Application: 19-11-
(U 39 M)
Exhibit No.: (PG&E-3)
Date: November 22, 2019
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2020 GENERAL RATE CASE PHASE II

PREPARED TESTIMONY

REVENUE ALLOCATION AND RATE DESIGN

PACIFIC GAS AND ELECTRIC COMPANY
2020 GENERAL RATE CASE PHASE II
EXHIBIT (PG&E-3)
REVENUE ALLOCATION AND RATE DESIGN

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CHAPTER 1
REVENUE ALLOCATION AND RATE DESIGN INTRODUCTION

A. Introduction

The second phase of Pacific Gas and Electric Company's (PG&E) test year (TY) General Rate Case (GRC) Phase II is the California Public Utilities Commission's (CPUC or Commission) opportunity to update electric marginal costs and revise the associated revenue allocation and rate design for each customer class. The Commission's decision in this proceeding will set marginal cost, revenue allocation, and rate design policies for the next three years, including the rate design that will ultimately be applied to PG&E's authorized revenue requirements, which are determined in other proceedings.

Rate design in Phase II proceedings can be generally described to include marginal cost of service studies, revenue allocation and rate design.[1] PG&E's marginal cost of service studies are used to support revenue allocation and rate design presented in this exhibit. Revenue allocation is the step in the rate design process through which individual revenue requirement functions (e.g., distribution or generation) are assigned (or allocated) to each rate group or customer class. Revenue allocation results provide the target levels of revenue based on the fully allocated cost of service. PG&E's proposals for revenue allocation adjust revenue for each customer group to better reflect the fully-allocated cost of service results.

The next step in the rate design process is to derive the prices, or rates, that will apply to each rate schedule based on the allocated revenue. PG&E's proposals in this proceeding retain the already authorized time-of-use (TOU) periods and seek to minimize rate design changes, such as changes to TOU differentials and customer charge levels, to provide a period of stability in rates as discussed further below.

PG&E's proposals in this exhibit are based on July 1, 2019 rates and adopted 2019 test year sales. Present rates used in this exhibit for comparison with the proposed rates have been recalculated, where necessary, so that the

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1 See Exhibit (PG&E-2) for PG&E's cost of service studies.

comparison to proposed rates will reflect only the requests in this proceeding. For example, PG&E has developed present Commercial and Industrial (C&I) and present Agricultural rates with the revised TOU periods (as authorized by D.18-08-013 and D.19-05-010) to reflect July 1, 2019 revenue levels, even though the rates with those new, later TOU periods had not yet been implemented by July 1, 2019. Similarly, present rates for Schedules E1 and EL-1 were recalculated to reflect July 1, 2019 revenue levels and the change to a four-month summer season (and an eight-month winter season) which was adopted by D.18-08-013, even though the change to a four-month summer season did not occur until October 1, 2019.[2] PG&E has made these adjustments so that the rate changes reflected in proposed rates and bill comparisons are based on the changes requested in this proceeding.

In Section B of this chapter, PG&E describes its rate design policy objectives. PG&E's guidelines for revenue allocation and rate design are described in Sections C and D, respectively, setting the stage for specific revenue allocation and rate design proposals in the chapters that follow.

The remainder of this chapter is organized as follows:

- Section B – Rate Design Objectives
- Section C – Revenue Allocation
- Section D – Rate Design
- Section E – Organization of the Exhibit
- Section F – Conclusion

B. Rate Design Objectives

In this proceeding, PG&E seeks to make progress toward rates that are more cost-based, more economically efficient, and promote greater equity among customers, as part of a six-year path forward to fully allocating cost to each customer class. However, efforts to meet these goals must invariably balance multiple competing objectives including: compliance with statutes and CPUC rules, rate stability, understandability, and customer acceptance. PG&E's

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2 PG&E notes that present rates for Schedule EL-1 shown for illustration in this proceeding were developed with a 35.5 percent California Alternate Rates For Energy (CARE) discount, while proposed rates provide for a 35 percent discount which will be implemented in 2020 pursuant to D.15-07-001.

revenue allocation and rate design proposals are guided by the following objectives.

1. Cost of Service

Public Utilities (Pub. Util.) Code Section 451 requires that the Commission establish rates that are "just and reasonable." Traditionally, "just and reasonable" rates are based on cost of service. The costs of providing utility services vary with customer usage characteristics and with the facilities needed to serve a customer. The Commission has a long history of using Equal Percent of Marginal Cost (EPMC) to establish a cost-based allocation of revenue among customer classes.[3]

In this proceeding, PG&E proposes using the EPMC approach for generation and distribution revenue allocation. Under this approach, each customer class is assigned revenue responsibility for generation and distribution, respectively, in proportion to the marginal cost of generation and distribution service for that class, such that the total revenue for each component is collected.

The Commission has consistently held that utilities' underlying marginal costs should be the basis for revenue allocation and rate design so that customers receive clear and appropriate cost-based price signals associated with their usage characteristics.[4] Doing so encourages more efficient use of energy and the delivery system. Further, appropriate price signals help prevent un-economic decision-making by customers. As noted in Decision (D.) 18-08-013 on PG&E's 2017 GRC Phase II:

> The advantages of the EPMC approach are its simplicity, transparency and fairness. The equation…is simple and transparent, but *it relies on an accurate assignment of marginal costs to each class*. It is fair because it assigns the non-marginal costs to each class proportionate to

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[3] See Exhibit (PG&E-2), Chapter 1 for background with regard to the use of marginal cost for cost of service. PG&E uses the terms "full cost" and "full EPMC" revenue responsibility interchangeably in this exhibit.

[4] In D.15-07-001, addressing residential rate reform, the Commission described 10 rate design principles. Many support cost-based rate design. For example, (2) Rates should be based on marginal cost. (3) Rates should be based on cost causation principles. (5) Rates should encourage reduction of both coincident and non-coincident peak demand. (7) Rates should generally avoid cross subsidies, unless the cross subsidies appropriately support explicit state policy goals. (9) Rates should encourage economically efficient decision making. (See D.15-07-001, p. 28.)

their marginal cost responsibility, which means that those classes that impose the greatest additional (or new) costs on the utility also bear the greatest burden for the existing utility costs. This creates and incentive for every class to avoid imposing additional (or new) costs on the utility, which in theory keeps rates for all classes as low as possible.[5]

The Commission has found "that EPMC-based rate design is:

- Cost-based;
- A reasonable balance between equity and efficiency in revenue allocation and ratesetting; and
- The Commission's preferred starting point for evaluating the reasonableness of revenue allocation and rate design."[6]

The EPMC method makes good policy sense for distribution and generation because it provides a more equitable and economically efficient basis for the allocation of PG&E's distribution- and generation-related revenue requirements.[7]

As the Commission noted above, it is vital that the assignment of marginal costs to each class be as accurate as possible. Marginal costs have not been fully litigated since PG&E's 1993 and 1996 GRCs, as the parties have been able to settle most or all issues in Phase II proceedings since then. However, such settlements typically involve caps and floors that have moderated movement of classes to their full cost basis. PG&E here proposes a process for moving all customer classes gradually to their full cost of service over a period of six years, and in this proceeding, asks the CPUC to approve the rate changes necessary to implement the first three years of that transition. PG&E would then reassess cost of service in its 2023 GRC Phase II and propose the continuation of its transition plan in that proceeding.

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5 D.18-08-013, pp. 14-15 (emphasis added). That decision also noted that "D.96-04-050 established EPMC as the Commission's preferred starting point for cost-based rate design and was one of the final Commission decisions to fully litigate marginal costs, revenue allocation, and rate design issues for a major electric utility…. [because o]ur adoption of settlements is not precedential… the findings and conclusions of D.96-04-050 remain valid and should be regarded as the starting point for the Commission's evaluation of whether revenue allocation and rate designs are reasonable." (D.18-08-013, p. 19.)

