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Supporting documents to PG&E's previous Comments submitted to this docket on April 23, 2021. A link to Attachment A is provided here: https://www.epri.com/research/programs/072127/results/3002021204

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Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

COMMERCIAL ELECTRIC VEHICLE DAY-AHEAD HOURLY REAL TIME PRICING PILOT

PREPARED TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
COMMERCIAL ELECTRIC VEHICLE DAY-AHEAD HOURLY
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CHAPTER 1
BACKGROUND AND POLICY

A. Introduction

The purpose of this chapter of Pacific Gas and Electric Company's (PG&E) testimony is to provide the policy background and context for PG&E's application for a dynamic rate option for Commercial Electric Vehicle (CEV) customers in compliance with the requirements of Ordering Paragraph (OP) 9 of California Public Utilities Commission (CPUC or Commission) Decision (D.)19-10-055. PG&E's dynamic rate proposal is a Day-Ahead Hourly Real Time Pricing Pilot (DAHRTP-CEV Pilot).[1]

D.19-10-055 found that there are at least some CEV customers interested in a dynamic rate option with fluctuating hourly prices, and that rate choices for CEV customers are inherently desirable to help lower fuel costs and provide incentives for widespread transportation electrification (TE).[2] The decision found that, therefore, there is benefit in exploring an optional dynamic rate that CEV customers could elect if they believe that rate would benefit their operations.[3]

In D.19-10-055, the Commission directed PG&E to file an application for a dynamic rate option for CEV customers no later than 12 months after the effective date of the decision, and recommended that PG&E address a number of specific questions prior to Commission consideration of such a dynamic rate

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[1] The DAHRTP-CEV Pilot rate includes a generation component with hourly granularity that will be published on the day before the prices are effective, thus a day-ahead hourly dynamic rate option. According to the Federal Energy Regulatory Commission (FERC), Real-Time Pricing (RTP) is a retail rate in which the price for electricity typically fluctuates hourly reflecting changes in the wholesale price of electricity. According to FERC, RTP prices are typically known to retail customers on a day-ahead or hour-ahead basis. https://www.ferc.gov/sites/default/files/2020-06/2008-glossary.pdf. This definition of retail RTP is distinct from the definition of "real-time" typically used by transmission system operators in wholesale markets, which can imply hour-ahead, day-of, price communication only.

[2] D.19-10-055, p. 28.

[3] *Id*.

for implementation.[4] PG&E addresses each of the questions posed by D.19-10-055 in this exhibit.[5]

As the Commission's questions anticipate, PG&E believes any implementation of RTP should be done at a measured pace to ensure effectiveness of such a rate and to avoid unintended or unforeseen negative consequences. This is because of the uncertainty regarding revenue recovery and cost shifts, the nascent nature of vendor and technology support for CEV customers, Community Choice Aggregator (CCA) and other Energy Service Provider (ESP) participation,[6] bill impacts, and considerations regarding operational infrastructure and scalability. Based on the answers to the questions posed by the Commission in D.19-10-055, and consistent with PG&E's recent comments and evidence provided in the Commission's Draft Transportation Electrification Framework (TEF),[7] PG&E proposes to conduct the DAHRTP-CEV Pilot for a limited number of PG&E CEV Account Holders[8] before offering such a rate option for all PG&E CEV Account Holders. PG&E's pilot proposal is guided by these additional policy considerations:

1) <u>Advancing Transportation Electrification</u>: PG&E's first CEV rate proposal was adopted by D.19-10-055. It aimed to expand electric transportation by implementing rates that allow CEV charging to be less expensive per mile than petroleum fueling, while avoiding cost shifts to non-participants. PG&E's proposed DAHRTP-CEV Pilot rate in this application is designed to enable customers to assist in grid management and to further save fuel costs by aligning their charging sessions with periods of reduced energy

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4 *Id.*, pp. 29-30.

5 The responses to the Commission's questions are summarized in this chapter in Section 1a, and in detail in Chapters 2 and 3.

6 Including Direct Access ESPs.

7 PG&E Opening and Reply Comments Sections 9, 10, and 12 (September 14 and 25, 2020) on the CPUC Energy Division Staff's draft TEF proposal (February 3, 2020), Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification (DRIVE OIR), R.18-12-006 (Dec. 19, 2018). The draft TEF addresses whether investor-owned utilities should offer optional dynamic rates for all electric vehicle (EV) customers, and transition commercial EV customers to default dynamic rates over time.

8 PG&E referred to PG&E CEV Account Holders as "CEV Customers" in its original CEV rate proposal (Application (A.) 18-11-003). PG&E has revised the terminology for clarity in this filing.

costs. These periods of reduced energy cost tend to also be periods with high levels of generation from renewables and other non-greenhouse gas (GHG) emitting resources.[9] PG&E's pilot approach will investigate the potential for the DAHRTP-CEV Pilot rate to further support the expansion of electric transportation by reducing the cost of CEV charging without shifting costs to non-participants.

2) Achieving Load Management and Decarbonization Goals: California aims to rapidly transition to a low carbon electric grid to meet the Senate Bill (SB) 100 goals for GHG reduction.[10] This transformation—and the rise of renewables, particularly solar—presents new operating challenges for planning and operating the grid, including a need for greater flexibility. Many stakeholders hypothesize that dynamic pricing in general, and RTP in particular, is an effective tool for achieving the three related but distinct objectives of load management, increased grid reliability, and GHG reduction.[11] PG&E cautions that a holistic roadmap that ties together these three goals with TE has not yet been considered. PG&E's DAHRTP-CEV Pilot proposal is an element of the work that can help test these hypotheses, even while policies and activities around dynamic rates and RTP for all customers continue to evolve.

In addition, any new rate proposal must be considered within the context of the Commission's 10 rate design principles that were reaffirmed in PG&E's 2017 General Rate Case (GRC) Phase II decision[12] and the Modern Rate Architecture framework outlined by PG&E in its 2018 Rate Design Window

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[9] PG&E calculates a correlation of -0.40 between the day-ahead price at the PG&E Default Load Aggregation Point (DLAP) and the percentage of California Independent System Operator (CAISO) load met by non-emitting resources, over the period January 1, 2017 to September 30, 2020. Thus, high proportions of generation from non-emitting resources have generally been associated with low energy prices at the PG&E DLAP in recent years.

[10] SB 100 (De León, Chapter 310, Statutes of 2018) states:

> "[T]he Public Utilities Commission, State Energy Resources Conservation and Development Commission, and State Air Resources Board should plan for 100 percent of total retail sales of electricity in California to come from eligible renewable energy resources and zero-carbon resources by December 31, 2045."

[11] Preliminary Root Cause Analysis, Mid-August 2020 Heat Storm, pp. 67-68.

[12] D.18-08-013 p. 37. The rate design principles have also been articulated by the Commission in D.17-08-030 pp. 30-31; D.17-01-006 p. 37; D.15-07-001 pp. 27-28.

(RDW) Application.[13] The proposed DAHRTP-CEV Pilot will allow PG&E and the Commission to obtain data to determine whether its proposed rate is consistent with these guiding principles, including cost causation and economic efficiency. It will also allow PG&E to assess both benefits and costs, such as the reasonableness of any cross-subsidies borne by non-participating and non-benefiting customers, before the rate is considered for wider applicability.

Finally, because PG&E's DAHRTP-CEV Pilot addresses broader rate design issues and policies related to dynamic pricing that are currently being addressed in Phase 2 of PG&E's 2020 General Rate Case (GRC Phase 2) proceeding (A.19-11-019) and the draft TEF, PG&E views its DAHRTP-CEV Pilot application as a useful first step toward potential broader adoption of dynamic rate options for all customers.

For a more comprehensive step, PG&E believes consolidating this application with PG&E's already pending GRC Phase 2 proceeding would be a constructive way to enable a broader and more holistic approach to evaluating the adoption of dynamic pricing rates such as the DAHRTP-CEV Pilot rate. It would also incorporate the overall policy guidance on TE, which will be provided by the Commission in its DRIVE OIR early next year.[14]

In summary, PG&E proposes that the Commission:

- Adopt PG&E's proposed DAHRTP-CEV Pilot rate option for a limited number of PG&E CEV Account Holders with the objective of leveraging the results for other customer classes as determined in A.19-11-019 in the future.
- Direct PG&E to test and evaluate the proposed DAHRTP-CEV Pilot rate to begin addressing the objectives discussed in detail in Chapter 3 and summarized below.

The remainder of this chapter is organized as follows:

- Section B – Overview
- Section C – Commercial EV Policy

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13 A.17-12-011 pp. 3-8.

14 The CPUC also has previously found that a specific RTP rate proposal should be made and evaluated in an individual utility's GRC:

> "The analysis of a particular utility's costs and billing determinants in GRC Phase 2 proceedings is essential to the task of rate design, including the task of designing demand charges and RTP tariffs." (D.19-03-002 Finding of Fact (FOF) 12.)

- Section D – PG&E's DAHRTP-CEV Pilot Proposal
- Section E – Cost Recovery
- Section F – Organization of Exhibit
- Section G – Conclusion

B. Overview

1. Regulatory Background

a. PG&E's Commercial EV Rate Application

PG&E filed an application for approval of new commercial rates for customers using load serving Electric Vehicle Service Equipment (EVSE) on November 5, 2018 (A.18-11-003). A joint stipulation between PG&E and the Public Advocates Office (Cal Advocates) on May 22, 2019 outlined three innovative CEV rates for the Commission's consideration. The CEV rates were proposed with no demand charges or fixed charges. Costs would instead be collected through a newly defined subscription charge and time-of-use (TOU) energy charges.

The scoping memo issued in A.18-11-003 asked whether it is reasonable that PG&E's proposed CEV rate proposal lacks a dynamic rate option.[15] As discussed above, D.19-10-055 found the lack of such a rate option in the proceeding reasonable, but ordered PG&E to submit a proposal for an optional dynamic CEV rate no later than 12 months after the effective date of the decision. The decision recommended that PG&E address ten specific questions as part of PG&E's proposal to for a dynamic rate for CEV customers.[16]

The following is a summary of PG&E's responses to the Commission's questions, with references to further detailed responses to the questions in the subsequent chapters of PG&E's testimony:

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[15] D.19-10-055, p. 5.

[16] D.19-10-055, pp. 29-30.

TABLE 1-1
SUMMARY OF RESPONSES TO COMMISSION'S QUESTIONS IN D.19-10-055

Questions and Summary Responses	Ref.
1. Assuming that any dynamic rate must utilize the CAISO wholesale market price data, how will the dynamic rate utilize such data? Will the rate use day-ahead prices only, or will it use day-of and real-time CAISO prices as well? *PG&E's proposed DAHRTP-CEV Pilot rate uses day-ahead prices only.*	Ch. 2
2. Are there data other than CAISO data, such as a GHG signal data, that should be used as the basis for a dynamic rate instead? *Although a parallel signal corresponding to wholesale market real-time prices could theoretically be developed and broadcast similarly to the GHG signal established by D.19-08-001 for the Self Generation Incentive Program (SGIP), as a practical matter, this would raise significantly more complex technology, billing and other system issues. Furthermore, customer understanding, satisfaction, and ability to plan when best to charge may be negatively impacted.*	Ch. 2
3. What time interval should be utilized for the rate? If a longer interval is utilized (e.g., a 1-hour retail rate price) than the wholesale price data used to inform the retail rate (e.g., 15-minute or 5-minute CAISO real-time market data), how will the differences in temporal granularity be reconciled? *PG&E's proposed DAHRTP-CEV Pilot rate would use hourly intervals, which correspond to the granularity provided in CAISO's published price and generation data used to develop the rate. The fact that real-time CAISO prices are not published until less than an hour prior to the operating interval would make it significantly harder for customers to plan when best to charge under a rate that uses real-time CAISO prices.*	Ch. 2
4. Will the dynamic rate focus solely on periods of overgeneration where CAISO wholesale prices are negative, or will dynamic rates seek to send critical peak price signals as well? *PG&E's proposed DAHRTP-CEV Pilot rate focuses on periods of oversupply where CAISO prices are zero or negative and seeks to send "critical peak price signals" for higher-cost hours through the capacity portion of the rate.*	Ch. 2

TABLE 1-1
SUMMARY OF RESPONSES TO COMMISSION'S QUESTIONS IN D.19-10-055
(CONTINUED)

5. Given that overgeneration events may be either system-wide or limited to a transmission constrained area, should a dynamic rate available to all customers only signal system-wide events? *While some oversupply is local to a sub-Load Aggregation Point (LAP), PG&E's analysis indicates that zero or negative CAISO day-ahead prices generally appear in almost all sub-LAPs at the same time. Thus PG&E's proposed DAHRTP-CEV Pilot rate generally accounts for most day-ahead forecasted over-supply events within its service territory, whether CAISO system, PG&E system, or local.*	Ch. 2
6. At what level of spatial granularity should wholesale prices be sourced? Should it be the DLAP, the sub-LAP, price node (Pnode), or circuit substation-level? What challenges would the use of any sub-system level of granularity present? For example, if 16 sub-LAPs exist in PG&E's territory, and if a dynamic rate is designed to reflect a particular sub-LAP's wholesale prices, then how will the rate be communicated to customers in 16 different sub-LAPs simultaneously? *PG&E's proposed DAHRTP-CEV Pilot rate uses DLAP prices for the generation energy and capacity components. While sub-LAP level energy prices could potentially provide a more accurate price signal in some areas, the DLAP prices would capture the vast majority of price variance, and thus benefits from a day-ahead rate. Differentiating by sub-LAP or finer granularities would add complexity that would increase customer confusion and implementation costs significantly, without a corresponding increase in benefits.*	Ch. 2
7. How should distribution rates be treated in a dynamic rate scheme? Should distribution capacity costs be included in a dynamic rate? *PG&E does not propose to include distribution rates for its proposed DAHRTP-CEV Pilot rate.*	Ch. 2

TABLE 1-1
SUMMARY OF RESPONSES TO COMMISSION'S QUESTIONS IN D.19-10-055
(CONTINUED)

8. What technical and operational challenges must PG&E overcome in order to make a dynamic rate using CAISO price data available to customers? What is the estimated cost of that work? *The main internal PG&E technical and operational challenges include updating PG&E's current systems to automate the daily price calculations, price communication, price storage, and rate framing to bill the hourly prices. Chapter 3 provides a summary of the estimated cost of the DAHRTP-CEV Pilot.*	Ch. 3
9. Do EVSE customers or EVs currently have the technology available to automatically take advantage of a dynamic rate? How will a dynamic rate interact with and support the work of various technical working groups currently organized under R.18-12-006? *PG&E CEV Account Holders are likely to have EVSEs and EVs that are at different levels of technical maturity and may not have the technology available to automatically take advantage of the DAHRTP-CEV Pilot rate. The ability for some participating PG&E CEV Account Holders to be able to automatically obtain and pass hourly pricing through to EV drivers will require Electric Vehicle Service Providers (EVSP) to upgrade their EVSE* and customer-facing applications *to enable automated integrations with PG&E's Pricing Tool and display the pricing to EV drivers. Recommendations from the R.18-12-006 VGI Working Group final report informed this testimony and any approved EV rate pilot programs shall follow guidance provided by the Commission's final decision on the TEF.*[17]	Ch. 3
10. If most adjustments in a dynamic rate take place within the generation component of the rate, then how will CCAs operationalize the rate (if at all)? Are CCAs capable of mirroring or otherwise designing a dynamic rate that their customers can take advantage of? What operational challenges do the CCAs face with such a rate? *If a CCA or other ESP agrees to participate in PG&E's DAHRTP-CEV Pilot (whether by mirroring the rate or using its own calculations), the participating CCA/ESP will: (1) need to calculate, or provide instructions for the pricing tool to calculate the generation component of its dynamic prices for its customers, and (2) need to collaborate with PG&E to continue to bill customers for the total electric bills. PG&E and the participating CCA/ESP will need to collaborate closely to anticipate, identify, and attempt to resolve operational challenges both before and while conducting the pilot.*	Ch. 3

b. California's Load Management Challenge and the Objectives of Dynamic Pricing

As discussed above, California seeks to rapidly transition to a low carbon electric grid in order to meet the SB 100 goals for GHG reduction. This transformation and the rise of renewables, particularly solar, presents new planning and operating challenges for the grid.

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17 Draft TEF proposal, DRIVE OIR.

One challenge is the oversupply of renewable generation in the middle of the day when CAISO's potential supply exceeds customer demand, which can result in curtailment of renewable resources. The second challenge is a need for greater flexibility due to increasing quantities of variable energy resources with limited dispatch flexibility. Solar's expansion on the electric grid in California continues to exacerbate challenges with the ramping up of non-solar, GHG-emitting generation resources as the sun sets.

As the grid decarbonizes and more flexibility is needed, timing issues, or imbalance, between generation output availability and demand on the system can be addressed by building more supply side resources like storage and/or by finding more ways to manage demand.[18] PG&E interprets the term "load management" to refer to an overall objective that can be achieved through a variety of tools that aim to influence changes in load for demand-side flexibility. For example, technology-specific programs that issue direct incentives to customers (e.g., EV incentives, SGIP) or policies that set standards for efficiency (e.g., building standards like Title 24) can change load over different time scales. In addition, changes in load can be achieved through customer response, either behavioral or technology-enabled, to signals from rates and programs for demand response. In a perfect world, technology and signals are implemented together in a manner that optimizes demand-side flexibility.

Dynamic rates are one tool in the load management toolbox that is hypothesized to help align load shape with the needs of the grid and provide flexibility. The theoretical appeal of dynamic rates is that energy users receiving price signals from the wholesale market will provide more effective and targeted load shifting and reduction response than they would on a conventional TOU rate. This creates benefits for customers, the environment, and the grid, and results in lower overall

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18 Comments by CAISO on Load Management Rulemaking, January 24, 2020. Available at: http://caiso.com/Documents/Jan24-2020-Comments-DraftScopingMemo-LoadManagementRulemaking-19-OIR-01.pdf.

costs. Real-time pricing, with more granular price signals than other dynamic pricing structures, seeks to fine-tune the price signal, which can theoretically provide an incentive for more efficient load reduction and load shifting.

However, it is currently unclear and unproven how effective and cost-effective dynamic rates really are when compared to other tools for demand side load management (or even when comparing different types of dynamic rates to one another). This is especially true for RTP, which has not been implemented widely. In addition, it is unclear that RTP applied to CEV customers will be aligned with the other public policy goal of accelerating widespread TE. It remains to be seen how dynamic rates perform on load management goals versus dispatchable programs, standards, or technology incentives combined with non-dynamic time-varying rates such as TOU.[19]

c. Dynamic Pricing Activities in California

In California, there has been accelerated focus on the development of dynamic rates—RTP in particular—as a tool to address load management challenges.

PG&E has designed its DAHRTP-CEV Pilot rate proposal in the context of other activities and policy developments in the areas of dynamic pricing, including: (1) the California Energy Commission's (CEC) Load Management OIR;[20] (2) the CEC's California Flexible Load

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[19] The vast majority of load from PG&E's customers will soon be on TOU rates. California has been transitioning customers to TOU rates for two decades, starting with transitioning large commercial and industrial customers to mandatory TOU rates in 2010. Over 95 percent of PG&E's non-residential customers are on TOU rates now, and residential customers are being transitioned to default opt-out TOU rates over several years, beginning with a pilot in 2018, and then in waves beginning in October 2020 through early 2022. Marketing, Education and Outreach (ME&O) efforts have educated customers to respond to highest prices during a 4-9 p.m. peak period.

[20] CEC Docket # 19-OIR-01 p. 3, "will amend the existing load management standards to increase flexible demand resources, through rates, storage, automation, and other cost-effective measures." This includes consideration of how to: "(a) structure a tariff with electricity prices that change frequently enough to help offset the variability in a 100% renewable grid, and (b) support the tools that enable automated response to prices and/or system conditions." https://www.energy.ca.gov/proceedings/energy-commission-proceedings/2020-load-management-rulemaking.

Research and Deployment Hub (CalFlexHub) Solicitation;[21] and (3) Phase 2 of PG&E's and San Diego Gas & Electric Company's (SDG&E) GRC proceedings,[22] which are currently underway.

In each of SDG&E's and PG&E's GRC Phase 2 proceedings, the respective Administrative Law Judges issued rulings regarding dynamic or RTP rates.[23] The rulings raised issues to evaluate whether an RTP rate is just and reasonable. In addition, the Administrative Law Judges' (ALJ) rulings provided for the use of pilots (or optional rates with capped enrollment) to assess RTP rate proposals. On August 27, 2020, the ALJ ruling in PG&E's 2020 GRC Phase II proceeding (A.10-11-019) also encouraged parties to address several issues summarized as follows:

- Are existing rates sufficient to meet the objectives of potential RTP rates and would a pilot RTP rate with capped enrollment be duplicative?
- What is customer interest in a new RTP rate?

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21 On September 9, 2020 the CEC released GFO-19-309, a $16 million solicitation to fund a single awardee to establish the CalFlexHub. CalFlexHub seeks to, among other items, "develop advanced signal-responsive (price, marginal greenhouse gas emissions, etc.) and interoperable technology solutions that enable commercialization and market adoption of flexible demand resources" and document "consumer acceptance." The Hub will fund research and pilots aimed at increasing the use of advanced flexible demand technologies to respond to signals, including real time rates. CalFlexHub has an Anticipated Agreement Start Date of May 2021 and an Anticipated Agreement End Date of March 31, 2025. https://www.energy.ca.gov/solicitations/2020-09/gfo-19-309-california-flexible-load-research-and-deployment-hub.

22 A.19-11-019 and A.19-03-002, respectively.

23 A.19-11-019, Assigned Administrative Law Judge's E-Mail Ruling Inviting Intervenor Testimony on Real-time Pricing Rates (August 27, 2020). The ruling states:

> "This testimony should specifically address the benefits and tradeoffs inherent to RTP pricing, including whether and to what extent it could result in revenue shortfall and intra-class cost shifts, and it should include bill comparisons and any other relevant data that can facilitate a complete evaluation of customer impacts under specific RTP designs."

A.19-03-002, Assigned ALJ's E-mail Ruling Allowing for Supplemental Testimony Regarding Dynamic Rates (July 17, 2020). The ruling authorized supplemental testimony to address concerns about RTP pricing, such as whether it could result in intra-class cost shifts, provide bill comparisons and other data necessary to evaluate a new RTP rate.

- How should cost shift and revenue under-collection risk be tracked, studied and addressed?
- What is the cost of designing and automating an RTP rate?
- What are the potential bill impacts and other customer impacts?
- How can a pilot be designed (e.g., customer eligibility, program caps, measurement and evaluation)?

PG&E's DAHRTP-CEV Pilot is designed, in part, to address these issues for participating PG&E CEV Account Holders.

C. Commercial EV Policy

PG&E proposed its existing CEV rate in 2018 to help accelerate widespread TE, as directed by SB 350.[24] In its 2017 TE SB 350 Application (A.17-01-022),[25] PG&E identified several significant existing customer barriers to widespread TE, including vehicle operating (fuel) costs. To accelerate TE, operators of all types of vehicles and associated charging infrastructure must have opportunities to save on fuel costs compared to fossil fuels. PG&E's CEV rate was designed to reduce the existing barrier of fuel operating costs.

