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Calder J. Silcox

PACIFIC GAS AND ELECTRIC COMPANY

COMMERCIAL ELECTRIC VEHICLE RATE PROPOSAL

PREPARED TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
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CHAPTER 1
COMMERCIAL ELECTRIC VEHICLE RATE DESIGN POLICY AND PROPOSAL OVERVIEW

A. Introduction

This chapter describes Pacific Gas and Electric Company's (PG&E) proposed new Commercial Electric Vehicle (CEV) rates. The CEV rates aim to address barriers to widespread transportation electrification that customers, stakeholders, and PG&E have identified related to electricity costs for charging Electric Vehicles (EV). The remainder of this chapter will:

- Provide an overview of policy and regulatory history related to EV charging and utility rates that forms the basis for this proposal;
- Summarize customer research PG&E undertook to inform its commercial EV rate design;
- Describe the proposed new commercial EV rate design, its components, and rationale; and
- Propose PG&E's implementation plan for new commercial EV rates if and when they are approved.

Through this filing, PG&E proposes to create a new Commercial EV Charging rate class, which would include two new rate schedules (EV-Small and EV-Large). Distinct from current commercial and industrial (C&I) rates, these EV schedules would feature two components, a monthly "subscription charge," based on the customer's maximum charging capacity, and a time-of-use (TOU) volumetric rate, designed to encourage customers to charge at times of greater grid capacity and renewable generation, and lower marginal cost. These new rate proposals aim to improve the fuel costs of commercial EV charging, simplify rate structures and price signals for customers, and align with utility costs. Designed to be cost of service, PG&E believes these new rate schedules will accelerate transportation electrification by improving the total cost of ownership to EV drivers, fleets, and charging infrastructure developers, which should encourage further investments in clean transportation. Accelerated EV adoption can increase charging loads and revenues, which may improve the use of PG&E's electric system and put downward pressure on rates for all customers.

1. The Proposed Commercial EV Rate Solution Addresses Critical Barriers to Accelerated EV Adoption in Important Market Sectors and Complements State Policies and Investments

California has ambitious environmental goals to reduce greenhouse gas (GHG) and criteria pollutant emissions, of which a significant portion currently originate from the transportation sector.[1] As the electric sector continues to reduce GHG emissions and electric generation portfolios in California become increasingly renewable, electrification of the transportation sector is a core strategy to meet the state's climate goals. In January 2018, Governor Brown issued Executive Order (EO) B-48-18, setting a new statewide target of 5 million zero-emission vehicles by 2030, and by 2025, installing 250,000 vehicle chargers and 10,000 Direct Current Fast Chargers (DCFC).[2] These goals add to the state policy directives currently being implemented pursuant to Senate Bill (SB) 350 (2015), which directed the California Public Utilities Commission (CPUC or Commission) and investor-owned utilities to propose programs and investments to accelerate widespread transportation electrification.[3]

In its 2017 Transportation Electrification SB 350 Application (A.) (A.17-01-022), PG&E identified several significant existing barriers to widespread transportation electrification, including vehicle operating (fuel) costs.[4] To accelerate widespread transportation electrification, operators of all types of vehicles, and associated charging infrastructure, must have opportunities to save on fuel costs compared to fossil fuels. While PG&E, stakeholders, and the Commission have made strides in addressing several of the barriers previously identified, the fuel cost barrier remains an issue in a variety of EV use cases. The Governor's 2016 Zero Emission Vehicle

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1 California Greenhouse Gas Emissions for 2000 to 2016, Trends of Emissions and Other Indicators. California Air Resources Board (CARB). https://www.arb.ca.gov/cc/inventory/pubs/reports/2000_2016/ghg_inventory_trends_00-16.pdf.

2 EO B-48-18 https://www.gov.ca.gov/2018/01/26/governor-brown-takes-action-to-increase-zero-emission-vehicles-fund-new-climate-investments/.

3 SB 350, 2015: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

4 A.17-01-022, p. 1-8.

(ZEV) Action Plan[5] highlights a variety of areas for state agencies to implement market-transformation of the transportation sector toward zero emissions. The 2016 Plan specifically prioritizes "ensuring ZEVs are accessible to a broad range of Californians," and "making ZEV technologies commercially viable in targeted applications [within] the medium-duty, heavy-duty and freight sectors." The Plan directs the CPUC to "ensure electricity rates are fair and reasonably enable the electrification of public transportation and freight." PG&E's proposal aims to address this action, while supporting several other identified state activities.

The remainder of this section examines barriers faced by three varied, critical market sectors in advancing a cleaner transportation sector: medium- and heavy-duty fleets (particularly transit buses), public fast charging, and multi-family residential charging.

a. Medium- and Heavy-Duty Fleets

California's trucks, buses, and non-road equipment, many of which are fueled by diesel, contribute outsized GHG and particulate matter emissions to the state's inventory. These vehicles include a multitude of vehicle types, duty cycles, and vocations. However, for nearly all of them, two factors are core purchase motivators that might lead a fleet owner to choose an electric option over the status quo: total cost of ownership and operational capability. Enabling a more attractive fuel cost can significantly improve the total cost of ownership, tipping the scale toward adoption of an EV.[6]

For fleets using EVs, especially early adopters, utilization of charging equipment can be low. On PG&E's current commercial rates, which include demand charges, average per-kilowatt-hour (kWh) costs increase as utilization decreases (assuming all other factors equal), because the demand charge portion of the bill is spread across fewer

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5 2016 ZEV Action Plan. Governor's Interagency Working Group on ZEV. https://www.gov.ca.gov/wp-content/uploads/2017/09/2016_ZEV_Action_Plan.pdf.

6 Meeting ZEV Charging Needs While Addressing Grid Constraints: Some Issues and Principles for MDHV (p. 2). Ryan Schuchard, CALSTART, presented at the CPUC ZEV Rate Design Forum 2018. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457684

kWh. For low-utilization EV charging customers, this drives higher dollars-per-mile operational costs—sometimes higher than the gasoline or diesel equipment. This can be exacerbated when fleets have particularly rigorous duty-cycles and must charge at a high rate of power with little operational flexibility to meet business requirements.[7] Transit agencies running electric buses exemplify this characteristic, operating each vehicle from daybreak into the late evening, often surpassing 100 or 150 miles per day,[8] and requiring a rapid charge during the few overnight hours of downtime, when the bus must also be cleaned and serviced. Transit fleet operators and others can also be unfamiliar with electric rate structures, which can be more complex than fossil fuel retail pricing.

CARB is considering an Innovative Clean Transit (ICT) regulation to transition the state's public transit bus fleets toward zero-emission technologies by 2040.[9] In a staff report detailing the proposed regulation, CARB identifies both charging infrastructure and electricity rates as potential challenges to this transition. While utility support for the charging infrastructure for transit buses was addressed specifically in Decision (D.) 18-05-040,[10] the charging fuel cost barrier remains for transit fleets in PG&E's service territory and was highlighted in comments by the California Transit Association throughout the SB 350 proceeding[11] and in the ICT rulemaking.[12] PG&E's proposed CEV rate design can help reduce this fuel cost barrier for electric buses should the

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7 *Ibid*.

8 Transit Agency Survey, Preliminary Results. ACT (ICT) Workgroup Meeting, August 29, 2016. CARB. https://www.arb.ca.gov/msprog/bus/transit_survey_summary.pdf

9 See: https://arb.ca.gov/msprog/ict/ict.htm.

10 PG&E's FleetReady Program will dedicate at least 15 percent of the infrastructure budget in support of transit bus electrification.

11 Opening Comments of California Transit Association on the Proposed Decision for the Transportation Electrification Standard Review Projects (A.17-01-020), p. 4. April 19, 2018.

12 California Transit Association Response to the Initial Statement of Reasons for the Proposed Innovative Clean Transit Regulation, September 24, 2018. https://www.arb.ca.gov/lists/com-attach/767-ict2018-BWNXOFM8AjAKYARb.pdf.

ICT regulation be adopted, helping transit fleets transition more rapidly to zero emissions.

PG&E’s proposed rates also complement other medium- and heavy-duty state investments. CARB’s Proposed 2018-2019 Funding Plan for Clean Transportation Incentives directs $180 million for heavy-duty vehicle and off-road equipment investments.[13] These build on more than $180 million in freight demonstration projects since 2013, and nearly $400 million in vouchers, incentives and pilot funding for off-road freight, trucks, and buses. As increasing state investments aid fleets with capital purchasing of EVs, improved rate design for charging these vehicles will complement the state’s programs and can accelerate fleet uptake of electric options through lower total cost of ownership.

b. Expanding Public Fast Charging

The California Energy Commission’s (CEC) latest statewide Plug In Electric Vehicle Infrastructure Projections[14] point to a need for between 9,000-25,000 public DCFCs by 2025 to support growth in EV adoption commensurate with state goals. The Governor’s 2018 EO B-48-18 similarly calls for 10,000 DCFCs by the same year. Significant capital investments will be needed to achieve this level of DCFC infrastructure growth over the next several years, and fast-charging operators must see a positive business case to attract the necessary private capital to continue growing DCFC networks statewide. These networks may prove critical to wider adoption of light-duty EVs, even if utilization is initially low: they provide all drivers with a safety-net to complete longer distance trips, they allow those without access to consistent daily charging to refuel conveniently, and they enable electrification of the

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13 Proposed Fiscal Year 2018-19 Funding Plan for Clean Transportation Incentives For Low Carbon Transportation Investments and the Air Quality Improvement Program, Table 1. September 21, 2018. https://www.arb.ca.gov/msprog/aqip/fundplan/proposed_1819_funding_plan.pdf.

14 Staff Report – California Plug-In Electric Vehicle Infrastructure Projections 2017-2025. CEC, March 16, 2018. https://www.nrel.gov/docs/fy18osti/70893.pdf.

growing rideshare sector, which requires fast charging to support high daily mileage.[15]

For DCFC operators, electricity costs are a primary component of the business case. With relatively few EVs on the road today, utilization of DCFCs may be low. Similar to the fleet example above, lower utilization of equipment, coupled with demand charges, can lead to high average electric costs per kWh. DCFC operators also currently have little control over when drivers use their equipment, and thus cannot easily reduce electric demand or shift usage to lower-cost hours. Drivers use DCFCs when they require a quick refueling and prefer to complete their trip as soon as possible. If these higher electricity costs are passed along to drivers, the price can be significantly higher than the gasoline equivalent. On top of these high electric prices, the DCFC operator may need to recover capital investments from drivers, further increasing their fuel costs. Without other sources of revenue than driver payments, DCFC operators face an uphill business case to recover infrastructure investments and may be unlikely to expand networks.[16] At the CPUC's 2018 Rate Design Forum, this was articulated by Rocky Mountain Institute's expert, whose presentation highlighted that "demand charges kill at low utilization" and advocated that rate design should support fast charging infrastructure, allowing charging to be "profitable so that it is sustainable."[17]

Some existing DCFC deployments have been funded through negotiated settlements with the state (i.e., the NRG Energy, Inc./EVgo Freedom Station network and Electrify America's planned DCFC investments) and through state-funded grant projects, such as the

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15 Reply Brief of General Motors LLC on The Priority Review Transportation Electrification Proposals From San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE), and PG&E. A.17-01-020. July 10, 2017. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M197/K132/197132659.PDF.

16 Finding the Value in EV Fast Charging and Storage. Salim Morsy, Bloomberg New Energy Finance. October 15, 2018. (Report available from PG&E upon request).

17 Rate Design for DC Fast Charging. Presentation to CPUC ZEV Rate Design Forum June 7, 2018 Chris Nelder, Rocky Mountain Institute. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457677.

CEC's Alternative and Renewable Fuels Vehicle Technology Program investments. An improved rate design for public DCFC can improve the value of these existing or committed investments and attract additional private capital to meet the significant estimated need for DCFC in 2025 and beyond. A more robust DCFC network across the state will reduce driver range anxiety and further accelerate adoption for passenger vehicles.

c. Multi-Unit Dwelling Charging

While multi-unit dwelling (MUD) charging is, in practice, similar to single-family home residential charging, PG&E generally treats these accounts as commercial accounts, which have access to different rates. For some MUDs, EV charging is in a central, common area, and generally metered separately from individual residents' units. This common-area charging load is treated as a commercial electric service and would typically be applicable to the A-6 or A-10 rate schedule. For locations on A-6, there is no demand charge, so the low-utilization issue described above is not a factor. However, the off-peak rate on A-6 is just under $0.19/kWh, several cents higher than the off-peak rate on the residential EV rate. For locations on A-10, the demand charge in that rate is challenging when coupled with low utilization of charging. The demand charge structure can also present challenges to buildings looking to equitably and predictably split charging costs between tenants who use the charging.