6 D.18-08-013, pp. 19-20.

7 D.18-08-013, p. 17.

2. Rate Stability

While it is important to move toward more appropriate, economically-efficient and cost-based price signals, this goal should be balanced with a concern for mitigating change which may include sudden and unduly large bill increases. Historically, mitigation of change has included a combination of the moderation of the changes made in both revenue allocation and in rate design. As the Commission noted in PG&E's last GRC Phase II:

> Of course, other considerations may lead us to find that deviations from EPMC-based and marginal cost-based revenue allocation and rate designs are reasonable….. In the revenue allocation context, 'caps and floors' may be used to limit the rate impact of changes to a class's revenue allocation from one GRC Phase II proceeding to the next. Similarly, in the rate design context, fully cost-based rates may be mitigated in order to ensure that bill impacts between GRC Phase II cycles are not extreme. But an EPMC-based and marginal cost-based revenue allocation and rate design is our favored starting point.[8]

In this proceeding, PG&E moves to adjust revenue allocation, but PG&E specifically acknowledges the substantial changes that customers will be experiencing as a result of already adopted rate initiatives over the next few years. For that reason, PG&E recommends minimizing changes in rate design at this time.

In PG&E's 2018 Rate Design Window (RDW) (D.19-07-004), the Commission has continued the process of reevaluating Residential rates with the goal of moving forward to default Residential customers to TOU rates. The default of Residential customers to PG&E's new default TOU rate is currently planned to begin in October 2020 and continue in waves for a period of up to eighteen months, ending in 2022. To ensure that changes in rate design do not disrupt this process, PG&E proposes to implement many of its rate design proposals in 2023.

In D.18-08-013, the Commission approved new seasonal periods and TOU periods for Non-Residential rates. In addition, in that decision the Commission approved illustrative rates that established the relationships in rates that would be used to implement the rates with new TOU periods. In D.19-05-010, the Commission further considered Agricultural rates and

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8 D.18-08-013, p. 20.

adopted enhancements to the illustrative rates adopted by D.18-08-013 that will be used to implement the new Agricultural rates. These new rates were made available to C&I customers on a voluntary basis beginning in November 2019 (expected beginning in March 2020 for Agricultural rates). If customers do not opt-in to the new rates with new TOU periods, they will be moved to rates with new TOU periods on a mandatory basis beginning in November 2020 for C&I customers (expected beginning in March 2021 for Agricultural customers).

PG&E currently believes a decision in this proceeding is not likely to be issued before second quarter of 2021 and could be later. Thus, rates with new TOU periods would become mandatory for Non-Residential customers only a short time before a decision is expected in this proceeding. If rates were significantly altered by a decision in this proceeding, the period the rates were available on an opt-in basis would have much less value in informing and educating customers about the final new rates. Such a change could well jeopardize the extensive efforts taken to provide for a smooth transition to the mandatory new TOU periods for Non-Residential customers. Accordingly, PG&E generally requests that the Commission adopt Non-Residential rates in this proceeding that retain substantially the same structure, with similar rate relationships, as authorized by D.18-08-013 and D.19-05-010.

3. Understandable and Provide Meaningful Options

Along with economically efficient, cost-based pricing, rates should empower customers to take actions to control their energy expenses. Rates should be meaningful in that they allow customers to make choices that permit operational changes that will allow them to reduce their energy expenses. In order to accomplish this objective, rates should be understandable and as simple as possible while retaining appropriate price signals. Rate design proposals should seek to balance the increasing complexity of rates, with the need to provide rates that are understandable and empower customers to take actions to reduce their energy expenses.

Rates should also be as transparent as possible. This means unbundled rates (that is, rates unbundled by component such as distribution, Public Purpose Programs (PPP) and generation) should recover costs that are correctly captured within each unbundled component. For example, distribution and generation rates should not be used to recover costs that are associated with providing a public benefit program that might be more appropriately billed with PPP charges. To this end, PG&E recommends in this proceeding that a limited number of programs be reclassified for recovery with PPPs. In addition, in this proceeding PG&E proposes to separately identify the Power Charge Indifference Adjustment (PCIA) as a separate component of bundled generation rates.

C. Revenue Allocation

In this proceeding, PG&E is proposing changes in revenue allocation and rate design for generation, distribution and PPP. In addition, the proposed changes to rates affect both the residential Conservation Incentive Adjustment (CIA) rate and the California Alternate Rates for Energy (CARE) surcharge which is a component of the PPP rate.[9] PG&E's proposals for revenue allocation are described in detail in Chapter 2 of this exhibit.

PG&E's objectives for revenue allocation in this proceeding are: (1) to better align cost of service for each customer class through class level revenue allocation; and (2) to achieve greater transparency in rates and charges for policy-related initiatives mandated by both the CPUC and the state of California.

As discussed in Exhibit (PG&E-1), even though cost of service has been developed at a more disaggregated level separately recognizing the costs and benefits of Net Energy Metering (NEM) customers, the revenue allocation changes proposed in this proceeding are based on the current customer classes and are fully constrained to ensure that the current rules for NEM rate design are satisfied. This means that rates proposed for NEM customers in this proceeding will continue to be equal to the rates paid by Non-NEM customers. The approach to revenue allocation is summarized in the sections below.

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[9] Total rates consist of a number of different functions including: distribution; transmission; generation; Nuclear Decommissioning; PPP; Competition Transition Charges; the New System Generation Charge (NSGC); Energy Cost Recovery Amount; Department of Water Resources Bond; and greenhouse gas allowance volumetric and by semi annual credits. In addition, Direct Access (DA) and Community Choice Aggregation (CCA) customers pay the PCIA and the Franchise Fee Surcharge. Transmission charges are regulated by the Federal Energy Regulatory Commission and are not subject to change in this proceeding. PG&E's proposals for change in this proceeding are limited to rates for PPP, generation and distribution.

1. Generation Revenue Allocation

PG&E proposes to allocate generation revenue to bundled customers in two pieces. First, PCIA revenue for each bundled customer group is determined based on the current PCIA for bundled customers (that is, bundled customers are subject to the current PCIA vintage and PCIA rates). Second, the remaining generation revenue is allocated to bundled customers based on generation marginal costs described in more detail in Exhibit (PG&E-2).

In the past, the PCIA was identified separately only for DA and CCA customers. Even though these same costs had been recovered in bundled generation rates, the PCIA for bundled customers had not been identified separately. In order to support the goals of transparency and equity of cost allocation among bundled, DA and CCA customers, PG&E proposes to allocate the PCIA separately to bundled customers.[10] In addition, PG&E proposes to separately identify this rate element in each rate schedule, but to continue to combine this item with generation for bundled customer billing.

Generation marginal cost at the class level is the sum of marginal costs of generation received from NEM customers, the generation delivered to NEM customers and the generation delivered to non-NEM customers. Marginal generation capacity costs, marginal generation energy costs, and flexible capacity costs are determined in Exhibit (PG&E-2), Chapter 3 on a cents per kilowatt-hour (kWh) basis by TOU period. These marginal costs are then scaled (on a kWh basis) to the sales forecast used in this proceeding (currently 2019 sales)[11] to develop marginal cost revenue. For purposes of determining full cost of service for each customer class generation received from NEM customers is allocated to each customer class at marginal cost, while generation marginal cost associated with

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[10] The Commission made the following comment with regard to changes to bundled bills to separately display the PCIA: "We agree that bundled customers should be made aware of the fact that all customers are paying their share of the utility's uneconomic costs." D.18-10-019, p. 119.

[11] PG&E will update its testimony to reflect the 2020 sales forecast once it is approved in the 2020 Energy Resource Recovery Account proceeding (A.19-06-001).

deliveries to NEM customers and generation marginal costs associated with deliveries to Non-NEM customers is scaled by EPMC.

2. Distribution Revenue Allocation

PG&E proposes to allocate distribution revenue based on distribution EPMC reflecting the marginal costs described in more detail in Exhibit (PG&E-2). Distribution marginal cost at the class level is the sum of marginal customer costs for NEM customers, marginal customer costs for Non-NEM customers, marginal distribution capacity costs for energy received from NEM customers, marginal distribution capacity costs for energy delivered to NEM customers and marginal distribution capacity costs for energy delivered to Non-NEM customers. Marginal distribution capacity costs are determined in Exhibit (PG&E-2), Chapter 8 on a cents per kWh (¢/kWh) basis by TOU period (where appropriate). These marginal costs are then scaled (on a kWh basis) to the forecast used in this proceeding (currently 2019 sales) to develop marginal cost revenue. For purposes of determining full cost of service for each customer class, distribution marginal capacity associated with energy received from NEM customers is allocated to each customer class at marginal cost, while marginal distribution capacity marginal costs associated with deliveries to NEM customers and distribution capacity costs associated with deliveries to non-NEM customers is scaled by EPMC. Marginal customer access costs for NEM customers and Non-NEM customers developed in Exhibit (PG&E-2), Chapter 9, are then applied to forecast of customers to determine the marginal customer cost revenue which is scaled by EPMC to determine revenue allocated to each customer class.