The proposed DAHRTP-CEV Pilot rate may help further by providing additional opportunities for customers to reduce their electric fueling costs. It may also reduce environmental and grid-related costs by enabling more efficient use of the grid. Public Utilities Code (Pub. Util. Code) Section 740.12(a)(1)(G) states:

> Deploying EVs should assist in grid management, integrating generation from eligible renewable energy resources, and reducing fuel costs for vehicle drivers who charge in a manner consistent with electrical grid conditions.[26]

The CEV rate was designed to reduce fuel costs by minimizing the impact of demand charges on customers, particularly those who may have low utilization as they begin to transition their fleets to EVs. PG&E designed the DAHRTP-CEV Pilot rate to enable customers to assist in grid management and

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24 Sen. Bill No. 350 (Public Utilities Code § 740.12).

25 PG&E Testimony Application A.17-01-022.

26 Pub. Util. Code § 740.12(a)(1)(G).

further save costs by aligning their charging sessions with periods of reduced energy costs and often lower environmental impacts.[27]

PG&E hypothesizes that the demand and cost savings potential for the proposed DAHRTP-CEV Pilot rate will vary substantially among different customer segments within the CEV customer class. Any dynamic rate has a unique set of opportunities and barriers to adoption, due to the rate's complexity and the need for customer-side technology that enables the customer to charge based on dynamic price signals. These take different forms for different customer groups and, consequently, may affect customer experience differently.

1. PG&E's CEV (BEV) Rate

PG&E's current CEV rate, rolled out as the Business Electric Vehicle (BEV) rate, was launched with basic billing on May 1, 2020 and with full functionality on October 1, 2020.[28] As of September 1, 2020, 13 customers had enrolled 186 accounts on the BEV rate, and PG&E is actively monitoring usage and enrollment. As data are collected, PG&E will have more meaningful insights into the rate's effectiveness and whether a dynamic rate may be of interest to commercial customers. PG&E will conduct a workshop in 2021 to share data on BEV rate adoption.[29]

2. Customer Experience

a. Customer Research

While developing the application for the BEV rate,[30] PG&E partnered with the Electric Power Research Institute (EPRI) to conduct

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[27] For example, in the CPUC's Avoided Cost Calculator (ACC), the marginal GHG emissions rate is essentially proportional to the energy price divided by the price of natural gas, so low energy costs correspond to low marginal emissions. The 2020 version of the ACC model is at: https://www.cpuc.ca.gov/General.aspx?id=5267.

[28] PG&E received approval to execute a phased implementation for the CEV subscription rate which prioritized and frontloaded the rate's essential features to make billing and subscription tracking available May 1, 2020 (Phase 1), while leaving time to develop and implement the remaining functionality by October 1, 2020 (Phase 2).

[29] D.19-10-055, p. 75, OP 12.

[30] A.18-11-003.

research to better understand customer and stakeholder priorities for CEV-specific rate designs.[31]

Per PG&E's CEV testimony:

> One of the objectives of EPRI's research was to evaluate the tradeoff between a simpler, more consistent rate structure, versus one that is more complex and dynamic. To test these concepts, EPRI shared three conceptual rate designs across a spectrum of complexity of fixed charges, demand charges, and volumetric charges.

EPRI found that most customers preferred simpler rates that reduce the impact of demand charges due to low utilization. Some respondents believed that, with appropriate software solutions, there is potential to manage load and save money with dynamic rate designs.[32]

Based on PG&E's and EPRI's customer insights, any CEV rate must meet the following criteria to be successful:

- Simple: The rate must be simple, easy for customers to understand, and not present cost volatility that could "make or break the EV business case."
- Economically beneficial: The rate must reduce the total cost of ownership for customers owning or leasing EVs by keeping electricity costs on par or lower than diesel.[33]

b. Rate Simplicity

Due to the variability of the price signals in dynamic rates and the tie to wholesale energy markets, dynamic rates may not be easy for most EV customers to understand. This is especially true for customers transitioning to EVs who may have no prior experience with electricity as fuel. This is the case with many of PG&E's EV Program applicants, such as transit agencies. This observation is confirmed by EPRI's research, where it found that customers such as fleet operators can be

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31 See Attachment A at the end of this chapter. Report: EPRI, CEV Rate Design, Stakeholder Interview Results, Technical Report (October 2018). EPRI interviewed 23 entities, ranging from fleet operators, charging service providers, vehicle makers, and non-governmental organizations over a several-week period in mid-2018.

32 *Ibid* p. 3-2.

33 *Ibid*. p. 4-1.

unfamiliar with electric rate structures, which can be more complex than fossil fuel retail pricing.[34] A dynamic rate is likely harder for many customers to understand since it adds more complexity that can inhibit adoption. On the other hand, many EVSPs have been exposed to dynamic rates in other jurisdictions (including SDG&E's Power Your Drive pilot rate), and may find PG&E's proposed DAHRTP-CEV Pilot rate simpler than one that varies by circuit or can be updated on the same day, as with SDG&E's rate.[35] The complex landscape of EV charging, in which some end-use customers do not need to be aware of the electricity rate their service provider is paying while others face the rates directly, complicates customer education efforts.

The knowledge gap may be partially addressed with targeted Marketing, Education and Outreach (ME&O). PG&E details the proposed targeted ME&O plan for the DAHRTP-CEV Pilot in Chapter 3. However, a large portion of the ME&O anticipated to be required for the DAHRTP-CEV Pilot rate to be successful is the responsibility of site hosts, technology, and software providers who will be working with customers to receive and respond to the dynamic price signal.

A key objective of the DAHRTP-CEV Pilot is to address whether dynamic rates can overcome their lack of simplicity. One hypothesis is that a dynamic rate may also be significantly simplified for customers if automated technology is used to manage charging to align with low cost hours ("set and forget").

c. Rate Cost Effectiveness

When considering the range of customers who may adopt the dynamic rate, PG&E hypothesizes that cost savings potential varies based on duty cycle flexibility, adoption costs, and resource alignment.

- Duty Cycle Flexibility: The ability of a customer to shift its EV charging behavior based on the flexibility of its vehicle operations, or duty cycle, to charge during fluctuating low-cost hours.

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34 *Ibid*. p. 4-11.

35 SDG&E, EV Vehicle-Grid Integration (VGI) Pilot Program Eighth Semi Annual Report.

- Adoption Costs: Due to the hourly variability of the proposed dynamic rate, it is likely that customers may require enabling technology to be able to successfully respond to the rate. As discussed in Chapter 3, PG&E proposes to design the dynamic rate such that a customer could take advantage of it with or without technology. However, customers may need an integrated, automated means to simplify their responses to the changing hourly prices. To respond automatically, customers will require technology that is capable of automatically discovering the day-ahead hourly rates and notifying customers, so that they can change their charging behavior, which adds costs to the installation of EV chargers. PG&E recommends piloting the dynamic rate with EV customers to better understand these costs and their implications.
- Resource Alignment: The CPUC VGI Working Group defines resource alignment as "whether the "EV actor" and the "EVSE actor" are "unified" (meaning both the EV and EVSE are controlled and/or operated by the same actor) or "fragmented" (meaning controlled and/or operated by different actors).[36] For example, a transit agency would likely be unified, as the agency would manage both the transit buses and the charging infrastructure. Conversely, Direct Current Fast Charger (DCFC) stations would typically be fragmented because the owner of the charging infrastructure would not be the same as the operator of the vehicle charging at the DCFC. Furthermore, charging at workplaces and at Multi-Unit Dwellings (MUD) may be unified or fragmented, or both. Fragmented resource alignment can lead to a misalignment of incentives (the "principal-agent problem"), add complexity, and potentially reduce the dynamic rate's value proposition. PG&E recommends targeting the DAHRTP-CEV Pilot rate to customers who have unified resource alignment as well as those who have

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36 Report: VGI Working Group, Final Report of the California Joint Agencies VGI Working Group (June 30, 2020), p. 19. Available at: https://gridworks.org/wp-content/uploads/2020/07/VGI-Working-Group-Final-Report-6.30.20.pdf.

fragmented resource alignment, to understand the complexities involved with both scenarios.

d. The Role of Technology in Simplifying the Dynamic Rate and Enabling Cost Savings

Technology and automation may simplify a dynamic rate for customers. For customers to respond to the dynamic rate (whether manually or through automated technology), the following actions must be completed:

- The utility must be able to enable the customers by sending a day-ahead 24-hour price schedule to the customer. This technology requirement is discussed in Chapter 3.
- The customer must be able to receive the day-ahead, 24-hour price schedule from the utility and adjust its behavior based on the schedule. This is discussed in this chapter below.

In EPRI's research, it found that:

> …most [customers] believe that the industry's ability to respond to more complex price signals and rate design structures from the utility would grow over time as more EVs are deployed, utilization rates grow, and load management software and charging infrastructure technology improves.

However:

> …several operators were clear that they are still in the learning curve phase and need to gain additional insight on how to best incorporate these new technologies into their respective lines of business.[37]

Customer technology readiness can be assessed by considering a customer's ability to conduct price discovery and charge schedule execution.

- Price Discovery: PG&E will communicate the dynamic rate each day to customers in machine-readable format and via a publicly accessible website. Technology providing customers with the ability to automatically conduct price discovery is a key enabler for dynamic rate participation. In some cases, where resource

[37] See Attachment A at the end of this chapter. Report: EPRI, CEV Rate Design, Stakeholder Interview Results, Technical Report (October 2018) p. viii.

alignment is fragmented, multiple parties must be able to discover pricing. For example, at a MUDs, if EV drivers are to pay for charging based on dynamic prices, the EVSP must be aware of the pricing to accurately bill their customers. The EV driver should also be educated on the dynamic rate, and be aware of the 24-hour pricing, so it can choose when to charge at a low cost.

- Charge Schedule Execution: Once pricing is known, it must be communicated to the EVSEs or the EVs so they can execute a low-cost charge session. Managed charging enables customers to take advantage of fluctuations in price signals throughout the day to charge their vehicles at the lowest cost while optimizing for the timing of operations. To execute managed charging, customers must have networked chargers, smart vehicles and/or onsite communications. In many cases, the customer will need to optimize for many factors to execute a low-cost charging session, like demand and operational flexibility. Some customers have energy management technology onsite or own or lease vehicles with managed charging capability. However, not all customers have communications systems, EVSEs, or EVs that possess these capabilities. For example, in PG&E's Electric School Bus Renewables Integration Priority Review Project, PG&E found that models of electric school buses are often not designed to accommodate delayed charging, let alone managed charging. These buses electronically disconnect charging capability after a period of time if they are plugged into a charger and do not receive a charge, thus eliminating their ability to participate in rates that require automated dynamic charging.[38] In some instances, technology may be limited or nascent. In others, customers may need to make costly upgrades to participate on the proposed dynamic rate or may not have the staff, time, or expertise to benefit from dynamic rate price signals. Ultimately, PG&E recommends testing the DAHRTP-CEV Pilot rate across different EV customer

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38 Report: Joint IOUs' Interim Report on Priority Review Projects (Jan 31, 2020) p. 177.

segments to understand technology readiness for different types of EV customers.

3. Customer Segmentation

a. Overview

The total available market of potential customers for the proposed dynamic rate includes, but is not limited to, the five use cases laid out in D.19-10-055, which approved the structure for a CEV rate: public DCFC, workplace charging, multi-family residential, transit fleets and medium-duty delivery fleets.

PG&E completed preliminary outreach to assess potential customer demand and barriers to dynamic rate adoption by use case to develop a hypothesis to the following question: Can the dynamic rate provide a simple, understandable pricing structure and low-cost electric fuel based on current customer capabilities? PG&E hypothesizes that a customer with unified resource alignment and significant duty cycle flexibility may realize the most value from the dynamic rate and proposes to test this hypothesis with a pilot.

b. Public DCFC

Public DCFC operators offer destination and on-route charging to individual EV drivers and seek to maximize utilization for their chargers. DCFC resource alignment tends to be fragmented.

DCFC duty cycles are inflexible. EV drivers tend to use DCFCs when they require quick refueling. Dwell times vary by driver, but in many cases are only as long as is needed to charge sufficiently, usually less than an hour.[39] For drivers in transit, there is likely to be little appetite to charge at a different time and introduce uncertainty into what should be a routine and predictable process of EV charging.

Public DCFC operators have little control over when drivers use their equipment and thus cannot easily reduce electric demand or shift usage to lower-cost hours. Most DCFC operators strive for high

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[39] Report: U.S. Department of Energy, Plug-In Electric Vehicle Handbook for Public Charging Station Hosts (Apr 2012) p. 6. Available at: https://afdc.energy.gov/files/pdfs/51227.pdf.

utilization and would be unlikely to shift charging if it reduces the number of drivers who can use each charger. If higher electricity costs resulting from the dynamic rate are passed along to drivers, the price differential between electricity and the gasoline equivalent diminishes. If electricity costs are not passed on to customers, then the DCFC operator takes on risk in managing operations due to the rate.

In developing this rate proposal, PG&E informally engaged several DCFC operators, some of whom expressed limited interest in dynamic rates, noting they would need to better understand the value before committing to the system upgrades required to optimize for the rate. Some also conveyed that an increase in complexity is likely to cause customer confusion when rates are unexpectedly high due to the volatility of a dynamic rate. According to EPRI's research, "fast charging infrastructure was generally deemed unable to respond to dynamic rate options."[40] PG&E hypothesizes the dynamic rate would not provide a simple, low-cost electric fuel option for most public DCFC operators.

The only exception to the above hypothesis is that DCFC stations that combine multiple charging ports with energy storage (ES) and photovoltaic (PV) systems behind the same meter could potentially use the volatility of a dynamic rate to improve the economics of the ES and PV systems.

c. Workplace Charging

Resource alignment for workplaces tends to be fragmented because in most cases the individual using the charger (i.e., the employee) and the entity owning the charger (i.e., the business) are different. Vehicles at workplaces tend to have flexible duty cycles, as they tend to have longer dwell times and are typically parked for 4-8 hours.[41] In PG&E's Electric Vehicle Charging Network (EVCN) Program, over 80 percent of the participants in PG&E's custom pricing program are workplace site

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40 See Attachment A at the end of this chapter. Report: EPRI, CEV Design, Stakeholder Interview Results, Technical Report (October 2018) p. 4-5.

41 Report: EV Charger Selection Guide (Jan 2018) p. 3. Available at: https://afdc.energy.gov/files/u/publication/EV_Charger_Selection_Guide_2018-01-112.pdf.

hosts rather than MUDs.[42] These site hosts choose their own pricing plan as opposed to simply passing through PG&E's pricing, potentially implying a workplace site host is more comfortable with electric rates and setting pricing to optimize for their needs compared to MUDs.

Workplaces may incent maximum turnover to increase the number of employees who can charge during the workday, often by pricing by time connected to the charger.[43] Maximizing turnover and a dynamic rate may provide misaligned incentives. Maximizing turnover encourages customers to charge quickly with little flexibility, whereas a dynamic rate could encourage a driver to increase dwell time at the charger while they wait for the lowest cost hour to charge. On the other hand, the lowest energy and capacity prices are generally in the mid-morning to early afternoon. Therefore, based on amount of charge required, multiple vehicles could feasibly charge during low cost hours during a typical workday.[44] PG&E hypothesizes that workplace charging on the proposed dynamic rate could produce cost savings with proactive and engaged customers.

d. Multi-Family Residential or Multi-Unit Dwellings

MUDs typically have fragmented resource alignment. MUD EV site hosts do not control when chargers are utilized. Usually tenants will charge when it suits their schedules. Tenants can dwell at chargers for up to 10 hours, providing flexibility to the site host and an ability to respond to dynamic rates.[45]

If MUDs choose to pass on the costs of charging to their tenants, as over 60 percent of current EVCN MUD site hosts have opted to do (as

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42 84 site hosts participating in PG&E's EVCN Program choose the Custom pricing option. 14 customers are categorized as MUD and 70 are categorized as workplace.

43 Report: UCLA Luskin School of Public Affairs, EV Charging at Work (Nov 2016) p. 12. Available at: https://innovation.luskin.ucla.edu/wp-content/uploads/2019/03/EV_Charging_at_Work.pdf.

44 *Ibid.* From Figure 4, average charging time varies by time of day, but is generally between 2 and 3 hours.

45 Report: EV Charger Selection Guide (Jan 2018) p. 3. Available at: https://afdc.energy.gov/files/u/publication/EV_Charger_Selection_Guide_2018-01-112.pdf.

compared to workplace site hosts), there will need to be significant education and outreach so that tenants understand the time-varying rates.[46] Without education and outreach, higher or inconsistent bills may dampen customers' enthusiasm for EVs. PG&E hypothesizes that MUD charging on the proposed dynamic rate would likely produce cost savings under the right circumstances and with the right educational resources.

e. Transit Operators

Transit operators tend to be unified actors. They typically operate their own charging equipment and electric buses and make unified charging decisions. Transit vehicles are charged at a central depot or on-route. Transit operators have particularly rigorous duty cycles, often operating from the early morning into the evening and requiring high-powered charging during evening dwell times. For these reasons, schedules both for charging and daily operations are often less flexible.

On-route charging generally does not allow for any flexibility, as drivers tend to use on-route chargers for less than an hour on their routes. Overnight depot charging may provide more flexibility. Given transit operators' particularly rigorous duty cycles, they may not be able to consistently take advantage of the dynamic rate, which could erode cost savings. PG&E hypothesizes that a dynamic rate is unlikely to be beneficial or adopted by most transit customers, though it may be beneficial on a case-by-case basis, taking route topology, battery size and specific bus duty cycles into consideration.

f. Medium Duty Delivery

Medium Duty (MD) delivery operators are likely to have unified resource alignment, as they tend to operate both their onsite charging equipment and EVs. Delivery operators have indicated less flexibility for charging and a preference for clear, stable rates.[47]

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[46] 94 site hosts participating in PG&E's EVCN Program choose the Pass-Through pricing option. 57 customers are categorized as MUD and 37 are categorized as workplace.

[47] See Attachment A at the end of this chapter. Report: EPRI, CEV Rate Design, Stakeholder Interview Results, Technical Report (October 2018) p. 3-1.

Cost savings become more likely if operators can take advantage of low-cost charging periods while maintaining minimal or no impact to operations. PG&E hypothesizes the proposed dynamic rate may provide cost savings to MD delivery operators. MD delivery operators with fleets of vehicles that have longer charging windows are more likely to garner greater cost savings from use of a proposed dynamic rate.

4. Policies and Design for Long-Term Customer Experience

Looking ahead, several opportunities may enhance the value proposition of the dynamic rate for EVs:

- TE policy is expected to lead to accelerated EV adoption. California continues to implement a range of policy and regulation to address transportation emissions. The California Air Resources Board recently passed the Innovative Clean Transit Rule, the Advanced Clean Trucks Rule, and is working on additional segment-specific regulation for 2021 and beyond. As policy continues to drive accelerated vehicle adoption, customers are likely to increase the number of EVs in their fleets, increasing overall load shift capacity, and the ability to save on the dynamic rate.
- Technology and customer readiness are likely to continue to advance. As customers adopt and become more familiar with EVs and EV rates, dynamic rates may become more attractive. With more cost-effective, advanced automation, the dynamic rate could provide value to a larger segment of TE customers.
- Complementary technologies, like battery storage, are becoming less expensive. As the cost of battery storage decreases, the use case for a dynamic rate for CEV customers may rely on connected ES. Under current BEV rates, connected ES may be used to reduce peak demands to manage subscription charges, and shift load between lower – and higher-priced hours ("energy arbitrage") to manage generation charges. Under dynamic pricing, the energy charges have more variability so energy arbitrage could provide greater customer benefits. It should be noted that optimizing for the BEV subscription charge and variable dynamic generation pricing is a complex challenge, as these two objectives may not always be aligned.

D. PG&E's DAHRTP-CEV Pilot Proposal

PG&E proposes to pilot a 36-month DAHRTP-CEV Pilot limited to 50 PG&E CEV Account Holders.[48] This pilot will allow PG&E to assess: (a) the gaps in information needed to determine whether a dynamic RTP rate is effective; (b) uncertainties about the applicability of RTP to the CEV class; and (c) other unknowns. PG&E's DAHRTP-CEV Pilot proposal can begin to address some of these information gaps. However, given its narrow focus on PG&E CEV Account Holders, it may not be possible to recruit a sufficient number of participants to conclude observed relationships are statistically significant. It is also uncertain whether the participating customers will be diverse enough to indicate customer understanding and benefits, particularly for customers in disadvantaged communities. In addition, it will also not be possible to generalize results to other customer classes.

1. Pilot Objectives

PG&E hypothesizes that automated engagement through utility-side enablement technologies and appropriate customer-side system integration can unlock benefits for some CEV customers enrolled in a dynamic rate. However, given the nascent TE marketplace and the lack of data showing customers that they could save on the rate, PG&E proposes to conduct a DAHRTP-CEV Pilot in order to assess the value proposition of a dynamic rate for CEV customers and gather lessons to inform broader implementation of a dynamic rate. PG&E proposes to investigate the following questions through the DAHRTP-CEV Pilot.

- What technical and operational challenges must PG&E overcome to make the DAHRTP-CEV Pilot rate available to customers? What is the cost of that work?
- Can participating PG&E CEV Account Holders technically integrate with PG&E's proposed DAHRTP-CEV Pilot rate? What is the cost of that work?

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48 For simplicity, PG&E assumes CEV Account Holders may have, on average, ten charging ports per account. Not all charging ports are expected to be in use simultaneously. PG&E proposes to provide incentives to no more than 500 EV drivers in this pilot.

- Does the proposed rate provide cost savings to participating PG&E CEV Account Holders, when considering the upfront costs needed to automate response to the DAHRTP-CEV Pilot rate? Which use cases can achieve the greatest savings without diminishing the end-use customer experience?
- Does the proposed rate provide system benefits, like system capacity use, GHG reduction and renewables integration? Does the proposed rate provide both system and customer benefits simultaneously?

PG&E's DAHRTP-CEV Pilot is designed in part to address these issues for participating PG&E CEV Account Holders.

2. Rate Design

PG&E's proposed DAHRTP-CEV Pilot rate is a rate rider that would replace the current TOU generation rates on Schedules BEV-1 and BEV-2 with a generation rate derived from CAISO's day-ahead hourly wholesale market, forecasted load and GHG-free generation. Rates related to distribution, transmission, and non-bypassable charges would continue to be assessed as specified in the original BEV schedules. The generation rate includes an energy portion, a capacity portion, and a non-time-differentiated revenue neutral rate adder. The design of the generation rate rider is discussed in detail in Chapter 2.

3. Customer Enablement

PG&E proposes to develop a pricing tool that would allow for PG&E and CCA/ESPs serving PG&E customers to compose their hourly dynamic generation rate component prices, and a pricing communication platform that will publish and disseminate hourly pricing to customers and third parties via a website or an Application Programming Interface. No sub-metering will be enabled and no rate comparisons will be provided in the DAHRTP-CEV Pilot. Customer enablement is discussed in detail in Chapter 3.