Nearly one-third of Californians live in multi-family buildings.[18] Increasing access to charging in this segment was highlighted in the ZEV Action Plan, which directs the Department of Housing and Community Development, CARB, and the California Building Standards Commission to "make home charging easy to install and use, with a special focus on MUDs, disadvantaged and low- and moderate-income communities." To this end, CARB suggested this year that the CALGreen Building Standards Code should be updated to require a

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[18] California's Housing Future: Challenges and Opportunities, California Department of Housing and Community Development. Figure 1.10. February 2018. http://www.hcd.ca.gov/policy-research/plans-reports/docs/SHA_Final_Combined.pdf.

higher percentage of EV-ready parking spaces in MUDs to meet anticipated charging demand over the next decade.[19] The proposed EV rate would complement these proposed increased building standards which would help improve access to charging in MUDs. However, without a rate option that enables EV ownership and fuel savings for this large segment of car owners in apartments and condos, EV adoption may be stunted.

In each of these groups, it is not uncommon to find instances where electric costs do not offer significant—or any—cost savings compared to internal combustion fuels. Without access to lower-cost fuel, fleets and residents of MUDs are unlikely to invest in the additional capital costs of purchasing an EV and installing charging infrastructure. And for public fast charging companies, higher electricity costs lead to longer payback on charging infrastructure installations, stymieing future investments,[20] and potentially leading to higher charging prices passed along to drivers. Accelerating adoption in these three areas is paramount to meeting state EV goals and broader climate and clean air policies. Medium- and heavy-duty fleets, many of which utilize diesel today, are a key contributor to air quality issues that plague the state, particularly California's disadvantaged communities. And increasing access to public fast charging and enabling residential charging in MUDs are critical paths to opening EV ownership to a wider public. Through this proposal, PG&E aims to address identified issues of costs to charge EVs for these and other commercial customer segments, which will be vital to meeting the goals of SB 350 and California's climate and clean air policies.

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[19] EV Charging Infrastructure: Multi-family Building Standards, CARB Technical and Cost Analysis: 2019 Code Cycle. April 13, 2018. https://arb.ca.gov/cc/greenbuildings/pdf/tcac2018.pdf.

[20] Rate Design for DC Fast Charging. Presentation to CPUC ZEV Rate Design Forum June 7, 2018 Chris Nelder, Rocky Mountain Institute. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457677.

2. Prior CPUC Decisions Support New Rate Designs for Commercial EV Use Cases, Though Few Utilities Outside of California Have Sought to Address This Topic

a. Existing Alternative Fueled Vehicle Order Instituting Rulemaking and SB 350

In Rulemaking (R.) 13-11-007, the Commission elevated rate design policy among the three tracks it would consider in addressing alternative-fueled vehicle adoption. That scoping memo noted three rate contexts, including residential, workplace, and medium/heavy-duty vehicle charging rates.[21] PG&E's past activities in EV rate design have focused primarily on the residential sector, where the majority of EV adoption has occurred to-date. PG&E has offered its residential EV rate since 2013, allowing customers to access low-cost charging hours overnight and successfully encouraging EV drivers to avoid charging during peak hours in the late afternoon and evening. Approximately 25-30 percent of EV drivers in PG&E's service territory have opted in to this rate, a significantly higher adoption rate than for optional TOU rates among the general residential population.[22] Surveys of current EV owners indicate that saving money on fuel costs is the single largest motivation factor for drivers to acquire an EV, significantly more important than environmental benefits or high-occupancy vehicle lane access.[23]

After the enactment of SB 350 (SB 350, 2015), the Commission's guidance ruling noted utility "Transportation Electrification (TE) applications may propose projects to change the rate structures, including demand charges, that are currently in effect for EVs used in commercial applications," citing the statute enacted in SB 350, Public

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21 R.13-11-007. Assigned Commissioner's Scoping Memo and Ruling, Section 3.5 (pp. 18-20). July 16,2014. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M098/K861/98861048.PDF.

22 For comparison, as of September 2018 approximately 9 percent of residential electric customers were enrolled in a non-EV TOU rate.

23 Center for Sustainable Energy (2018). CARB Clean Vehicle Rebate Project, EV Consumer Survey Dashboard. Retrieved September 8, 2018 from http://cleanvehiclerebate.org/survey-dashboard/ev.

Utilities Code (Pub. Util. Code) § 740.12(a)(1)(G), which states that "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."[24]

PG&E did not propose in its SB 350 TE proposals any rate-design specific activities, though several of the utility's Priority Review Projects aimed to examine interactions of existing rates, fuel costs, and enabling technologies through customer demonstrations with varying medium, heavy-duty, and non-road fleets. Through the SB 350 Standard Review application process, several parties identified the need for PG&E to propose EV charging rates, and in its opening brief PG&E supported "the consideration of innovative and cost-effective EV rate design proposals and options as part of its overall EV programs." PG&E committed to filing new commercial EV rate options at a future date, suggesting this occur within 6-12 months of a decision on the Standard Review Projects,[25] which subsequently was issued May 31, 2018. This proposal fulfills that commitment.

This proposal also complies with the recent additions to the Pub. Util. Code Section 740.15, enacted in SB 1000 (2018), which directs the Commission to consider "rate strategies that can reduce the effects of demand charges on EV drivers and fleets, and help accelerate the adoption of electric vehicles," and a "tariff specific to heavy-duty electric vehicle fleets or electric trucks and buses that encourages the use of charging stations when there is excess grid capacity."[26] PG&E's CEV rates are designed with consideration for these specific fleet use-cases, in addition to commercial light-duty charging. The proposed rates also

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24 R.13-11-007. Assigned Commissioner's Ruling Regarding the Filing of The Transportation Electrification Applications Pursuant to SB 350, Section 3.6 (p. 20). September 14, 2016.

25 Opening Brief of PG&E on the SB 350 Standard Review Project Transportation Electrification Proposals of PG&E, SCE, and SDG&E, Section H. November 21, 2017. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M201/K923/201923962.PDF

26 SB 1000, 2018, Section 4. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB1000.

reduce the effects of demand charges through the subscription pricing structure.

b. SCE and SDG&E Commercial EV Rates

Little activity has occurred in commercial rate design specific to EVs, except in California, especially for medium/heavy-duty fleet applications. Through their SB 350 priority and standard review projects, both SCE and SDG&E proposed rates that addressed EV charging for non-residential customers. In D.18-05-040, the Commission approved SCE's three commercial EV rates that temporarily collect most revenues through TOU energy charges before gradually re-introducing demand charges over five years. SDG&E proposed several Grid Integration Rates (GIR) that layer dynamic adders on top of hourly base rates and grid integration charges. The public GIR was approved for use with sites in one of SDG&E's priority review project pilots. The residential GIR was approved similarly for use by participants of its Residential Charging Program, while the commercial GIR was denied. SDG&E is also testing the use of a similar Grid Integration Rate for its Power Your Drive Program.

c. EPRI Utility Benchmarking of EV Rates

In 2017, PG&E engaged the Electric Power Research Institute (EPRI) to survey other EV-focused rate designs from utilities around the country. The results confirmed that other than SCE and SDG&E, few utilities had proposed or implemented commercial EV charging rates. Of the 32 EV rates identified, only 11 were non-residential. Of those, the majority were either rates used to directly charge drivers for use of utility-owned charging stations, or rates to charge site hosts to recover the costs of utility-owned charging equipment. Neither of these situations were particularly relevant to PG&E's rate design development. Hawaiian Electric and DTE Energy have rates designed for commercial EV charging, though only for loads under 100 kilowatt (kW) or Level 2 chargers, respectively. At the time of the study, only SCE and Pacific Power had developed commercial rates that addressed higher power charging and concerns with demand charges and lower utilization.[27] The Pacific Power rate design, like SCE's recently approved commercial EV rates, shifts revenues temporarily into volumetric energy charges and then shifts them back into demand-based charges over a ten-year period. While PG&E's proposed EV rate similarly aims to reduce the impact of demand charges on EV charging end-uses, PG&E has also taken a different approach from SCE and Pacific Power's commercial EV rates. Through this proposal, PG&E will create a new rate class for commercial EV charging, allowing the utility to design the rate based on cost of service for these customers, and separately track and allocate costs attributable to EV charging customers as the market continues to develop.

d. PG&E's Commercial EV Rate Proposal Provides Benefits for EV Charging Customers and Non-Participating Customers

D.18-05-040 acknowledged several benefits to EV owners and operators of the SCE proposed commercial EV rates,[28] as modified by stipulations with parties. These include:

- Reduced demand charges relative to current rates;
- Attractive volumetric rates during daytime super-off-peak (SOP) and overnight hours;
- Reduced bill volatility between seasons;
- Long-term rate design stability; and
- Downward pressure on non-participating customers rates due to contribution to recovery of fixed system costs.

PG&E's proposed CEV rates, as described in Section C below, feature the same benefits on which the Commission based its decision to approve the SCE EV rates.

Leading up to D.18-05-040, a diverse group of parties recommended the Commission adopt SCE's modified proposal. The Public Advocates Office at the California Public Utilities Commission's

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[27] EPRI. Review and Assessment of Electric Vehicle Rate Options in the United States. January 8, 2018. https://www.epri.com/#/pages/product/3002012263/?lang=en.

[28] Decision on the Transportation Electrification Standard Review Projects (D.18-05-040), pp. 116-117. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457637.

(Cal PA) opening brief notes that the reduced impact of demand charges "will encourage more EV load and allow customers to focus on the TOU price signals."[29] PG&E's proposal similarly reduces the impact of demand charges through a lower, simpler "subscription charge," which should enable the same outcomes Cal PA supported. While The Utility Reform Network (TURN) did not address SCE's rate proposal specifically, it noted that further data collection on the rate may inform future design.[30] PG&E's proposal to develop a new customer class and track costs and revenues comports with TURN's suggestion.

As described in Chapter 2, PG&E's proposed rates are cost-based, and PG&E does not expect any significant cost shift from the design of these new rates and creation of a new customer class. In fact, the rates should encourage and accelerate transportation electrification, putting downward pressure on rates for non-participating customers. Also, as outlined in Chapter 2, PG&E will track any potential for cost shifting through the 2023 General Rate Case (GRC) and, if needed, address the rate design in the appropriate forum.

e. PG&E's Proposal Is Aligned With PG&E's Modern Rate Architecture, CPUC Rate Design Principles, and PG&E's Broader TE Portfolio

The creation of a Commercial EV Charging rate class aligns with the Modern Rate Architecture framework that PG&E proposed in its 2018 Rate Design Window Application (A.17-12-011).[31] EV charging use cases have a load profile that is distinct from the building loads more common in C&I rate classes today. By treating these customers as a distinct rate class, PG&E can more accurately assign fixed and variable costs to serve these customers, ensuring that rates more accurately

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29 Opening Brief of the Office of Ratepayer Advocates on the Standard Review Transportation Electrification Proposals from SDG&E, SCE and PG&E, p. 52. November 21, 2017.

30 Opening Brief of TURN on the SB 350 Transportation Electrification Standard Review Proposals From SDG&E, SCE, and PG&E, p. 82. November 21, 2017.

31 Rate Design Window 2018 (A.17-12-011). Prepared Testimony, Chapter 1, Section B. December 20, 2017. http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=433764.

reflect those costs. An EV charging rate class also allows PG&E to more transparently track and assign costs to serve and revenues from EV charging customers. If those costs and revenues are misaligned, it provides PG&E the ability to propose changes to the class and rates in future GRCs, while also considering customer costs and state policies to support transportation electrification.

PG&E's proposal also broadly aligns with the rate design principles that the Commission has incorporated into recent decisions (D.15-07-001, D.17-01-006, and D.17-08-030), and which were presented at the EV Rate Design Forum in June 2018.[32] In the table below, PG&E outlines how this application meets those principles, and where they are addressed in this testimony, if applicable:

32 Basics of Rate Design as Applied to Electric Vehicles (p. 2). http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457672.