3. Public Purpose Program Revenue Allocation

PPP revenue currently includes two components: (1) the CARE Surcharge, which funds the cost of the CARE Program and the Food Bank Rate Assistance Program; and (2) the cost of non-CARE programs to be recovered as PPP or Public Benefits charges.

a. CARE Surcharge

As a result of revenue allocation and rate design changes in this proceeding, PG&E proposes to recalculate the CARE discount and the

CARE surcharge component of the PPP rates using the currently-effective method. Specifically, PG&E proposes to retain the method currently used to determine the CARE shortfall revenue requirement and to allocate the total CARE surcharge revenue requirement among non-exempt customers on an equal ¢/kWh basis. PG&E proposes to reset the CARE surcharge rates when implementing this decision and to retain the current practice to reset the CARE surcharge once per year thereafter in the Annual Electric True-Up proceeding (typically on January 1).

b. Non-CARE Components Approved for Recovery as PPP

Except for the specific exceptions listed below, PG&E proposes to allocate the non-CARE components of PPP based on Equal Percent of Total Revenue (EPT, total revenue with generation imputed for DA and CCA customers). As discussed in Chapter 2, this represents a small change from the currently approved allocation of these program costs which currently includes the following program costs: (1) Energy Savings Assistance (ESA, or low income energy efficiency); (2) Procurement Energy Efficiency and Public Goods Charge Energy Efficiency; (3) Electric Program Investment Charge; and (4) Statewide Marketing, Education and Outreach (ME&O).[12]

While not included in PPP rates at the time of this filing, the Commission has approved several programs to be included in PPP charges based on the same allocation used for other non-CARE PPP programs. In this proceeding, PG&E proposes the same change in allocation to these programs as it is proposing for the other non-CARE PPP programs based on EPT. These programs include (1) the measurement and evaluation study for the NEM successor tariff (D.18-09-044, Ordering Paragraph (OP) 13); (2) San Joaquin Valley Disadvantaged Community (DAC) Pilot Program Costs (D.18-12-015, OP 23); (3) San Joaquin Valley DAC Data Gathering Costs (D.18-08-019, OP 13); (4) DAC Green Tariff , DAC Community Solar Green Tariff and the DAC Single Family Solar Home Program Discount,

12 D.18-08-013 adopted a common allocation for all these cost components.

if inadequate allowance revenue is available (D.18-06-027, OP 8 and OP 14); and (5) Behind the Meter Thermal Storage Program Costs (D.19-06-032, OP 5).

In addition, also while not included in PPP rates at the time of this filing, the Commission has approved the Tree Mortality Non Bypassable Charge for inclusion with PPP charges (D.18-12-003, OP 9). In that case, however, the Commission specified the revenue allocation for this program. PG&E proposes to use the Commission authorized approach for this component which is equal to the 12-month coincident peak demand method authorized for NSGC.

c. Non-CARE Components Proposed for Recovery as PPP

Finally, PG&E requests that two programs currently recovered as distribution charges be recovered as PPP charges. Specifically, PG&E requests that Self-Generation Incentive Program (SGIP) and California Solar Initiative (CSI) Program costs be moved from distribution to PPP.[13] SGIP costs are currently recovered in distribution, but the Commission revised the allocation for these costs in D.16-06-055 and D.18-08-013. Accordingly, PG&E proposes to recover these SGIP costs with PPP charges but retain the Commission approved allocation methodology which is based on the benefit received by each customer class. PG&E proposes that CSI costs, which were previously collected in the same manner as other distribution revenue, be collected in the PPP charge based on the standard EPT allocation for non-CARE PPP revenue.

Finally, in Phase 1 of the 2020 GRC (Application (A.) 18-12-009), PG&E has requested a Hydro Public Benefit Cost Non-bypassable charge. In PG&E's request, PG&E deferred the question of rate design for this component to this GRC Phase II.[14] If the Commission adopts a

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[13] CSI costs include the Single Family Affordable Solar Housing and Multifamily Affordable Solar Home program costs. In adopting San Diego Gas & Electric Company's proposal to recover SGIP and CSI in PPP rates, the Commission explained that "This shift supports our rate design principles favoring rates that are based on cost causation principles and making incentives explicit and transparent, is reasonable, and should be adopted." (D.17-08-030, p. 72.)

[14] A.16-12-009, Exhibit (PG&E-5), Chapter 8, p. 8-24.

Hydro Public Benefit Cost Non-bypassable charge in GRC Phase I, PG&E proposes that this rate be allocated based on the standard EPT allocation for non-CARE PPP revenue and collected with PPP charges on customer bills.

4. Revenue Allocation Results

Revenue allocation results are provided in Chapter 2 of this exhibit, and are provided in detail in Appendix B of Exhibit (PG&E-4). As mentioned above, in this proceeding PG&E proposes to transition all customer classes to their full cost revenue responsibility over a 6-year period. In order to moderate the change to full cost, generation and distribution rates for each customer class would be adjusted by an equal amount each year toward full cost. These adjustments would be applied in addition to any revenue requirement changes. Non-CARE PPP rates (i.e., those components of the PPP rate excluding the CARE surcharge) would be adjusted to the proposed levels in the first year of the 6-year transition period. PG&E's trajectory toward implementation of full cost in six years would be adjusted, if necessary, in the 2023 GRC Phase II proceeding.

In general, PG&E's proposed allocation would allow both each customer class and each rate schedule within a customer class to be adjusted to full cost over a six-year period. In certain instances, however, PG&E proposes to mitigate the allocation of costs within a customer class for individual rate schedules or groups of rate schedules to preserve relationships across rate schedules, or to avoid unacceptable bundled bill increases resulting from the intra-class revenue allocation. These exceptions are described as applicable in the following chapters.

D. Rate Design

As discussed previously, PG&E is seeking changes to rates for generation, distribution and PPP in this proceeding. Unlike PPP rates which are collected in volumetric charges (per kWh), rates for distribution and generation can be collected on a monthly basis (per customer), on a volumetric basis (per kWh), and on the basis of demand (per kW). In addition, both generation and distribution charges may be time-differentiated. PG&E's proposed rates are discussed in the following chapters of this exhibit: Chapter 3, "Residential Rate

Design"; Chapter 4, "Commercial and Industrial Rate Design"; Chapter 5, "Agricultural Rate Design"; and Chapter 6, "Streetlight Rate Design." Proposed rates for year 3 are set forth in detail in Appendix C of Exhibit (PG&E-4), "Present and Proposed Rates."

In D.18-08-013, the Commission clearly indicated its preference for time-differentiated rates that feature differentials equal to fully-scaled marginal cost, and requested that PG&E prepare a number of rate design illustrations to supplement the record in this proceeding to provide parties and the Commission a full range of rate designs. These illustrations are provided in Appendix G, "Illustrative Rate Designs for Commercial and Industrial Customers," and Appendix H, "Illustrative Rate Designs for Agricultural Customers," of Exhibit (PG&E-4).

1. Distribution Customer Charge

Customer charges are assigned entirely to the distribution rate component of each tariff. PG&E generally advocates that customer charges should be determined based on their full, cost-based levels. These levels are derived by scaling up class-specific customer marginal costs by the EPMC multiplier associated with PG&E's distribution revenue. In this proceeding, however, PG&E does not propose changes to the current customer charges, or, in the case of Medium and Large C&I customer charges, the mechanisms currently approved for updating them.[15] Where the proposed customer charge does not collect the fully-scaled marginal cost, residual customer-related revenue responsibility will necessarily be assigned to non-time varying demand and/or energy charge components of the distribution rates applicable under each rate schedule.

