-income customers to real-time market prices. Customers may elect to sign up for new rates without an understanding of the risks or, because most loads are inelastic, with limited ability to react. This can result in extreme customer costs during extreme weather or other significant events.

2.3.3. Technical Feasibility

MCB rates also face several technical prerequisites that would need to be satisfied before implementation of an MCB rate. PCE faces some of the similar challenges as PG&E, including the lack of transmission and distribution marginal costs currently called for in the regulation. Assessing the hourly and locational costs is difficult to ascertain with reliable methodologies. Consequently, there is no obvious data source to access hourly values to use as inputs to an MCB rate.

In addition, the hourly capacity costs are currently impossible to assess, because CPUC jurisdictional entities are transitioning to a new hourly capacity construct currently. The 24-hour slice-of-day framework will generate differential value of capacity in different hours. However, the CPUC has not finished implementing the slice-of-day methodology and several cost containment proposals remain unresolved. Over time, hourly capacity costs should be established by the market, but until Load Serving Entities develop expertise in trading hourly products over some years, it will be impossible to assess the capacity value in each hour.

In addition, since PCE is not its own billing agent, additional prerequisites exist and remain to be resolved including access to billing quality hourly data on a time basis. This likely requires CPUC action to order PG&E to provide such data to PCE.

PCE strongly supports the goals of load shifting as a key cost-containment strategy, but there are a significant number of prerequisites that remain to be implemented on a usable, statewide basis.

2.3.4. Benefits to the Grid

If the MCB rate is successful in shifting load to cheaper-to-serve times of day beyond what the TOU rates already achieve, this could provide marginal cost savings in the medium term. However, unpredictable customer behavior may actually impose costs on the grid as well.

The changing nature of the grid supply may mean that this value will diminish as California shifts to a fully decarbonized grid. Variable energy resources vary strongly not just by hour, but seasonally. In PCE's modeling of achieving a fully decarbonized energy supply that meets PCE’s load on an hourly basis with 100% renewable energy, the most important constraints on the grid are likely to shift from concerns about capacity during net peak load periods to daily energy constraints during seasons with the low solar over a 24-hour cycle. These constraints will arise in winter months, during which lower solar production to charge storage will drive constraints in the early morning hours. A portfolio that has both sufficient generation and storage to be capable of meeting overnight winter loads with diminished generation will have considerable excess energy to serve peak load with zero marginal cost energy at other times of the year. What this means is that if storage is capable of meeting load whenever it occurs, then load shifting from one hour to another will deliver few if any grid benefits. In contrast, shifting load from one season to another would be far more significant, but it is difficult to conceive of how this might be accomplished and whether an MCB rate would incentivize investments in such technologies.

In addition, MCB rates may drive customer behavior in ways that force greater distribution costs. In particular, there are some indications that TOU rates have concentrated electric vehicle (EV) charging in hours immediately after the end of high TOU rate periods. This can actually increase the need for distribution investment to address new higher peak demands outside of TOU hours. If EV drivers move their charging to a small number of low price hours in response to MCB rates, peak demand on the distribution circuits during those hours could spike. This would require significant distribution investments to accommodate new, higher peak demand. For example, if MCB rates send a signal to charge during solar hours based on CAISO wholesale market prices, that may drive very high loads on particular distribution circuits, triggering large-scale upgrades. Thus, responding to grid-level signals may drive high costs on specific circuits. Since the bulk of retail rates are made up of transmission and distribution charges, increasing these investments may swamp any benefit seen on energy generation costs. The interplay of these dynamics is difficult to predict, meaning that the net benefit to the grid from MCB rates is impossible to assess and may result in a net detriment to the grid.

In the medium term, the key analysis is the degree to which an MCB rate will shift load from expensive hours to cheaper ones. However, absent critical data on the hourly elasticity of electricity as described above, that analysis is currently not feasible to do.

2.3.5. Benefits to Customers

The benefits to participating customers depend on whether existing TOU rate differentials are greater or less than the hourly differences in marginal costs. In theory, if the difference between high-rate hours and low-rate hours is less than the hourly differences in marginal costs, then shifting to an MCB rate may save customers money if they can shift loads to relatively cheaper hours. Under a TOU rate, customers already save money by shifting load outside of the peak window. The benefit to customers then depends on whether customers would save even more money under an MCB rate, but that depends on the details of how the MCB and TOU rates compare in each hour and which hours customers shift usage from and to which hours. Thus, determining whether customers would or would not realize rate benefits will depend on the actual rates by hour relative to existing TOU rates. Since the MCB rates are not currently feasible to develop, it is not possible to analyze the degree of benefits to customers currently.