TABLE 1-1
CPUC RATE DESIGN PRINCIPLES AND ALIGNMENT WITH PG&E PROPOSAL

Line No.	Rate Design Principle	PG&E Commercial EV Rate Design
1	Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost	The proposal includes a mechanism to track the performance of the rate design against cost causation and effectively measure any potential cost shift. If there is a cost shift PG&E will re-evaluate the rate or make an explicit recommendation on how to address the cost shift in the 2023 GRC. This supports affordability for all customers, including low income and medical baseline customer cost affordability. Further, PG&E's proposal also establishes a new rate class that is, until 2023, potentially providing incremental revenues towards fixed costs. This too supports low income and medical baseline customer affordability. (See Chapter 2 Section F)
2	Rates should be based on marginal cost	CEV rate TOU periods and rate values are designed based the marginal costs and forecasts used in PG&E's 2017 GRC Phase 2. (Chapter 2, Section C)
3	Rates should be based on cost-causation principles	Creation of the new commercial electric vehicle rate class allows the utility to design CEV rates based on cost-of-service for these types of customers, which are different from most existing C&I customers. (Chapter 2, Section B)
4	Rates should encourage conservation and energy efficiency	Broadly, rates that enable adoption of electric vehicles, as the CEV rates do, encourage resource conservation and energy efficiency in that EVs are typically significantly more efficient than equivalent internal combustion engine vehicles.[a]
5	Rates should encourage reduction of both coincident and non-coincident peak demand	Allowing customers to choose a lower subscription level if they can maintain demand levels below that subscription amount encourages customers to reduce overall demand at all times in order to save on monthly charging costs. Higher volumetric prices during the peak TOU hours also discourage use during coincident peak times. (Chapter 2, Sections D, E)

(a) According to a recent report from the Union of Concerned Scientists, heavy-duty EVs are up to four times more efficient than diesel and natural gas vehicles. See: Delivering Opportunity report, October 2016 (p. 24). https://www.ucsusa.org/sites/default/files/attach/2016/10/UCS-Electric-Buses-Report.pdf.

TABLE 1-1
CPUC RATE DESIGN PRINCIPLES AND ALIGNMENT WITH PG&E PROPOSAL
(CONTINUED)

Line No.	Rate Design Principle	PG&E Commercial EV Rate Design
6	Rates should be stable and understandable and provide customer choice	For commercial EV charging use cases, replacing demand charges with the subscription charge enables more monthly bill stability and uses a pricing model with which customers are more familiar. Allowing customers to choose their subscription level also enables greater optionality for customers who may be more proactive in managing charging loads. (Chapter 1, Sections B and C)
7	Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals	Creation of the new commercial electric vehicle rate class and rates for commercial EV charging help to separately track revenues from and costs to serve these customers to avoid cross subsidies. PG&E does not anticipate any cost shift in the creation of these rates, but if the rate design is shown to incur cost shifting, PG&E will propose a treatment in a future GRC. This could include a policy-driven cross-subsidy, or gradual modification of the rate design to reduce cost shifting. (Chapter 2, Section F)
8	Incentives should be explicit and transparent	PG&E does not anticipate any revenue shortfall or cross subsidies in the creation of these rates. However, if the rate design is shown to incur cost shifting, PG&E will propose a treatment in a future GRC. Aligned with PG&E's Modern Rate Architecture, this would be explicitly tracked, and in support of the state's policies to reduce emissions from the transportation sector. (Chapter 2, Section F)
9	Rates should encourage economically efficient decision making	Clear cost-based signals in TOU energy pricing on the proposed CEV rates should encourage customers to schedule charging, when possible, to the lowest cost hours, either during the SOP or off-peak hours, encouraging economically efficient decision making. (Chapter 2, Section C)
10	Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.	PG&E will leverage ongoing outreach for programs such as EV Charge Network, FleetReady and Fast Charge, including engagement with vehicle makers and charging service providers, to educate customers about the new rates and potential fuel savings resulting from taking service on CEV rates. (Chapter 1, Section E)

This proposal should also bolster PG&E's approved and pending programs supporting EV infrastructure deployment at customer sites. Those programs target the same sectors and customer types that would be eligible for this rate offering, and improved rate offerings should encourage customer participation in the programs, including FleetReady and Fast Charge, the EV Charge Network Program, and the proposed EV Charge Schools and EV Charge Parks pilots. In early or informal discussions with interested customers for the approved utility EV infrastructure programs, customers have highlighted the interdependency of rates and infrastructure in making decisions to electrify or install charging at their sites.

3. PG&E's Commercial EV Rate Proposal Aims to Address Customer and Stakeholder Concerns With Existing Commercial and Industrial Rates

PG&E's existing C&I rate schedules are undergoing several changes resulting from the utility's most recent 2017 GRC Phase 2 (D.18-08-013).[33] Even with the approved changes, these rates, including A-6, A-10, E-19, and E-20, will likely remain a barrier for many commercial EV charging use cases. These rates are designed to align with the cost to serve large commercial customers, but they are designed based on loads that are considerably different from EV charging loads. Current rates' use of maximum and peak demand charges result in high costs for EV charging customers that have typically low load factors. PG&E's proposed new EV rate schedules would replace the customer and demand charges with a subscription charge, designed to reduce the impact of these costs on overall customer bills, while the high differential between peak and off-peak energy charges are designed to shift usage out of the highest-cost hours. The proposed EV rates also aim to reduce complexity for customers, through more consistent TOU price periods, which are the same year-round and seven days per week.

B. EPRI-Led Customer and Stakeholder Research Formed the Basis for PG&E's CEV Proposal

1. Introduction of EPRI Research

To better understand customer and stakeholder priorities for CEV-specific rate designs, PG&E engaged the EPRI to conduct targeted

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[33] These changes include shifts to PG&E's TOU periods to better align with current and future marginal energy costs, as well as cost allocation of demand and volumetric charges.

interviews with representatives from groups, including fleet operators, charging service providers, vehicle makers, and non-governmental organizations. EPRI interviewed 23 entities over a several week period in mid-2018. Many of these groups have previously contacted or worked with PG&E in evaluating EV fleet and commercial charging infrastructure deployments or participated in previous EV regulatory proceedings. PG&E sought input from these participants on general rate concepts as part of the rate design process.[34]

The primary objective of the research was to evaluate the tradeoff between a simpler, more consistent rate structure, versus one that is more complex and dynamic. To elucidate these concepts, EPRI shared three conceptual rate designs across a spectrum of complexity of fixed charges, demand charges, and volumetric charges (see Figure 1). EPRI also collected stakeholder feedback on a range of other topics, including TOU periods, metering, and renewable integration.

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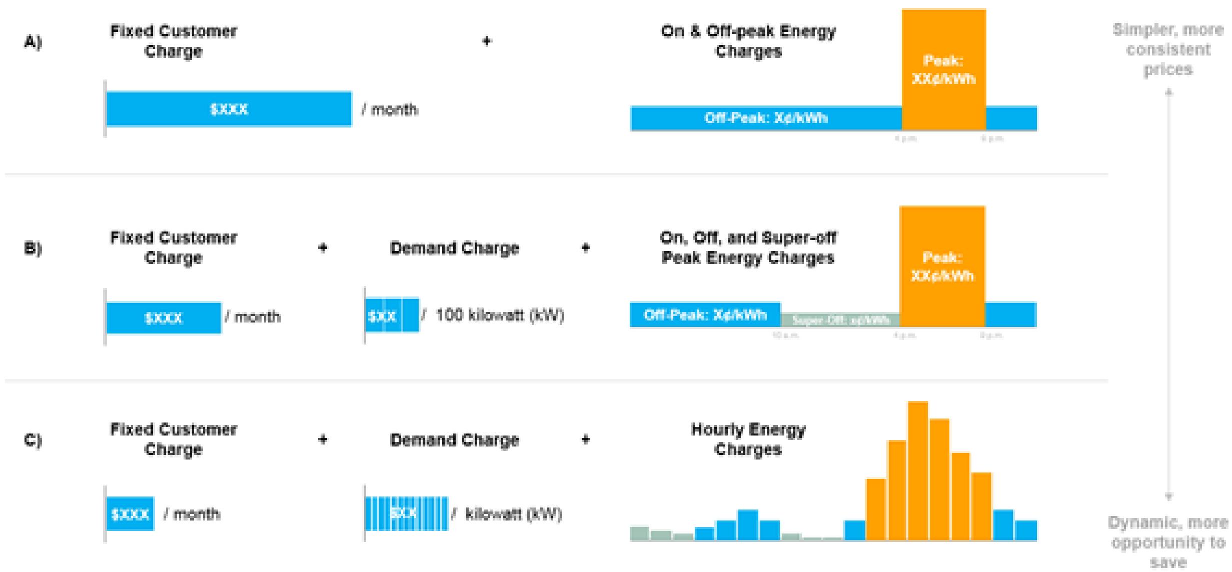
34 PG&E and EPRI developed a list of contacts at 35 organizations involved in the commercial EV market to request input for the project. The interview respondents do not reflect a random sample of utility customers, but instead represent customers and stakeholders that have previously interacted with the utility or shown early interest on matters regarding EVs and/or rates.

FIGURE 1-1
COMMERCIAL EV CONCEPTUAL RATE DESIGNS



Note: Figure 1 Conceptual rate structures presented to EV rate research interviewees.

2. Key Findings of EPRI Stakeholder and Customer Interviews Regarding Commercial EV Rate Design

Although respondent preferences varied across the customers and stakeholders interviewed, several general trends emerged from EPRI's discussions that informed PG&E's commercial EV rate design:

a. Preferences Varied for Simple or Dynamic Rates, With Most Customer Groups Preferring Simpler Structures for the Near Term

Some respondents favored more basic rate structures that offered simplicity and more predictable bill amounts to aid in budget planning. These respondents were typically fleet and workplace charging customers that might not have operational flexibility to respond to more dynamic price signals. Other respondents, generally vehicle makers and software providers, favored more variable rates, such as hourly price signals, which would allow them to manage charging loads to the lowest cost periods, and leverage technologies like energy storage to offset more expensive periods. Many respondents expressed that such dynamic rate structures would be better implemented when the technologies that enable load management are further developed, and after the customers have gained more basic experience operating EVs and charging infrastructure. As one respondent concluded, there is no "one-size-fits-all," and choice or flexibility is important.

b. Traditional Demand Charges Are Largely Unpopular for EV Charging

The majority of the EV-focused customers and stakeholders interviewed disliked demand charges as a method for collecting utility costs for two main reasons. First, demand charges, especially non-coincident or maximum demand charges, can make it difficult for customers to achieve costs that are near the system average due to low charging utilization, even when charging occurs primarily or fully off-peak. Second, many customers find demand charges difficult to reduce or avoid, particularly in public fast charging, where drivers have little appetite to charge at a different time or accept a lower rate of charge. Respondents looked to PG&E to develop alternate rate structures to recover demand-based costs. They showed interest in more familiar pricing models with set amounts such as the subscription-type pricing that is common with cellphone or cable plans, or a pricing based on charging station size.

c. TOU Rates Are Generally Understood

Respondents generally understood why utility rates vary by time of day, and that growing solar generation in California is creating low-cost energy in the middle of the day, while shifting peak costs later into the evening. Respondents acknowledged these TOU periods conceptually, and showed interest in a midday "Super-off Peak" (SOP) period. They also accepted the evening peak period as reasonable, and most expressed some flexibility in responding to peak periods that were shifted an hour earlier or later than the times shared (4-9 p.m.).

EPRI's final report, Commercial Electric Vehicle Rate Design Stakeholder Interview Results, is attached as Appendix B.

3. The Proposed CEV Rate Design Incorporates Learnings From Customer Research and Additional Stakeholder Outreach and Feedback

PG&E considered these learnings in the proposed CEV rate design process. The design is simpler than existing commercial rates, by using just two components (subscription and energy charges), while eliminating potentially confusing seasonal TOU variability. In particular, the proposed rate design aligns with customer preferences for a simple, consistent rate by including a set "subscription" charge instead of traditional demand charges. This pricing structure is used in other services and is more familiar to customers, and the structure of the subscription charge improves costs for low-utilization customers. The TOU volumetric energy charges include a mid-day SOP period, a component in which customers expressed interest. The subscription and TOU pricing still offer optionality for customers who plan to implement more dynamic load management tools and encourage customers to shift charging to lower-cost hours.