4. Target Customers and EVSE Recruitment

PG&E has initially sized the DAHRTP-CEV Pilot for 50 PG&E CEV Account Holders. During the pilot, PG&E plans to: (a) provide participating PG&E CEV Account Holders who have installed EV charging infrastructure an operational understanding of the DAHRTP-CEV Pilot rate; (b) test the feasibility of the technology; and (c) evaluate participants' experience.

PG&E will target customers for the proposed dynamic rate based on the five use cases adopted in D.19-10-055: public DCFC, workplace charging, multi-family residential or MUDs, transit operators and MD delivery fleets.[49] PG&E hypothesizes that the proposed dynamic rate may be most beneficial for CEV customers with unified resource alignment and significant duty cycle flexibility, and that workplace, MUD, and MD delivery operators with large fleets of vehicles that have longer charging windows are more likely to garner greater cost savings from utilization of a proposed dynamic rate.

Incentives of no more than $1.6 million will be provided for: (a) a one-time EV-owner incentive to decrease customer barriers to participation and encourage continued engagement in the DAHRTP-CEV Pilot, and (b) a technology-specific incentive for EVSP to mitigate the financial risk of upgrading their systems to enable automated integrations with PG&E's customer enablement tool.

Target customers and EVSE recruitment are discussed in detail in Chapter 3.

5. Marketing, Education and Outreach

ME&O efforts for PG&E's DAHRTP-CEV Pilot will directly engage with customers to assess their level of interest and understand the customer experience through one-to-one and one-to-many outreach efforts. The ME&O plan objectives are discussed in detail in Chapter 3.

PG&E aims to collaborate with customer-side technology providers to enhance ME&O efforts, and, where appropriate, to develop resources and materials to enhance their efforts. Technology providers are expected to lead one-to-many outreach to customer segments with the support of PG&E on an as-needed basis. PG&E will conduct direct-to-customer one-to-one outreach via phone calls and/or e-mails to customers that have an existing PG&E relationship.

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49 D.19-10-055, p. 12.

6. Evaluation, Measurement and Verification

PG&E expects to engage appropriate internal and external experts during the pilot design phase to define a robust evaluation framework. This will inform realistic requirements and expectations around data type, granularity, fidelity, and availability to accurately test the hypotheses listed above. PG&E also expects to collect and analyze qualitative data (e.g., surveys) to understand impacts and associated implications.

E. Cost Recovery

As detailed in Chapter 3, on a preliminary basis and subject to further refinement, PG&E forecasts $3.9 million to $6.0 million in costs to implement the DAHRTP-CEV Pilot. In this application, PG&E is not seeking immediate approval of the reasonableness of the costs it incurs to implement the DAHRTP-CEV Pilot. Instead, PG&E is requesting to record the incremental costs of implementing the DAHRTP-CEV Pilot in a new memorandum account—Dynamic and Real-Time Pricing Memorandum Account (DRTPMA). The costs in the DRTPMA would be reviewed in a future GRC Phase I proceeding or separate application, before being recovered in customer rates.

PG&E will record in the DRTPMA the actual costs it incurs pursuant to the Commission's orders for the DAHRTP-CEV Pilot. If the Commission requires PG&E to incur costs that are greater or lesser than the forecasted costs set forth above, PG&E may adjust the amounts to be collected in rates to reflect the actual costs recorded during this period.

PG&E proposes that the pilot costs discussed in Chapter 3 be recovered in the distribution component of rates. The costs described in testimony are largely related to the development of infrastructure (i.e., the platform to communicate pricing) which is beneficial to all customers. The proposed DAHRTP-CEV Pilot pricing tool is specifically structured to be able to take in prices from CCAs/ESPs.

F. Organization of Exhibit

This exhibit has a total of 3 chapters. The remainder of this exhibit is organized as follows:

- Chapter 2 – Rate Design
- Chapter 3 – Proposed CEV Day-Ahead Hourly Real Time Pricing Pilot

G. Conclusion

In this chapter, PG&E has discussed the general policy objectives and context that have guided its proposal for a DAHRTP-CEV Pilot and provided answers to the specific questions posed by the Commission, which are needed in order to approve a dynamic rate. PG&E's proposed DAHRTP-CEV Pilot provides a way to evaluate the potential for a dynamic rate option with fluctuating hourly prices to help PG&E CEV Account Holders and EV Drivers reduce their impact on the grid and environment while potentially lowering their costs. At the same time, PG&E's DAHRTP-CEV Pilot rate proposal is a first step in evaluating the broader potential among other customer classes for DAHRTP, while policies and activities around dynamic pricing and RTP continue to evolve. The DAHRTP-CEV Pilot will also allow PG&E to evaluate whether its proposed rate is consistent with the Commission's ten rate design principles that were adopted in the Residential Rate OIR Phase II decision (D.14-06-029) and the Modern Rate Architecture framework outlined by PG&E in its 2018 RDW rate design principles. It will also allow PG&E to assess the consequences, such as unintended or unreasonable cross-subsidies, before determining whether the rate should be adopted more broadly. PG&E also summarized its proposal for a DAHRTP-CEV Pilot, focusing on: pilot objectives, rate design, customer enablement; target customers and EVSP recruitment; ME&O; and Evaluation, Measurement, and Verification.

PG&E respectfully requests approval of its proposals in this application. Finally, as this application is limited to a DAHRTP-CEV Pilot, PG&E believes consolidation of this application with PG&E's 2020 Phase II GRC proceeding is appropriate. A broader and more holistic approach to the adoption of dynamic pricing rates, including a pilot addressing a broader set of customer classes, can be considered in PG&E's GRC Phase II proceeding with other public policy goals. These goals include the policy guidance to be provided by the Commission on TE in its DRIVE OIR early next year and on expanded electrification generally.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

ATTACHMENT A

COMMERCIAL ELECTRIC VEHICLE RATE DESIGN, STAKEHOLDER INTERVIEW RESULTS, ELECTRIC POWER RESEARCH INSTITUTE, FINAL REPORT, OCTOBER 2018

Commercial Electric Vehicle Rate Design

Stakeholder Interview Results

2018 TECHNICAL REPORT

Commercial Electric Vehicle Rate Design

Stakeholder Interview Results

3002014013

Final Report, October 2018

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Commercial Electric Vehicle Rate Design: Stakeholder Interview Results. EPRI, Palo Alto, CA: 2018. 3002014013.

ABSTRACT

It is believed that rate design plays a key role in determining consumer interest in electric vehicles (EVs). The use of demand charges for fast charging applications and fleet deployments is increasingly a key consideration for distribution planners due to the potential infrastructure investments required to serve such facilities. Many utilities, regulators, as well as the general population, support the deployment of EVs to realize societal and grid benefits including reduced emissions through efficient electrification. Therefore, they are interested in designing rate options that will accelerate EV adoption. A commercial EV rate can be an important complement to supporting a community's clean transportations goals.

However, due to the existing low utilization rates for charging infrastructure coupled with and high power demand, especially when charging is unmanaged, means that existing utility rates with demand charges can result in a high average cost per kilowatt-hour (kWh). These higher fuel or operating costs can negatively impact the business case for EVs or infrastructure growth if the result is that customers may pay more for electricity than the equivalent amount of gas/diesel. Although commercial EV utilization is expected to increase and technology costs are expected to decrease over the next 10 to 20 years, current rate designs may discourage charging in instances where the loads have low load factors (and thus higher costs per kWh).

To better understand the impact rate design has on commercial EV adoption and infrastructure growth, EPRI conducted stakeholder interviews to answer the question of how important different rate design options are to commercial customers in their decision to electrify their fleets or install EV charging equipment. Applications with higher potential grid impacts are of particular interest. This research explores commercial customer perceptions and understanding of different rate design options. While it is important to note that rate design includes balancing multiple objectives and that the results of this study are qualitative in nature, these customer insights may be used to inform utilities, regulators and other stakeholders in subsequent rate design efforts.

Keywords

Electric vehicle fleets
Electric vehicle charging stations
Commercial electric rate structures
Electricity demand charges
Time-of-use electric rates
Electric vehicle rate design options

Deliverable Number: 3002014013

Product Type: Technical Report

Product Title: Commercial Electric Vehicle Rate Design: Stakeholder Interview Results

PRIMARY AUDIENCE: Electric utilities, regulators, electric transportation industry stakeholders and commercial customers seeking to electrify vehicles

SECONDARY AUDIENCE: General public

KEY RESEARCH QUESTION

It is believed that rate design plays a role in determining consumer interest in electrifying transportation. Many utilities and regulators support the deployment of electric transportation (ET) to realize societal benefits including reduced emissions through efficient electrification. Therefore, there is interest in designing rates that will accelerate ET adoption while still meeting cost recovery objectives. Accordingly, a commercial electric vehicle (EV) rate can be an important complement to supporting a community's clean transportation goals. EPRI conducted this research to help answer the question: "How important are different rate design options to commercial customers in their decision to electrify their fleets or install charging equipment?"

RESEARCH OVERVIEW

This work builds upon secondary research completed earlier this year to summarize the current state of utility rate design, for both residential and commercial consumer groups, specific to electric vehicles in the U.S. electricity market [1]. The objective of this new research is to assess the impact utility rate design options might have on the deployment of electric vehicles for various commercial EV applications such as fast charging and destination charging applications as well as fleet and public transit. This work was conducted in collaboration with Pacific Gas & Electric Company.

As part of this research project, EPRI conducted stakeholder interviews with commercial electric utility customers and other commercial ET stakeholders with business interests in California. Representatives from four key perspectives were interviewed: 1) workplace and public charging, 2) fleet operators and public transportation agencies, 3) EV and equipment manufacturers and software providers, and 4) environmental groups/NGOs. Interviewees participated in 45-minute telephone discussions with EPRI, in which they were asked to share their understanding and preferences for various aspects of different commercial EV charging rate design options. Visual aids were prepared to help facilitate these conversations and sent to interviewees in advance of the calls. Discussion topics included: the ability to respond to dynamic EV charging rates, preferences for fixed prices and simpler rate structures, the ability to respond to time-of-use pricing and demand charge price signals, expectations of future EV charger utilization rates, and related topics.

It is important to note that the sample size and make-up of this study does not allow conclusions to be extended to the general population. However, the feedback received remains informative for future rate-making considerations.

KEY FINDINGS

The following lists some of the highlights from the stakeholder interviews.

- The interviewees varied in their preferences for simple and more consistent rate options as compared to dynamic and more complex electric vehicle charging rate options, largely depending on their respective use cases. When coupled with software solutions to help manage charging, some believed there is potential to manage load and save money with dynamic rate design options while others preferred simplicity in order to focus on their core business and minimize price risk.
- Demand charges in general were unpopular among study participants. Interviews revealed that demand charges can be difficult to understand and to manage in their routine operations. A stated concern about demand charges is that they are not believed to reflect the significance of how much time is spent at peak capacity. The bill uncertainty associated with volatility in demand is perceived to add risk to business operations and may influence decisions to electrify transportation. Several interviewees expressed concern that demand charges can "make or break" the EV business case. Respondents representing the fast charging use case expressed the most concern about the ability to manage charging patterns and the resultant adverse financial impacts from demand charges.
- The utility's cost driver for certain hours designated as "peak" or "off-peak" was well accepted and understood, as was the correlation to solar production as a driver of such costs. However, the connection to cost drivers for demand was less clear. Several study participants voiced a desire for recalibration of demand charges to reflect coincident utility system peak times and seasonality versus individual monthly peak by account.
- The cost drivers of energy charges, such as those reflected in time-of-use price signals were sometimes confused with the drivers of demand charges, which are generally calculated to recover fixed infrastructure investments sized to meet peak loads on a localized basis. A few commented that they understand a utility's challenge to recover infrastructure costs and encourage utilities to work with large customers for mutual resolution/benefit, such as investment in energy storage at specific sites or other demand response agreements.
- Preferences for conceptual rate designs varied among the options presented to the interviewees, again according to the use case of each interviewee. Most favored a choice of EV rate options, offering comments including, "choice is always good" and "there is no one-size-fits- all" solution. Most believe that the industry's ability to respond to more complex price signals and rate design structures from the utility would grow over time as more EVs are deployed, utilization rates grow, and load management software and charging infrastructure technology improves. Additionally, several operators were clear that they are still in the learning curve phase and need to gain additional insight on how to best incorporate these new technologies into their respective lines of business.

WHY THIS MATTERS

The results of this research can help to expand understanding of commercial customer preferences for, and responses to, various potential EV charging rate design constructs. In addition, the results identify which pricing elements might create barriers to EV adoption and why, as well as possible accelerators to adoption that can help meet legislative and regulatory requirements for fleet electrification and other environmental or societal objectives, such as meeting GHG reduction and localized particulate reduction (air quality) standards.

HOW TO APPLY RESULTS

These customer insights can inform utilities, regulators, and stakeholders in legislative and regulatory forums where utility rate design options are considered. The findings can also provide additional insight into the currently perceived needs of key EV industry stakeholders. The results are qualitative and informative, but not necessarily extendable (in the statistical sense) to a larger population.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- Anyone interested in better understanding current perceptions of industry stakeholders in the commercial EV industry may be interested in this report. This report was a collaboration between EPRI Program 182: Understanding Electric Utility Customers and Program 18: Electric Transportation.

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PROGRAM: Understanding the Electric Utility Customer Program 182

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BACKGROUND AND RESEARCH OBJECTIVES

The intent of this research was to explore the role that rate design plays in determining consumer interest in electric vehicles (EVs) for commercial applications and to assess customer understanding and acceptance of various rates design constructs. The use of demand charges for fast charging applications and large commercial vehicle fleets is increasingly a keyconsideration for distribution planners due to the potential infrastructure investments required to serve such facilities. Many utilities and regulators support the deployment of EVs to realize societal and grid benefits including reduced emissions, efficient electrification, and job creation. Therefore, they may be interested in designing rate options that will accelerate EV adoption. A commercial EV rate is an important complement to supporting a community's clean transportations goals.

However, due to initial low utilization factors and high power demand (together creating low load factors for these customers), existing rate designs with demand charges can result in a high average cost per kWh for these customers. Accordingly, even though commercial EV utilization factors are expected to increase, and technology costs are expected to decrease over time, current rate design constructs may be seen as a barrier to adoption in the near term. Compared to simple $/gallon costs, electric rate design options can vary in complexity, with different combinations of components (customer charge, demand charges, energy charges, TOU periods) and seasonal and time-of-use variation used in the calculation of cost per kilowatt hour of electricity, impacting both the average rate and overall bill a given customer may pay.

As the basis for the findings shown in this report, EPRI conducted stakeholder interviews to answer the question of how important different rate design options are to commercial customers in their decision to electrify their fleets or install charging equipment. Applications with higher potential grid impacts such as public/workplace charging, fleet charging, and highway quick charging facilities were of particular interest. This research explores commercial customer perceptions of different rate options and identifies which may create adoption barriers and why, as well as identifies possible adoption accelerators that can help meet regulatory requirements for fleet electrification.

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SAMPLE AND METHODOLOGY

EPRI staff collaborated with utility representatives to compile a list of key influencer contacts at 35 commercial EV organizations, including but not limited to utility customers in California, in the following sectors:

- Workplace/public charging
- Fleets and public transport agencies
- Vehicle and equipment manufacturers and software providers
- Environmental groups/non-governmental organizations (NGOs)

The interview respondents do not reflect a random sample of utility customers, but instead represent customers and stakeholders that have previously interacted with the utility or shown early interest on matters regarding EVs and/or rates.

Sample

A total of 23 entities responded and were interviewed in this study. Interview responses shown in this report are reflected by these categories. Agencies and companies interviewed included the following:

Public/workplace charging category:

- Aerovironment
- Chargepoint
- PG&E Transportation Services

Fleets/Transit Districts category:

- Amazon
- Cruise
- Contra Costa County Transit Authority (CCCTA)
- SSA Terminal
- San Joaquin Regional Transit District
- Ryder
- Sysco
- Valley Transit Authority

Vehicle and equipment manufacturers and software providers:

- Chanje
- Electrify America
- EV Connect
- Engie Storage
- Green Lots
- BYD
- ProTerra
- Tesla
- Zoox

Environmental/NGO category:

- Center for Transportation and the Environment
- Natural Resource Defense Council (NRDC)
- Union of Concerned Scientists

Methodology

As a first step in the recruitment process, a utility representative sent an email invitation to these contacts, with some background information and a brief explanation of the research objectives.

EPRI facilitated follow-up calls to confirm interest and scheduled interviews with 23 of the 35 EV stakeholder organizations contacted. Once participation was confirmed, an email confirmation, a 45-minute calendar meeting invitation, and visual aids were sent in advance of the scheduled interview. Actual interviews for each organization included from one to four respondents. Responses were aggregated when more than one respondent participated. Interviewees did not receive any financial compensation or incentive for their participation in this study.

Interview results and findings are presented in this report in aggregate; no comments are attributed directly to any one participant or stakeholder organization, although some anonymous responses are provided as representative of a group of stakeholder opinions in Chapter 4.

Interview discussion and survey questions covered the following general topics:

- Background on study
- Review of interviewee roles in selecting or recommending EV charging rates
- General outlook on EV marketplace
- Preference for simple/consistent vs. dynamic EV charging rates
- Overview of rate components (fixed, demand, energy charges)
- Preference between conceptual rate designs

- Price block and subscription quantity demand charge concepts
- Time-of-use (TOU) hours and super off-peak charging in TOU energy charge
- Discount/subsidy options
- EV charger utilization rates over time
- Renewable energy options for EV charging
- Choice of rates versus a single commercial EV charging rate offering
- Metering options for EV charging

See appendices for the interview guide and conceptual rate design visual aids provided to interviewees in advance and referenced during the telephone discussion.

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KEY FINDINGS

General Outlook on EV Marketplace

Study participants expressed general optimism about the development of the EV marketplace. However, there was also a general sentiment among interviewees that deployment is still early in the EV adoption cycle and a desire for growth to occur more quickly. Most interviewees have, or are expecting to acquire, software tools to manage EV charging in future, but many also noted that the technology is still evolving.

Most interviewees are very or somewhat familiar with traditional electric utility rate components: fixed customer charges; demand charges for power delivery as measured in kilowatts (KW); and volumetric energy charges for the amount of electricity a customer uses as measured in kilowatt hours (kWh). Most participants had influence or a major role in choosing EV charging rates for their organization or recommending rates to their customers.

Interviewees shared their general appreciation for the invitation to participate in this study. They said they saw the utility's initiation of this study as positive interest in the voice of the customer and success of the EV marketplace. Stakeholders demonstrated significant enthusiasm for the ability to weigh into the electric rate design process, evidenced by the strong response rate of invitees.

Electric Rate Component Understanding and Preferences

Participants were asked the same question near the beginning and toward the end of the discussion: *Overall, would you prefer a simpler EV charging rate that offers more consistency and predictability in your monthly electric bill, or a more dynamic rate that offers more opportunity to save on electric costs?*

While there was no clear overall preference across respondents, EV use cases and associated rate preferences are often consistent within the designated categories.

- Workplace charging managers interviewed expressed a preference for simpler rates, even though their operations generally are more flexible because of "dwell time" and software controls to optimize TOU energy pricing. Several thought they could also benefit if super off-peak charging hours were offered mid-day. Fast-charging location operators were particularly averse to demand charges due to their inability to manage timing or quantity of consumer demand, especially in more remote locations where utilization rates may remain low for the foreseeable future.
- Delivery and transit fleet operators tended to indicate less flexibility, at least in the near term, in their ability to optimize charging times because of operational demands and schedules associated with those business models. They tended to favor a simpler rate design in the near-term that would result in more predictable monthly electric bills, although this was not

universal. Most expressed the potential for bill savings opportunity from overnight, off-peak rate options. Some indicated that with better control technology and experience, they could potentially benefit from the more complex rate options that provide additional savings opportunities over time.

- Vehicle manufactures and software providers were the most open to dynamic rates options, favoring the operational flexibility offered by these structures. They recognized more bill savings potential through the use of control technology for the other segments than were generally represented by the segments themselves.
- NGOs interviewed tended to indicate a slight preference for the more dynamic rates options, while acknowledging that there were many use cases to cover.

Demand charges were found to be unpopular, at best, among study participants. Most indicated they believe there must be another way to recover the utility costs associated with demand charges.

- Demand charge calculations are somewhat misunderstood among interviewees. Several respondents indicated that they have been taken by surprise by unexpectedly high bills due to demand charges.
- Others shared some confusion between TOU and monthly peak demand cost principles, e.g., interviewees who asked why low or no demand charges are not offered during super off-peak energy price periods.
- Demand charges were characterized by some as an unfair burden and a barrier to customer attempts to accelerate the development of the EV marketplace.
- Several others stated that demand charges have considerable impact on the overall EV business case.

Many of the participants, regardless of sector, said they are not ready to manage or optimize hourly energy prices but could be in the future with new software controls and more experience. Also, the concept of a higher fixed charge option in lieu of a demand charge was understood and in many cases preferred.

Choice and Alternative Rate Designs

Participants were asked to consider and provide feedback on three conceptual rate designs that ranged from simple/consistent to more dynamic/complex, the latter providing greater potential opportunity to save on electricity costs. Preferences for these conceptual rate designs, and combinations thereof, varied widely and most interviewees favored a choice of EV charging rate design options. When asked if it was difficult to compare rates, responses varied with no particular pattern among respondents.

Some notable patterns in responses did include the following:

- Several voiced a desire for lower or no demand charges. Some suggested recalibration of the demand billing determinant to reflect coincident system peak versus individual monthly peak.

- Of the options reviewed, survey participants expressed the least interest in the option including demand charges applied to 100 kilowatt-increment blocks to help reduce bill volatility. Some participants did, however, express interest in a subscription level offering, similar to a cell-phone plan.
- Many stated a preference for the super off-peak TOU period. The ability to shift to off- peak or super-off-peak hours varied by operational schedule and the extent of and ability to manage charging infrastructure of the participating organizations.
- Fleet operators and fast charging providers more consistently expressed concern with the ability to modify usage patterns to adapt to utility rate designs.

When specific time periods were discussed, most respondents understood why on- and off-peak periods were set as they were, to reflect periods of high or low system-wide electricity use. There was some interest in dynamic electric pricing from those organizations with charging flexibility and software tools available to respond to hourly pricing signals. Others thought hourly prices would be too difficult to manage.

When asked if there were changes interviewees might recommend to the rate design options presented, most targeted reducing or eliminating the demand charge and a few were outspoken against higher fixed charges. Regarding their ability to understand how to compare rate options, most felt capable, but some found it a confusing exercise.

TOU Hours

When asked their opinion about whether the stated peak hours (4 – 9 pm) should be revised, most respondents expressed that the hours were generally reasonable. A few suggested pushing the window back an hour and most expressed some flexibility in this regard. Entities that do overnight charging generally were not in favor of late night peak periods to ensure adequate charging time before fleets leave in the morning, and several expressed an interest in a super-off-peak overnight period.

When asked how respondents could adapt to the hourly energy rates that are based on the utility's system prices, including their ability to fit charging into the cheapest hours or to purchase software solutions, responses varied by use case.