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15 A residential customer charge is being considered in Phase III of the 2018 RDW (A.17-12-011 et seq) for implementation a year after default TOU has been launched. As of the time of this filing, Phase III of the 2018 RDW has been submitted for decision upon the filing of concurrent Reply Briefs in October 2019, and a decision is expected in early 2020. Accordingly, PG&E is not here proposing a Residential customer charge for default Residential service. PG&E reserves the right to update this showing, as may be necessary, after the 2018 RDW Phase III residential fixed charge decision is issued in A.17-012-011.

2. Distribution Demand and Energy Charges

As a general principle, PG&E recommends that distribution revenue that is not collected in the customer charge should be collected in demand charges, since customer demands are the primary drivers of distribution capacity costs. Ideally, the time differentiation in distribution rates would be accomplished through a peak period distribution demand charge, or alternatively, through time differentiated energy rates. All remaining revenue would then be assigned to a non-coincident demand charge or non-time differentiated energy rates. In the rate design testimony in the following chapters, PG&E describes its proposals for distribution rate design.

3. Generation Demand and Energy Charges

PG&E recommends that generation revenue should be collected in time differentiated demand[16] and energy charges. As discussed above, PCIA is now allocated to bundled customers separately and should be collected from bundled customers on a non-time differentiated, per kWh basis (i.e., the same way it is collected from DA/CCA customers). PG&E generally recommends that generation capacity costs be used to time differentiate generation rates through either a peak period generation demand charge, or alternatively, through time-differentiated energy rates. All remaining revenue would be assigned to collection through energy rates. In the rate design testimony in the following chapters, PG&E describes its proposals for generation rate design.

4. Total Rate Calculation

As noted above, in this proceeding, PG&E is proposing changes only to rates for distribution, generation and PPP. Rates for all other functional revenue requirement components remain unchanged in illustrative rates presented for approval in this proceeding. In general, rates for each functional revenue requirement component are added together to determine the total bundled rate.

However, total Residential rates that include rate tiers are determined differently. In general, total bundled tiered rates are first determined to collect the total revenue, and then rates are unbundled to each functional

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[16] Generation costs are included in reservation charges pursuant to Schedules S and SB.

revenue requirement component and the CIA is set residually. Residential rates design proposals are set forth in Chapter 3 of this exhibit.

5. Peak Day Pricing

D.18-08-013 adopted new TOU periods for C&I customers with a later peak period. Similarly, D.18-08-013, and subsequently D.19-05-010, adopted new TOU periods for Agricultural customers with a later peak period. Those decisions, however, did not adopt Peak Day Pricing (PDP) rates with consistent, later event hours. Instead, D.18-08-013 approved settlements[17] that recommended the following steps for the PDP program:

- Suspend default of eligible customers to PDP for the period prior to the date when rates with new, later TOU periods become mandatory (November 2020 for C&I rates and March 2021 for Agricultural rates).
- Continue the existing PDP program on an opt in basis during the period prior to November 2020 for C&I rates and prior to March 2021 for Agricultural rates.
- Ensure PDP is available once the new TOU periods become mandatory: PG&E is required to file a Tier 3 advice letter in 2020 in time to gain Commission approval to establish new PDP rates. That Tier 3 advice letter must include revised pricing and PDP event hours that are the same hours adopted for the residential Smart Rate™ Program. [18]
- Resume default of eligible C&I customers to PDP beginning on November 1 following approval of a Tier 3 advice letter, provided approval occurs by July 1 of that year. Resume the default of eligible Agricultural customers to PDP beginning on March 1, following approval of a Tier 3 advice letter, provided approval occurs by November 1 of the prior year.

Accordingly, to ensure that PDP is available to Non-Residential customers, PG&E will file a Tier 3 advice letter in 2020 in time to gain

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17 The Standby and Medium and Large Light and Power Rate Design Settlement Agreement, the Small Light and Power Rate Design Settlement Agreement and the Agricultural Rate Design Settlement Agreement, approved by D.18-08-013.

18 Subsequently, in D.19-07-004 in the 2018 RDW, the Commission approved revised residential Smart Rate event hours of 5 p.m. to 8 p.m. (D.19-07-004, pp. 64-67, Conclusion of Law 49 to 51, OPs 20 to 21.)

Commission approval to establish C&I and Agricultural PDP rates with event hours of 5 p.m. to 8 p.m. such that the revised program can be available by November 1, 2020, in anticipation that customers that are taking service on PDP will be enrolled automatically in the new PDP beginning on that date. In addition to proposing changes to the event hours and pricing in the Tier 3 advice letter, PG&E will also request that customers no longer be defaulted to the PDP program. Instead, the program would be retained on an 'opt-in' basis. By addressing this issue in the Tier 3 advice letter, there would be an adequate opportunity to gain approval to end the default process prior to 2021. However, in the event that the Commission has not acted on PG&E's proposal to end the process to default customers to PDP prior to the 2021 operating season, PG&E is also including that proposal in this proceeding. Specifically, PG&E proposes to make PDP available on an opt-in basis, and to end the process of defaulting eligible customers to PDP.

6. Additional Rate Design Proposals

In Chapter 7 of this exhibit, PG&E proposes to continue its Economic Development Rate (EDR). PG&E believes the EDR is a valuable tool to retain and attract sales in California and should be continued through this GRC cycle. The proposed program would have the same structure as the current EDR (with the same percentage rate reductions) with greater rate reductions for customers in cities and counties with higher unemployment rates.

In Chapter 8 of this exhibit, PG&E presents its proposal for revisions to DA/CCA fees. In the last GRC, PG&E revised its rates for DA meter fees, the DA/CCA Meter Data Management Agent fee, and for DA/CCA billing fees. In this proceeding, PG&E focuses it revisions to fees that were not addressed in the last GRC.

Finally, in Chapter 9, PG&E presents its proposal for the Essential Use Study Plan as required by D.18-08-013.

E. Organization of the Exhibit

Exhibit (PG&E-3) has a total of 9 chapters. The remainder of this exhibit is organized as follows:

- Chapter 2 – Describes the revenue allocation methods used for each of PG&E's functional revenues;
- Chapter 3 – Sets forth PG&E's Residential rate design proposals;
- Chapter 4 – Sets forth PG&E's C&I rate design proposals;
- Chapter 5 – Sets forth PG&E's Agricultural rate design proposals;
- Chapter 6 – Sets forth PG&E's Streetlight class rate design proposals;
- Chapter 7 – Sets forth PG&E's proposal for continuing the Economic Development Rate Program;
- Chapter 8 – Describes PG&E's proposals for updating fees for DA and CCA customers; and
- Chapter 9 – Sets forth PG&E's plan for the Essential Use Study as required by D.18-08-013.

The following appendices are also provided in Exhibit (PG&E-4):

- Appendix A – Recorded Average Number of Customers and Sales;
- Appendix B – Revenue and Average Rate Summary at Proposed Rates;
- Appendix C – Present and Proposed Rates;
- Appendix D – Illustrative Bill Impacts;
- Appendix E – Summary of Compliance Requirements;
- Appendix F – Baseline Territory Study;
- Appendix G – Illustrative Rate Designs for Commercial and Industrial Customers;
- Appendix H – Illustrative Rate Designs for Agricultural Customers;
- Appendix I – Dimmable Streetlight Rate Design Proposal;
- Appendix J – Schedule E-CREDIT Update;
- Appendix K – NEM and Non-NEM Cost of Service Study; and
- Appendix L – Statements of Qualifications.

F. Conclusion

In this chapter, PG&E has discussed the general policy objectives that underlie its proposals, including continuing to make progress towards rates that are economically efficient, cost-based and promote equity among customers, as balanced with other objectives. PG&E has also summarized its revenue allocation proposal and its proposed guidelines for designing rates in this proceeding. PG&E respectfully requests approval of its revenue allocation and rate design proposals as presented in this exhibit.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

REVENUE ALLOCATION

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
REVENUE ALLOCATION

A. Introduction

In this 2020 General Rate Case (GRC) Phase II, Pacific Gas and Electric Company (PG&E) is proposing gradual changes to revenue allocation in order to bring each classes' revenue responsibility closer to their cost of service. PG&E's goal is to transition allocations to full cost of service over a period of six years. Specifically, PG&E is proposing that distribution and generation revenues be adjusted 1/6th of the way towards allocations in proportion to marginal cost revenue each year for the next three years. PG&E would then reassess marginal costs in its 2023 GRC Phase II and propose the continuation of its transition plan for the following three years in that proceeding. By implementing a multi-year transition plan with a series of relatively small annual changes, PG&E will be able to move customers closer to cost without a single large "step" in rates and without the sometimes counter-intuitive results created by implementing caps and floors.