In addition, after initially designing the CEV rates, PG&E conducted a series of informational previews with over 40 EV charging customers and fleets, technology and service providers, vehicle manufacturers, ratepayer advocates, and environmental advocates to garner feedback and reactions to the rate design. While generally positive, the feedback also offered several concrete suggestions to improve rate design from customers' perspectives, which PG&E strived to incorporate in the final proposal outlined below. For example, the structure and size of the subscription charges and overages, as detailed in Section C, includes elements identified by these stakeholders.

C. Overview of Proposed PG&E Commercial EV Rate Design & Commercial EV Charging Rate Class

Based on the customer research summarized above, CPUC rate design principles, and other market conditions, PG&E designed the proposed CEV Rates with two components: a monthly "subscription charge" based on the customer's connected charging load, and a TOU energy charge to account for volumetric consumption. PG&E proposes two rates, based on the size of customers' connected charging load:

- EV-Small: Connected charging load of 100 kW and under; and
- EV-Large: Connected charging load above 100 kW.[35]

The rate designs are described below, with further detail included in Chapter 2.

1. Subscription Charge

The subscription charge will be based on a customer's connected charging load, providing greater simplicity and consistency in costs to customers, compared to the demand charges they face today. The subscription charge allows customers to plan on a single monthly amount based on their charging installation, which would only be increased if the customer installs additional charging at the site. Like subscription pricing models for cellphone plans, customers will be able to elect for a lower plan level if they can manage their load below that chosen amount, and would incur an overage if they exceed that amount. This optionality also encourages customers to pursue load management strategies to lower their subscription charge costs. This pricing model should also be familiar and understandable to customers. The subscription charge is also significantly lower, on an equivalent per-kW basis, compared to existing demand charges, allowing EV charging sites with low utilization to access more favorable average prices than current rates. PG&E intends to allow customers to revisit their subscription level for the next billing period throughout the year, within reasonable limits of PG&E's billing and customer service systems. PG&E will allow new customers on these EV rate schedules a short grace period (for example three months) to determine an appropriate subscription level without incurring overage charges, should they exceed their subscription. This structure should, for many customer types, help improve the EV business case and lower average fuel costs for electricity.

2. TOU Volumetric Charges

The TOU periods proposed will deliver straightforward price signals to customers, encouraging EV charging with lower prices at times when

[35] For the EV-Large rate, PG&E developed both Secondary and Primary voltage level service, with corresponding rate values for each voltage-level.

generation costs are lower and there is generally sufficient capacity on PG&E's electric system, and discouraging charging at times when costs are high and the system is more constrained. Unlike current C&I rate designs, the TOU periods are consistent year-round, seven days per week. This creates a simpler price signal for EV customers to manage their charging load around. The seasonal consistency is more akin to the relatively consistent gasoline or diesel fuel costs with which these customers are familiar—and with which the CEV rates are compared when evaluating the purchase of an EV vs. a traditional-fuel vehicle.

Peak Period: PG&E set the peak period hours for the CEV rate from 4 p.m. – 10 p.m., all days, year-round. Given that many EV charging use-cases are more flexible and price responsive than home or building loads, it is reasonable to expect these customers to delay charging one additional hour compared to the 4 p.m. – 9 p.m. peak-period in business rates approved in D.18-08-013.

SOP Period: PG&E set a SOP period from 9 a.m. – 2 p.m., all days of the week, year round. This should encourage customers to charge EVs when there are higher levels of renewable energy in the generation supply, aligning with Pub. Util. Code Sections 740.12 and 740.8. On hot summer days, the SOP also acts as an inducement to charge before temperatures rise and air conditioning loads start ramping up in the mid afternoon. Finally, this lowest-cost period may encourage installation of on-site battery storage to shift peak consumption to the SOP.

Off-Peak: All other hours each day would be off-peak, from midnight to 9 a.m., 2 p.m. – 4 p.m., and 10 p.m. to midnight. These hours are intended to provide customers with access to extended low-cost charging times and encourage charging when there is typically capacity on the electric system.

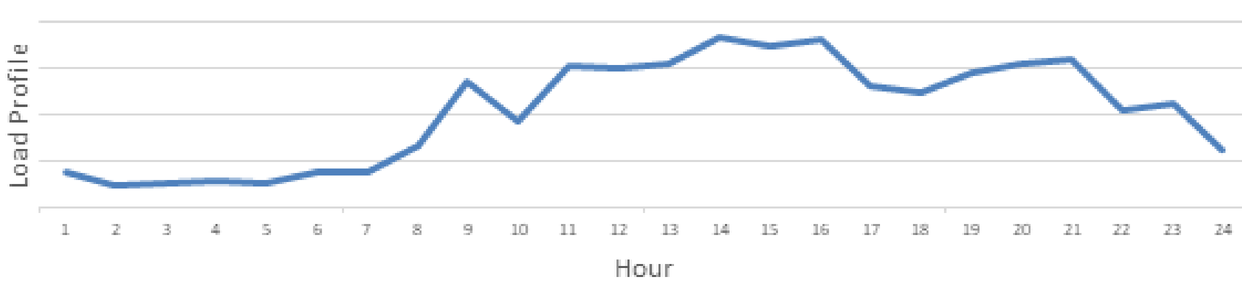
While fairly simple, these TOU volumetric charges will allow customers to reduce costs through charging management technologies or energy storage. For those that seek even more dynamic price signals, demand response programs provide an additional layer that more sophisticated customers can access.

3. PG&E Leveraged Existing Data and EV Charging Use Cases to Estimate CEV Rate Billing Determinants and Develop Rate Class

To develop the new commercial EV charging class and associated rate values, PG&E developed customer site types that the utility expects will take service on the proposed EV rates and estimated their load profiles and approximate number of customers in 2020 to generate billing determinants for the rate class. These values were estimated across five representative customer/site types: public DCFC, workplace, multi-family residential, transit fleets and medium-duty delivery fleets. Where sample site load data was available, such as for public fast charging, workplace, and residential charging, PG&E used existing site load profiles and site assumptions (i.e., number of charging events, or vehicles and miles traveled) to generate billing determinants for the site. For the transit and medium-duty site types, PG&E developed estimated load profiles based on fleets' operational constraints, TOU price signals, and, where available, existing research.[36]

For example, to generate the rate class billing determinants for Public DCFC customers, PG&E used the below example load curve, for hourly energy usage, based on existing customer data:

FIGURE 1-2
SAMPLE DCFC HOURLY LOAD PROFILE



PG&E then assumed the following site and usage characteristics that were then applied to this load curve.

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36 For example, the medium-duty site load profile was adapted from results of a National Renewable Energy Lab field test of electric delivery trucks (https://www.nrel.gov/docs/fy17osti/66382.pdf see p. 29) and modified to reflect customer response to TOU pricing, shifting charging earlier into mid-day hours and later into overnight hours.

- Total chargers per site: 4
- Charger power rating: 125 kW
- Hours per day chargers utilized: 2 hours
- Customer population on rate in 2020: 150

These site usage characteristics and populations, applied to the individual site load curves, produce the billing determinants used to develop the rate values, as described in detail in Chapter 2. Given daily travel patterns do not vary significantly seasonally, PG&E assumed the same load curve and site characteristics for each day of the year. PG&E developed distinct load profiles, site and population assumptions for each of the five use-cases to estimate the total commercial EV rate class load profiles and billing determinants used in the rate design. The customer site characteristics for all five customer types are listed in the table below:

TABLE 1-2
CUSTOMER CLASS SITE CHARACTERISTICS

Line No.	Site Type	Site Factors	Rate Customers in 2020
1	DCFC	Chargers/site: 4 kW/charger: 125 Hours utilized/day: 2	150
2	Workplace	Chargers/site: 12 kW/charger: 6.6 Vehicles: 24 Miles/vehicle/day: 20 kWh/mile: 0.3	600
3	Multi-family	Chargers/site: 10 kW/charger: 6.6 Vehicles: 10 Miles/vehicle/day: 30 kWh/mile: 0.3	200
4	Transit	Chargers/site: 12 kW/charger: 100 Vehicles: 24 Miles/vehicle/day: 150 kWh/mile: 2	6
5	Medium Duty	Chargers/site: 12 kW/charger: 19 Vehicles: 12 Miles/vehicle/day: 45 kWh/mile: 1.4	25

While PG&E acknowledges other types of EV charging customers may also take service on the rate, the above approximations allow PG&E to develop relative billing determinants to form the rate class. The full calculations and sources for the above site characteristics are detailed in PG&E's workpapers. For the purposes of designing the small and large rates, PG&E used the workplace and multi-family billing determinants for the EV-small rate, and the DCFC, transit and medium-duty billing determinants for the EV-large rate.

4. Customer Eligibility for CEV Rates

The new rates will be available to any retail customer that would otherwise take service on existing commercial or industrial rate schedules, including A-1, A-6, A-10, E-19, and E-20, including customers with existing services dedicated to EV charging. Pursuant to the Commission's guidance SB 350 Assigned Commissioner's Ruling, PG&E will define the eligible types of customer loads for EV-specific rates to comport with the definition of TE to allow all types of EVs, vessels, trains, boats, or other equipment (e.g., aircraft) that are mobile sources of air pollution and GHG emissions. The new rates will also be available to customers in Community Choice Aggregation service territories and those served by Direct Access, and will be subject to the same rules and treatment as other C&I rates in those cases.

All customers taking service on these rates, and within the class, would be required to have the EV charging separately metered from existing building or facility loads. No other loads, except those directly associated with the EV charging (such as energy storage), would be permitted to take service on the CEV rates.

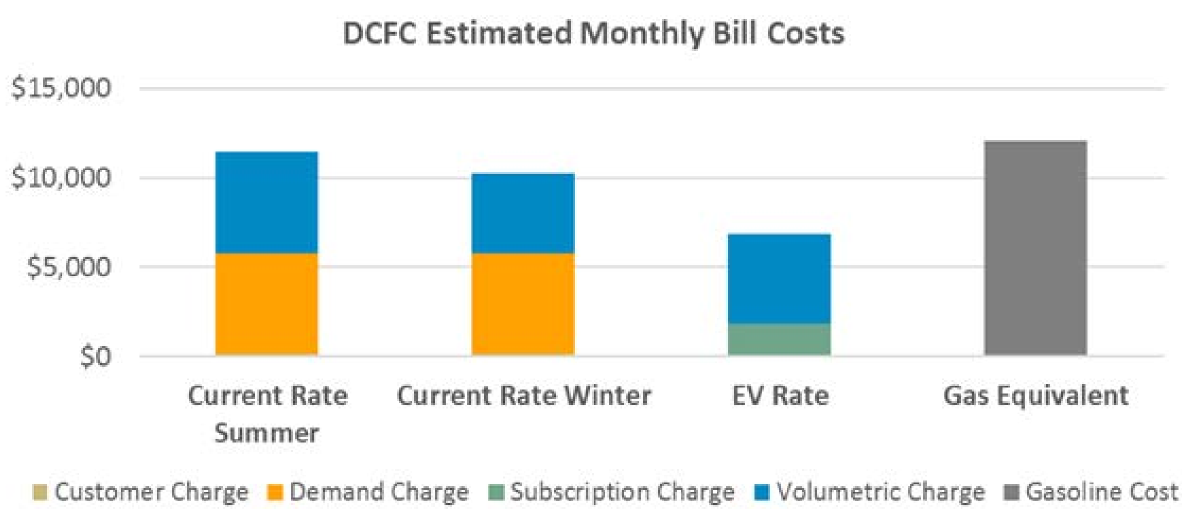
Given that these new service connections would be billed in a separate rate class from that of the existing metered service at a site, retail customers that would take service on the CEV rates would be eligible for typical allowances under Rules 15 and 16, and would not be subject to the special facilities charges that typically apply when retail customers install a second utility service connection at their premise.