3. Rate Identification Number (RIN)

Since CCA bills are controlled and printed by the IOU billing agent (PG&E in this case), PCE has limited input on the design and placement of RINs on the customer billing statements. However, PCE is working with its third-party provider for data management and billing services, Calpine Energy Solutions (Calpine), and PG&E to comply with LMS requirements for RINs.

3.1. RINs and QR Codes on Customer Bills

PCE, Calpine, and PG&E have agreed to utilize the Electronic Data Interchange (EDI) 810 files to pass through RINs to PG&E for inclusion on the customer billing statements. The RINs are expected to be available to customers via billing statements and online customer accounts by April 2024.

Per PG&E's LMS Compliance Plan, the IOU will include the RIN and QR code on the customer billing statement in the rate schedule code section of the electric service agreement details page. PG&E has stated that it does not plan to include a QR code that links to a webpage.

3.2. Statewide RIN Access Tool

PCE has participated in CEC-led workshops on the development of the Statewide RIN Access Tool and provided input on the process, when able. However, PCE's involvement in the development of the tool is limited, just like it is with the design and placement of the RINs on the customer billing statements. PCE and other stakeholders are currently waiting for PG&E to propose a timeline for the development of the Statewide RIN Access Tool.

4. Load Flexibility Programs

4.1. Overview

Load flexibility and grid reliability are key elements of PCE's decarbonization strategy. PCE has multiple offerings currently and is exploring a number of additional leading-edge options for its customers. Currently, these programs appear likely to play a central role in PCE's load-shifting strategy to meet the objective of the LMS, especially if participation in the RTP pilots proves unworkable.

PCE has established the following objectives for its distributed resources programs:

- Provide grid benefits, especially peak shaving to reduce wholesale costs and carbon intensity, aiding further penetration of renewables.
- Enable resilience.
- Lower operating costs for customers.
- Make electrification more economically beneficial.
- Create scalable deployment through sustainable models.

PCE's approach includes a focus on avoiding unnecessary capacity increases which can result in added costs and reliability challenges. This includes guidelines for residential electrification within 100-amp service,[11] use of low-power charging in multi-family buildings, and fleet infrastructure planning.[12] In addition, PCE programs emphasize continuous load shaping, in contrast to event-driven curtailment, to maximize the benefits of load shaping for customers and the grid.

PCE has focused on developing a portfolio of flexible and effective load-shaping programs aimed at significantly reducing grid peak loads. PCE has also worked to innovate with technology and software providers to advance functionality that will allow for broad participation and help maximize potential resources, optimized for customer and grid needs. Multiple approaches are being continually assessed and PCE is learning from these initiatives to inform future program designs and the technology needed to scale adoption.

PCE currently offers a portfolio of load flexibility programs with a diversity of enabling technologies, and different tiers of engagement to provide options for customers. Following is a list of current and planned program offerings, including several pilots that are being tested for reliability, load reduction, and customer adoption.

4.1.1. Electric Vehicle Managed Charging

Overview: PCE territory has one of the state's fastest adoption rates for EVs with over 45,000 EVs on the road today and EVs accounting for over one-third of new vehicle sales. Managing EV charging is a high priority for PCE with an emphasis on residential charging, where most evening charging is occurring, and shifting vehicle load daily out of the evening peak. In addition, minimizing the secondary midnight peak that can affect local distribution networks is also a priority. PCE has focused on leading-edge strategy by using vehicle telematics, which controls EV charging through the vehicle as opposed to charger-based

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[11] Blake Herrschaft, *Design Guidelines for Home Electrification*, 7-12 (2023), https://www.peninsulacleanenergy.com/wp-content/uploads/2023/04/Design-guidelines-for-home-electrification-v041223.pdf

[12] *San Carlos Case Study: EV chargers for your fleet, less is more*, Peninsula Clean Energy, https://www.peninsulacleanenergy.com/san-carlos-case-study-ev-chargers-for-your-fleet-less-is-more/; *Access to slow EV chargers could speed up EV adoption among renters*, Canary Media, https://www.canarymedia.com/articles/ev-charging/access-to-slow-ev-chargers-could-speed-up-ev-adoption-among-renters

load management. Because the installed base of smart chargers is very small and such chargers are expensive, the telematics approach holds greater promise because nearly all vehicles can participate without special equipment.