The lack of established marginal costs has made it difficult for PG&E to move towards cost-based allocations in the past decade. The prior two GRC cases settled with less than 1 percent adjustments for bundled customers. In the 2017 GRC Phase II, PG&E advocated for minimal revenue allocation adjustments because substantial shifts in time-of-use (TOU) periods were already going to be major rate changes facing customers during that rate case cycle. In this case, PG&E is minimizing changes in its rate design, which will make it easier to move customer classes closer to their costs of service.

PG&E bases its illustrative revenue allocation on the same general methods proposed in its 2017 GRC Phase II proceeding. In the decision that adopted the settlements filed in that proceeding, Decision (D.) 18-08-013, the California Public Utilities Commission (CPUC or Commission) adopted two approaches for revenue allocation. The first approach provided methodologies to be used for the *initial* allocation of costs following a decision in that proceeding. Table 2-1 provides a summary of the current and proposed allocation methods for distribution, generation and Public Purpose Program (PPP) functional revenues to be used upon implementation and in each year of the six-year transition plan to move each customer class to full cost.

TABLE 2-1
CURRENT AND PROPOSED ALLOCATION METHODS

Line No.	Functional Revenue Category	Customer Group[(a)]	Adopted Approach in Last Phase II (Adopted Methods Were Approved Via Settlement[(b)])	Proposed in This Phase II
1	Distribution	All customers	Equal Percent of Marginal Cost (EPMC), limited through application of caps and floors on Direct Access and Community Choice Aggregation (DA/CCA) customers.	Same as prior GRC, but using gradual, annual changes toward full cost.
2	Generation	Bundled service customers	EPMC, limited through application of caps and floors on bundled customers.	Same as prior GRC, but using gradual, annual changes to full cost.
3	PPPs – California Alternate Rates for Energy (CARE) Surcharge	All customers	All CARE distribution and Conservation Incentive Adjustment (CIA) rate differences will be funded through the CARE surcharge, which will be allocated based on equal-cents-per kilowatt-hour (kWh). Set once per year.	Same as prior GRC.
4	PPPs – Self-Generation Incentive Program (SGIP)	All customers	Allocated in distribution as specified by Resolution (Res.) E-4926.	Move revenue to PPP with the same allocation, resulting in no rate impact.
5	PPPs – Tree Mortality	All customers	Not in 2017 GRC Phase II.	Allocated by the 12 Coincident Peak method, per D.18-12-003.
6	PPPs – Other Non-CARE Surcharge Revenue	All customers	Decision approved a settlement combining all Non-CARE surcharge programs into a single allocator. After implementation, allocation is based on current revenue share.	Allocated on Equal Percent of Total Revenue (EPT) share with generation imputed for DA/CCA customers, (EPT).

(a) "All customers" includes eligible Bundled, Direct Access (DA), Community Choice Aggregation (CCA), and Departing Load (DL) customers.
(b) "Settlement" refers to the Marginal Cost/Revenue Allocation Settlement adopted in D.18-08-013.

Table 2-2 provides a summary of the current allocation methods for other functional revenues that PG&E is not proposing to adjust in this proceeding.

TABLE 2-2
CURRENT ALLOCATION METHODS FOR OTHER FUNCTIONAL REVENUE

Line No.	Functional Revenue Category	Customer Group[(a)]	Currently Approved Allocation
1	Department of Water Resources Bond Charges	All customers	Equal cents per kWh
2	Competitive Transition Costs	All customers	Top 100-hour allocation
3	Nuclear Decommissioning	All customers	Equal-cents-per kWh
4	Transmission Rates (including the Transmission Revenue Balancing Account Adjustment (TRBAA), Transmission End-Use Customer Refund Adjustment (T-ECRA) and Transmission Access Charge Balancing Account (TACBA) rate)	All customers	12 coincident peak demands (Transmission and T-ECRA) and equal cents per kWh (TACBA and TRBAA)[(b)]
5	Reliability Services	All customers	12 coincident peak demands
6	Energy Cost Recovery Amount	All customers	Equal cents per kWh
7	New System Generation Charge	All customers	12 coincident peak demands
8	CIA[(c)]	All residential customers	Set residually, reflecting decrements from or increments to schedule rates, to preserve the tiered residential total rate structure pursuant to the constraints set forth D.15-07-001.
9	Power Charge Indifference Adjustment (PCIA)	All eligible DA, CCA and DL customers	Set by vintage in accordance with current methodology used in present rates.

(a) "All customers" includes eligible Bundled, DA, CCA, and DL customers.
(b) Transmission rates are established by the Federal Energy Regulatory Commission and are not subject to change by the CPUC in this proceeding.
(c) PG&E has not changed its approach to CIA design, but CIA rates are affected by changes to other charges made in this proceeding.

Finally, the second approach adopted by D.18-08-013 established the revenue allocation methodologies to be applied for revenue requirement (RRQ) changes *between* GRC Phase II proceedings. In summary, for changes between GRCs, PG&E proposes: (1) to continue to apply the methods set forth in Table 2-1 for PPP charges; use the approaches described in Table 2-3 for distribution and generation rates; and (3) to continue to apply all the methods set forth in Table 2-2 for other functional revenues. Any distribution and generation revenue adjustments from the transition plan would be added to other RRQ changes throughout the plan. These proposed methods will apply unless specifically addressed in the following rate design chapters.

TABLE 2-3
ALLOCATION METHODS FOR DISTRIBUTION AND GENERATION FUNCTIONAL REVENUES BETWEEN PHASE II PROCEEDINGS

Line No.	Functional Revenue Category	Customer Group[a]	Last Adopted Approach in Last Phase II (Adopted Methods Were Approved Via Settlement[b]	Proposed in This Phase II
1	Distribution	All customers	Equal percentage changes.[c]	Same as prior GRC.
2	Generation	Bundled service customers	Equal percentage changes.	Same as prior GRC.

(a) "All customers" includes eligible Bundled, DA, CCA, and DL customers.
(b) "Settlement" refers to the Marginal Cost/Revenue Allocation Settlement adopted in D.18-08-013.
(c) The CPUC fee will continue to be separately allocated on a $/kWh basis per Res.M-4828.

In this chapter, PG&E describes its proposed approach for determining the initial allocation of costs following a decision in this proceeding. The remainder of this chapter is organized as follows:

- Section B – Model Improvements
- Section C – Marginal Cost Revenue Calculations and Full Cost Retail Average Rates
- Section D – Distribution Allocation
- Section E – Generation Allocation
- Section F – Public Purpose Program Allocation
- Section G – Implementation of Rate Changes
- Section H – Conclusion

B. Model Improvements

While the main structure of PG&E's Revenue Allocation and Rate Design (RARD) model used in the 2017 GRC Phase II has largely been preserved for the 2020 case, there are some substantial additions that allow for more detailed analysis of the cost of service for Net Energy Metering (NEM) and Non-NEM customers. Improvements for the 2020 RARD model include:

- Separate marginal cost revenues for the NEM and Non-NEM subgroups of customers;
- Separate billing determinants for NEM and Non-NEM, including the identification of energy returned to the grid;
- Separate full-cost average rate calculations for NEM and Non-NEM;
- Incorporation of generation flexible capacity marginal cost revenues; and
- Explicit allocation of winter super-off-peak billing determinants and revenues.