D. Comparison of Customer Bills Under Current Rates, Future Commercial Rates, and Proposed EV Rates

PG&E modeled the proposed rates for the five customer use cases and site types outlined above to compare bill impacts against existing C&I rate structures,[37] as well as approximate gasoline/diesel equivalent costs. While these examples only model specific assumptions of site and usage patterns, they provide directional indication that the proposed rates enable valuable savings over current rates and gas or diesel fuels. The results of this modeling is captured below, with the full calculations available in PG&E's workpapers.

In the DCFC example, the total bill is reduced by an estimated 36 percent, on average, over the course of the year, and enables significant savings compared to gasoline equivalent, at recent prices:

FIGURE 1-3
SAMPLE DCFC ESTIMATED BILL COST COMPARISON



Similarly, in the workplace example, the average rate is reduced significantly, from approximately $0.40/kWh under current rates, to $0.18/kWh under the proposed rate, yielding significant savings.

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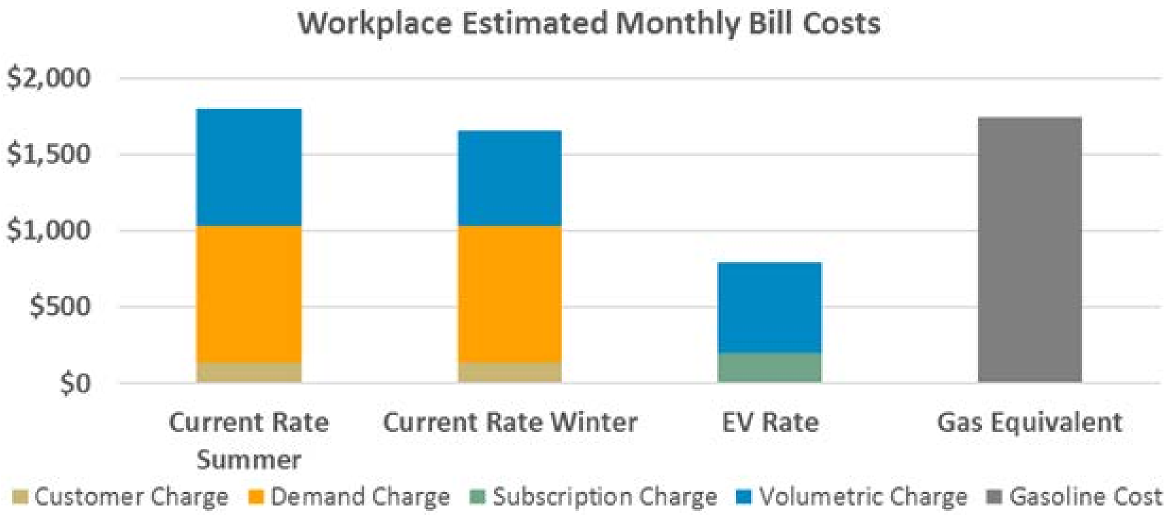
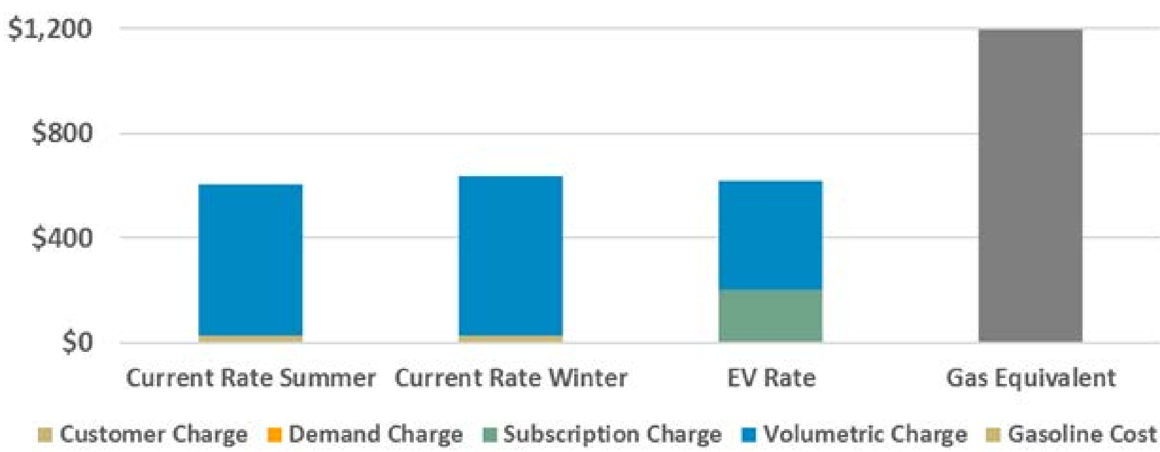
[37] For the purposes of this analysis, PG&E modeled the existing C&I rates that were recently approved in D.18-08-013, and will be implemented by PG&E. These recently approved rates are a more apt comparison with what will be available on similar timelines.

FIGURE 1-4
SAMPLE WORKPLACE ESTIMATED BILL COST COMPARISON



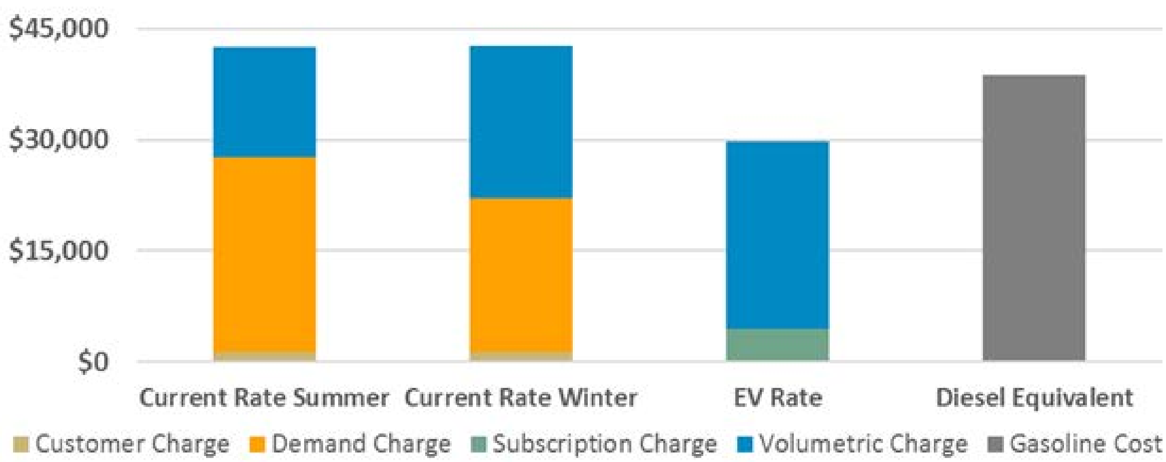
For the modeled MUD site, the savings were much more modest, though still represent opportunity to save compared to gasoline. In this case, the savings were not as significant because this example has a low load-factor (utilization) of 6 percent, and is compared against the A-6 schedule, which does not include demand charges. Improved utilization of the charging stations could lead to greater savings compared to the current rate:

FIGURE 1-5
SAMPLE MULTI-FAMILY ESTIMATED BILL COST COMPARISON



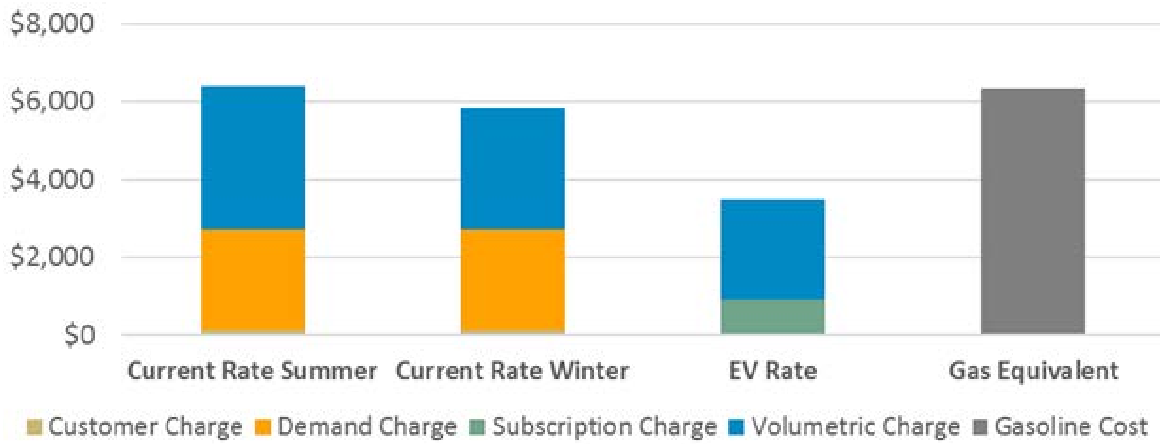
For the Transit site modeled, the proposed CEV rate results in 30 percent annual savings, enough to reduce costs below the cost of diesel equivalent. For these fleets, in particular, the average diesel fuel cost is significantly lower than retail fuel costs. This sample site, also has higher utilization than the others, at 25 percent, which enables an average per kWh rate of $0.14/kWh:

FIGURE 1-6
SAMPLE TRANSIT ESTIMATED BILL COST COMPARISON



Finally, for the medium-duty sample site, similar reductions in average costs occur, approximately 40 percent, compared to current rates:

FIGURE 1-7
SAMPLE MEDIUM-DUTY ESTIMATED BILL COST COMPARISON



E. Implementation of CEV Rates

1. Implementation Timeline and Coordination With Existing EV Activities

Upon approval, PG&E will work expeditiously to implement the new rate schedules and make them available to customers on an optional basis. The implementation of these new rates will be coordinated with other planned rate changes, such as those approved in D.18-08-013.

PG&E will also coordinate customer outreach regarding the rates through the outreach ongoing with the utility's EV infrastructure programs, including the EV Charge Network program, FleetReady and Fast Charge, as most, if not all, participants in those programs would be eligible to take service on the proposed EV rates.

PG&E is not requesting a revenue requirement for the implementation of this rate. Any costs for the billing-system implementation of the new rates will be funded through approved GRC funding for rate implementation, and education and outreach will similarly be funded through the approved budgets within the aforementioned infrastructure programs and/or GRC funding for EV-related customer education.

F. Conclusion

PG&E believes the creation of the proposed CEV rates will bring benefits to customers pursuing transportation electrification, as well as broadly to non-participating customers. The proposed rates are aligned with the CPUC's rate design principles, customer preferences, and support California's bold climate policy goals and associated strategies and investments to reduce emissions from the transportation sector. PG&E respectfully requests approval of this CEV rates proposal.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

COMMERCIAL ELECTRIC VEHICLE RATE PROPOSAL

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CHAPTER 2
COMMERCIAL ELECTRIC VEHICLE RATE PROPOSAL

A. Introduction

The purpose of this testimony is to describe in detail Pacific Gas and Electric Company's (PG&E) proposal to offer a Commercial Electric Vehicle (CEV) rate option to customers consistent with Decision (D.) 18-05-040.[1] In this chapter, PG&E describes two specific elements of its new CEV rate: the formation of a new rate class for CEV customers; and a proposal for two CEV rates: Small CEV and Large CEV, with both a primary and secondary voltage option for the Large CEV rate. These proposals were developed by PG&E using a process that integrates cost of service analysis, conventional cost allocation, cost-based rate design and customer research. The CEV rate class will be created as an addition to PG&E's existing seven rate classes.[2] The basic structure of the Small and Large CEV rates is the same, with different rate values and units.

Section B of this testimony describes the CEV rate class designation proposal in greater detail. Section C describes the cost allocation proposal for the CEV rate class. Sections D and E describe each of the two rate proposals (Large CEV and Small CEV) respectively, including resulting bill analyses. Finally, Section F includes a description of the cost of service tracking process that will apply to the CEV rate. The customer research results underlying and supporting PG&E's CEV rate proposal is contained separately in Appendix B and described in Chapter 1.

B. PG&E's CEV Rate Class Proposal

This section presents PG&E's proposal to create a new CEV rate class. PG&E is proposing a new rate class for CEV customers because of the distinctly different load profiles and cost of service for this class, as well as the business needs of this rate class. These differences include load shapes, load factors and customer payment preferences. PG&E's CEV rate proposal is designed to

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1 D.18-05-040, p. 85 ("…PG&E will file rate proposals optimized for commercial charging applications within 6-12 months of a decision in A.17-01-020 et al.…").