- Workplace charging entities and other "long dwell time" use cases indicated that they could use controls and operating procedures, but still preferred simpler rate structures.
- Fast charging use cases generally did not view hourly pricing as a preferred option because they are beholden to driver convenience.
- Fleet operator use cases generally acknowledged some ability to adapt to hourlyenergy rates, assuming control technology and delayed charging solutions are employed, and saw an opportunity to leverage the TOU hours presented due to high overnight charging.
- Vehicle manufactures and software providers noted the highest value in the flexibility offered by hourly TOU prices.
- NGOs did not indicate a strong preference for one set of TOU hours over another.

When asked if they could benefit from the super off-peak period in the middle of the day, certain sites indicated that they could benefit and others not, depending on business application, routes, delivery schedules and peak transit times. There was general consensus that a super-off-peak charging period rate would benefit workplace charging operators, or if applied throughout the weekend, could be good for charging station operators with heavy weekend traffic. Several expressed an interest in having a super-off-peak period overnight, although most recognized the correlation to solar production mid-day. Some suggested that sites with battery installations could benefit.

Price Blocks

On the concept of "fixed price block" demand charges, in which a fixed cost is applied to set increments of demand (e.g. a set cost for a 100 kW block of demand) and what load increments seemed reasonable for such blocks, there was some confusion on the construct and, in general, it was the least favored rate design element among interviewees. Some expressed concerns about price ratcheting and rate cliffs and others expressed that they don't want to pay for energy they don't use. Interviewees offered little insight into the load increments for the price blocks, but generally perceived that these loads would go up over time. Interviewees who did provide alternatives suggested basing pricing on station size (i.e. power level) as the key consideration. Interestingly, respondents were more favorable to an overall fixed bill or subscription amount, similar to cell-phone service.

EV Utilization Rates and Incentives

When asked if they would favor a temporary utility discount to help improve the business case for EV charging while customer utilization grows, most participants were favorable toward a discount/subsidy for a period of several years. Interviewees suggested a wide range of timeframes – anywhere from two years to the year 2040, to reflect California clean transportation targets – but the majority suggested a period of five years for a discount or subsidy of some kind.

Interviewees shared notably different fleet infrastructure investment strategies. Some indicated an approach that would minimize upfront infrastructure costs by maximizing the number of vehicles per charger, while others shared that they would prefer having enough chargers to plug in all vehicles at the same time. They also varied in their preferences of how to administer an incentive.

- Many leaned toward a discount on the demand charge
- Less than half of participants favored an overall bill credit over a rate component specific discount
- Of those preferring a bill discount, there was no clear preference between annual or monthly
- There were a few notable suggestions regarding other incentives beyond, or instead of, a rate discount, such as sharing infrastructure costs or offering demand response programs
- Some expressed concern with the "cliff effect" or inadequate preparedness of customers for the eventual discount sunset date
- There was also some concern about the incentive structure potentially masking the true cost of charging and needed investment in charge management solutions and/or operational changes.

Renewable Energy and Metering Options

A few questions regarding interest in renewable energy and alternative metering configurations were added when time allowed. Interviewees that responded generally had some interest in an option that would ensure the power they received was generated by renewable energy sources. However, most were not interested in paying a premium for this option and some believed their investment in EVs represented their support for greener energy. Others suggested that such investments are the utility's responsibility.

The preference and/or ability to meter EV charging load separate from other building load varied across interviewees and sectors. Most expressed an ability to do so and preferences were based on the ability to diversify overall demand with other onsite load.

4

DETAILED INTERVIEW RESPONSES

Role and General EV Industry Outlook of those Interviewed

Interviewees came from all levels of their organizations. Many were associated with governmental or regulatory relations. Others served in system operator or business development roles. Almost all had some role in influencing the rate options that they or their customers would choose from a set of electric utility offerings.

When asked, the general consensus was that the commercial EV market is moving in the right direction, but there is a shared desire among stakeholders for it to evolve more quickly. Most believed that additional charging infrastructure is still needed. While considered a solid business prospect for many applications (as long as electricity costs are on par with diesel), infrastructure availability and utility rates remain key open issues.

Participants identified reliability of infrastructure, rate certainty, emission reduction targets and other policy goals, as additional drivers of success for the EV marketplace beyond costs.

> *"We need multifamily, workplace, home and public infrastructure to drive widespread adoption as well as a fast charging network that rivals the speed and convenience of gas stations."*

The non-governmental organization (NGO) perspective reflected that EV "range anxiety" continues to be a significant obstacle to adoption and that access for multi-family and all community income levels are concerns. It was further noted that people without garages continue to have access issues.

Vehicle and software providers indicated that the market is starting to take off, but that vehicle adoption still has a long way to go with vehicle adoption. One indicated that utility investment in EV infrastructure is helping.

Fleet respondents see transit being increasingly electrified and charging equipment and vehicles coming down in cost. A common viewpoint was that when there is parity cost of vehicle, energy cost, and operating/maintenance cost, electric rates will be a key determinant of long-term EV viability. Respondents cited year-over-year fleet expansion as an indication of growth.

> *"10% of transit bus purchases in 2017 were electric, which is a big difference from the light duty side. There are more products on the market, more competitors... a lot of growth potential. The longest pole in the tent is always utility infrastructure."*

Those in the public transportation organizations interviewed did not perceive their sector of the industry moving as fast, indicating that a few new manufacturers are focusing on electric vehicle production, but that manufacturers that have been in this space for decades are moving slower. Some cited an uptick in maintenance costs and learning curve issues. For these respondents, rate design is just one component in a larger, complex system, that will need to be addressed.

> *"We then as public officials are forced to buy this technology from unproven manufacturers and we are seeing issues with the buses, including doors and windows not working. Batteries and propulsion systems are not the issues. We have battery producers trying to build buses and quality is impacted. This is an issue when we're trying to move thousands of people daily."*

Cost Basis for Comparison

To compare the cost of electric vehicles against other options, most look at dollars per mile, either on a fuel basis or a total cost basis. Some consider cents per kWh, and others look at total cost of vehicle ownership. Fleet operators had a variety of cost bases for comparing vehicles, including: dollars per mile, price per package delivered, and life of equipment based on cost of engine hours.

When participants were asked to identify other benefits not reflected in cents per mile, they most often cited carbon and emissions reduction, but also included less noise pollution, potential of using EVs for grid services (e.g., flexibility to charge off peak and improve asset utilization for utilities and reduce costs for everyone), higher passenger satisfaction, reduced sound pollution inside fulfillment centers, safety benefits, and reduced operating expenses.

> *"EVs don't have as many hazardous waste issues. For example, spills are greatly reduced. However, [electric buses] are made of a composite [material], so they're lighter and don't hit the metal ground sensors as well. So, the gates would close on the new [electric] buses and we had to install laser eye sensors. Because they're so quiet, our drivers need to be more aware of dogs, kids, people who might not hear them coming. Passengers like that EVs are quieter."*

> *"Our electric fork lift proposals had spreadsheets with savings, but customers responded more to maintenance cost savings and safety improvements. The same benefits are called out by residential EV makers about maintenance and not having to go to the gas station."*

Public and workplace charging respondents also shared a positive outlook for the industry.

Rate Constructs – Understanding, Preferences and Trade-offs

During the stakeholder discussions, the interviewer explained that more complex rate design options reflect the fact that utility costs vary hour to hour and when that price volatility is passed through to customers, it can provide opportunity for to adjust their energy usage and save money. Conversely, it was also shared that simpler rates can provide more consistency and predictability to monthly bills but less opportunity for bill savings through managing usage across time periods.

Overall, there was no clear consensus among interviewees when asked for their preference for simplicity and price certainty over more complex rate design options that yield incremental savings opportunities. Preferences varied within and across surveyed market segments. There seems to be commercial customer demand for both simplicity and opportunities to save.

> *"The bottom line is that we want lower operating costs and solutions that allow [our customers] to optimize [their electricity use] without having to be heavily involved in it. We need active management with software solutions."*

Some suggested that EV drivers are not ready for complex price signals.

> *"Our number one goal is to get EV drivers to the charging stations. Consumers are still reluctant to rely on fast charging, so initially, you can kill the small pool of drivers with complex and higher-priced rates. Longer term it makes sense [to offer more choices]. It also depends on who pays the bill. Not all [charging station operators] will pass along the utility rate structure to the end-use consumer."*

When asked if they wanted a choice of rate offerings, almost all respondents favored options to address various use cases. However, a few cautioned that in this early stage of market development, customer confusion is a concern. Regarding their ability to understand how to compare rate options, most felt capable, but some found it a confusing exercise.

> *"Even on behalf of my customers, including school districts, hospitals, waste water treatments plants, who you'd think are sophisticated energy managers, but they don't have a good understanding of how they are charged for electricity."*

Passing on Costs End Users

When asked if they pass through utility prices to end users (where applicable), responses varied. Many simply charge by hour. For destination charging, generally level two workplace and shopping, the customer is often the property or infrastructure owner. They pay the utility bill so it's often not a cost to the drivers. For "higher-powered chargers (e.g. DC fast chargers)", charging price varies by owner and jurisdiction.

> *"We are seeing everything. One thing we provide is a very flexible price structure. We let them set TOU periods, flat session fee, and by duration, and we see they use all of them. There is a wide range [of end-user pricing] used but [charging station operators are] still asking for recommendations. They're still trying to determine the best way to do it."*

For workplace and public charging entities, they often do not pass through the utility's price to charge EVs. Public charging owners, where they can, set prices to optimize charging behavior they want from their customers. Some provide hourly prices, some free charging. It was further noted that local government sponsored charging stations may have different pricing policies, such as modifying price at different times of day to encourage drivers to move cars once sufficiently charged.

Alternative Rate Design Constructs

Medium/Large commercial rates are often three-part rates, designed to recover costs using some combination of these three components: a fixed customer charge amount, a cents/kWh energy rate, and a $/kW demand rate. When asked how familiar the respondents were with these cost components, all responded somewhat to very familiar.

If utilities think about re-structuring electric rates for EV charging use cases, a number of options can be considered. To facilitate the discussion and review trade-offs and preferences, the EPRI interviewer reviewed three graphics with the interviewees, shown below.

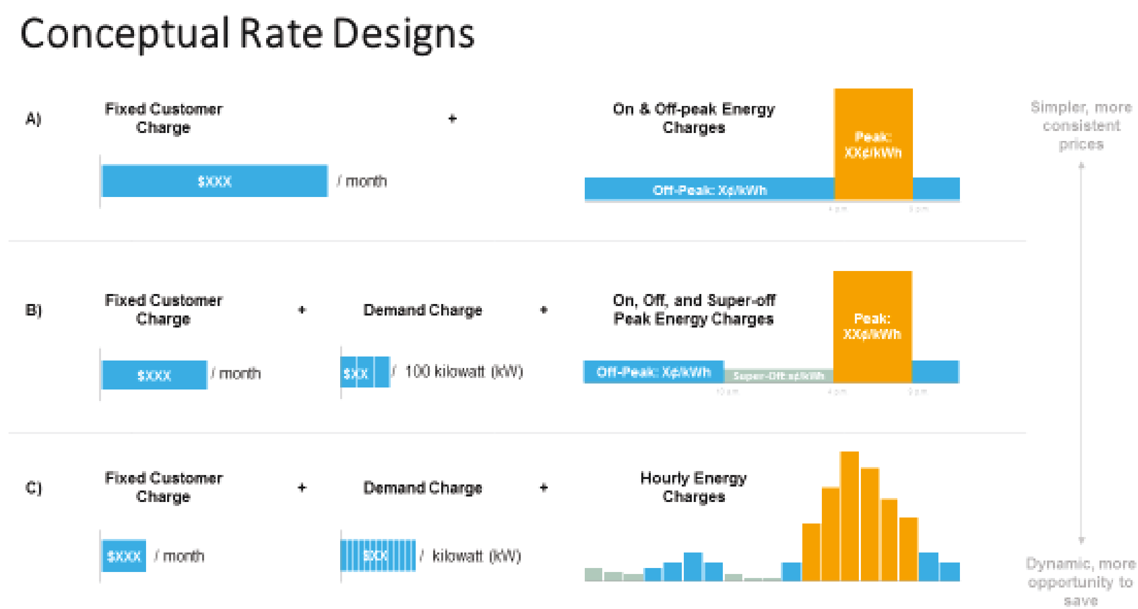

Figure 4-1
Conceptual Rate Designs

Interviewee preferences for aspects of these rate design options varied widely. There was no clear consensus on preferred structure, but some alignment on preferences by category of respondent. Many stated that as the market evolves, there will be greater demand for more dynamic rate options. Interest correlated strongly with the ability to take advantage of the lower cost options, such as off-peak charging and demand management.

Workplace/public charging category

The conceptual rate Option A with no demand charge was often cited as best for workplace charging, fast charging and residential applications. Public/workplace charging respondents generally preferred Options A or B. Workplace charging was cited as the most flexible to manage charging due to the long dwell times at the sites.

> *"[Option] A makes the most sense for fast charging sites, but we understand why demand charges are necessary. as you move toward B and C, makes more sense for level 2 where you have more flexibility in how much time people are charging and more ability to manage their charging."*

Fleets/Transit Districts category

Responses from fleet operators tended to favor B although there was interest in the bill stability offered by Option A. In general, there was an expressed interest in super-off-peak charging opportunities by fleet operators.

> *Option B provides more ability to save. Most customers operate during regular business hours start 5-6 a.m. We are done by rush hour so overlaying pretty well with grid power demand. Vehicles are back to facilities by 5p.m. A little intelligence canbe used to delay charging. Paying for storage to manage costs to off-peak hours will bea hard startup cost.*

> *"I'd prefer Option A. Transit operations are pretty risk averse, so stable is better for fleet planning 5-10 years out. Especially if we don't have battery storage. Demand charges are a concern because we sometimes have special events and we are stuck with that peak for rest of month."*

Some transit customers interviewed shared that they are focused on delivering transit to customers and generally don't want to dwell on when to charge and what to pay. They want to plug in when needed and focus on their primary business.

Vehicle and equipment manufacturers and software providers

Option C was generally viewed as best over the long run by vehicle manufactures and software providers. Fast charging infrastructure was generally deemed unable to respond to dynamic rate options,

> *"Unequivocally, C. My job to optimize for the customer and I want that flexibility."*

> *"Probably C. As an EVSE that has thought about this a lot, it gives me the most flexibility to run my business the way I want. I can install PV and storage. I would need to think about how I would pass it along to my customers. A is definitely easiest to communicate and better than current system, but doesn't give me the most flexibility long term. Maybe A for next couple years, but C best long term."*

Environmental/NGO category

Responses varied from the NGOs interviewed such that there was no clear preference.

> *"Probably B. [Option] A doesn't provide enough signals for when to charge unless the peak rate is extremely high. A also doesn't encourage fleets to think about all other customers because there is no demand charge."*

> *"I like C if the customer has tools to respond to it." "They need an option D that is purely volumetric."*

Proposed Changes to Options Presented

When asked if there were changes they might recommend to the rate design options provided, most interviewees targeted reducing or eliminating the demand charge.

> *"We want something demand charge-free now and, when things pick up, we'll have a better idea for what's best. Now what we see is demand charges as a cost per mile are pretty high."*

A few were outspoken against higher fixed charges but respondents generally found favorable aspects within the options discussed. Some preferred a higher fixed charge to a demand charge due to simplicity and price certainty. There was generally a wide range of responses to the energy charge options with no clear preference for any group, however the TOU hours provided were generally understood deemed reasonable.

With regard to load management services, those entities interested in providing load management across all their chargers see an opportunity in doing analysis and recommending alternative pricing for end users/drivers. Others thought it was the utility's role to proactively provide such information.

TOU Hours

When asked if there was value in shifting the stated peak hours, most respondents believed the hours presented in these rate options (4 p.m. – 9 p.m.) were reasonable. A few suggested pushing the window back an hour (to 5 p.m. to 10 p.m.). Of those that provided specific alternatives, responses varied.

> *"For fleet applications, moving hours could make a difference, but most vehicles go out in the morning. Some 15-40% come back into the yard mid-day and everyone is back out by rush hour. They come back in between 7-9 p.m. [The peak period] seems to be well crafted in that regard."*

> *"Between 4-9 p.m. is close to the 'sweet spot' for when vehicles are out on their routes, except of course for in route fast chargers. So, [conceptual rate] B might be better for that application, or for an agency interested in storage, they could [accommodate a peak period from] 10 a.m.-4 p.m. or after 9 p.m."*

> *"Our preference would be to have a super-off-peak overnight from 10 p.m. –6 a.m. and 11 a.m.- 4 p.m."*

When asked how respondents could adapt to the hourly energy rates that are based on the utility's system prices, including their ability to fit charging into the cheapest hours or purchase software solutions, workplace charging entities and other longer dwell time use cases indicated that they could use controls and operating procedures. However, those operating fast charging applications generally did not view hourly pricing as a preferred option because they are beholden to driver convenience. Fleet operator responses varied. Some thought that controls solution for delayed charging might fit into their operating model. Others said that they aren't currently willing to add charging time to the list of constraints that they use to plan their operations.

> *"For trucks, we plan around delivery windows and traffic so we are pretty limited to responding to prices for time of day; we have a rolling 24-7 schedule. We can't reconsider the whole configuration of our operation to orient around low energy prices."*

Workplace and public EV charging site hosts indicated they can use super-off-peak charging to manage infrastructure costs and to help drivers better understand their own charging patterns and spending. Respondents did not see an advantage in super-off-peak for fast charging applications due to unpredictability of demand.

When asked if they could benefit from the super-off-peak period in the middle of the day, certain sites indicated that they could benefit and others not, depending on business application, routes, delivery schedules and peak transit times. There was general consensus among interviewees that a super-off-peak mid-day period would benefit workplace charging or, if super-off-peak rates applied throughout the weekend, it could be good for charging sites with heavy traffic. Several expressed an interest in having the super-off-peak period overnight, although most recognized the correlation to solar production mid-day. Some suggested that sites with battery installations may benefit from that rate. Fleet operators shared that they didn't see much benefit for regular in-facility or depot charging in super-off-peak mid-day hours. Some thought there could be some benefits if "opportunity charging" was well placed in the community for use in the middle of the day to extend range.

> *"Vehicle integration capabilities change that equation, for example, if there is a minimum amount of charge needed based on distance to the next destination and time of departure."*

Price Blocks

On the topic of demand charges applied to set blocks of usage, and what load increments seemed reasonable under such an option, there was some confusion on the construct and, in general, it was the least favored rate design element.

> *"I don't really understand price blocks so I don't have a strong opinion on the increments. If you're going to have a 350 KW charger, which our customers are about to deploy, we're going to hit [that peak demand] at least once in the month."*

Some expressed concerns about price ratcheting and rate cliffs and others expressed that they don't want to pay for energy they don't use. Those who provided alternatives to the price block increments sited station size as the key consideration.

> *"Start with 100 KW and go in blocks of 50 for now. As the market evolves, then you can probably grow that to 250 KW."*

Fleet and public transit respondents cited the California mandate to have an all-EV heavy transit fleet by 2040, which would impact price block load requirements over time. So some suggested an interim price block as they progress toward the all-electric vehicle requirement over time.

Cell Phone Bill Model

Respondents were asked about a rate option where consumers could sign up for a set KW amount and pay a fixed price for use up to the specified demand limit and then incur additional charges for use past that limit (similar to current cell phone data subscriptions). Responsesvaried from unsure to interested. Some reflected positively that this pricing construct is familiar and thus understood. Some wanted to understand costs to "break contract" and asked how the KW caps would be set.

> *"[This demand subscription] is more attractive from the standpoint of knowing my fixed monthly bill amount will go up over time as utilization increases. It's a novel way to charge me less in early years, but a way to charge me more on demand as utilization and coincident peak increase… A way for [the utility] to grow with me."*

At least one respondent did cite the potential for unintended consequences.

> *"A danger is when cell phone providers started promoting unlimited data and adoption exceeded expectation with all the data streaming, so they had to change theiroffering. Banks/financing entities need certainty of electric rates five to 10 years down the road in order to be confident in financing these EV businesses with high upfront costs. If banks aren't happy, then that adds to cost of capital."*

Utilization Factors over Time

When asked if utilization of a charger will grow over time, virtually all respondents indicated that they expect their utilization of a charger will grow. Fleet operators indicated that investment decisions being made now would impact utilization rates in the future.

> *"There are a couple of schools of thought in depot charging now. People with available manpower and flexibility are thinking about higher power chargers and moving [vehicles] around. Some have fewer [chargers] but shift vehicles for lower infrastructure costs. Others just plug in all the [vehicles] to smaller chargers and regulate with energy management/smart charging."*

It was noted that while fast charging applications would see higher utilization rates over time, there would likely remain differences in urban and rural utilization factors, even at build out. When asked to project future charging utilization rates, eight hours was a typical current charging time. Some saw utilization going up to 12 hours per day but few fast charging applications predicted future around the clock charging.

> *"Ideally, 24 hours, but at a minimum, 12 hours is where we want to go. If we can open chargers to general public, we can increase utilization."*

> *"It depends. 12 hours per day, max. 8 a.m. to 8 p.m. Realistically, it's more like 35- 40% utilization [of chargers]. With autonomous/self-driving EVs, you can schedule them to charge at night; public hours are during the day."*

When asked the extent to which respondents either currently had software solutions to help adapt to hourly energy rates, many did not, however most expect to have options in the future to better respond to utility price signals.

> *"[Adapting to hourly electric rates] would require software and intelligence, perhaps a bit of onsite storage and a change of behavior. For example, delivery trucks and buses are working in the middle of day. During the peak period, delivery trucks may be tapering off, but EV taxi fleets may just be starting as others get off of work."*

When asked if they expect to implement smart charging solutions (software controls) that would help spread charging over more or different hours at a lower power rate, study participants generally responded yes, but added that technology is costly and still in development. Most charging station operators indicated that they are more interested in throughput and recouping their investment in EVs.

> *"I don't think we know that right now. It's going to be interesting to see how transit agencies approach it. Peak hours stop around 10 p.m., then we're out in the morning. We might eventually manage spares with peak transit times and prices."*

Role of Rate Discount in Industry Evolution

We asked interviewees whether a temporary utility discount would help improve the business case for EV charging while customer utilization grows, as well as how long such a discount would need to be offered or phased out. Responses varied widely. Five years was the most commonly cited response.

Some expressed a concern about what happens when such a subsidy goes away and whether customers would adequately prepare with investments if the true price was masked. Others questioned how to gauge if the discount was working and when it is no longer useful. A few indicated that due to the public benefits of electrification and California policy objectives, long-term electric utility subsidies could be warranted.

> *"Alternative rate options may be preferable [to a discount], such as rates without demand charges. If they have made capital investments, they may not be able to shift much when the discount goes away. It takes 12 years to turn over a fleet from whenever they start. Waiving [some charges] for five years is not enough."*

> *"It may drive early adoption but be back to where we are today if discounts fully phased out."*

When asked which aspect of the rate a discount would best be applied to, most expressed a preference for the demand charge.

> *"The only issue we have with cost is demand charges. Any subsidy would need to be associated with the demand charge itself."*

> *"That [demand charge] is the scary part. the big risk and unknown. It's hard for fleet managers to live in a variable world. The move from diesel to electricity is a learning curve."*

Preferences for different bill credit options varied but most preferred it be applied to the demand charge rather than any other rate component. Some agreed that a rate credit of any kind should gradually decrease over time rather than being phased out all at once.