C. Marginal Cost Revenue Calculations and Full Cost Retail Average Rates

Marginal cost revenues for distribution and generation have been developed based on the marginal costs discussed throughout the chapters in Exhibit (PG&E-2). Marginal customer access costs are provided in Chapter 9 of Exhibit (PG&E-2). All other marginal costs are developed on a per-kWh basis, by class and schedule, and separately for NEM and Non-NEM customers (that is, separately for delivered and received energy as applicable), and by TOU period where appropriate. Average marginal costs for generation are developed in Exhibit (PG&E-2), Chapter 3 of and average marginal distribution capacity costs are developed in Exhibit (PG&E-2), Chapter 8.

In the revenue allocation step, these marginal cost values are then multiplied by the forecasted kWh[1] of each schedule to determine each schedules' marginal cost revenue for NEM and Non-NEM separately. Marginal customer costs are multiplied by forecasted customer months to determine marginal customer cost revenue for NEM and Non-NEM separately. Marginal cost revenue is then summed to develop class and schedule level marginal cost revenue.

These marginal cost revenues are used to create EPMC allocation factors just as PG&E would have determined them in prior GRCs. The decision to develop separate marginal cost revenues for NEM and Non-NEM customers does not affect the overall revenue allocation. Had PG&E not developed these NEM-specific costs, the resulting combined costs would have been the weighted

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1 This proposal uses the 2019 forecasted sales as developed in PG&E's 2019 Energy Resource Recovery Account (ERRA) application. PG&E will update the RARD model with 2020 forecasted sales from the 2020 ERRA at a later date once approved.

average of the two groups, resulting in the same total marginal cost revenue and allocations. After the removal of certain non-allocated revenues, described in Sections D and E below, the remaining revenue requirements for distribution and generation are allocated in direct proportion to the marginal cost revenues for each schedule. Table 2A-1 shows a summary of the full-cost average rates that would result from that allocation.[2]

The results of Table 2A-1 differ from the NEM and Non-NEM Cost of Service Study provided in Exhibit (PG&E-1), Chapter 1, and Appendix K of Exhibit (PG&E-4) because Table 2A-1 is limited by the rate design rules currently in place for NEM. Specifically, unlike the NEM and Non-NEM Cost of Service Study in Exhibit (PG&E-1), the rates for NEM and Non-NEM customers must be the same, and NEM customers get full retail credit for on energy returned to the grid.[3] The allocations must be applied to each schedule for NEM and Non-NEM combined since the two groups cannot be given individual revenue responsibilities while they continue to have identical rates. While full retail credit is given for transmission and NBC revenues, PG&E continues to apply the EPMC scaling only on energy delivered to the customer and not on received energy, similar to the treatment outlined in Chapter 1 of this Exhibit.[4] This is done because it more accurately reflects the benefits of received energy by PG&E and can be applied to the combined group without specifically changing NEM rates. While the model produces average rate impacts for NEM and Non-NEM separately in the proposed rates files, those results are not indicative of the actual rate impacts that NEM customers would experience as the model assumes all customers are on the new TOU periods even though most NEM customers would still be on the more favorable legacy (i.e., grandfathered) TOU periods.

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2 A more detailed summary of revenue and average rate is provided in Appendix B of Exhibit (PG&E-4).

3 While NEM 2.0 customers do not receive retail credit for some NBC’s, PG&E’s current NEM population is 95 percent NEM 1.0 and so all customers are modeled as NEM 1.0.

4 The marginal cost revenue for received load is very small (less than 1 percent) compared to delivered load. PG&E has modeled the impact from applying the EPMC scaling to received load and the overall rate impact is minimal (less than 0.1 percent for most classes).

D. Distribution Allocation

As discussed above, PG&E proposes to allocate its distribution revenue requirement based on distribution marginal cost revenue. PG&E proposes to mitigate the rate changes that would result from a full-cost allocation by only moving 1/6th of the way to full cost each year for three years instead of applying caps and floors, as has been done in the 2014 and 2017 GRC’s. In order to achieve this transition, PG&E has developed percentage changes that would be applied to modify present rate distribution revenues (net non-allocated) for each schedule on implementation and the following two years. Schedules that have their rates designed together are grouped so that each schedule’s distribution revenue goes up by the same percentage. This includes E-1/EL-1, A-1/A-6/A-15, each E-19 voltage with its respective voluntary schedule, AG-B/AG-C, and each E-20 voltage with its respective FPP schedule. In addition, even though TC-1 receives its own cost allocation, PG&E proposes to limit the distribution increase on this rate schedule to the class average change since allocating the full cost to this schedule would result in a very large rate increase. These distribution changes are listed in Table 2A-3.

PG&E will continue to directly assign to each schedule the estimated CARE Program discounts and certain non-allocated distribution revenues (i.e., Electric Base Interruptible Program discounts, employee discounts, other standby revenue, streetlight facilities charges, and the CPUC fee). PG&E proposes to continue to allocate distribution Family Electric Rate Assistance (FERA) program costs to only the residential class.

E. Generation Allocation

Similar to section D, above, PG&E proposes to allocate its generation revenue requirement based on generation marginal cost revenue. PG&E proposes to mitigate the rate changes that would result from a full-cost allocation by only moving 1/6th of the way to full cost each year for three years instead of applying caps and floors, as has been done in the 2014 and 2017 GRC’s. In order to achieve this transition, PG&E has developed percentage changes that would be applied to modify present rate generation revenues (net non-allocated) for each schedule on implementation and during the following two years. Schedules that have their rates designed together are grouped so that each schedule’s generation revenue goes up by the same percentage. This includes

E-1/EL-1, A-1/A-6/A-15, each E-19 voltage with its respective voluntary schedule, and AG-B/AG-C. In addition, generation revenue is transferred from AG-B/C to AG-A in order to equalize the average bundled rate impact between the two groups and help mitigate the increases that would otherwise be assigned to AG-B/C. These generation changes are listed in Table 2A-3.

As described in more detail in Chapter 1, PG&E is explicitly treating the above-market (PCIA) portion of generation revenues as a non-allocated revenue and applying it to all bundled customers with a rate equal to the latest vintage of PCIA for each class.

F. PPP Allocation

PG&E proposes to include four components in PPP rates based on revenue allocation that differs for each. The four components are: (1) the CARE surcharge which funds the cost of the low-income CARE Program; (2) all other existing programs including the Electric Program Investment Charge and Former Energy Efficiency Public Goods Charge, Procurement Energy Efficiency, Energy Savings Assistance, and Statewide Marketing, Education and Outreach[5]; (3) the Self Generation Incentive Program (SGIP); and (4) the Tree Mortality Non-Bypassable Charge.

For the CARE surcharge, PG&E proposes to continue the current method of resetting the CARE shortfall rates once each year. These CARE shortfall rates, equal to the difference between the Non-CARE and CARE distribution and CIA rates ultimately established in this proceeding, are multiplied by forecast CARE sales to determine the cost of the CARE discount, referred to as the CARE shortfall revenue requirement.

PG&E proposes to continue to reflect the cost of the CARE distribution and CIA discount in the CARE surcharge component of PPP, allocated on an equal cents per kWh basis to all eligible customers, consistent with the language in

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5 The Commission has approved recovery of several other items as Non-CARE PPP charges that are not currently included in rates. PG&E proposes EPT allocation for these as well. As mentioned in Chapter 1, these include (1) the measurement and evaluation study for NEM, (2) San Joaquin Valley Disadvantaged Community (DAC) Pilot Program Cost, (3) San Joaquin Valley DAC Data Gathering Costs, (4) DAC Green Tariff, DAC Community Solar Green Tariff and the DAC Single Family Solar Home Program Discount, if inadequate allowance revenue is available, and (5) Behind the Meter Thermal Storage Program.

Public Utilities (Pub. Util.) Code section 327(a)(7), enacted through Senate Bill 695, which established Pub. Util. Code Sections 739.1 and 739.9.

The second component is currently allocated to customer groups based on an equal percentage change to the component's current revenue. PG&E proposes to allocate this in proportion to each schedule's share of total revenue with generation imputed for DA/CCA customers (EPT). Table 2A-4 compares the present and proposed allocation methods for these components. If approved in GRC Phase I, PG&E would also propose to allocate the Hydro Public Benefit Cost Non-Bypassable Charge based on EPT.[6] Additionally, PG&E proposes to reclassify the revenues from two programs mentioned in Chapter 1 from Distribution to PPP: (1) California Solar Incentives which PG&E proposes to allocate according to the EPT method described above, and (2) SGIP, described below.