2 Residential, Small Commercial and Industrial, Medium Commercial and Industrial, Large Commercial and Industrial, Standby, Streetlights, and Agricultural.

not only provide a true cost of service rate option for CEV customers, but also to encourage customer acceptance of the rate by offering an innovative and creative solution for these customers. This approach also aligns with broader state policy initiatives to accelerate widespread transportation electrification as required by Senate Bill 350, and described in Chapter 1.

The creation of a new CEV rate class also allows PG&E to track the revenues associated with this new transportation-related load relative to the costs incurred for these customers. This tracking is necessary to allow for the review of the rate design and measure any resulting cost shifts that can then be addressed in PG&E's 2023 General Rate Case (GRC) Phase 2. As will be described in further detail in Section F, the CEV related costs and revenues are not currently included in PG&E's GRC revenue and cost allocations. Given that these revenues are additional to previously approved forecast revenue, any costs collected for these customers above marginal costs will put downward pressure on all PG&E customers' rates.

1. Current Rate Offerings for CEV Customers

Before discussing the distinct characteristics and cost of service of CEV customers, it is important to outline the rate alternatives currently available to commercial customers with Electric Vehicles (EV). There are four existing rates for these customers: A-6, A-10, E-19 and E-20,[3] within the existing Small, Medium and Large Commercial and Industrial (C&I) classes.

- A-6, which is only available for customers under 75 kilowatts (kW) of maximum demand and less than 150,000 kilowatt-hours (kWh) annual load has a customer charge and time-differentiated volumetric charges, but no demand charges.
- A-10, which is for customers greater than 75 kW of maximum demand, but less than 500 kW of maximum demand, includes customer charges, demand charges and time-differentiated volumetric charges, with the demand charges designed to collect transmission and seasonal, non-time-differentiated generation and distribution costs. The A-10 rate schedule has options for Primary and Secondary voltage service.

[3] PG&E's small general service rate, A-1, is not applicable for customers purchasing power to serve EV charging, per D.11-07-029, as the Time-of-Use (TOU) differential in the rate does not sufficiently encourage off-peak charging.

- Finally, E-19 and E-20, which are available to customers with greater than 500 kW or 1,000 kW of maximum demand respectively, also include customer charges, demand charges, and time-differentiated volumetric charges. However, for both E-19 and E-20, demand charges are complex with significant seasonal peak, partial-peak and maximum demand charges, and they are designed to collect transmission costs, as well as seasonal and time-differentiated generation and distribution costs. It is important to note that these customers typically have high load factors, and therefore, these customer groups advocate to include significant percentages of cost recovery in demand charges. The E-19 and E-20 rate schedules also have options for Primary and Secondary voltage service.

To assess these current options for CEV customers compared to the new CEV rate, the revenue recovery by type of cost was reviewed for the current rates and customers classes available to CEV customers. Table 2-1 below shows the results. These results are based on PG&E's proposed 2019 Annual Electric True-Up (AET) revenue recovery.[4] These revenue allocations are as follows:

TABLE 2-1
COST ALLOCATION BY RATE (2019 AET)
(MILLIONS OF DOLLARS)

Line No.	Rate Component	A-6 + A-10 S		E-19 + E-20 P		E-19 + E-20 S	
1	Generation	$480.6	48%	$243.5	53%	$243.5	53%
2	Distribution	310.6	31%	112.0	24%	112.0	24%
3	Transmission	121.6	12%	54.0	12%	54.0	12%
4	Non-Bypassable	98.9	10%	51.9	11%	51.9	11%
5	Total	$1,011.7	100%	$461.4	100%	$461.4	100%

Table 2-1 shows that, for all classes, approximately 12 percent of the revenue collected is for Transmission and about 11 percent for Non-Bypassable Charges (NBC). The remaining 77 percent is collected through generation and distribution, with different percentages for A-6 and

4 PG&E filed its Preliminary AET advice letter 5376-E on September 4, 2018.

A-10 vs E-19 and E-20, with the difference explained by different revenue allocation factors for these customer groups.

Using current rates, the expected revenues collected from the new CEV rate customers are shown in Table 2-2 below:

TABLE 2-2
COST ALLOCATION TO CEV CUSTOMERS UNDER CURRENT RATES
(MILLIONS OF DOLLARS)

Line No.	Rate Component	E-CEV-S		E-CEV-L S		E-CEV-L P	
1	Generation	$6.1	55%	$12.6	37%	$2.0	12%
2	Distribution	3.2	29%	13.8	40%	9.5	56%
3	Transmission	1.0	9%	6.4	19%	4.2	25%
4	Non-Bypassable	0.8	7%	1.3	4%	1.3	8%
5	Total	$11.1		$34.2		$17.0	

Comparing these results to those in Table 2-1, Table 2-2 shows that this group of customers are allocated a disproportionate amount of costs using the current rate structure for their class. For example, note that for customers that would take service under the E-CEV-L S rate 19 percent of the revenues collected are for transmission, compared to the 12 percent for each of the current classes. Also, NBCs are significantly lower (between 4-9 percent of revenues) than those collected from current rate classes (approximately 11 percent). Given NBCs are volumetric and meant to evenly spread costs across all rate classes, this unusually lower level of revenues collected for this cost category, relative to total revenues collected, shows these customers are paying significantly more toward fixed costs than other C&I rate classes. These differences cannot be explained by differences in marginal costs, because these rates are designed to collect marginal costs through variable volumetric and demand charges and fixed costs through non-peak demand charges and customer charges. Instead, these differences imply that this customer group is allocated a disproportionate amount of fixed costs due to the combination of the existing rate structure and the CEV rate class load profiles. These findings justify the need to review the load profiles and cost structure for these customers vs the C&I rate classes.

2. Need to Review and Revise Differences Between CEV vs. Traditional C&I Customers' Load Profiles and Cost Structure

There are several notable differences between CEV customers and traditional C&I customers. First, as discussed in Chapter 1, the CEV class load shape is generally consistent across days, months, and seasons. The charging profiles for commercial fleets, large scale public charging, and multi-family charging are not heavily influenced by weather or other seasonal factors. Second, for several of the customer groups within this rate class, the customer consumption behavior is naturally conducive to volumetric price signals, as charging can be scheduled within hours during which the vehicle is idle, which tends to also coincide with excess renewable generation or low system loads. Third, the load factor for this customer group is naturally low at this time, but is expected to improve with increased EV charger utilization as the EV market expands.

Conventional practice for offering optional rates is to create a "revenue neutral" rate option for customers in a rate class. However, the load shape and cost of service for a CEV rate class is so different from the Small, Medium and Large C&I customers classes that creating a "revenue neutral" rate would result in a rate structure that is impractical, lacks customer acceptance and is not cost of service-based. This is driven by two key factors: first, the CEV rate class has a significantly lower load factor than Medium to Large C&I rate classes, and second, the rate design for Medium to Large C&I rate classes is designed to collect significant fixed cost revenues from demand charges versus variable energy charges.

Current rate design for Medium to Large C&I customers is targeted to recover fixed costs through maximum demand charges and some TOU-dependent costs through peak demand charges. The existing rate schedules (A-6, A-10, E-19 and E-20) are well suited for these high load factor customers and reflect cost of service for the average population of those customers. However, for CEV customers with such different load profiles and low load factors, the current rate structure would unfairly shift costs to them from high load factor customers. Further, many of these CEV customers can modify their energy use to respond to variable energy charges, but have limited means for decreasing maximum demand, and thus, the existing rate schedules do not meet this customer group's needs. Finally, applying existing rate schedules to the CEV rate class would then also hamper state policy objectives to increase adoption of EVs, because current charging options often have a low load factor.

By creating a new rate class for CEV customers, the actual marginal costs and related Equal Percent of Marginal Cost (EPMC) scalars that collect fixed costs can be directly allocated to this rate class, and rates can then be designed to effectively collect these costs using a rate structure that sends the right price signals for this customer group.

C. Cost Allocation to CEV Rate Class

PG&E used 2017 GRC Phase 2 Marginal Costs to determine the cost of allocation for the new CEV class. Specifically, there were three marginal costs considered:

1) Marginal Energy Costs (MEC) – based on 2020 forecasted marginal costs proposed in the 2017 GRC;
2) Marginal Generation Capacity Costs (MGCC) – based on generation capacity costs from the 2017 GRC; and
3) Marginal Distribution Capacity Costs (MDCC) – based on Primary, Secondary, New business and Customer marginal costs submitted in the 2017 GRC.

PG&E calculated marginal cost revenues separately for the Small CEV and Large CEV rates because the two groups have different assumed customer types and load profiles. These marginal cost revenue calculations are important since the cost of service for these customers is so different from most existing C&I customers.

In addition to the generation and distribution costs, transmission costs were also allocated using the transmission rates applied to the A-6 transmission rate.

The methodology for allocating each of these cost types is described in more detail below.

1. Proposed TOU Periods

The first step in allocating marginal costs is to determine the TOU periods and any seasonal differentiation. This determination was done using the hourly energy (kWh) class profiles outlined in Chapter 1, Section C.

For this rate, no seasonal differentiation is proposed for rate design. This is because, as noted above, the CEV class load shape is generally consistent across days, months, and seasons and setting annual time-differentiated rates would enable better customer acceptance and understanding.

The time periods (TOU periods) were then set based on optimizing the capture of the most expensive MEC hours in the peak period and the least expensive MEC hours in the Super Off-Peak (SOP) period, while maintaining only three periods. To that end, the periods defined for this rate are as follows:

- Peak Hours: 4 p.m. to 10 p.m. all days (weekends and weekdays)
- SOP Hours: 9 a.m. to 2 p.m. (weekends and weekdays)
- Off-Peak Hours: All other hours

These compare to recently-adopted TOU periods for the C&I class, which are as follows:

- Peak Hours: 4 p.m. to 9 p.m. all days (weekends and weekdays)
- Partial Peak Hours: 2 p.m. to 4 p.m. AND 9 p.m. to 11 p.m. all summer days
- SOP Hours: 9 a.m. to 2 p.m. all days, March through May
- Off-Peak Hours: All other hours

The major changes are the addition of 10 p.m. to the peak period and elimination of the partial peak hours and having the 2-3 p.m. and the 10-11 p.m. hours move to the off-peak. Also, the SOP period is extended to the entire year. Based on 2020 MEC data provided in the 2017 GRC Phase 2, the 10 p.m. hour is forecasted to be, on average, the 6th most expensive hour (with the 4 p.m. hour as the 7th). Further, the 9 a.m. to 2 p.m. hours are forecasted to be the five most inexpensive hours, on average. Therefore, it is reasonable to modify the TOU periods, given the goals of decreasing TOU periods and no seasonal differentiation for this class.

2. Marginal Generation Costs Allocation

The marginal cost revenues for these marginal costs were computed consistently with the calculation of marginal cost revenues in the 2017 GRC Phase 2. Specifically, MEC revenues are calculated in two steps. First, the hourly MEC revenues are calculated by multiplying the hourly MEC cost by the hourly kWh for the class using the class profiles outlined in Chapter 1, Section C. Second, these revenues are summed for each of the proposed TOU periods (as outlined in Chapter 2, Section C.1. above). To then calculate the Primary and Secondary MEC, the Transmission-level costs were scaled for losses.[5]

MGCC revenues to be applied to each proposed rate schedule were estimated by multiplying the estimated CEV portion of system Peak Capacity Allocation Factor (PCAF) by the marginal generation cost revenues presented in the 2017 GRC.[6] The CEV portion of system PCAF was estimated by scaling the E-19 system PCAF amounts by the ratio of CEV to E-19 load in each hour.

The total generation costs were computed by applying the 2017 GRC Generation EPMC of 2.45 to the sum of the MEC and MGCC revenues, with the fixed costs then being the difference between total generation costs and marginal revenues.

3. Marginal Distribution Cost Allocation

The MDCC revenues were applied to each rate schedule similarly to the MGCC revenues by taking the load weighted ratios of the CEV distribution PCAFs to the E-19 distribution PCAFs. The main difference is that these ratios were then applied to the A-10 marginal distribution cost revenues for

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5 Primary at approximately 1.9 percent and Secondary at approximately 6.9 percent as filed in PG&E's 2017 GRC Phase 2.