> *"It makes more sense because as energy volume increases over time, if you have the same overall demand, it seems more in line and more manageable."*

There wasn't a strong preference from most for an annual vs. monthly bill credit and a few did not favor rate discounts at all.

> *"That approach would be misleading. It's not a path toward what we have to fix, just a subsidy. You're not giving the right signal to the site in order to guide future decisions/ investments. You would just have really angry [utility] customers at the end when the subsidy is gone and no one would understand what happened."*

Some shared other options to support EV adoption beyond a rate discount.

> *"Maybe other programs that allow the utility to jointly market, or offer development funds that drive the utility's customers to deploy charging stations."*

> *"At the end of a useful life of a battery in an EV/bus (300 kWh per pack), the value is not well known/understood. If there's a way for the utility to give us certainty at the end of a seven-year battery pack, it would help adoption and the financiers. The battery pack maybe is no longer useful for a bus, but still has ten years of life left for a stationary application. If the utility could use those and put a value on it, it would help adoption."*

Renewable Energy

When asked their level of interest in, and willingness to pay more for, renewable energy, responses varied among interviewees from various EV market sectors. Many expressed an interest based on organizational principles, but some were unwilling to pay more for renewable energy options.

> *"Potentially. There are lots of variables to think about. We are working on a low carbon fuel standard path for renewable that could make the economics work."*

> *"It depends on what the company wants for environmental values or marketing perceptions... If the company can get RECs, maybe."*

Most fleet operators expressed an interest in renewable energy, but they were not sure about their organization's willingness to pay a premium for it, citing cost fundamentals compared to diesel fuel as a primary driver in the decision to electrify. Public transit organizations not willing to pay more cited strict budgets and the fact that most do not operate in the black as it is.

A couple of interviewees were of the opinion it is the utility's responsibility to increase renewable sources to meet new load and that EV customers demonstrate their commitment to environmental responsibility by choosing zero emission vehicles for fleets.

Metering, Service Connections and Charging Patterns

To take advantage of lower EV-specific rates, almost all participants indicated an ability to separately meter the EV load if offered the separate service connection. Most expressed an interest in combined EV charger and building/facility load. Some recognized that it depends on site selection since chargers may be a separate load from a maintenance or service facility. Those who did have other loads at the charging facility recognized the benefit of using excess electric capacity when available.

Additional Comments

Most respondents felt the questions posed in the interview had covered the issues involved with EV charging rates. A few had additional ideas to share.

> *"Commercial EVs are such a great fit for utilities to improve asset utilization. Utilities and regulators are focused on recovering past costs and aren't thinking of new load that may appear."*
>
> *"It's a question of infrastructure and in some cases additional infrastructure will be required. Sometimes that's built into rates and sometimes not. Some additional clarity around that is good and a great place for incentives. Put the build out cost into the rate structure."*
>
> *"I just want to repeat the point I kept making about low utilization pared with spikey demand. I've been thinking a lot about utilities helping with stationary controllers or storage to help with all of this. [Electric] utilities already are investing in infrastructure so instead of a subsidy, why not help with technology solutions?"*
>
> *"The idea of third party charging provider, like a fleet operator who can outsource electricity as fuel to another vendor. Rate design should also be flexible enough to accommodate for outsourced charging providers for fleets."*
>
> *"Building out a charging network is a network. It will encourage them to charge more even at home. Don't get too narrow and design for location-specific charging. Look at network wide solutions. Help the entire network."*

Fleet operators' feedback specifically included the following:

> *"We are concerned about interoperability, so encourage it in hardware and software so we can scale across the country."*
>
> *"Investing in the infrastructure itself would be one. Looking at time-based demand charges is another. A third might be a utility bulk purchase of vehicles and providing low-interest leasing to owner-operators. The utility could get volume discounts and pass them along."*

"Utilities can provide education on how the rate structures would work, and make suggestions on how customers could retool operation to fit charges. Education on infrastructure setup to support operations would be very beneficial as well, and any rebate or grant funds to support infrastructure development."

"What would help the public transit environment would be earlier adoption from legacy bus manufacturers and understanding how rate structures work. They still don't fully understand. Demand charges and how they impact our operation is unclear. Do I need to change my operation if I bring in the buses to fuel up at different times? If so, I need them to be out in the field longer, and if battery tech is not ready, I have a problem."

5
CONCLUSIONS

EPRI conducted this research to help answer the question: "How important are different rate design options to commercial customers in their decision to electrify their fleets or install EV charging equipment?" Findings from this study suggest that rate design matters. Due to initially low utilization factors and high power demand (together creating low load factors for these customers), existing rate designs with demand charges can result in a high average cost per kWh for these customers. Accordingly, even though commercial EV utilization factors are expected to increase over time, and technology costs are expected to decrease, current rate design constructs may be seen as a barrier to adoption in the near term.

Electric utilities and regulators can apply these insights from commercial customers and EV industry stakeholder in several ways. In the near term, utilities may consider offering some level of choice in their commercial EV charging rates to address the variation in use cases and to maximize the social benefits associated with EV adoption, as well as meeting efficient electrification and greenhouse gas reduction targets.

Most stakeholders expressed strong concern about how demand charges may impact EV adoption. Since demand charges are constructed to recover costs related to peak usage which is impacted by the addition of EV charging patterns, this is an important consideration as more vehicles are electrified over time. Accordingly, additional exploration of how this rate design element can be used within EV rates seems warranted. Options such as the time interval over which demand charges are applied represent one aspect that could be evaluated in more detail.

Stakeholders also expressed a strong interest in cost certainty over time and in support from the utility to help them better understand and manage these new loads as electrification continues. Utilities and regulators may consider implementing design structures that will be reasonably consistent over time, in addition to creating mechanisms to educate customers early in the process, because investments being made now will influence and possibly limit future operational flexibility. Lastly, it would be valuable to check in with stakeholders periodically to assess how perceptions are changing as the industry evolves.

A

COMMERCIAL EV RATE DESIGN CONSUMER PERCEPTIONS SURVEY: DISCUSSION GUIDE

1. What is your role at your organization?
2. In general, do you think the market for commercial EVs and fast charging infrastructure is headed in the right direction?
3. What do you see are the drivers of success besides cost?
4. How do you compare the cost of electric vs gas vs diesel vehicles (i.e. cents per mile or other)?
5. What other benefits may be realized from electrification of transport that would not be reflected in cents per mile?
6. Do you have a role or would you have input in selecting electric service pricing plans/rate options for your EV charging?
7. More complex rates can provide opportunity for customers to adjust their energy usage and save money. This is because utility costs can change hour to hour and when they pass along that price volatility to customers, utility costs go down, whereas when they absorb and hedge for this price volatility, utility rates reflect this added cost. For example, hourly or TOU-based price periods vs. one price for all hours. On the other hand, simpler rates can provide more consistency and predictability to the consumer and may be preferred so that management of usage within given time periods and in response to varying price signals isn't a concern. Overall, would you prefer a simpler EV charging rate that offers more consistency and predictability in your monthly electric bill, or a more dynamic rate that offers more opportunity to save on electric costs?
8. How do you (or most of your customers) charge the end users/drivers for the use of their public/workplace EV charging equipment and the associated electricity? For example, if the owner of a charging station saves on a TOU electric rate, do they tend to pass those savings through to end users/EV drivers (lower price at off-peak hours)?

Refer to Figure B-1.

9. Commercial EV rates are typically designed to recover costs using one or more of these three cost components: a fixed $/month charge, a cents/kWh energy rate, and a $/kW demand rate. How familiar are you with commercial electric rates and the associated cost basis of these components?

Refer to Figure B-2.

10. If we think about re-structuring electric rates to something that would work better for your EV charging use case(s), there are a number of options we can consider. This graphic looks at 3 options, with various alternatives for the components we just discussed. Seeing these rate options which would you choose and why?
11. If you could make changes to that rate, what might you change and why? If you could mix aspects of A, B, & C, is there another combination that would be preferable?
12. Let's walk back through each one and discuss what you do or don't like. For option A, what do you think about the 4-9 p.m. window for the peak hours? If you were to shift that somewhat, how would you change it?

Refer to Figure B-3.

13. For Option B: On the "Price-Block" demand charge, what increments would make sense to you as usage increments to which a fixed dollar amount would be charged (i.e. $450 for the first 200 kW, $900 for 400 kW, etc.)?
14. For Option B, would you benefit from the super off-peak period in the middle of the day? Similarly, what do you think about the hours 10 a.m. to 4 p.m.? If you could shift them a little, how might you change them?
15. Now let's consider a different option for the fixed and demand charge components; something sort of like your cell phone bill: you sign up for a certain amount of data each month, and only pay extra if you exceed that limit. If we thought about the demand charge like a cell phone subscription, where you pay for a certain amount of demand and incur additional charges if you go past that limit, would that be an attractive option?

Refer to Figure B-4.

16. For Option C, how would you adapt to the hourly energy rates that are based on hourly system prices. Could you fit your charging into the cheapest hours? Would it require some sort of software solution that you don't have today?
17. Do you expect your utilization of a charger will grow over time? In other words, if you install a charger today that gets used for two hours each day, do you expect it to be used for more hours per day in the future?
18. In an ideal future situation, what do you think would be the maximum number of hours per day a charger would be used?
19. Conversely, do you expect you might implement smart charging solutions (software controls) that would help spread charging over more hours at a lower power rate? Or shift the charger to more preferable hours?
20. Do you expect your utilization of a given charging unit will grow over time? In other words, if you install a charger today that gets used by for two hours each day, do you expect it to be used for more hours per day in the future?
21. In an ideal future situation, what do you think would be the maximum number of hours per day a charger would be used?

22. Do you think, over that period of time, that you would be able to improve your utilization of the chargers to spread demand charges over more kWh? Or do you expect you might be able to use software to better manage your charging throughout the day in the future?
23. Conversely, do you expect you might implement smart charging solutions (software controls) that would help spread charging over more hours at a lower power rate or shift the charger to more preferable hours?
24. If the utility offered a temporary discount to help improve the business case for EV charging while customer utilization grows, how long would that discount need to be before it was phased out?
25. Do you think over that period of time you would be able to improve your utilization of the chargers to spread demand charges over more kWh? Or do you expect you might be able to use software to better manage your charging throughout the day in the future?
26. Let's reviews some different applications of a potential discount a rate design elementand which of these approaches would you prefer and why.

    Option 1; If a discount where to be applied to the fixed charge in option A, and gradually lessen the discount over time until the customer pays the full amount, what do you think of that idea?

    Option 2: What if the discount was applied to the demand charge in options B or C and gradually phased out over time?

    Option 3: What if a reduction in the volumetric charges slowly increased over time (peak vs. off-peak)?

    Option 4: Another approach would be to leave the rate components at the levels they should be to reflect true costs, but provide a bill credit. For example, a monthly credit might be shown as a line item on the bill, indicating the dollar and percentage amount of the discount as compared to what the charges would be otherwise. Alternatively, a credit might be provided annually as a line item on your bill in the month of your preference
27. Are there any other approaches for PG&E to provide the incentive that would work best for your business?
28. Would you be interested in an option that would ensure that the power you receive has been generated by renewable energy sources? Would you be interested in the renewable option if there was an additional cost, say for example 5% - 10%?
29. Now that we're almost done with this interview, I'll ask you once again: Overall, would you prefer a simpler EV charging rate that offers more consistency and predictability in your monthly electric bill, or a more dynamic rate that offers more opportunity to save on electric costs
30. Would you prefer to choose from multiple EV rate design options or would it be better to just have one EV rate?
31. Do you find it hard to compare rate options?

32. To take advantage of lower EV-specific rates, would you be able to separately meter the EV load if offered the separate service connection?
33. Do you think it would be advantageous to try to combine EV charging with the rest of your building/facility to manage the two loads together?Is there anything else you'd like to add or something we didn't discuss today that you think should considered or prioritized for commercial EV rate design?

B

VISUAL AIDS USED IN COORDINATION WITH SURVEY QUESTIONNAIRE

The following visual aids were provided to interviewees to inform the conversation during the survey.

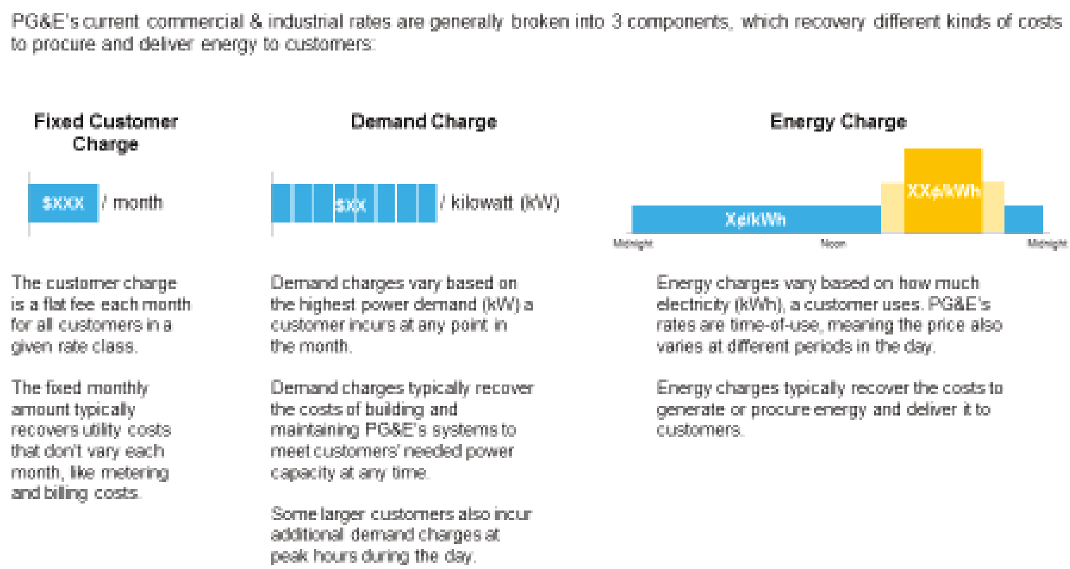

Figure B-1
First visual aid used in coordination with survey questionnaire

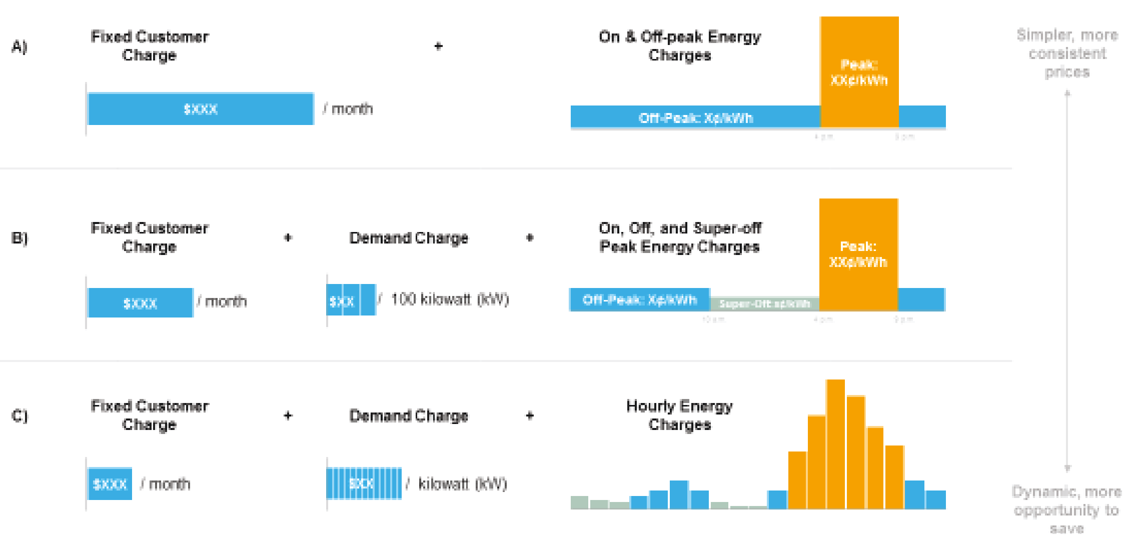

Figure B-2
Second visual aid used in coordination with survey questionnaire

Figure B-3
Third visual aid used in coordination with survey questionnaire

Figure B-4
Fourth visual aid used in coordination with survey questionnaire

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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

RATE DESIGN

PACIFIC GAS AND ELECTRIC COMPANY
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RATE DESIGN

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RATE DESIGN

A. Introduction

The purpose of this chapter of Pacific Gas and Electric Company (PG&E) testimony is to describe the rate design proposal for a dynamic rate option for Commercial Electric Vehicle (CEV) customers. PG&E's dynamic rate proposal for CEV customers is a Day-Ahead Hourly Real-Time Pricing (DAHRTP-CEV) Pilot rate, consistent with Decision (D.) 19-10-055. The DAHRTP-CEV Pilot rate has been designed to be cost-based and provide customers with a more accurate price signal than the standard CEV schedules. It provides customers with a price that can be different in each hour of each day—indicating to customers the most beneficial times to charge their vehicles. It also helps customers reduce overall greenhouse gas (GHG) emissions by avoiding the hours in which the system is most stressed and increases the utilization of renewables by charging when renewable generation is being curtailed due to oversupply. In this chapter, PG&E explains its proposed rate option, how rate values are derived, and calculations for operating the rate on a daily basis.

Section B describes how the proposed rate is structured and its marginal and fixed cost components. Section C replies to certain questions posed in D.19-10-055. Section D addresses considerations related to Real-Time (RT) distribution rates, net energy metering (NEM) customers, and other demand response programs.

B. PG&E's Dynamic Rate Option for CEV Proposal

1. Summary

PG&E's proposal for the DAHRTP-CEV Pilot rate is a rate rider that would replace the current time-of-use (TOU) generation rates on Schedules BEV-1 and BEV-2 with a formula for determining hourly rates on a day-ahead (DA) basis. Rates related to distribution, transmission, and non-bypassable charges would continue to be assessed as specified in the original BEV schedule. Each day, PG&E will determine the generation prices for each of the 24 hours in the following day based on DA market prices and forecasted load and generation for each hour.

The proposed prices in each hour will be composed of three parts: (1) the DA market energy price from California Independent System Operator (CAISO), (2) a capacity adder based on forecasted adjusted net load (ANL) in each hour, and (3) a non-time-differentiated adder.

2. Total Generation Costs

PG&E's generation rates include three broad cost categories: (1) energy-related marginal costs; (2) capacity-related marginal costs; and (3) other costs including above-market, Power Charge Indifference Adjustment (PCIA) costs. Ignoring cost differences at different voltage levels due to line loss for the moment, the costs for the two marginal cost categories vary by hour but do not vary by end-use schedule. Generation marginal costs only vary between schedules when averaged over TOU periods because the load patterns vary between customer classes, creating different weighted averages of cost in both energy and capacity. However, when generation is priced at an hourly level (and not averaged over TOU periods) and includes hourly capacity costs, there is no longer a need to vary generation marginal costs between schedules, and a system average can be used.

a. Calculating Marginal Generation Costs (MGC)

The time-varying generation costs that inform PG&E's proposed DAHRTP-CEV Pilot rate were developed from scenarios of time-varying MGCs forecasted for 2021. These MGCs consist of marginal energy costs (MEC), plus marginal generation capacity costs (MGCC). Forecast scenarios of MEC and MGCC for 2021 were developed in PG&E's 2020 General Rate Case (GRC) Phase 2 Errata testimony.[1] The DAHRTP-CEV Pilot rate would use actual market prices from the CAISO and forecasts of capacity costs created daily. The MGCs developed in PG&E's 2020 GRC 2 are used to calculate the rate adder described in Section 2(c) of this Chapter. PG&E's 2020 GRC 2 MGC can also be used to develop distributions of expected prices and 24-hour price shapes, as described in Section 2(d) below.

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[1] Application 19-11-019, Exhibit (PG&E-2), Chapter 2, July 2020.

PG&E developed hourly MEC and MGCC forecasts using 10 "weather years" (2005-2014). These contain 3,650 days of 24-hour MEC and MGCC marginal costs. The MECs are forecasts of DA energy prices in dollars per megawatt-hour ($/MWh) or cents per kilowatt-hour (cents/kWh) at the PG&E Default Load Aggregation Point (DLAP), adjusted to account for losses. The MGCC are forecasts of the hourly value of capacity, converted into the same units and adjusted for losses and the 15 percent planning reserve margin. MGCCs are calculated using a peak capacity allocation factor (PCAF) methodology, which assigns capacity costs only to hours in which the ANL[2] exceeds a threshold equal to 80 percent of the average of annual peak ANLs over the 10 weather scenarios.[3] Hourly MGCC is then allocated proportionally to the amount each hour's ANL exceeds the threshold.

b. Developing Operational Generation Cost Forecasts

This section describes at a high level how the generation costs will be developed day by day after the rate has been implemented. Generation costs are equal to the sum of megawatt-hour, MGCC, and a revenue-neutral rate adder discussed below.

1) MEC

The MECs are the loss-adjusted DA prices at the PG&E DLAP. These prices are available on the CAISO's Open Access Same-time Information System (OASIS) web site at 1 p.m. on the day before "Operating Day." The CAISO DA prices are multiplied by a loss factor of 1.069 to represent costs at the secondary distribution level.

2) Marginal Generation Capacity Costs

As described above, MGCCs are calculated from ANL, which, in turn, is calculated from load and GHG-free generation. While

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2 The Net Load referred to in descriptions of the CAISO's famous Duck Curve is equal to gross, or metered load (i.e., load supplied to customers net of grid exports from customers), less utility-scale wind and solar production. ANL also subtracts other GHG-free resources: nuclear, hydro (both small and large hydro), and other renewables such as geothermal, biomass, and biogas. ANL is essentially the amount of load that must be met by thermal generators, imports and energy storage.

3 Errata testimony, footnote 29 on p. 2-14 and p. 3-3.

CAISO publishes DA forecasts of load and wind and solar generation on OASIS, they do not publish forecasts of nuclear, hydro or other renewable generation. Thus, PG&E proposes a DA forecast of ANL that uses DA forecasts of load and wind and solar generation with 2-day prior actuals from OASIS for the other components of ANL (nuclear, hydro, and other renewable generation).

Of the three additional components listed above, hydro and other renewable generation have little variation from day-to-day because: (1) hydro generation input to the ANL calculation is actually the lagged 25-day average;[4] (2) geothermal, biomass and biogas generation have little variability day to day;[5] and (3) nuclear generation is almost constant except for outages. The error in the forecast of ANL could be reduced by using the nuclear generation at 1 p.m. on the day before operating day, rather than 2-day prior data as with the other components. However, this would introduce another step in generating the forecast with relatively little improvement, so PG&E recommends using 2-day prior actual data for all three components discussed in this paragraph.

The last step in calculating MGCCs is to compare the forecasted ANL_h in each hour h with the annual threshold, with hourly MGCC given by the formula:

$$MGCC_h = \frac{MGCC * (ANL_h - Thresh) * CapLoss * PRM}{Sum\ (ANL\ above\ Threshold)}$$

Where:

- MGCC = Annual MGCC from 2020 GRC Phase II ($102.66/kW-year);

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4 *Ibid*., footnote 37 on p. 2-22.