Status: PCE recently completed its second phase pilot of managed charging. The first phase was a proof of concept executed in 2020 with 7 vehicles. The proof of concept successfully demonstrated curtailment of charging at peak while ensuring drivers received the charging necessary for their daily needs. Following a competitive solicitation, PCE launched its second-phase pilot demonstrating scaled operation of EV-managed charging. PCE selected EV.energy as its partner and engaged researchers at UC Davis to develop an experimental design to evaluate incentive structures and assess outcomes. About 700 vehicles participated in the second-phase pilot. Data collection has been completed and analysis is underway. PCE anticipates finalizing its ongoing program design and ramping up its recruitment in the coming months. Incentives to sign up are offered to EV purchasers through PCE's income-qualified used EV incentive in addition to direct marketing to customers.

4.1.2. Solar and Storage for Public Buildings

Overview: Public agencies have significant interest in the deployment of solar and storage systems to reduce costs and provide resilience for power outages and emergencies. In addition, the Inflation Reduction Act's "direct pay" provisions allow public agencies to access the Investment Tax Credit without an intermediary, improving the economics of distributed generation systems. PCE operates an aggregate solar and storage program aimed at improving the economics of distributed solar and storage for public agencies. This program operates in cohorts in which PCE assumes the role of developer, providing upfront project development services, procurement, and financing under a PCE-supplied power purchase agreement (PPA) for the local government agency. Systems are then deployed by a construction firm under contract with PCE. PCE owns the systems and provides ongoing operations and maintenance support with a performance guarantee. The storage systems will provide backup power for outages and dispatch for grid peak load reduction.

Status: This program was launched in 2020 with significant legal and site development work to establish the program. Initial 12 systems with 1.7 MW of solar are now completing construction.[13] The second round of the program is in contracting. The initial installations are the solar portion, and storage is intended to be added to select sites. Additional solar and storage sites are in development with as much as 6 MW of storage. Dispatch may be administered directly through a PCE distributed energy resource management system (DERMS), battery management systems, or contractually specified with service providers.

[13] *US climate law introduces billion-dollar 'game-changer' for nonprofits*, Canary Media https://www.canarymedia.com/articles/climatetech-finance/us-climate-law-introduces-billion-dollar-game-changer-for-nonprofits

4.1.3. Residential Solar and Storage

Overview: Residential storage systems, typically paired with solar, are growing in popularity. Currently in PCE territory, there are approximately 34,000 systems with a total of 71.6 MW of storage.[14] With the state's adoption of the Net Billing Tariff, it is expected that residential solar and storage adoption will grow. PCE has had a residential solar and storage program since 2020. That program has provided outreach and incentives for customers to adopt solar and storage systems. The systems are installed by a competitively selected provider and the storage systems dispatch at the grid peak as specified under the contract between PCE and the provider.

Status: PCE's residential solar and storage program completed its enrollment phase between 2020 and 2023. Nearly 400 new system installations were completed, and an additional 200 existing systems were enrolled. Under the agreement with the provider, the provider offers battery storage dispatch during the evening peak, and PCE purchases the rights to this capacity over a 10-year term. The dispatch capacity is factored into PCE's annual load forecast submitted to the CEC, and subsequently, the CEC reduces PCE's forecasted RA capacity as a result of a lower forecasted peak load. PCE is continually working with the provider to further optimize the dispatch schedule to maximize the grid value, such as by concentrating as much energy capacity into a narrower, 2-hour dispatch window. In addition, PCE anticipates developing a follow-on program that will again provide support to homeowners in deploying solar and storage systems, while also providing capacity services to the grid. Dispatch may be administered directly through a PCE DERMS or contractually specified with service providers.

4.1.4. FLEXmarket

Overview: PCE utilizes the innovative FLEXmarket program to provide incentives to project implementers based on the measured grid benefits. PCE is implementing this approach because most cost energy efficiency programs do not adequately target load-shaping benefits. In addition, incentives are not targeted based on grid benefits nor measure actual results. This program operates across all customer classes for permanent load shifting achieved by targeted energy efficiency and beneficial electrification. The program utilizes Normalized Metered Energy Consumption (NMEC) methodology to assess projects based on their actual performance weighed against grid benefits with the Avoided Cost Calculator (ACC). This is a CPUC-funded program.