6 Specifically, for the CEV-S rate, the load weighted ratio of the CEV-S PCAF equivalent and E-19 S PCAF was applied to the E-19 S MGCC revenues. Next, for the CEV-L S rate, the load weighted ratio of the CEV-S PCAF equivalent and E-19 S PCAF was applied to the E-19 S MGCC revenues. Finally, for the CEV-L S rate, the load weighted ratio of the CEV-L PCAF equivalent and E-19 P PCAF was applied to the E-19 P MGCC revenues.

the CEV-S rate, while the E-19 marginal distribution cost revenues were used for the relevant CEV-L rate.[7]

Like Generation fixed costs, the fixed distribution costs were computed as the difference between total distribution costs (using the 2017 GRC Distribution EPMC of 1.76), and marginal revenues.

4. Transmission Cost Allocation

For transmission, the allocated costs were computed as the A-6 Transmission Operator (TO) rate plus the sum of transmission balancing accounts[8] times the estimated kWh for each rate. This approach reflects the equivalent retail costs of transmission. That is, the California Independent System Operator charges the utility specific TO rate, plus reliability services and the Transmission Access Charges on the gross system load. For other Medium and Large customer rates (e.g., A-10 and E-19 and E-20), these costs are built into demand charges based on the transmission costs to be allocated to those rate classes, divided by the class demand billing determinants. The transmission rate is not time-differentiated for these customers and is collected via a maximum demand charge. This is because these customers prefer demand-based charges for transmission. However, since the load profiles of the CEV class are more similar to those of the Small Commercial class, PG&E proposes using the purely volumetric transmission rate from Small Commercial for CEV rates.

5. Results of Cost Allocations

The revenue allocation was done for both the Small and Large CEV rates, including secondary (E-CEV-L S) and primary (E-CEV-L P) voltages for the large rate. The results are shown in Table 2-3 below.

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7 Specifically, for the CEV-S rate, the load weighted ratio of the CEV-S distribution PCAF equivalent and E-19 S distribution PCAFs was applied to the A-10 Primary, Secondary and New Business revenues. Next, for the CEV-L S rate, the load weighted ratio of the CEV-S distribution PCAF equivalent and E-19 S distribution PCAFs was applied to the E-19 S Primary, Secondary and New Business revenues. Finally, for the CEV-L P rate, the load weighted ratio of the CEV-L distribution PCAF equivalent and E-19 P distribution PCAFs was applied to the E-19 P primary and new business revenues.

8 Transmission Access Charge Balancing Account, Transmission Revenue Balancing Account, End-use Customer Refund Balancing Account, and Reliability Services Balancing Account.

TABLE 2-3
COST ALLOCATION RESULTS
(MILLIONS OF DOLLARS)

Line No.	Rate Component	E-CEV-S		E-CEV-L S		E-CEV-L P	
1	Generation	$3.3	47%	$6.8	51%	$1.2	51%
2	Distribution	1.9	27%	3.4	25%	0.6	25%
3	Transmission	1.0	14%	1.7	13%	0.3	14%
4	Non-Bypassable	0.8	12%	1.3	10%	0.2	10%
5	Total	$7.0		$13.2		$2.3	

These results are consistent with the ratios of cost shown in Table 2-1 for the C&I customer groups.

D. PG&E's Small CEV Rate Proposal

PG&E proposes a new rate, E-CEV-S, for small CEV chargers. The rate consists of a subscription rate and time-differentiated energy rates. It applies to separately-metered EV charging sites with a maximum load of 100 kW.

1. E-CEV-S Subscription Rate

The E-CEV-S Subscription rate is per 10 kW of connected load. That is, this charge is applied to each 10 kW of connected load, up to 100 kW. For example, if a customer has 56 kW of connected load, the billing determinant for the subscription rate is 6 units (56/10, rounded up to the nearest 10 kW or 60 kW). The subscription rate is a per month charge. The unbundled rate includes separate subscription charges for generation and distribution and no subscription charge for transmission or other charges.

The distribution subscription charge was designed to capture all non-variable distribution costs. That is, all but Primary marginal distribution costs, including the EPMC. The generation subscription charge was set to the fixed charges times the proportion of PCAF in the non-peak to ensure these fixed costs are collected despite usage patterns.

Customers will be able to choose a subscription below their connected load unit level of service if they can manage their load to that level (e.g., for the example above, they could choose a subscription of only 50 kW connected load). If a customer's actual maximum demand in a month exceeds the subscription level, the customer will pay an overage fee equal to 200 percent of the equivalent monthly kW subscription rate for all additional units of subscription. For example, if this example customer elected a 50 kW level of service, but maximum demand was 56 kW, the customer would be charged their selected subscription rate (rate times 5 units), plus an overage fee of 1 unit times 200 percent of the subscription rate.

The overage fee was designed to incent customers to choose their optimal subscription service while dis-incenting gaming. An overage fee is consistent with other PG&E rate options that apply set service levels.

2. E-CEV-S Volumetric Rates

The E-CEV-S volumetric rates have been designed to send significant price signals to customers to consume in the non-peak hours. To that end, this rate has the addition of a super-off-peak rate that applies between 9 a.m. and 2 p.m. every day, all year. The peak hours for this class are defined as 4 p.m. to 10 p.m. every day and the off-peak hours are all other hours. PG&E is proposing constant peak, off-peak and SOP prices throughout the year, rather than seasonal rates. Furthermore, PG&E expects EV charging load to be highly price-responsive, relative to other system loads, so a price signal is required to discourage consumption during that hour.

The rates have four components: generation, distribution, transmission and NBCs. The generation volumetric component consists of the marginal generation cost by TOU plus the Power Charge Indifference Adjustment (PCIA). Fixed costs not collected in the subscription (e.g., the peak PCAF portion of fixed costs) are applied to the peak rate. Further, the marginal capacity costs are allocated to each time period using the system PCAF proportions in each period.

The distribution volumetric component collects only the primary distribution costs because all other costs are collected in the subscription charge. The allocation among TOU periods is based on the CEV distribution PCAF proportions.

Finally, the volumetric rate for transmission is set to the A-6 TO rate plus current transmission related balancing account volumetric rates. Also, the NBCs are set to the A-10 NBC rates. Table 2-4 below shows the PCIA and NBC rates that apply to the E-CEV-S rate.

TABLE 2-4
SMALL CEV PCIA AND NON-BYPASSABLE RATES

Line No.	Rate Component	
1	PCIA	$0.02466
2	NBCs	
3	PPP	0.01337
4	ND	0.00020
5	CTC	0.00097
6	ECRA	(0.00005)
7	DWR Bond	0.00549
8	NSGC	0.00167
9	Total NBCs	$0.02165

3. E-CEV-S Rate Proposal

The proposed rates for E-CEV-S are shown in Table 2-5.

TABLE 2-5
SMALL CEV RATE PROPOSAL
(E-CEV-S)

Line No.	Rate	
1	Subscription (per 10 kW)	$25.10
2	Energy Charges	
3	Peak (4 p.m. – 10 p.m.)	$0.30297
4	Off-Peak (all other hours)	$0.11800
5	SOP (9 a.m. – 2 p.m.)	$0.09266

The rate components are shown in Table 2-6.

TABLE 2-6
SMALL CEV RATE COMPOSITION
(E-CEV-S)

Line No.	Rate	Generation	Distribution	Transmission	NBCs	Total
1	Subscription Charge	$2.51	$22.60	–	–	$25.10
2	Peak	$0.24078	$0.01379	$0.02674	$0.02165	$0.30297
3	Off-Peak	$0.06402	$0.00559	$0.02674	$0.02165	$0.11800
4	SOP	$0.04012	$0.00415	$0.02674	$0.02165	$0.09266

E. PG&E's Large CEV Rate Proposal

PG&E proposes a new rate, E-CEV-L, for Large CEV charging. The rate consists of a subscription rate and time-differentiated energy rates. To account for the potential for different distribution level service connections, two rates were computed for E-CEV-L: Primary (E-CEV-L P), and Secondary (E-CEV-L S).

1. E-CEV-L Subscription Rate

The E-CEV-L Subscription rate is per 50 kW of connected load. That is, this charge is applied to each 50 kW of connected load. For example, if a customer has 560 kW of connected load, the billing determinant for the subscription rate is 12 units (560/50 rounded up). The subscription rate is a per month charge. There are separate subscription charges for generation and distribution and no subscription charge for transmission or other charges.

The distribution subscription charge was designed to capture all non-variable distribution costs. That is, all but primary marginal distribution costs, including the EPMC. The generation subscription charge was set to the percent of non-peak PCAF fixed charges to ensure these fixed costs are collected despite usage patterns.

As with the E-CEV-S rate, customers will be able to choose their connected load unit level of service (e.g., choose only 11 units or 550 kW connected load for the example above). In the event that a customer's actual maximum demand in a month exceeds the subscription level, the customer will pay an overage fee equal to 200 percent of the equivalent monthly kW subscription rate for all additional units of subscription. As with the E-CEV-S rate, the overage fee was designed to incent customer to choose their optimal subscription service while discouraging gaming.

2. E-CEV-L Volumetric Rates

The E-CEV-L volumetric rate has the same TOU periods proposed in the E-CEV-S rate. The actual rates differ reflecting the different cost allocations and billing determinants (amount of Peak, SOP and Off-Peak energy or kWh).

Table 2-7 shows the PCIA and the NBCs for the E-CEV-L rates.

TABLE 2-7
LARGE CEV PCIA AND NON-BYPASSABLE RATES

Line No.	Rate Component	E-CEV-L P	E-CEV-L S
1	PCIA	$0.02104	$0.02104
2	NBCs		
3	PPP	0.01173	0.01269
4	ND	0.00020	0.00020
5	CTC	0.00083	0.00083
6	ECRA	(0.00005)	(0.00005)
7	DWR Bond	0.00549	0.00549
8	NSGC	0.00155	0.00155
9	Total NBCs	$0.01975	$0.02071

3. E-CEV-S Rates Proposal

The proposed rates for E-CEV-L P are shown in Table 2-8.

TABLE 2-8
LARGE CEV RATE PROPOSAL
(E-CEV-L)

Line No.	Rate	Primary E-CEV-L P	Secondary E-CEV-L S
1	Subscription (per 50 kW)	$172.87	$183.86
2	Energy Charges		
3	Peak (4 p.m. – 10 p.m.)	$0.29526	$0.30267
4	Off-Peak (all other hours)	$0.10807	$0.11079
5	SOP (9 a.m. – 2 p.m.)	$0.08663	$0.08882

The rate components are shown in Table 2-9.

TABLE 2-9
LARGE CEV RATE COMPOSITION
(E-CEV-L)

Line No.	Rate	Generation	Distribution	Transmission	NBCs	Total
1	(E-CEV-L P)					
2	Subscription Charge	$15.74	$157.13	–	–	$172.87
3	Peak	$0.23552	$0.01325	$0.02674	$0.01975	$0.29526
4	Off-Peak	$0.05855	$0.00304	$0.02674	$0.01975	$0.10807
5	SOP	$0.03577	$0.00437	$0.02674	$0.01975	$0.08663
6	(E-CEV-L S)					
7	Subscription Charge	$17.60	$166.26	–	–	$183.86
8	Peak	$0.24459	$0.01063	$0.02674	$0.02071	$0.30267
9	Off-Peak	$0.06040	$0.00294	$0.02674	$0.02071	$0.11079
10	SOP	$0.03650	$0.00487	$0.02674	$0.02071	$0.08882

F. Tracking Cost of Service versus Recorded Revenues from the CEV Rate Class

In developing this rate, PG&E recognizes the potential for cost shifting, specifically from the allocation of fixed generation costs to the peak volumetric rate using PCAFs. That is, if those costs are put into the peak generation rate and the realized billing determinants are dramatically different from forecasted, then the collection of fixed costs could vary from forecasted, creating a cost shift. This cost shift would only affect generation revenue, and only occur in the event that customers charged less during the peak period than the forecast billing determinants.