5 The standard error for a “forecast” of geothermal plus biogas plus biomass generation equal to its 2-day prior value (which reproduces the proposed input to the ANL forecast calculation) is only 68 megawatt (MW), approximately 4.8 percent of its average generation over January 2017-September 2020, and 0.3 percent of average CAISO load.

- Thresh = 80 percent of average annual peak ANL over all 2021 scenarios (25,313 MW CAISO-wide);
- CapLoss = Loss factor for capacity (1.091);
- PRM = Factor for planning reserve margin (1.15); and
- Sum (ANL above Threshold) = Average annual sum of ANL above Thresh over all 2021 scenarios.

3) Revenue Neutral Rate Adder

The third component of the DAHRTP-CEV Pilot rate is a rate adder that would collect other non-marginal costs collected in generation (including the portion included in bundled generation rates for the PCIA) as necessary to ensure that the rate is revenue neutral.[6] The proposed revenue neutral rate adder would not vary by time of day.

PG&E proposes to base all of its generation revenue neutral calculations on the bundled average generation rate. The CEV class has only been in service since May 2020, and there is not yet sufficient data to create a robust set of billing determinants for this class. Creating a proposed rate rider that is revenue-neutral to the system average simplifies implementation. It does so by requiring only one set of RT rates each day instead of requiring a set for each rate schedule. This methodology also makes it easier to apply these rates to other classes if RT rates are used with non-CEV classes at a later date.

Using the calculation of system MGC from the 2020 GRC Phase 2 Errata,[7] the total generation marginal cost revenue is about

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6 Ordering Paragraph 2 of D.20-03-019 required PG&E, Southern California Edison Company, and San Diego Gas & Electric Company to collaborate and submit a joint proposal for bill and tariff changes to show a PCIA line item in their tariffs and bill summary tables on all customer bills. On August 31, 2020, PG&E submitted Advice Letter (AL)-5932-E to implement the joint proposal by the last business day of 2021. If the joint proposal is implemented, PCIA will no longer be part of bundled generation revenue and the adder will be reduced accordingly. PG&E's proposal is to not have the adder vary by rate schedule even when it includes PCIA. Once PCIA is removed from generation, it will be a separate rate component that can vary by schedule and will no longer be affected by this rate rider.

7 Errata Revenue Allocation and Rate Design workpapers "MCRev_GRC.xlsx".

$2.1 billion. The total generation Revenue Requirement under May 1, 2020, rates is about $4.0 billion. The difference between these is divided by forecasted bundled sales to give a revenue neutral adder of $0.05281/kWh.

Since customers on this option will be receiving hourly DA RT rate signals that include an accurate capacity component based on the CAISO market, they would not be eligible for critical peak pricing options such as Peak Day Pricing. They would also be ineligible for demand response programs and the Demand Response Auction Mechanism (DRAM).

c. Total Generation Cost Examples

The table below gives some information about the expected distribution of the generation rate. Table 2-1 lists the percentiles of total generation price (including the flat adder) for each hour in PG&E's forecasted 2021 prices. For convenience, the table lists different values by season[8] even though the DAHRTP-CEV Pilot rate will not need any defined seasons.

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[8] The standard 2020 GRC seasons are used: Summer is June through September, Winter is October through February, and Spring is March through May.

TABLE 2-1
FORECASTED 2021 GENERATION PRICES BY PERCENTILE RANK
(CENTS/kWh)

	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Summer Percentiles																								
5th	8.5	8.1	7.8	7.7	7.8	8.0	7.1	5.3	5.3	5.1	4.9	4.9	5.0	5.2	5.3	5.3	6.5	7.6	9.1	10.3	11.3	10.7	9.9	9.2
10th	8.7	8.3	8.1	8.0	8.0	8.2	7.7	6.2	5.3	5.3	5.3	5.3	5.3	5.3	5.3	6.1	7.4	8.4	9.8	10.7	11.6	10.9	10.1	9.4
25th	9.1	8.7	8.5	8.4	8.5	8.7	8.5	7.3	6.1	5.5	5.4	5.5	5.7	6.0	6.6	7.7	8.7	9.6	10.5	11.5	12.1	11.2	10.4	9.6
50th	9.4	9.0	8.9	8.8	8.8	9.1	9.2	8.4	7.6	7.1	6.9	7.0	7.3	7.6	8.2	9.0	9.8	10.4	11.2	12.4	12.8	11.7	10.7	9.9
75th	9.6	9.3	9.2	9.1	9.2	9.5	9.7	9.2	8.5	8.1	8.0	8.2	8.5	8.7	9.2	10.0	10.6	11.1	11.9	21.1	62.5	12.3	10.9	10.1
90th	9.8	9.5	9.4	9.3	9.4	9.7	10.0	9.6	9.0	8.7	8.6	8.8	9.1	9.4	10.0	10.7	11.3	11.9	13.0	146.5	156.1	59.4	11.2	10.3
95th	9.9	9.6	9.5	9.4	9.5	9.8	10.2	9.7	9.2	9.0	9.0	9.1	9.4	9.7	10.4	11.1	11.7	12.3	46.8	209.2	205.9	106.8	11.3	10.4
Winter Percentiles																								
5th	8.9	8.6	8.5	8.5	8.4	8.6	8.8	7.8	5.6	5.3	4.9	5.0	4.9	4.9	5.3	5.3	7.2	9.4	11.4	10.8	10.4	10.3	9.8	9.3
10th	9.0	8.7	8.7	8.6	8.6	8.8	9.1	8.3	6.2	5.3	5.3	5.3	5.3	5.3	5.3	5.9	7.8	9.9	11.6	11.0	10.5	10.5	9.9	9.4
25th	9.2	9.0	8.9	8.9	8.9	9.1	9.5	8.9	7.3	6.1	5.7	5.7	5.6	5.7	6.0	7.0	8.6	10.8	11.9	11.3	10.8	10.7	10.2	9.6
50th	9.5	9.3	9.2	9.1	9.2	9.5	9.9	9.6	8.3	7.4	7.0	6.9	6.9	7.0	7.3	8.1	9.7	11.7	12.4	11.7	11.1	11.0	10.5	9.9
75th	9.7	9.5	9.5	9.5	9.6	9.9	10.4	10.1	9.0	8.4	8.1	8.0	8.0	8.1	8.3	8.9	10.4	12.3	12.9	12.2	11.5	11.3	10.7	10.2
90th	10.0	9.8	9.8	9.8	9.9	10.2	10.8	10.6	9.7	9.2	9.1	9.0	9.0	9.1	9.2	9.5	10.7	12.7	23.6	12.6	11.8	11.6	11.0	10.3
95th	10.2	10.1	10.0	10.0	10.1	10.4	11.1	10.9	10.0	9.6	9.4	9.4	9.4	9.4	9.5	9.8	10.8	13.0	66.3	48.1	12.1	11.9	11.1	10.5
Spring Percentiles																								
5th	8.4	7.9	7.6	7.5	7.5	7.8	7.3	5.3	4.2	3.7	3.7	3.7	3.7	3.7	3.7	3.7	4.0	5.3	7.5	9.9	10.8	10.2	9.5	9.0
10th	8.6	8.1	7.8	7.7	7.7	8.1	7.9	5.9	5.0	3.7	3.7	3.7	3.7	3.7	3.7	3.7	4.8	5.3	7.9	10.3	11.0	10.3	9.7	9.1
25th	8.9	8.4	8.2	8.1	8.2	8.5	8.5	7.0	5.3	5.0	4.3	4.1	4.2	4.2	4.3	4.7	5.3	6.3	8.6	10.8	11.3	10.7	10.0	9.5
50th	9.2	8.8	8.6	8.5	8.6	8.9	9.1	8.0	6.1	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.8	7.4	9.3	11.2	11.7	11.0	10.2	9.8
75th	9.5	9.1	9.0	8.9	9.0	9.3	9.6	8.8	7.4	6.1	5.4	5.3	5.3	5.3	5.5	5.9	7.1	8.5	10.1	11.7	12.0	11.3	10.5	10.0
90th	9.7	9.3	9.2	9.2	9.3	9.6	10.0	9.6	8.3	7.2	6.7	6.4	6.4	6.4	6.6	7.2	8.2	9.8	11.5	12.1	12.3	11.6	10.7	10.2
95th	9.8	9.5	9.4	9.4	9.4	9.8	10.1	9.9	8.7	7.8	7.3	7.2	7.1	7.3	7.3	7.9	8.7	10.4	12.0	12.3	12.5	11.8	10.9	10.3

There can be a great deal of volatility in the summer evening prices during extreme events. PG&E expects prices above $2.00/kWh to occur approximately 14 hours per year and above $3.00 about 2 hours per year.[9] In terms of timing of the highest and lowest cost hours, Table 2-1 indicates that the *expected*, or *average* peak hour is always Hour Ending (HE) 21 in the summer (except HE20 for very high percentiles), HE19 in the winter; and HE21 in the spring. Likewise, the expected lowest-priced hour is HE11 in summer, and HE12 or HE13 in winter and spring. However, the peak hour and the hour with the lowest price can shift depending on weather and date within a season. Table 2-2 shows the expected percentage of days within each season in which prices are the greatest and the least for each hour.

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9 Using May 1, 2020, Revenue Requirements.

TABLE 2-2
PERCENTAGE OF FORECASTED HIGHEST AND LOWEST PRICES
BY HOUR AND SEASON

	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
SUMMER EXTREME HOURS																								
Percent High Hrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	32.7	66.6	0.2	0.0	0.0
Percent Low Hrs	0.0	0.2	0.2	0.7	0.4	0.2	0.0	0.8	7.0	25.7	44.1	16.3	3.7	0.6	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WINTER EXTREME HOURS																								
Percent High Hrs	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.1	71.7	9.4	0.2	0.5	0.0	0.0
Percent Low Hrs	0.0	0.0	0.9	1.0	0.1	0.1	0.0	0.0	0.5	8.8	20.8	20.8	26.2	16.8	3.1	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
SPRING EXTREME HOURS																								
Percent High Hrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.9	48.9	39.9	0.0	0.0	0.0
Percent Low Hrs	0.0	0.4	6.5	7.2	0.0	0.0	0.0	0.0	1.4	3.6	7.6	9.4	23.6	18.5	13.0	5.1	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0

As an additional reference, Tables 2-3 and 2-4 below show the distribution of simulated historical values from January 2017 through September 2020.[10]

TABLE 2-3
SIMULATED HISTORICAL PRICES FROM JANUARY 2017 TO SEPTEMBER 2020
BY PERCENTILE RANK
(CENTS/kWh)

	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Summer Percentiles																								
5th	7.5	7.4	7.3	7.2	7.4	7.6	7.4	6.3	5.8	5.8	5.9	5.9	6.2	6.6	6.8	7.1	7.3	7.7	8.4	9.6	9.3	8.7	8.0	7.7
10th	7.6	7.5	7.4	7.4	7.5	7.8	7.8	7.0	6.4	6.5	6.6	6.7	7.0	7.2	7.5	7.6	7.8	8.0	8.8	9.9	9.5	8.8	8.1	7.9
25th	8.1	7.9	7.8	7.8	7.9	8.2	8.2	7.6	7.1	7.1	7.2	7.4	7.7	8.0	8.2	8.3	8.5	8.9	9.8	10.8	10.0	9.2	8.6	8.3
50th	8.5	8.4	8.3	8.2	8.3	8.5	8.7	8.4	7.9	7.8	7.9	8.1	8.3	8.6	8.7	8.9	9.2	9.8	11.0	12.1	10.7	9.6	9.0	8.7
75th	8.9	8.6	8.5	8.5	8.5	8.9	9.3	9.1	8.4	8.4	8.5	8.8	9.0	9.3	9.6	10.0	10.4	11.1	13.7	40.3	24.0	10.3	9.4	9.1
90th	9.4	9.1	8.9	8.9	8.9	9.2	9.9	9.5	9.0	9.0	9.3	9.6	9.9	10.2	10.7	11.3	12.8	38.3	105.0	125.3	93.3	38.3	10.5	9.8
95th	10.1	9.6	9.5	9.2	9.3	9.6	10.2	9.9	9.3	9.3	9.6	10.2	10.6	11.2	12.2	22.3	64.5	107.5	170.0	185.7	139.0	77.7	12.2	10.5
Winter Percentiles																								
5th	7.8	7.7	7.6	7.6	7.8	8.3	8.7	8.5	7.9	7.1	6.6	6.5	6.4	6.5	6.7	7.3	8.3	9.5	9.7	9.4	9.1	8.8	8.4	8.1
10th	8.1	8.0	7.9	7.9	8.0	8.5	9.0	8.8	8.2	7.6	7.2	7.1	6.9	6.9	7.0	7.7	8.6	9.7	10.0	9.6	9.4	9.0	8.6	8.3
25th	8.5	8.3	8.3	8.3	8.4	8.8	9.5	9.3	8.6	8.1	7.8	7.7	7.5	7.5	7.8	8.4	9.1	10.3	10.7	10.2	9.9	9.4	9.0	8.7
50th	8.9	8.7	8.6	8.6	8.7	9.2	10.1	10.0	9.2	8.7	8.4	8.3	8.2	8.3	8.4	9.0	9.7	11.2	11.5	10.8	10.4	9.8	9.4	9.1
75th	9.5	9.3	9.1	9.1	9.3	9.9	10.9	10.8	9.7	9.2	9.1	8.9	8.8	9.0	9.2	9.6	10.7	12.9	13.0	12.1	11.1	10.6	10.1	9.6
90th	10.4	10.1	9.9	10.0	10.4	11.4	12.2	12.2	10.6	10.2	9.9	9.8	9.6	9.8	10.0	10.7	12.7	15.6	15.5	14.0	12.8	12.1	11.3	10.7
95th	11.9	11.4	11.0	11.2	11.7	12.9	14.2	13.3	12.0	11.7	11.2	10.7	10.6	10.8	11.0	12.3	14.3	17.7	19.1	16.6	14.7	13.7	12.8	12.2
Spring Percentiles																								
5th	6.6	6.4	6.1	6.1	6.3	7.1	6.8	5.7	5.3	5.3	5.2	4.9	4.7	4.9	4.9	5.1	5.3	5.9	7.7	8.8	8.8	8.3	7.8	7.3
10th	7.0	6.6	6.3	6.4	6.8	7.5	7.4	6.2	5.6	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	6.5	8.1	9.1	9.0	8.5	7.9	7.5
25th	7.4	7.1	6.9	6.9	7.3	8.0	8.3	7.6	6.8	6.1	5.8	5.6	5.6	5.5	5.5	5.9	6.1	7.3	8.6	9.8	9.9	9.1	8.3	7.8
50th	7.8	7.6	7.5	7.4	7.7	8.5	9.3	8.6	7.6	7.1	6.8	6.6	6.5	6.5	6.6	6.9	7.2	8.0	9.4	10.8	10.8	9.7	8.6	8.1
75th	8.2	8.0	7.9	7.9	8.1	9.0	10.1	9.7	8.4	7.9	7.6	7.4	7.4	7.3	7.5	7.7	8.0	8.7	10.2	11.9	11.4	10.1	9.0	8.4
90th	8.7	8.4	8.3	8.3	8.5	9.4	10.9	10.6	9.2	8.6	8.4	8.0	8.0	8.1	8.2	8.4	8.7	9.9	11.4	13.1	12.0	10.6	9.5	8.9
95th	9.2	8.9	8.7	8.7	9.0	9.9	11.3	10.9	9.6	9.0	8.8	8.6	8.4	8.4	8.6	8.9	9.3	10.9	13.0	14.1	13.0	10.9	10.0	9.4

10 MEC in the simulation are equal to DLAP prices times the loss factor. Marginal Capacity Costs are calculated according to the formulae in Section 2.B.2.b.2, using CAISO's DA forecasts of load and utility-scale wind and solar generation, and 2-day-lagged values for nuclear, biomass, biogas, and geothermal generation to calculate ANL. The revenue neutral adder was not changed for this historical presentation.

TABLE 2-4
PERCENTAGE OF SIMULATED HISTORICAL JANUARY 2017 TO SEPTEMBER 2020 HIGHEST AND LOWEST PRICES BY HOUR AND SEASON

	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
SUMMER EXTREME HOURS																								
Percent High Hrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	80.1	8.4	0.0	0.0	0.0
Percent Low Hrs	0.2	0.2	1.0	21.3	2.3	0.2	0.0	1.4	28.7	26.0	10.5	3.9	3.1	1.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WINTER EXTREME HOURS																								
Percent High Hrs	0.0	0.0	0.0	0.0	0.0	0.0	2.8	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0	48.3	5.1	0.2	0.0	0.0	0.0
Percent Low Hrs	0.0	0.0	10.3	7.9	0.2	0.0	0.0	0.0	0.2	1.8	8.5	10.1	33.5	24.6	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SPRING EXTREME HOURS																								
Percent High Hrs	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.1	53.0	36.1	0.0	0.0	0.0
Percent Low Hrs	0.0	0.3	4.9	5.4	0.0	0.0	0.0	0.8	2.7	3.5	6.8	9.0	20.4	20.9	15.5	5.2	4.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Note that the forecasted prices peak up to an hour later than the historical simulated ones, while the lowest forecasted prices are both lower and more concentrated in the middle of the day than the lowest historical simulated prices. This is to be expected because both utility-scale and distributed (rooftop) solar generation are greater in the forecasted dataset compared to the historical simulations, while load, wind, and other generation sources are relatively similar between forecasted and historical data.

d. Primary and Transmission Customers

For Primary and Transmission voltage customers, PG&E proposes to use the same marginal cost drivers, but with smaller gross-ups for line losses. Instead of using a 6.9 percent energy loss factor for Secondary customers, Primary customers would have a 1.9 percent loss factor, as shown in PG&E's 2020 GRC Phase 2 Errata testimony.[11] For capacity, the loss factor is 9.1 percent for Secondary and 2.9 percent for Primary. Transmission customers would not have any loss factor. These loss factor changes would apply to the energy and capacity cost calculations but would not apply to the revenue neutral adder.

3. Updating Rate Values With Revenue Requirement and Sales Changes

The flat adder rate is based on Revenue Requirements from May 1, 2020, effective rates and a 2020 sales forecast to have easy alignment with the 2020 GRC Phase II marginal cost revenue calculations. If adopted, PG&E will adjust the rates to new Revenue Requirement and sales levels that are in effect at the time of implementation.

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[11] Exhibit (PG&E-2), Chapter 2

PG&E proposes that the MGC for evaluating capacity should remain constant until reevaluated in the 2023 GRC. Therefore, any changes to Revenue Requirement or sales forecasts would only affect the flat revenue neutral adder portion of the rate. The calculation of the other portions would remain the same until updated in the 2023 GRC. As the flat adder was determined with system generation information, updates to the adder rate should be in line with average bundled rates. For May 1, 2020, rates, the bundled average generation rate was $0.11224/kWh.[12] Therefore, to keep this rate revenue neutral with average generation, PG&E proposes to keep the delta between the bundled average rate and the revenue neutral flat rate adder constant at $0.05943 ($0.11224 minus $0.05281). Therefore, increases in Revenue Requirement would be captured in the flat adder while retaining the same difference between the adder and the bundled average generation rate.

C. Answers to Commission's Questions in D.19-10-055

In D.19-10-055, the California Public Utilities Commission (Commission) posed a set of questions "that should be addressed before the Commission orders PG&E to implement such a rate for its customers."[13] In this section, PG&E addresses those questions that pertain to the structure and implementation of the proposed rate as described above. Other questions posed in the decision are addressed in later chapters.

1) *Assuming that any dynamic rate must utilize CAISO wholesale market price data, how will the dynamic rate utilize such data? Will the rate use DA prices only, or will it use day-of and RT CAISO prices as well?*

As described in Section B, the proposed DAHRTP-CEV Pilot rate uses DA prices only, adjusted to account for losses to primary or secondary distribution voltage where appropriate. While day-of RT CAISO prices (from either the 15-minute or 5-minute markets) do represent the most up-to-date MEC, implementing rates with such fine granularity and frequent updates would be a very significant undertaking with little added benefit, even in a pilot. PG&E prefers to "walk before we run" by instituting a DA pilot rate.

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[12] AL 5661-E-A, Attachment 1.

[13] D.19-10-055, p. 29.

2) *Are there data other than CAISO data, such as a GHG signal data, that should be used as the basis for a dynamic rate instead?*

A GHG signal forecasting and broadcasting system was established by D.19-08-001 for the Self-Generation Incentive Program (SGIP) and has been implemented by WattTime and the SGIP Program Administrators.[14] This signal is essentially equal to a multiple of the 5-minute RT price, with a floor of zero and a cap corresponding to a heat rate of 12,500 British thermal units/kWh.[15] While PG&E considers that a parallel signal corresponding to actual RT prices could be developed and broadcast similarly to the GHG signal, billing and other Information Technology issues would be significantly greater than for a DA, hourly rate such as that proposed here. In addition, the fact that RT prices are not published until less than an hour prior to the operating interval would make it significantly harder for customers to plan when best to charge under a rate that uses RT CAISO prices.

3) *What time interval should be utilized for the rate? If a longer interval is utilized (e.g., a one-hour retail rate price) than the wholesale price data used to inform the retail rate (e.g., 15-minute or five-minute CAISO RT market data), how will the differences in temporal granularity be reconciled?*

As discussed above, PG&E is proposing that the rate use hourly intervals, which corresponds to the granularity provided in CAISO's generation data used to develop the rate. While a 15-minute granularity DA market has been proposed by CAISO, such a market does not yet exist and its implementation has been postponed by CAISO.[16] Therefore, any finer granularity prices would require using the day-of CAISO RT market price with corresponding higher implementation costs and challenges on both the

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[14] Historical GHG emission rates and the Application Programming Interface for the SGIP signal available at: www.SGIPsignal.com.

[15] The formula comes from the Avoided Cost Calculator (ACC), which per D.16-06-007 is to be used to value Distributed Energy Resources such as the Energy Storage incented by the SGIP program. Heat rate is a measure of the [in]efficiency of the marginal gas generator; the ACC considers that when the RT price is equal to or below zero, renewable generation is on the margin, while a heat rate of 12,500 is considered to represent a reasonable maximum actual gas throughput per kWh of output, with higher prices representing additional generator costs such as those due to fast ramping, or prices in excess of costs required to cover fixed costs and those from startup and/or running units for a loss in the middle of the day.

[16] See Day-Ahead Market Enhancements – Straw Proposal, February 3, 2020, p. 6.

Load Serving Entities (LSE) and customer side. In particular, the fact that RT prices are not published until less than an hour prior to the operating interval would make it significantly harder for customers to plan when best to charge under a rate that uses RT CAISO prices.