SGIP makes up the third component of PPP rates as it requires a different allocation. The revenues from SGIP will maintain their allocation as proscribed by Res.E-4926, and adopted by D.18-08-013, which will result in no rate impact.

Finally, the fourth item to be included with PPP rates is the Tree Mortality Non-Bypassable Charge. PG&E proposes to continue the authorized allocation for the Tree Mortality Non-Bypassable charge based on the same method used for NSGC (12-month coincident peak).

PG&E is not proposing to vary PPP allocations over its six-year transition plan. If approved, PG&E would reclassify the revenues from the programs mentioned above and adjust the Non-CARE allocations fully upon implementation.

G. Implementation of Rate Changes

The total rate levels PG&E will implement as a result of a final decision in this proceeding will depend on the RARD methods approved in this proceeding, as well as revenue requirements adopted by the CPUC or FERC in other proceedings. Illustrative rates provided in this exhibit are based on revenues collected by current rates (effective July 1, 2019) using forecasted 2019 billing determinants. As a result, the illustrative revenues do not include any forecast of future revenue requirement changes and are not based on the

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6 Application 18-12-009, PG&E GRC Phase I, Exhibit (PG&E-5), p. 8-24.

most recently adopted sales forecasts that will actually be used to set rates upon implementation.

In this section, PG&E describes its proposal to implement rates resulting from this proceeding as well as its proposal to implement rates arising from future revenue requirement changes.

If PG&E's proposal is approved, the initial rate change resulting from the decision in this proceeding will be implemented as soon as practicable. Assuming there are revenue requirement and sales forecast changes between, the rate change calculation would be conducted in three steps: (1) create interim rates based on the revenue requirements and sales forecasts used in this proposal; (2) adjust the distribution and generation revenues by the amounts listed in Table 2A-3 and then (3) allocate the revised revenue requirements pursuant to any subsequent rate changes and sales forecasts, using the guidelines set forth below.

In general, PG&E proposes to continue the existing practices for rate changes to implement revenue requirement changes as adopted in D.18-08-013. PG&E's proposed guidelines are set forth in Exhibit (PG&E-3), Chapter 2, Attachment A, and would apply unless specifically addressed in each rate design chapter. In particular, generation and distribution rules for rates changes are discussed in each rate design chapter.

Some rate changes, either proposed by PG&E or ultimately approved by the Commission, go beyond a simple change to a rate value and may require either a structural change to PG&E's billing system and/or an extended period of education for PG&E employees and customers. Such changes will be implemented by PG&E diligently, and as rapidly as possible, consistent with other workflow demands, as well as smooth operations of the systems involved, while also allowing time for adequate customer outreach and education. Timing for certain initiatives, such as changes to baseline quantities, are described in the following chapters.

H. Conclusion

Table 2A-1, "Revenue and Average Rate Summary at Full Cost Rates," shows the full cost revenue allocation with current retail rules, absent any caps, floors, or transition plan. Table 2A-2, "Revenue and Average Rate Summary at Proposed Rates," shows illustrative revenue results for PG&E's proposed allocation after the first year of the multi-year transition, as well as the cumulative effect of three years of transition, as described in this chapter. Exhibit (PG&E-4), Appendix B, provides these results in greater detail. PG&E recommends that the Commission adopt its proposed allocation methods and transition plans for the allocation of distribution, generation, and PPP.

TABLE 2A-1
REVENUE AND AVERAGE RATE SUMMARY AT FULL COST RATES

Line No.		Revenue at July 1, 2019 Rates ($000)	Revenue at Full Cost Rates ($000)	Class Average Percent Change in Revenues
1	Bundled Summary			
2	Residential	$3,304,993	$3,259,213	-1.4%
3	Small	$946,452	$1,026,479	8.5%
4	Medium	$756,667	$718,225	-5.1%
5	E-19	$899,250	$842,737	-6.3%
6	Streetlights	$37,498	$40,482	8.0%
7	Standby	$39,544	$39,368	-0.4%
8	Agriculture	$986,727	$1,119,997	13.5%
9	E-20 T	$311,283	$306,009	-1.7%
10	E-20 P	$534,070	$510,483	-4.4%
11	E-20 S	$188,962	$170,908	-9.6%
12	System	$8,005,445	$8,033,901	0.4%
13	DA/CCA Summary			
14	Residential	$2,141,347	$1,980,373	-7.5%
15	Small	$704,301	$825,047	17.1%
16	Medium	$704,786	$744,048	5.6%
17	E-19	$943,779	$909,724	-3.6%
18	Streetlights	$20,439	$18,220	-10.9%
19	Standby	$5,058	$5,025	-0.7%
20	Agriculture	$146,485	$164,162	12.1%
21	E-20 T	$157,957	$158,617	0.4%
22	E-20 P	$369,428	$368,306	-0.3%
23	E-20 S	$135,995	$128,428	-5.6%
24	System	$5,329,574	$5,301,951	-0.5%

TABLE 2A-2
REVENUE AND AVERAGE RATE SUMMARY AT PROPOSED RATES

			Year 1 of Transition		Cumulative Change After 3 Years	
Line No.		Revenue at July 1, 2019 Rates ($000)	Revenue at Proposed Rates ($000)	Class Average Percent Change in Revenues	Revenue at Proposed Rates ($000)	Class Average Percent Change in Revenues
1	Bundled Summary					
2	Residential	$3,304,993	$3,293,635	-0.3%	$3,279,866	-0.8%
3	Small	$946,452	$959,472	1.4%	$986,275	4.2%
4	Medium	$756,667	$751,198	-0.7%	$738,008	-2.5%
5	E-19	$899,250	$890,914	-0.9%	$871,643	-3.1%
6	Streetlights	$37,498	$36,865	-1.7%	$38,312	2.2%
7	Standby	$39,544	$39,117	-1.1%	$39,218	-0.8%
8	Agriculture	$986,727	$1,012,914	2.7%	$1,055,747	7.0%
9	E-20 T	$311,283	$310,427	-0.3%	$308,660	-0.8%
10	E-20 P	$534,070	$529,373	-0.9%	$521,817	-2.3%
11	E-20 S	$188,962	$185,308	-1.9%	$179,548	-5.0%
12	System	$8,005,445	$8,009,222	0.0%	$8,019,093	0.2%
13	DA/CCA Summary					
14	Residential	$2,141,347	$2,116,273	-1.2%	$2,061,913	-3.7%
15	Small	$704,301	$721,939	2.5%	$763,182	8.4%
16	Medium	$704,786	$711,312	0.9%	$724,407	2.8%
17	E-19	$943,779	$937,854	-0.6%	$926,601	-1.8%
18	Streetlights	$20,439	$19,613	-4.0%	$19,056	-6.8%
19	Standby	$5,058	$4,806	-5.0%	$4,894	-3.2%
20	Agriculture	$146,485	$147,292	0.6%	$154,040	5.2%
21	E-20 T	$157,957	$158,908	0.6%	$158,792	0.5%
22	E-20 P	$369,428	$369,653	0.1%	$369,114	-0.1%
23	E-20 S	$135,995	$134,505	-1.1%	$132,074	-2.9%
24	System	$5,329,574	$5,322,155	-0.1%	$5,314,072	-0.3%

TABLE 2A-3
REQUIRED DISTRIBUTION AND GENERATION CHANGES FOR EACH YEAR OF TRANSITION PLAN

Line No.	Schedule	Distribution Annual Allocation Change	Generation Annual Allocation Change
1	E-1 / EL-1	-2.2%	1.7%
2	A-1 / A-6 / A-15	5.5%	-1.3%
3	TC-1	5.5%	1.6%
4	A-10 T	2.1%	-2.8%
5	A-10 P	-1.6%	-2.2%
6	A-10 S	2.3%	-3.5%
7	E-19 T	-6.5%	0.3%
8	E-19 P	-1.9%	-0.1%
9	E-19 S	-1.5%	-1.9%
10	Streetlights	-8.0%	8.1%
11	Standby T	-12.4%	2.8%
12	Standby P / S	4.3%	-2.3%
13	AG-A	1.5%	4.5%
14	AG-B / C	6.4%	0.7%
15	E-20 T	-0.9%	-0.4%
16	E-20 P	-0.3%	-1.5%
17	E-20 S	-2.6%	-2.4%