Status: PCE launched its FLEXmarket program in 2023 for both the commercial and residential sectors and has successfully enrolled projects in the first iteration of the program. Initial program emphasis has been on attracting service providers and proving the general model of the program. PCE anticipates continuing the program subject to CPUC approval.

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[14] Q4 2023 PG&E Interconnection Data for Peninsula Clean Energy service territory

4.1.5. Residential Electrification Direct Install

Overview: PCE operates an income-qualified direct install program for electric appliances – replacing aging, polluting methane gas systems. This program has upgraded approximately 300 homes with heat pump water heaters or other efficient electric measures. Under the program, PCE has piloted whole-home electrification of 5 single-family homes to assess costs and demonstrate electrification that minimizes grid impacts by fully electrifying within 100 amps.[15] Finally, PCE has also piloted an advanced load-shaping technology in space and water heating combo systems which can shift load in both applications through the thermal storage and advanced system logic.[16]

Status: This program will be substantially expanded in 2024 to allow for whole-home electrification. Numerous innovations are envisioned to be incorporated into this program including electrification within 100 amps, as well as the potential use of advanced combo systems, and integration of load shaping for water heaters and thermostats, possibly through a PCE DERMS. Separate from this program, PCE currently provides incentives to customers for the installation of load-shaping combo systems.

4.1.6. GovEV

Overview: The GovEV program helps local municipal fleets plan for fleet electrification by providing technical assistance for vehicle replacement purchasing and the installation of EV chargers. As a component of this program, PCE produces a charging optimization plan, which outlines the cost potential of managed charging for their specific fleet. PCE is also making the ChargePilot charge management system by The Mobility House free for fleets, as part of the GovEV program for one year. The ChargePilot system (optional to fleets but recommended) will help shift more fleet charging to occur during off-peak hours and mitigate demand charges, as well as provide insights into EV charging metrics for fleet managers.

Status: The program is open and 10 fleets are currently enrolled. Installation projects are expected to begin in Calendar Year (CY) 2025.

4.1.7. Program Design to Meet LMS Goals

Each of these programs is envisioned to incorporate remote dispatch DERMS or comparable technologies, which will enable all of these programs to become automated MCB signal responsive programs, as envisioned in 20 Cal. Code Regs. § 1623.1(a)(1)(B).

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[15] *Yes, it's possible to electrify a home on just 100 amps*, Canary Media, https://www.canarymedia.com/articles/electrification/yes-its-possible-to-electrify-a-home-on-just-100-amps

[16] TRC / Rupam Singla, *Harvest Thermal Pilot: Measurement and Verification Report* (2023), https://www.peninsulacleanenergy.com/wp-content/uploads/2024/02/PCE-Harvest-Pilot-MV-Final-Report.pdf

The timeline and feasibility of the rollout of these technologies will be evaluated in future development of these programs.

4.2. Evaluation

PCE closely evaluates all programs it executes and anticipates that load-shaping programs will be evaluated with the following criteria:

- Amount of grid peak load reduction
- Consistency and reliability of load reduction
- Customer participation rate
- Cost of recruitment and operation
- Customer benefits, impacts, and satisfaction

4.2.1. Cost-Effectiveness

The costs associated with implementing a new load flexibility program include the following:

- Program development. This includes the costs associated with program design and setup, including integrating such programs with internal and external systems.
- Program administration. This involves ongoing costs to administer the program, including marketing, customer recruitment, customer education, development, and maintenance of customer tools, and any upfront or ongoing incentive payments that are part of the design.
- Technology and implementation costs. Each new load flexibility program requires significant investments in new technology platforms. These include external software systems that must be procured to communicate with and dispatch devices, as well as internal systems that must be developed and configured to integrate the external software.

PCE, as a CCA, may derive certain avoided cost value streams such as reduced RA costs and extreme event energy market costs. However, aside from CPUC-funded programs such as FLEXmarket, PCE does not have access to other value streams such as avoided distribution grid costs. Quantification of cost benefits is challenging and of limited confidence due to the volatile nature of the energy market, as described in the analysis of MCB rates above.