4) *Will the dynamic rate focus solely on periods of overgeneration where CAISO wholesale prices are negative, or will dynamic rates seek to send critical peak price signals as well?*

The proposed DAHRTP-CEV Pilot rate focuses on periods of oversupply[17] where CAISO prices are zero or negative. It also seeks to send "critical peak price signals" through the capacity portion of the rate, while sending more muted price signals corresponding to actual generation marginal costs at other times. PG&E notes that the proposed capacity portion of the DAHRTP-CEV Pilot rate would include a non-zero amount on approximately 3 hours per day for approximately 68 days of the year on average.[18] For comparison, PG&E's new Critical Peak Pricing (CPP) adder to be implemented in March 2021 includes a non-zero amount on approximately 3 hours per day on 9-15 days per year. Also, the capacity component of PG&E's proposed DAHRTP-CEV Pilot rate varies depending on the severity of the capacity tightness, whereas traditional CPP rates just have a single adder that applies uniformly across all peak hours, and for each day in which an event is called. This makes CPP rates simpler to understand but less cost-based and unable to have a tailored response depending on the severity of grid stress.

5) *Given that overgeneration events may be either system-wide or limited to a transmission constrained area, should a dynamic rate available to all customers only signal system-wide events?*

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[17] CAISO defines overgeneration as "a condition that occurs when total Supply exceeds total Demand in the ISO Balancing Authority Area." This can lead to over-frequency and in extreme conditions, manual intervention. The CAISO uses "oversupply" to describe the situation when *potential* supply exceeds demand; in those (much more frequent) conditions the RT and/or DA price can drop to zero or below, and renewable generation is curtailed economically. PG&E uses the term oversupply in this document as being synonymous with renewable curtailment.

[18] Calculation in workpapers.

The price at the PG&E DLAP, which includes areas in the major transmission zones North of Path 15 (NP15) and ZP26 (in between NP 15 and South of Path 15 (SP 15)), incorporates both system-wide over-supply events and also those that are local to its service territory.[19] While some oversupply is local to a sub-Load Aggregation Point (LAP), PG&E's analysis indicates that zero or negative CAISO DA prices generally appear in almost all sub-LAPs at the same time. Thus PG&E's proposed DAHRTP-CEV Pilot rate generally accounts for most DA forecasted over-supply events within its service territory, whether CAISO system, PG&E system, or local.

6) *At what level of spatial granularity should wholesale prices be sourced? Should it be the DLAP, the sub-LAP, price node, or circuit substation-level? What challenges would the use of any sub-system level of granularity present? For example, if 16 sub-LAPs exist in PG&E's territory, and if a dynamic rate is designed to reflect a particular sub-LAP's wholesale prices, then how will the rate be communicated to customers in 16 different sub-LAPs simultaneously?*

PG&E believes that its proposed DAHRTP-CEV Pilot rate appropriately uses DLAP prices for the generation energy and capacity components. First, as intimated in the last part of the question, communicating that the rate is different depending on location would be confusing for many customers, who are not used to energy prices that vary depending on the customer's location. A rate that differs based on the sub-LAP would also cause problems for PG&E's billing system, which does not currently track the sub-LAP designation, let alone the more geographically granular p-node.

Second, PG&E does not consider that generation capacity costs vary within its service territory (in particular, by sub-LAP),[20] so the capacity portion of the generation adder should be the same across PG&E service

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[19] The CAISO tracks oversupply in terms of various "buckets," including local vs. system economic curtailment, local vs. system self-schedule cuts, and local vs. system exceptional dispatch. In both 2019 and 2020 (through August 26), oversupply was composed of approximately 2/3 local economic curtailment, 1/3 system curtailment, and less than 2 percent local self-schedule cuts. However, most of the "local" curtailment appears to be local only in terms of being exclusively in NP15, SP15, or ZP26. See http://www.caiso.com/informed/Pages/ManagingOversupply.aspx and daily curtailment reports linked therefrom.

[20] Errata testimony, p. 2-5.

territory. As for finer granularities, while p-node energy prices do vary geographically, they correspond to prices paid to *generators*, not prices paid by *load*, so they may be inappropriate from a regulatory standpoint. Generation energy costs do not vary by circuit.

Third, as described in the answer to Question 5, over-supply events generally occur simultaneously in most of PG&E's sub-LAPs. Analysis using data from January 1, 2017, through August 27, 2020, indicates that negative or zero sub-LAP prices occurred in approximately 400 hours for 11 of the 15 PG&E sub-LAPs, and approximately 700 hours for the remaining four sub-LAPs. Of the outliers, Fresno, Kern, and "Other ZP26" all have significant utility-scale solar generation, but all have sub-LAP prices whose correlations with average DLAP prices are over 98 percent, indicating that their prices move almost in lockstep with the other sub-LAPs. Only the North Coast sub-LAP has both a high number of hours with zero or negative prices (680) and a lower correlation with DLAP prices (approximately 92 percent).

At the other end of the scale, only the Humboldt sub-LAP has both higher-than-average DA prices ($1.50/MWh greater than average) and a relatively low correlation with DLAP prices (88 percent). Humboldt has been a transmission-constrained area for a long time and is therefore served by PG&E's Humboldt Power Plant, so it is not surprising that its energy prices often diverge from others in PG&E's service territory. The other sub-LAPs that are not called out above all have correlations with DLAP prices greater than 98 percent, and in some cases greater than 99 percent.

In conclusion, PG&E considers that while sub-LAP level energy prices could potentially provide a more accurate price signal in some areas, using the DLAP prices as PG&E proposes would capture the vast majority of price variance, and thus benefit from a DA rate. Differentiating by sub-LAP would increase customer confusion and increase implementation costs significantly without a corresponding decrease in generation costs.

7) *How should distribution rates be treated in a dynamic rate scheme? Should distribution capacity costs be included in a dynamic rate?*

As described in more detail in Section D below, PG&E is not proposing to include distribution rates for its DAHRTP-CEV Pilot rate.

D. Other Considerations

1. RT Distribution Rates

PG&E's proposal does not include a RT component for distribution rates.[21] The underlying base CEV rate includes standard TOU differentials in distribution and these would remain in effect for customers taking the DAHRTP-CEV Pilot rate. PG&E believes that there would be load-management advantages to dynamic distribution prices, but it is not as straightforward as generation pricing that can be implemented based on system average conditions. More research and analysis need to be conducted before distribution is added as a RT component.

One of the main obstacles in creating a cost-based RT distribution rate is that distribution capacity constraints are much more localized. The Distribution Planning Areas (DPA) do not experience peak loads at the same times, and some areas have more reserve capacity than others. A single system-level price with significant volatility can create incorrect incentives for some circuits/DPAs. PG&E does not believe that a RT distribution rate would be beneficial without area differentiated pricing. Additionally, localized distribution pricing can often be temporary in nature—lasting only for the period where pricing can defer additional investment. This temporal aspect of any localized RT rate makes the pricing for such a program highly variable year to year, contributing to the uncertainty for customers and any investments they may make. Regulatory lag and the timing of distribution project approvals exacerbates the situation. Finally, as with varying generation prices by geographic area, incorporating area-based distribution rates would add substantial complexity to the information and billing systems and potentially cause confusion for customers with accounts in multiple areas.

2. NEM Customers

PG&E's intends to offer the DAHRTP-CEV Pilot rate to NEM customers that qualify for the base CEV rate. As the rate rider substitutes one set of

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21 Community Choice Aggregators (CCA) and Direct Access LSEs would be able to establish their own generation rate components for each 24 hours in day. The hourly CCA or Direct Access generation rate could be billed using PG&E's bill-ready billing under Electric Tariffs E-CCA and E-ESP.

generation rates for another, exports to the grid will need to be tracked by hour and will be given generation compensation equal to that hourly price. PG&E does not propose any special rules for NEM customers on the DAHRTP-CEV Pilot rate.

3. Other Demand Response Programs

As PG&E's proposed DAHRTP-CEV Pilot rate already incorporates the full market price for both energy and capacity, customers on the pilot rate should not be eligible to enroll in other demand response programs, or for DRAM where third parties use retail customer demand response to participate in the CAISO market. Such dual enrollment would represent "double dipping," not provide accurate costs signals to customers, and potentially lead to assuming duplicative grid benefits, i.e., in the demand response-related program and also under the DAHRTP-CEV Pilot rate.

E. Conclusion

In conclusion, PG&E respectfully requests approval of its rate design for the DAHRTP-CEV Pilot rate. Specifically, PG&E requests:

1) Approval of the rate rider format which substitutes one generation rate for another;
2) Approval of the use of CAISO's DA hourly price for the generation energy marginal cost;
3) Approval of PG&E's generation capacity costs for the purpose of determining the capacity adder, as well as PG&E's proposed methodology for calculating the DA PCAF component;
4) Approval of the revenue neutral rate adder and approval to use the same rate adder for all schedules; and
5) Approval of PG&E's proposed method for adjusting the revenue neutral adder with sales and Revenue Requirement changes.

PG&E's rate proposal provides customers with a more cost-based rate option, allowing them to respond more appropriately to grid needs. Customers that can shift their charging times will be able to use electricity at times beneficial to the grid and reduce overall GHG emissions and their charging costs.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

PROPOSED COMMERCIAL ELECTRIC VEHICLE DAY-AHEAD HOURLY REAL TIME PRICING PILOT

PACIFIC GAS AND ELECTRIC COMPANY
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
PROPOSED COMMERCIAL ELECTRIC VEHICLE DAY-AHEAD HOURLY REAL TIME PRICING PILOT

A. Introduction

The purpose of this chapter of Pacific Gas and Electric Company's (PG&E) testimony is to describe PG&E's proposed plan for a day-ahead hourly Real Time Pricing (RTP) pilot for Commercial Electric Vehicle (CEV) customers (DAHRTP-CEV Pilot). PG&E hypothesizes that automated engagement through utility-side enablement technologies and appropriate customer-side system integration can unlock benefits for some CEV customers enrolled in a dynamic rate. However, given the nascent transportation electrification (TE) marketplace and the lack of data showing customers that they could save on the rate, PG&E proposes to conduct a DAHRTP-CEV Pilot in order to assess the value proposition of a dynamic rate for CEV customers and gather lessons to inform broader implementation of a dynamic rate. PG&E proposes to include in the pilot no more than two Community Choice Aggregator (CCA) partners and possibly one other Electric Service Provider (ESP) who are interested in a DAHRTP-CEV rate.

Recommendations from the California Public Utilities Commission's (CPUC or Commission) Rulemaking (R.) 18-12-006 Vehicle Grid Integration (VGI) Working Group final report informed this testimony and any approved electric vehicle (EV) rate pilot programs shall follow guidance provided by the Commission's final decision on the Transportation Electrification Framework (TEF).[1]

The remainder of this chapter is organized as follows:

B. Pilot Objectives

C. Customer Enablement

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[1] Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group, (June 30, 2020). Available at https://gridworks.org/materials-produced-by-the-vgi-working-group-2/. CPUC Energy Division Staff's draft TEF proposal (February 3, 2020) in response to Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification (DRIVE OIR), R.18-12-006 (Dec. 19, 2018). Available at https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442463904.

D. Pilot Structure

E. Marketing, Education and Outreach (ME&O)

F. Implementation

B. Pilot Objectives

PG&E proposes to investigate the following questions through the DAHRTP-CEV Pilot:

- What technical and operational challenges must PG&E overcome to make the DAHRTP-CEV Pilot rate available to customers? What is the cost of that work?
- Can participating PG&E CEV Account Holders technically integrate with PG&E's proposed DAHRTP-CEV Pilot rate? What is the cost of that work?
- Does the proposed rate provide cost savings to participating PG&E CEV Account Holders, when considering the upfront costs needed to automate response to the DAHRTP-CEV Pilot rate? Which use cases can achieve the greatest savings without diminishing the CEV Account Holder and EV Driver customer experience?
- Does the proposed rate provide system benefits, like system capacity use, greenhouse gas (GHG) reduction, and renewables integration? Does the proposed rate provide both system and customer benefits simultaneously?

Due to the size of this pilot, PG&E expects that much of the evaluation will be qualitative. However, PG&E will aim to quantitatively evaluate these questions once significant data exists.

C. Customer Enablement

To begin to investigate the DAHRTP-CEV Pilot objectives, PG&E must first focus on technology platforms that can enable such a rate. A rate that is different each hour of the day requires development of new tools that can intake the day-ahead market data from the California Independent System Operation (CAISO), calculate the retail DAHRTP-CEV Pilot rate for each hour, and make those rates available for participating PG&E CEV Account Holders to see on a timely basis.

PG&E's proposed pricing tool and communication platform will allow PG&E, Community Choice Aggregators and other Energy Service Providers (CCA/ESP)[2] to compose day-ahead hourly prices and to publish and disseminate the hourly prices to customers and third parties via a non-PG&E website or Application Programming Interface (API). PG&E's proposed pricing tool and communications platform is necessary to implement PG&E's proposed DAHRTP-CEV Pilot rate. It can also potentially be leveraged in the future for similar dynamic rates that may be developed and piloted to other classes of customers.

The cost estimate for this technology ranges from $1,740,000 to $2,350,000. The current cost estimate includes a one-time cost ranging from $300,000 to $550,000 to build the technology platform and an additional $40,000 to $50,000 per month in operations and maintenance costs.

The remainder of this section discusses PG&E's proposed DAHRTP-CEV Pilot: (1) pricing tool; (2) pricing communication platform; (3) customer enrollment process; and (4) usage and cost presentment approach. In addition, section (5) provides PG&E's response to the Commission's question 10 in Decision (D.) 19-10-055 regarding CCA participation in the DAHRTP-CEV Pilot. Section D – Pilot Structure, discusses how customers can use the prices transmitted through the enablement platform, to respond to the DAHRTP-CEV Pilot price signal.

1. Pricing Tool

The pricing tool will:

(a) consume the CAISO day-ahead hourly Default Load Aggregated Point (DLAP) prices, as well as the day-ahead energy pricing from a non-IOU service provider (e.g. for CCAs/ESPs);

(b) consume the day-ahead CAISO hourly load, wind, and solar forecasts and calculate hourly capacity prices as described in Chapter 2 and consume any day-ahead capacity pricing from a non-IOU service provider such as a CCA/ESP;

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[2] Including Direct Access ESPs.

(c) apply the adders described in Chapter 2 for bundled customers, and adders for a non-IOU service provider based on that provider's specifications; and

(d) create the hourly prices.

PG&E envisions that CCA/ESPs could choose to use PG&E's DAHRTP-CEV generation rate or provide raw hourly prices to the pricing tool. In the latter case, the pricing tool will be programmed with logic to add charges for each service provider. For example, if a particular CCA/ESP provider procures its own Resource Adequacy (RA) capacity and wishes to price capacity as a short-run capacity cost,[3] then the pricing tool would apply a specified RA adder based on that CCA/ESP's cost. PG&E will provide this pricing file in a machine-readable format.

2. Pricing Communication Platform

The pricing communication platform will disseminate the hourly prices to all downstream systems. These systems include PG&E's billing system and the web site for customers and third parties to manually retrieve prices and the API for third parties that have machine-to-machine automation. To preserve neutrality, PG&E proposes publishing the prices on a non-PG&E-branded web site as well as the PG&E web site. In addition to providing day-ahead prices, this web site will also host historical prices.

The California Energy Commission (CEC) launched a Load Management proceeding, and components of the Customer Enablement functions (the "price portal" and dissemination of signals) are currently proposed to be in the scope for the CEC to develop and operate.[4] Without coordination, there is a likely chance of duplication, which will make it more challenging to define the requirements. PG&E is proposing that its customer enablement platform be designed to be reusable. If and when the CEC

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3 The capacity cost developed by PG&E represents a long-run capacity cost, i.e. the cost of building incremental capacity to meet peak loads, based on PG&E's assumptions in its GRC that new generation (in this case energy storage) is required in the near to medium term for reliability. CCA/ESPs may wish to use different assumptions about the need for new capacity or the levelized cost of building (or retaining) that capacity, which would result in different capacity costs than those developed in Chapter 2.

4 https://www.energy.ca.gov/event/workshop/2020-01/commissioner-workshop-scope-load-management-rulemaking-19-oir-01.

completes its Statewide Price portal, PG&E intends that the pricing communication platform would publish hourly pricing information to the CEC portal.

3. Customer Enrollment

PG&E anticipates CCAs/ESPs may use the communication resources, but only bundled customers and customers in a participating CCA/ESPs can enroll in the DAHRTP-CEV Pilot rate. The bundled customer would enroll in PG&E's proposed rate plan, and the participating CCA/ESP customer would enroll in that CCA/ESP's DAHRTP-CEV rate plan. Due to the volume of the proposed pilot, customer enrollment and disenrollment will be done manually.

4. Usage and Cost Presentment

PG&E will provide all enrolled customers with usage and interval cost information. PG&E will continue to support metered usage data sharing through its Your Account's Share my Data platform and procedures.[5]

5. Answer to Commission's Question 10 in D.19-10-055

In D.19-10-055, the Commission posed a set of questions "that should be addressed before the Commission orders PG&E to implement such a rate for its customers."[6] PG&E here addresses Question 10 which pertains to CCA participation.

Q 10. If most adjustments in a dynamic rate take place within the generation component of the rate, then how will CCAs operationalize the rate (if at all)? Are CCAs capable of mirroring or otherwise designing a dynamic rate that their customers can take advantage of? What operational challenges do the CCAs face with such a rate?

A 10. PG&E is proposing to conduct a pilot with at least no more than two CCA partners and possibly one other ESP who is interested in a

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5 Unlike other rate plans and options, PG&E does not propose to provide customers with rate comparisons, which calculate a hypothetical bill if the customer were to enroll in the dynamic rate option from past usage data. PG&E expects that customers will manage load based on the dynamic prices, and it would not be appropriate to apply historical usage patterns to compute hypothetical bills for customers who enroll in this optional rate plan. PG&E anticipates that customers who enroll in this optional rate plan will be sophisticated and use third-party software to manage their loads and bills.

6 D.19-10-055 p. 29.

DAHRTP-CEV rate to evaluate how the CCA/ESP can operationalize such a rate. The CCA will have the option of mirroring PG&E's proposed DAHRTP-CEV Pilot rate or designing a DAHRTP-CEV Pilot rate that aligns with the CCA's generation portfolio and operating needs. In the proposed pilot, PG&E and the CCA will be able to collaborate on how to implement a DAHRTP-CEV Pilot rate structure and determine the steps necessary to implement a DAHRTP rate to a broader customer base in the future. For this pilot, the CCA will be calculating the generation component of their day-ahead hourly prices for their customers. PG&E will work with the CCA to continue to bill the customers for the total electric bills.

D. Pilot Structure

This section details PG&E's proposed structure for the DAHRTP-CEV Pilot including: (1) pilot phases; (2) evaluation, measurement and verification (EM&V); and (3) budget and timeframe. In addition, section (4) provides PG&E's response to the Commission's question 9 in D.19-10-055 regarding customer automation technology and working groups.

1. Pilot Phases

Given the many variables and range of uncertainties to consider, PG&E is planning for an important initial design and customer outreach phase. During this phase, PG&E will validate initial customer segment participation and respective assumptions through the following steps:

- Direct engagement with customers to qualitatively assess level of interest, understand the participating PG&E CEV Account Holder experience, and identify highest value use cases. PG&E has already begun this work in preparation for this testimony and has reached out to customers to gather information. The ME&O details highlighted in Section E of this chapter includes both one-to-one and one-to-many outreach efforts for "unified" and "fragmented" customers, respectively.

Definitions for unified and fragmented customers are detailed in Chapter 1 of PG&E's testimony.[7]

- Simulation and modeling of theoretical impacts for various segments to understand rate positioning and value proposition from a data driven perspective.

Following pilot design, the implementation and evaluation will be conducted in three sequential phases. These phases, along with the initial design and customer outreach phase are detailed in the table below.

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7 PG&E Testimony: Proposal for a Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot, Chapter 1, pp.1-18, lines 18-22. Unified resource alignment refers to the case where the CEV customer and the Electric Vehicle Service Equipment (EVSE) are controlled and/or operated by the same actor. Fragmented resource alignment refers to the case where the CEV customer and the EVSE are controlled by different actors.

TABLE 3-1
PILOT PHASES AND DETAILS

Line No.	Phase	Description	Questions	Details
1	0 Months 0-3 post decision	Pilot Design and Customer Outreach	What is the customer experience with and interest in the DAHRTP-CEV Pilot rate? What are the modeled theoretical impacts of the rate?	Direct one-to-one and one-to-many customer outreach. Simulation and modeling of theoretical rate impacts.
2	1 Months 3-9 post decision	Technical Integration	What technical and operational challenges must PG&E overcome in order to make the DAHRTP-CEV Pilot rate available to customers? What is the cost of that work? Can participating PG&E CEV Account Holders technically integrate with PG&E's proposed DAHRTP-CEV Pilot rate? What is the cost of that work?	Look to enroll across all customer segments, no more than 50 unified and fragmented PG&E CEV Account Holders. PG&E CEV Account Holders may have multiple EV drivers using charging ports at the premise. For simplicity, PG&E assumes CEV Account Holders may have, on average, ten charging ports per account. While not all charging ports are expected to be in use simultaneously, PG&E proposes to provide incentives to no more than 500 EV drivers in this pilot. Test the technical integration of PG&E's price broadcast with up to three customer-side price discovery tools. Goal is to meet customer-side functional requirements while minimizing integration costs.
3	2 Months 9-33 post decision	Impacts for TE customers	Does the proposed rate provide cost savings to participating PG&E CEV Account Holders, when considering the upfront costs needed to automate response to the DAHRTP-CEV Pilot rate? Which use cases can achieve the greatest savings without diminishing the CEV Account Holder and EV driver experience? Does the proposed rate provide system benefits, such as system capacity, GHG reduction and renewables integration? Does the proposed rate provide both system and customer benefits simultaneously?	Data collection may include but is not limited to hourly rate, billing data, usage and demand from utility meters, hourly transformer loads, EVSE-level charge sessions, customer charging data, and weather. Customer engagement may be measured by customer satisfaction surveys and tracking information like platform signal uptime, average and max latency, errors per day, and endpoint utilization. Benefit evaluation methodologies will follow industry recommended protocols.
4	3 Months 33-36 months post decision	Scalability and Next Steps	What learnings from the DHRTP-CEV Pilot can inform expansion to other customers (CEV and non-CEV)?	Data analysis and extrapolation from previous phases. Assesses potential to scale the DAHRTP-CEV Pilot rate for both CEV and non-CEV customers.

2. Evaluation, Measurement, and Verification

PG&E's evaluation framework will inform realistic requirements and expectations around data type, granularity, fidelity, and availability to accurately test the hypotheses listed above.

Based on industry recommended protocols,[8] PG&E will consider the following elements when designing the evaluation framework:

- Statistical precision and sample size;
- Modeling methodologies (e.g. Ex-post and Ex-ante, day-matching vs. regression, pre-post and case-control, etc.);
- Impact persistence;
- Geographic segmentation; and

PG&E also expects to collect and analyze qualitative data (e.g., surveys) to understand impacts and associated implications.

3. Budget and timeframe

The estimated cost for the pilot (less Billing, ME&O, and Customer Enablement costs) is between $1,317,000 and $2,119,000, with an anticipated duration of up to 36 months to afford sufficient time for completion of sequential tasks across customer outreach and selection, vendor assessments, technology development, customer baselining, data collection, and evaluation.