It is important to note that even if the tracking shows a cost shift from this class to others, it is a hypothetical cost shift that would only be realized when the rate class is allocated total revenues allocated among all classes in the 2023 GRC Phase II. This is because this class is being established as an "incremental" rate class with incremental revenue allocated based on expected future cost of service, and is specifically designed to recover marginal generation, distribution and transmission costs, and the fixed distribution costs. This will result in an over collection of generation, distribution, and non-bypassable revenues that will then flow into balancing accounts and be allocated back accordingly as part of PG&E's Annual Electric True-Up. Only until this rate class becomes a class within the total revenue allocation process—typically done in PG&E's GRC Phase 2—will there be a risk of cost shift. In 2023, when PG&E's next GRC filing will occur, PG&E will have a more mature understanding of CEV customer load shapes, relative adoption levels across different CEV customer segments, and the overall state of the CEV market. PG&E will leverage that information, and input from other stakeholders, to propose changes to this rate structure which strike a balance between minimizing cost shifting, while also supporting continued adoption of electric transportation.

Further, PG&E proposes to implement a mechanism to track the difference between: (1) actual cost of service, plus contribution to fixed costs; and (2) actual revenues, and proposes to collect that cost shift from customers on an equal-cents-per-kWh basis. This mechanism is described below.

For each rate (E-CEV-S, E-CEV-L P, and E-CEV-L S), a shadow generation rate has been calculated that is based on the pure load weighted allocation of fixed costs by TOU. These rates are shown below.

TABLE 2-10
CEV SHADOW GENERATION RATES

Line No.	TOU Period	E-CEV-S	E-CEV-L P	E-CEV-L S
1	Peak	$0.11418	$0.11977	$0.12428
2	Off-Peak	$0.08896	$0.09574	$0.09906
3	SOP	$0.06506	$0.07297	$0.07516

At this time, PG&E is only requesting the tracking of the shadow rates to the actual costs to track and monitor any cost shifts to or from the CEV rate class.

After the 2023 GRC Phase 2, PG&E will re-examine the rate option and determine if cost shift has occurred. If a cost shift has been identified, PG&E will make a proposal in its 2023 GRC Phase 2 to either track and separately charge for this cost shift to all benefiting customers, or reset rates to eliminate the cost shift.

G. Conclusion

In conclusion, PG&E respectfully requests approval of PG&E's CEV rate proposal. Specifically, PG&E requests:

1) Adoption of the new CEV rate class as proposed in Section B;
2) Adoption of the revenue allocation for three rates for this rate class, as proposed in Section C;

3) Adoption of the CEV-S rate, as described in Section D;
4) Adoption of the CEV-L rate and two voltage level options for Primary and Secondary voltage outlined in Section E; and
5) Adoption of the CEV Cost of Service Tracking mechanism, as described in Section F.

PG&E's the CEV rate proposal provides an innovative rate structure that will facilitate the adoption of CEV technologies and promote the state's clean energy goals without creating an unacceptable and unsustainable cost shift to non-participating customers. In fact, with the growth of this rate class, aided by this rate proposal, the allocation of fixed costs across this additional load should exert downward pressure on all rates, and thus, support a clean energy California with affordable rates.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MARGOT C. EVERETT

Q 1 Please state your name and business address.

A 1 My name is Margot C. Everett, 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 or the Company).

A 2 I am the Senior Director responsible for the Rates and Regulatory Analytics Department. This department consists of: Rate Design; Load Forecasting; and Rate Data Analytics. Department responsibilities include:

- Designing electric and gas rates;
- Supporting rates-related cases, such as the Gas Cost Allocation Proceeding, General Rate Case Phase 2, and Rate Design Window;
- Providing data analytics and analysis and systems support;
- Analyzing customer: sales; load; rates; usage; and billing information.
- Developing the Company's electric and gas annual load forecasts, hourly load forecasts, peak day forecasts, and performing load research analyses, including developing the necessary analyses to comply with California Energy Commission requirements on load research;
- Analyzing customer load data and providing data analytics to support rate design and customer programs;
- Working with lines of business to develop rate and customer programs policy and case strategies;
- Managing tariffs and advice letter filings;
- Forecasting, revenue requirements and rates;
- Managing regulatory operations; and
- Managing annual electric and gas true-up advice filings.

Q 3 Please summarize your educational and professional background.

A 3 I received a Master of Science degree in Applied Economics from the University of California, Santa Cruz in 1985. I have over 30 years of experience in the energy industry with roles in: Regulatory Affairs; Risk Management and Compliance; Demand-Side Management; and Wholesale Power Contracts. My utility experience includes: PG&E; PacifiCorp;

PPM Energy; and Constellation Energy. I also have experience with energy consultants Energetics and Hagler Bailley.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Commercial Electric Vehicle Rate Proposal:

- Chapter 2, "Commercial Electric Vehicle Rate Proposal."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF CALDER J. SILCOX

Q 1 Please state your name and business address.

A 1 My name is Calder J. Silcox, 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 an Expert Business Analyst in PG&E's Clean Transportation group within the Grid Integration and Innovation department. My responsibilities include state policy and utility program strategy related to Electric Vehicles (EV), with a focus on customer engagement and rates.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree from the University of Pennsylvania 2012, studying Science, Technology and Society, with a focus in Energy, Environment and Technology. I have worked at PG&E since 2012, working for the office of the Senior Vice President of Customer Care until 2014. From 2015 through 2017, I oversaw customer outreach and policy engagement related to EVs within PG&E's Customer Energy Solutions department. In 2018, I joined the Clean Transportation group, working on similar maters.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Commercial Electric Vehicle Rate Proposal:

- Chapter 1, "Commercial Electric Vehicle Rate Design Policy and Proposal Overview."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX B

ELECTRIC POWER RESEARCH INSTITUTE

COMMERCIAL ELECTRIC VEHICLE RATE DESIGN: STAKEHOLDER INTERVIEW RESULTS

Commercial Electric Vehicle Rate Design

Stakeholder Interview Results

2018 TECHNICAL REPORT

Commercial Electric Vehicle Rate Design

Stakeholder Interview Results

3002014013

Final Report, October 2018

EPRI Project Manager
E. Erben

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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

EXECUTIVE SUMMARY

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.

EXECUTIVE SUMMARY

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 key consideration 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.

2
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.

3
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.

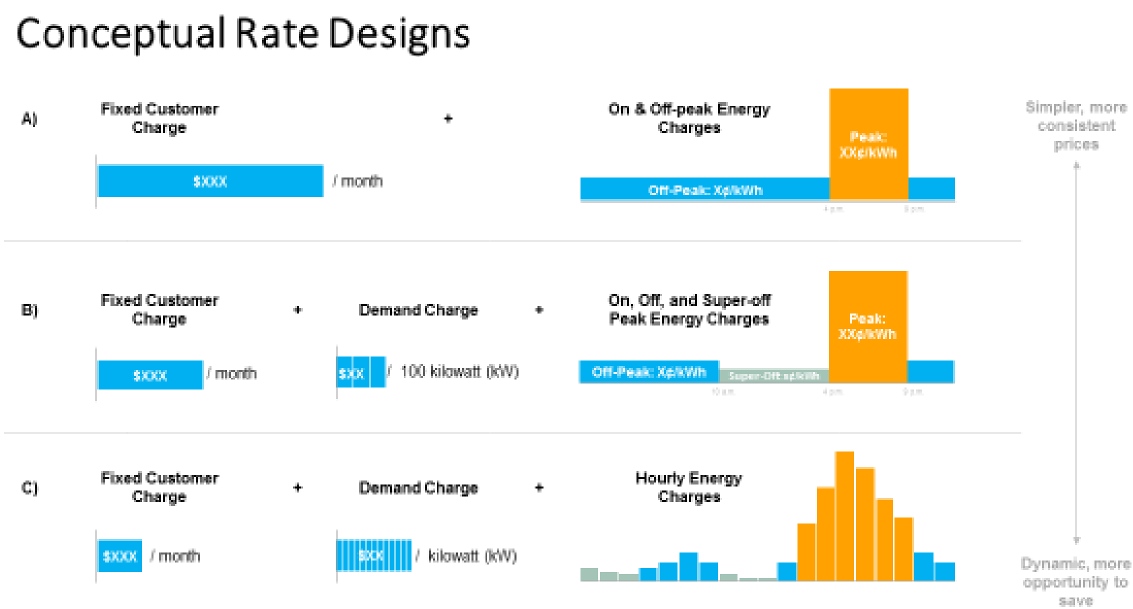

Figure 4-1
Conceptual Rate Designs

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). Responses varied 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.

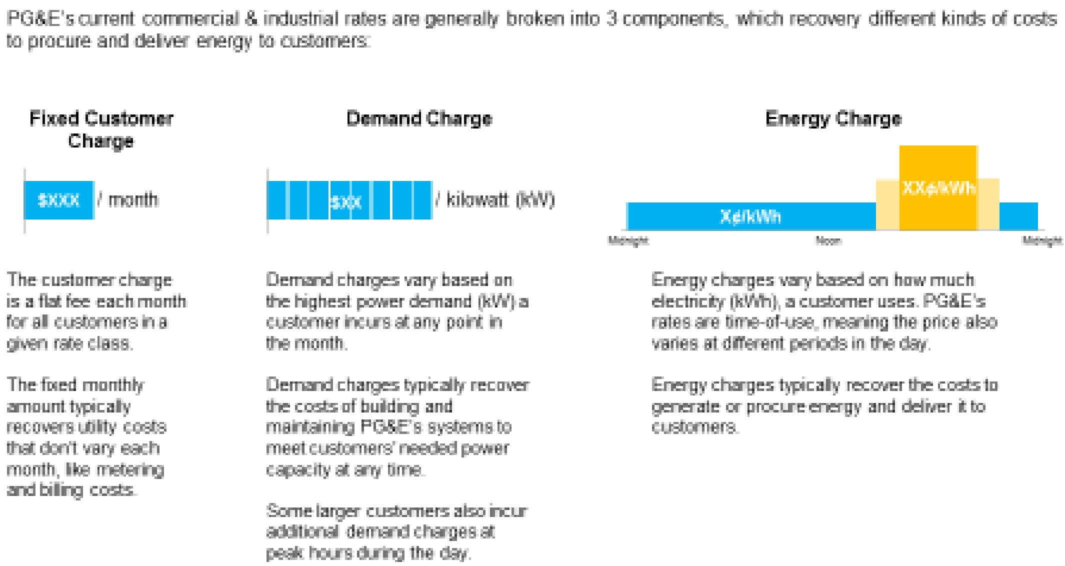

Figure B-1
First visual aid used in coordination with survey questionnaire

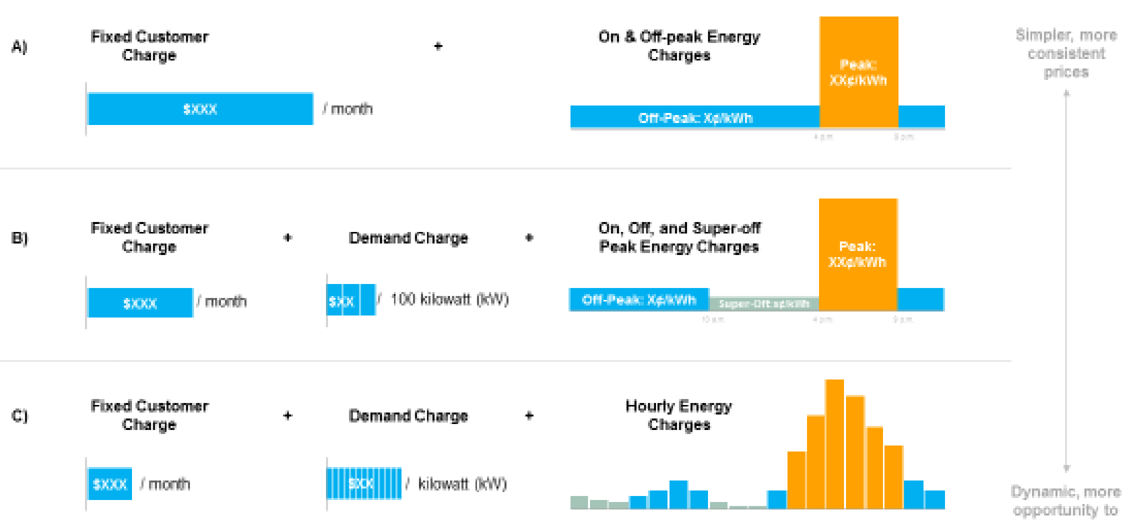

Figure B-2
Second visual aid used in coordination with survey questionnaire

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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