4.2.2. Equity

PCE has a major focus on equity across its programs. PCE's primary method of delivering equity benefits is in keeping generation rates low. Since inception, PCE has provided generation rates at least 5% below PG&E for all customers resulting in over $100 million in savings for the community since 2016. In 2024 PCE is currently keeping rates flat resulting in 10-15% savings for customers compared to PG&E for even greater savings. In addition, in

December 2023 PCE provided customers in the income-qualified California Alternate Rates for Energy (CARE) / Family Electric Rate Assistance (FERA) programs each a rebate of $300.

PCE has numerous programs targeted at delivering additional equity benefits. These programs include an EV charging incentive and technical assistance for apartment buildings, income-qualified incentives for e-bikes and EVs, and the above-mentioned home direct-install program.

PCE offerings are geared towards ensuring financial benefits for customers and ensuring access to additional benefits such as functional appliances, etc. Load shaping provides a potential additional tool for reducing customer costs, helping ensure shiftable load is occurring under the most favorable rates. However, most loads in low-income households have little or no shifting capacity. It is essential that households are not penalized for inflexible loads. In addition, while some customer segments are interested in technology it is important that participation not introduce undue complexity, especially in this segment. Therefore, any technologies introduced need high reliability and effective passive operation with as little resident intervention as possible.

4.2.3. Technical Feasibility

Load shaping measures as described above have been technically demonstrated by PCE or other parties. PCE currently engages in a “direct control” approach with EVs (a type of DERMS but only for EVs), contractually based load shaping for its residential storage, and a market-based “shaped” incentive structure in FLEXmarket.

However, real-time responsiveness introduces numerous added levels of complexity. Assets would need to be integrated through a DERMS as a management platform. However, the DERMS landscape is extremely fragmented. Currently, DERMS providers are only able to successfully dispatch a subset of deployed assets, even within an asset type (battery, vehicles, etc.). In addition, customers must retain override capabilities based on specific needs, particularly for batteries which may be needed for power outages in extreme weather, and vehicles for travel needs. Customers, service providers and manufacturers in many cases can have competing objectives (ex: backup vs. grid services) and interest in enrolling in competing programs. In principle, a portfolio approach could yield confidence that a predictable dispatch capacity can be achieved for an event-based program. However, PCE’s approach of daily “permanent” load shift offers the advantage of high predictability for the customer and other parties.

Furthermore, for real-time programs, data integration for the price signals would need to be established reflecting real-time conditions and PG&E billing systems would need to be restructured to allow billing based on those prices. A price signal system must address common standards for calculation, availability of data on a real-time basis, high up-time platform for serving the data, mechanism for customer visibility and other complexities.

PG&E's billing system would require major updates of a platform already strained by high complexity and billing information would need to be presented in a digestible manner for the customer with associated education and customer service support. Both of these areas are major barriers.

4.2.4. Benefits to the Grid

Load shaping provides several grid benefits including reducing costs, increasing reliability, and reducing emissions. Load shaping that is responsive to real-time conditions could potentially increase those benefits to the degree that responsive load shaping is able to provide additional load reductions, above that provided by permanent load shaping, at moments of grid strain.

However, different objectives would necessitate visibility to specific conditions. ISO-level load, transmission congestion, load aggregation points, and distribution circuit conditions each have distinct values that can contribute to the value of load shifting but are not necessarily easily evaluated in real-time by asset controllers, like PCE. Thus, PCE may be able to assess grid value at the level of generation costs but may have difficulty incorporating other grid benefits, except to the degree that data becomes available for other areas.

4.2.5. Benefits to Customers

Customer benefits of load shaping generally are assessed by PCE in relation to economic value. Specifically, cost reductions after considering customer installation costs and the change in operating costs. As noted above, PCE emphasizes permanent load shifting as a means of maximizing the operating cost benefits. Reliability is also an important benefit though this is difficult to quantify.

5. Conclusions

PCE strongly supports the goals of the LMS and is already working diligently to implement leading programs and approaches to deliver load flexibility in a cost-effective and technically feasible manner. Although load-flexibility technologies have many technical and policy prerequisites that must be satisfied before such approaches can deliver the full potential benefits, PCE is committed to deepening its current approaches and exploring the feasibility of other approaches as they become available.

Load flexibility is a key tool for PCE's core objective to provide its customers with 100% renewable energy in all hours. Given PCE's goals, it anticipates working with the CEC to develop new approaches and to provide real-world, on-the-ground expertise from the lessons derived from this work going forward.