Cost categories are detailed as follows:

- <u>Pilot Design</u> phase will be conducted in conjunction with initial customer outreach efforts with expected costs between $18,000 and $40,000.
- <u>Incentives</u> totaling no more than $1,259,000 are included in the cost estimate to decrease customer barriers to participation and to encourage continued engagement to produce meaningful results. They can be further split into technology-specific and one-time EV driver incentives.
  - <u>Technology Incentive</u>: Uncertainty around future dynamic rate product offerings and the novelty of the DAHRTP-CEV Pilot rate is likely to discourage CEV customers and their Electric Vehicle

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[8] Report: CPUC ED, Load Impact Estimation for Demand Response: Protocols and Regulatory Guidance, Attachment A (2008). Available at https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/81979.PDF.

Service Providers (EVSP) of choice from taking on the financial risk of upgrading their systems to enable automated integration with PG&E's pricing communication platform. To minimize this barrier, PG&E proposes a maximum per EVSP technology incentive of $365,000 with no more than 3 total unique customer-side integrations for the duration of the pilot. The maximum spend for the technology incentive is projected to be $1,095,000.

– One-time EV Driver Incentive: Similarly, PG&E believes EV drivers may be tentative about participating in the DAHRTP-CEV Pilot rate because there is little precedent, and it is hard for EV drivers to ascertain potential cost savings. PG&E proposes to provide up to 500 EV drivers who are willing to share their data and participate in surveys with an incentive to participate in this pilot program. Since some EV Drivers using a PG&E CEV Account Holder's charging station may not be PG&E customers, PG&E will limit incentives to EV Drivers that are PG&E bundled and unbundled customers. This incentive will be offered to EV drivers participating in this initial pilot and will not be offered on an on-going basis should the DAHRTP-CEV Pilot rate be offered beyond this pilot phase. The incentive will help reduce financial uncertainty customers may take on by participating in this novel pilot. PG&E plans to offer total customer incentives not to exceed $164,000.

- Evaluation and Reporting is expected to cost between $125,000 to $150,000. This cost covers a range of measurement and verification activities including, but not limited to, framework design, customer research, and impact analysis.
- Project Management will cover various planning, scheduling, and reporting activities across the customer enablement platform, ME&O, and customer-side pilot workstreams. Projected costs are between $360,000 and $670,000, based on similar cost allocations of previous pilot programs.

A more granular and refined budget and schedule will be provided based on findings from the pilot design and customer outreach phase referenced above.

4. Answer to Commission's Question 9 in D.19-10-055

In D.19-10-055, the Commission posed a set of questions "that should be addressed before the Commission orders PG&E to implement such a rate for its customers."[9] PG&E here addresses Question 9 which pertains to customer automation technology and working groups.

Q9. Do EVSE customers or EVs currently have the technology available to automatically take advantage of a dynamic rate? How will a dynamic rate interact with and support the work of various technical working groups currently organized under R.18-12-006?

A9. PG&E CEV Account Holders are likely to have EVSEs and EVs that are at different levels of technical maturity and may not have the technology available to automatically take advantage of the DAHRTP-CEV Pilot rate. The ability for some participating PG&E CEV Account Holders to be able to automatically obtain and pass hourly pricing through to EV drivers will require EVSPs to upgrade their EVSE and customer-facing applications to enable automated integrations with PG&E's Pricing Tool and display the pricing to EV drivers. PG&E anticipates that other ESVPs may also have similar technologies, given that many owners and developers of SGIP-incented energy storage have been responding to the dynamic SGIP GHG signal since early 2020.[10] However, even EVSPs and sophisticated customers who have basic technology that can take advantage of a dynamic rate would need to expend time and resources to develop a technical integration to PG&E's customer enablement platform. Recommendations from the R.18-12-006 VGI Working Group final report informed this testimony and any approved EV rate pilot programs shall follow guidance provided by the Commission's final decision on the TEF.[11]

E. Marketing, Education and Outreach

ME&O efforts for PG&E's proposed DAHRTP-CEV Pilot will seek to directly engage with customers to qualitatively assess level of interest and understand the PG&E CEV Account Holder experience. The remainder of this section

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9 D.19-10-055, p. 29.

10 SGIP signal portal is live at https://sgipsignal.com/.

11 Draft TEF proposal, DRIVE OIR.

details: (1) marketing objectives; (2) target audience; (3) enrollment plan; (4) technology provider support; (5) customer research; (6) metrics and tracking; and (7) estimated budget and timeline.

1. Marketing Objectives

As described in the Pilot section above, PG&E aims to enroll no more than 50 PG&E CEV Account Holders with existing installed EV charging infrastructure. This aims to give customers an operational understanding of the proposed DAHRTP-CEV Pilot rate, test the feasibility of the technology, and evaluate participants' experience with the rate.

The ME&O plan objectives are to:

- Enroll PG&E CEV account holders onto the proposed DAHRTP-CEV Pilot rate (direct enrollment by PG&E and/or support of technology providers' enrollment of PG&E CEV account holders).
- Provide education materials to support enrollment of PG&E CEV account holders and engagement with EV drivers.
- Conduct customer research to evaluate PG&E CEV account holder and EV driver interest in the proposed DAHRTP-CEV Pilot rate, the value proposition, and any other motivations and barriers for participation.

2. Target Audience

Creating an effective enrollment plan for the pilot requires clarity around the target audience being reached. PG&E categorizes customers in the following distinct target audience groupings: public Direct Current Fast Chargers, workplace, multi-unit dwellings, transit fleets and medium-duty delivery fleets.

The pilot is intended to test the hypothesis that the proposed DAHRTP-CEV Pilot rate could provide cost savings while simultaneously providing system benefits to the grid.

We anticipate deploying one-to-one outreach to unified customers and one-to-many outreach to fragmented customers, where appropriate.

Definitions for unified and fragmented customers are detailed in Chapter 1 of PG&E's testimony.[12]

3. Enrollment Plan

To enroll participants onto the proposed DAHRTP-CEV Pilot rate, PG&E expects to use both direct enrollment and supporting technology providers with their own enrollment efforts. PG&E proposes to assist with CCA/ESP efforts as well.

a. Tactics

Proposed tactics led by PG&E may include:

- **One-to-One Outreach:** Direct-to-customer outreach to enroll unified and fragmented PG&E CEV Account Holders is expected to be one-to-one phone calls and/or emails to customers that have an existing PG&E relationship. One-to-one outreach may be conducted by PG&E personnel or through the support of teleservices outbound calls.
- **Collateral/Tools:** PG&E may develop collateral and tools (i.e. email templates, fact sheets, sales toolkits, etc.) that showcase the opportunity of the proposed DAHRTP-CEV Pilot rate. These materials could be shared direct to customers, with technology providers, or with CCAs in support of the program goals.

4. Technology Provider Support

PG&E will need to partner with technology providers to implement the DAHRTP-CEV Pilot rate. PG&E expects that customers will need a technology solution to manage load related to DAHRTP-CEV Pilot rate price signals to participate in the rate.

Depending on the implementation design of the pilot and selected technology providers, enrolling participants into the pilot will likely require the support of both PG&E and the technology providers (and CCA/ESPs where applicable). In any event, PG&E aims to collaborate with technology providers to enhance marketing, education and outreach efforts. PG&E

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[12] Chapter 1, pp.1-18, lines 18-22. Unified resource alignment refers to the case where the CEV customer and the EVSE are controlled and/or operated by the same actor. Fragmented resource alignment refers to the case where the CEV customer and the EVSE are controlled by different actors.

intends to support technology providers by developing resources and materials to enhance their efforts where appropriate. In addition, PG&E assumes these resources can be purposed for use by CCA/ESP participants.

For one-to-many outreach to fragmented customers, technology providers are expected to lead those efforts and be supported by PG&E on an as-needed basis and PG&E CEV account holders may also support outreach to fragmented customers.

5. Customer Research

For the proposed DAHRTP-CEV Pilot rate, PG&E will take a 'test and learn approach.' PG&E's hypothesis is that this rate could provide cost savings while providing environmental and grid benefits. While PG&E expects cost savings to be a primary driver for participation as those drivers are a key component of pilot design, measurement, and evaluation, PG&E also needs to understand the customer experience in more detail to identify barriers and motivations for participation. These results may help in understanding the value proposition of a DAHRTP rate for other commercial customers.

To evaluate the customer experience, PG&E's Customer Experience and Insights team anticipates conducting qualitative and quantitative research with PG&E CEV Account Holders and EV Drivers throughout the pilot. Research will delve into customer barriers, motivations, and overall impressions. The aim of the research will be to position the program to succeed by taking the learnings from the pilot research and conducting research with prospective customers to determine customer interest and viability beyond the pilot.

Additionally, PG&E may leverage its Business Advisory Forum to further test the findings from pilot participants with a broader audience set. The Business Advisory Forum is an online customer panel of businesses that provides feedback on rates and other associated utility programs.

Based on previous PG&E customer research, customers prefer simple messaging that is easy to understand and gets to the point quickly. For the proposed DAHRTP-CEV Pilot rate, PG&E anticipates customers will want to know who the rate is targeted to, what the benefits are, and how they can take advantage of this option. This who/what/how approach will be fundamental to testing efforts, allowing PG&E to deliver clear and effective messaging to customers in the future.

6. Metrics and Tracking

Tracking of metrics allows PG&E to learn and improve throughout the ME&O process. PG&E plans to track and evaluate the success of its efforts based on the following metric types outlined in Figure 3-1.

TABLE 3-2
METRICS AND TRACKING OVERVIEW

Line No.	Metrics and Tracking	
1	Effort	Metrics
2	One-to-one Outreach	Number reached, Conversions
3	Collateral Support	Quantity, Co-Marketing Pieces
4	Customer Insights	Surveyed

a. Metrics Defined

- Reached: track how many customers were made aware via teleservices or other one-to-one outreach.
- Conversions: track ratio of customers reached to customers enrolled in the program.
- Quantity: track total number of pieces of collateral developed.
- Co-marketing Pieces: track number of co-marketing pieces developed for stakeholder use.
- Surveyed: track responses from surveys and other Customer Insights efforts.

7. Estimated Budget and Timeline

PG&E estimates it will cost a total of $153,000 to $443,000 to implement the ME&O plan outlined in Section E of this chapter. 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. ME&O efforts will align with the overall pilot implementation timeline.

F. Implementation

This chapter presents a summary of the high-level cost estimate for the DAHRTP-CEV Pilot using assumptions from experience with past Information Technology (IT) billing projects and rate pilots. This cost estimate assumes that the DAHRTP-CEV Pilot rate will be offered to customers in a pilot before scaling the offering to a wider group of customers and assumes implementation work will not start until after 2021.

PG&E estimates that the DAHRTP-CEV Pilot would cost between $3,851,000 and $5,953,000 and would last for up to 36 months. PG&E estimates that 50 or fewer PG&E CEV Account Holders will be interested in participating in the pilot.

In addition, this estimate assumes the pricing is based on CAISO's hourly day-ahead market. Any shift in this plan would require PG&E to re-evaluate the pilot design, implementation plan and costs. Any broadening of the pilot to other customer classes would also require re-evaluation and re-estimation.

The remainder of this section includes: (1) DAHRTP-CEV Pilot cost estimate; and (2) PG&E's response to the Commission's question 8 in D.19-10-055 regarding implementation challenges and costs.

1. DAHRTP-CEV Pilot Cost Estimate

This section provides: (a) detailed cost estimate for modifications required for the billing system; and (b) a summary of the costs of all the DAHRTP-CEV Pilot activities discussed previously in this chapter.

a. Complex Billing System Modification Costs

Based on the estimated number of DAHRTP-CEV Pilot participants, PG&E plans to build the rate in PG&E's Complex Billing System, which is used to bill some of PG&E's more complex rates such as Net Energy Metering (NEM) for Multifamily, Virtual NEM, NEM plus paired storage, and Standby Service. If it is later determined that PG&E should scale the offering of the DAHRTP-CEV Pilot rate more broadly, in effect requiring PG&E to bill the rate out of PG&E's Customer Care Billing System, IT billing implementation budgets, and timelines would be significantly larger and longer.

Assumptions used to develop the IT billing estimate for the DAHRTP-CEV Pilot include, but are not limited to the following:

- A new automated interface to extract the DAHRTP-CEV Pilot rate hourly prices and apply them to the Complex Billing System. Included with this functionality will be an automated tool to confirm rate prices have been received by a predefined daily timeframe, otherwise a notification will be sent signaling for manual intervention;
- The ability to store hourly prices for billing, reporting, and archiving needs;
- Modification of PG&E's automated monthly rate interface to exclude the DAHRTP-CEV Pilot rate, because the generation component of rates will be derived from the price communication platform rather than from sources that maintain PG&E's other set of rates;
- Modification of PG&E's rate-framing and rate calculation engine in the Complex Billing System to include hourly usage data to support the bill structure change;
- New interfaces to transmit billed hourly costs to the data warehouse and downstream systems;
- Testing rate calculations and other associated bill charges; and
- Testing for all price and usage data flowing between the Complex Billing System and the customer enablement platforms described above in Section C.

PG&E assumes that participating ESPs will calculate the generation component of their pilot customers' bills.

PG&E plans to replace its Complex Billing System starting in 2021, with completion expected in 2022. PG&E is not planning to implement the DAHRTP-CEV Pilot rate until after the Complex Billing System replacement and stabilization is completed. One of the important cost assumptions is that the DAHRTP-CEV Pilot will be implemented after the Complex Billing System upgrade is complete. This will avoid costs of designing, building, and testing the rate twice.

The cost estimate to build a DAHRTP-CEV Pilot rate is projected to range from $641,000 to $1,041,000, based on the high-level rate design outlined in this testimony and on the costs of previous similar Complex Billing System projects. The main reason for the variance between the high and low IT billing cost estimate can be attributed to unknown factors associated with the new Complex Billing System. For example, the lower end of the cost estimate assumes that the new billing system will automatically validate the day-ahead hourly price receipt and calculation, rather than manual validation by a Billing Operations employee. This assumption cannot be confirmed until after the requirements of the new Complex Billing System have been finalized and implemented. The second main variable contributing to the variance between the high and low IT billing cost estimate accounts for detailed design options that have not been finalized regarding how pricing and usage data will flow to the billing system from the customer enablement platforms described in Section C. These technical data flow design elements will be scoped out in further detail following the approval of the pilot.

b. DAHRTP-CEV Pilot Cost Summary

In summary, PG&E developed the following cost estimate based on four key assumptions: (1) Only PG&E CEV account holders will be billed; billing of fragmented EV end-users will continue to be performed by the PG&E CEV account holder; (2) the pilot will last up to 36 months with implementation beginning after the new Complex Billing System has been stabilized; (3) the pilot will have up to 50 CEV account holders with existing EV charging equipment; and (4) the generation component of the pilot rate will be based on the CAISO day-ahead hourly market. Any changes to these key assumptions, or other assumptions outlined in this filing, will result in a change in estimated costs. The implementation forecast includes a range of estimates to account for various unknowns. Table 3-3 provides an estimated total cost summary of the DAHRTP-CEV Pilot. These costs range from $3,851,000 and

$5,953,000. PG&E requests flexibility in spending among the different activities to conduct the pilot.

TABLE 3-3
COMMERCIAL EV
DAY-AHEAD HOURLY RTP PILOT
IMPLEMENTATION COST ESTIMATE SUMMARY
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Activities	Low Forecast	High Forecast
1	Customer Enablement	$1,740	$2,350
2	Pilot Design	18	40
3	Technology Incentive	650	1,095
4	Customer Incentive	164	164
5	Evaluation and Reporting	125	150
6	Project Management	360	670
7	Marketing, Education, and Outreach	153	443
8	Complex Billing System Modifications	641	1,041
9	Total for All Activities	$3,851	$5,953

2. Answer to Commission's Question 8 in D.19-10-055

In D.19-10-055, the Commission posed a set of questions "that should be addressed before the Commission orders PG&E to implement such a rate for its customers."[13] PG&E addresses Question 8 here, which pertains to customer automation technology and working groups.

Q8. What technical and operational challenges must PG&E overcome in order to make a dynamic rate using CAISO price data available to customers? What is the estimated cost of that work?

A8. The main internal PG&E technical and operational challenges include updating PG&E's current systems to automate the daily price calculations, price communication, price storage, and rate framing to bill the hourly prices. Estimated costs to deliver this rate as a pilot are included in the Section F, Complex Billing System Costs, ranging from $641,000 to $1,041,000 and the Section C, Customer Enablement, ranging from $1,740,000 to $2,350,000.

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[13] D.19-10-055, p. 29.

G. Conclusion

In this chapter, PG&E has described PG&E's proposed plan for a DAHRTP-CEV Pilot including pilot objectives, pricing communication, customer enrollment, pilot phases, EM&V, target customers and EVSP recruitment, and ME&O. Given the nascent TE marketplace and the lack of data showing customers that they could save on the rate, PG&E proposes to conduct the DAHRTP-CEV Pilot in order to assess the value proposition of a dynamic rate for CEV customers and gather lessons to inform broader implementation of a dynamic rate.

PG&E estimates the cost of the DAHRTP pilot will range from $3,851,000 and $5,953,000. PG&E requests flexibility in spending among the different activities to conduct the pilot. In addition, any changes to these key assumptions, or other assumptions outlined in this filing, will result in a change in estimated costs.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MICHELLE M. CHEDA

Q 1 Please state your name and business address.

A 1 My name is Michelle M. Cheda, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Product Manager in the Pricing Products group in the Customer Energy Solutions Department within the Customer Care organization. In this organization I am responsible for the implementation and administration of the Business Electric Vehicle rates, the Agricultural Time-of-Use Rate Defaults, and the Foodbank Discounts.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Agribusiness with a minor in Integrated Marketing Communications from California Polytechnic State University, San Luis Obispo and have obtained a Master's degree of Business Administration from Sonoma State University. I have been employed by PG&E since 2016 and prior to my current role, held a position as a Business Analyst in the Customer Energy Solutions, Government and Community Partnerships and Residential Energy Efficiency teams. I have worked on an array of programs for PG&E such as the statewide Energy Upgrade California program, residential Heating Ventilation and Air Conditioning Energy Efficiency programs, Proposition 39, and the Climate Credit Program.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot:

- Chapter 3, "Proposed Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot."
  - Section F, "Implementation."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JAMIE CHESLER

Q 1 Please state your name and business address.

A 1 My name is Jamie Chesler, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Senior Manager of Marketing Strategy responsible for marketing PG&E's customer facing programs for business and residential. Programs included in my purview are Energy Efficiency, Clean Energy Transportation, Distributed Generation, Demand Response, Resiliency and Rates.

Q 3 Please summarize your educational and professional background.

A 3 I graduated from Wesleyan University with a Bachelor of Arts degree in English in 1996. I earned a Master's degree in Business Administration from DePaul University's Kellstadt School of Business in 2005. I have a proven track record with over 20 years of experience leading marketing strategy and driving increased demand for both large and small organizations. Early in my career, I was fortunate to lead corporate marketing and communications for a small manufacturing and services company. My last ten years at Pacific Gas and Electric Company further developed my ability to manage larger more complex marketing campaigns and larger teams. My responsibilities include managing and coaching a diverse group of employees focused on customer-centric marketing strategy to drive growth through increased awareness and participation in customer facing programs in both the Business-to-Business and Business-to Customer space.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot:

- Chapter 3, "Proposed Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot."
  - Section E, "Marketing, Education and Outreach."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

ROSAPACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ANH DONG

Q 1 Please state your name and business address.

A 1 My name is Anh Dong, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Senior Manager in the Pricing Products Department. My responsibilities include defining and implementing Information Technology (IT) solutions to help customers better understand and manage their energy use and bills.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Chemical Engineering from the University of California at Berkeley in 1987, and a Master's degree in Business Administration from the University of California at Berkeley in 1992. I have worked at PG&E since 2010, in multiple roles mostly related to implementing IT system changes for complex Customer Care projects, such as web presentment, bill redesign, residential Time-of-Use transition, and new rate programs. For these implementations, my team worked with internal and external stakeholders, and internal IT teams and vendors to enhance or develop billing and payment products for residential and non-residential customers. Prior to that, I worked as an IT Project Director for the San Francisco Public Utilities Commission, where I managed a team of business analysts to implement IT projects, ranging from Learning Management System to the Customer Care and Billing System.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot:

- Chapter 3, "Proposed Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot":
  - Section C, "Customer Enablement."

Q 5 Does this conclude your statement of qualifications?

Q 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF LYDIA KREFTA

Q 1 Please state your name and business address.

A 1 My name is Lydia Krefta, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Principal Product Manager in the Grid Innovation team within the Grid Innovation and Integration organization at PG&E. My responsibilities include analysis, research and development, evaluation and strategy development related to electrification, both electric vehicles and building electrification.

Q 3 Please summarize your educational and professional background.

A 3 I have a Bachelor of Science degree in Engineering Science from Penn State University in University Park, Pennsylvania. I also have a Master's degree in Business Administration from the University of California, Los Angeles. Starting in 2009, I worked in the defense industry at Northrop Grumman Electronic Systems as an Engineer and Logistics Program Manager for the F-16 Spares and Repairs program. I joined PG&E in 2014 as part of the Gas Asset Management Team. After one year, I joined the Corporate Strategy team where I began leading electrification analysis and strategy development. I've continued to lead pilot development as part of electrification strategy in my current role in the Grid Innovation team.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot:

- Chapter 1, "Background and Policy":
  - Section C, "Commercial EV Customer Policy & Background"; and
  - Section D, "PG&E's DAHRTP-CEV Pilot Proposal."
- Chapter 3, "Proposed Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot":
  - Section A, "Introduction";
  - Section B, "Pilot Objectives"; and

– Section D, “Pilot Structure.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF SHARON T PIERSON

Q 1 Please state your name and business address.

A 1 My name is Sharon T Pierson, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Director of Rates in the Regulatory Affairs Department of PG&E. As the Director of Rates, I oversee the department responsible for retail electric and gas rate design, cost of service analysis, and load forecasting.

Q 3 Please summarize your educational and professional background.

A 3 I graduated from Mills College, Oakland, California in 2005 with a Bachelor of Arts degree, with honors, in economics. In 2006, I earned a Master of Business Administration degree, also from Mills College in Oakland.

I joined PG&E in 2007. Prior to my current position at PG&E, I held the following positions: Senior Manager, Electric Rates; Senior Manager, Regulatory Analytics; Manager, Electric Transmission Rates; and Senior Analyst, Electric Transmission Rates.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot:

- Chapter 1, "Background and Policy":
  - Section A, "Introduction";
  - Section B, "Overview";
  - Section E, "Cost Recovery";
  - Section F, "Organization of Exhibit"; and
  - Section G, "Conclusion."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF TYSEN STREIB

Q 1 Please state your name and business address.

A 1 My name is Tysen Streib, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Principal Data Scientist in the Rates and Regulatory Analytics Department within the Regulatory Affairs organization, and I am responsible for the design and operation of PG&E's filing-quality electric ratemaking models.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Chemical Engineering from University of California, Berkeley in 1998, and a Master's degree in Business Administration from Santa Clara University in 2006. From 1998 to 2006, I held various quantitative analysis and product management positions in the chemical analysis and semiconductor industries. From 2006 to 2007, I was a Product Manager for a small software company that designed stock market analysis tools. I joined PG&E in 2007 in the Finance organization, and then moved to Regulatory Affairs in 2012.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot:

- Chapter 2, "Rate Design."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.