TABLE 2A-4
REVENUE IMPACTS OF PPP PROPOSED CHANGES

Line No.	Rate Class	Revenue Impact From Distribution to PPP Reclassification ($000)	Revenue Impact From Changing PPP Allocation ($000)	Class Average Percent Change Bundled Rate
1	Residential	($914)	($3,701)	-0.1%
2	Small	($107)	($2,921)	-0.1%
3	Medium	$140	$1,348	0.1%
4	E-19	$334	$1,596	0.1%
5	Streetlights	$12	($63)	-0.1%
6	Standby	$33	($1,259)	-1.6%
7	Agriculture	($137)	$2,642	0.2%
8	E-20 T	$292	$1,840	0.2%
9	E-20 P	$245	$1,278	0.1%
10	E-20 S	$87	($760)	-0.1%
11	System	($15)	$0	0.0%

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT A

RATE DESIGN GUIDELINES TO IMPLEMENT REVENUE REQUIREMENT CHANGES

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
ATTACHMENT A
RATE DESIGN GUIDELINES TO IMPLEMENT REVENUE REQUIREMENT CHANGES

The following guidelines will be applied to changing rates for revenue requirement changes subsequent to the decision in the Pacific Gas and Electric Company's (PG&E) 2020 General Rate Case (GRC) Phase II proceeding, until the effective date of implementation of a decision in Phase II of PG&E's next GRC proceeding.

a) Revenue requirement changes will be identified by function (e.g., nuclear decommissioning, generation, etc.). Each customer class and schedule will be allocated the average percentage change in functional revenue necessary to collect the functional revenue requirement. This approach to allocating costs using a System Average Percentage Change (SAPC) by function will be employed, such that each customer group's share of each functional revenue requirement remains approximately the same. For schedules that are designed together, such as schedules that are designed on a revenue neutral basis, the SAPC by function will be applied to the combined rate design group.

b) Generation revenue developed to determine the appropriate starting point to apply the percentages from Exhibit (PG&E-3), Chapter 2, Table 2A-3, and will exclude directly assigned revenue (i.e., other standby and Power Charge Indifference Adjustment (PCIA) revenues). For the rate changes where there is a change to Competitive Transition Cost (CTC), current generation revenue used for purposes of allocation will be determined after the change to CTC is incorporated, consistent with current practice.[1]

c) CTC will be allocated based on the 100-peak hour allocation method. 100-peak hour allocation factors for CTC will be revised each year based on the most recent available information at the time PG&E files its annual Energy Resource Recovery Account forecast application consistent with current practice. The

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1 In addition, generation adjustments for SmartRate™ and Peak Day Pricing will be deducted from the generation revenue to be allocated as approved by the California Public Utilities Commission (CPUC or Commission).

New System Generation Charge and (for Direct Access/Community Choice Aggregation customers) the PCIA will be developed using the adopted method.

d) Distribution revenue (including the Conservation Incentive Adjustment) developed to determine the appropriate starting point to apply the percentages from Exhibit (PG&E-3), Chapter 2, Table 2A-3 will exclude directly assigned revenue (including, but not limited to, other standby revenue, streetlight facilities charges, meter charges, employee discounts, the Schedule A-15 facilities charge), estimated California Alternate Rates for Energy (CARE) Program discounts, as well as the CPUC Fee.

e) PPP rates will be developed as the sum of four pieces and will be allocated as follows:

1) The cost of the CARE Program will be determined and the CARE surcharge will be set once per year in the Annual Electric True-Up (AET) proceeding based on the difference between CARE and Non-CARE rates excluding the CARE surcharge, Self-Generation Incentive Program (SGIP) incentives funded through Public Purpose Program (PPP), California Solar Initiative incentives (CSI) funded through PPP, and the Department of Water Resources (DWR) Bond charge. The cost will be allocated to eligible customers on an equal-cents-per kilowatt-hour (kWh) basis and collected through the CARE surcharge component of PPP rates.

2) The cost of all other existing PPP components, as well as the new programs identified in footnote 5 of Chapter 2 will be allocated to customers based on an equal-percent of the sum of then-required revenue for these programs (that is, the same percentage will be applied to the then-required revenue for each customer group to determine the allocated revenue).

3) SGIP revenue will be allocated based on updated allocation factors each year, per Resolution E-4926.

4) The Tree Mortality Program will be allocated using the 12 coincident peak method.

f) The DWR Bond charge, the Energy Cost Recovery Amount and Nuclear Decommissioning charge shall continue to be collected on an equal-cents-per kWh basis for all eligible customers;

g) Transmission Owner and other Federal Energy Regulatory Commission (FERC) jurisdictional rates shall be set by the Federal Energy Regulatory Commission;

h) Greenhouse gas allowance returns will be set as specified separately by the California Public Utilities Commission;

i) PG&E will continue to make directly assigned adjustments for the Distribution Bypass Deferral Rate Memorandum Account in its AET filings. PG&E will continue the practices for discount recovery approved via approval of Advice Letter 3524-E;

j) The costs of the Family Electric Rate Assistance Program will continue to be assigned to the residential class;

k) Should the Commission approve an entirely new revenue requirement category to be included in rates between the effective dates of the 2020 GRC Phase II and the 2023 GRC Phase II decisions, the revenue allocation and rate design for that new revenue requirement category should be decided by the Commission at that time, and the rules governing existing revenue requirement categories will not govern or be precedential for that purpose; and

l) The CPUC Fee revenue requirement will be allocated on an equal-cents-per kWh basis and collected in distribution rates.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

RESIDENTIAL RATE DESIGN

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
RESIDENTIAL RATE DESIGN

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E or the Company or the Utility) rate design proposals for its Residential class of customers, to be implemented pursuant to a decision in Phase II of its 2020 General Rate Case (GRC) Phase II (Phase II). As described in Chapter 1, "Revenue Allocation and Rate Design Policy" of Exhibit (PG&E-3), these proposals include changes to distribution, public purpose program (PPP), and generation rate components. As discussed in Chapter 1, a key objective of PG&E's Residential rate proposal is to use marginal cost relationships, balanced with other objectives such as understandability, equity, and rate stability, to set distribution and generation rates.[1] PG&E sets forth its Residential rate design proposals in this testimony, focusing on changes to total bundled rates.

As discussed in Chapter 1 of Exhibit (PG&E-3), PG&E is generally minimizing rate design changes because it is proposing significant changes in marginal cost-based revenue allocations at the class level that would, gradually over the next six years, move each class to paying its fair share cost of serving that class—no more and no less. That allocation proposal would, at the end of the sixth year, result in a 1.4 percent reduction in the costs allocated to the Residential class. The CPUC has already made major progress on Residential rate reform through its Residential Rate Reform Order Instituting Rulemaking (OIR) proceeding Rulemaking (R.) 12-06-013 and the 2018 Rate Design Window (RDW) proceeding for the three major Investor-Owned Utilities (IOU) (Application (A.) 17-12-011 et seq.), and PG&E's proposals reflect those RDW decisions.

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1 PPP rates for the residential customer class are designed in accordance the guidelines described in Chapter 1 of Exhibit (PG&E-3).

1. PG&E's 2018 RDW Proceeding Fixed Charge Proposal

In Phase III of the 2018 RDW proceeding,[2] PG&E proposed that the current delivery minimum bill amount (DMBA) be replaced by a $6.37 per customer-month fixed charge, phased in over two years beginning in 2022. In the alternative, should PG&E's fixed charge proposal not be adopted, PG&E's contingency proposal was for the DMBA to be modified to apply to just the distribution component of the rate, inclusive of the Conservation Incentive Adjustment (CIA), rather than the entire delivery rate.[3]

Given the uncertainty regarding whether the California Public Utilities Commission (CPUC or Commission) will approve a fixed charge (and, if so, at what level),[4] the residential rates shown herein are based on the current $10 DMBA. PG&E will update its rates after a final 2018 RDW Phase II decision is issued.[5]

2. Summary of PG&E's Residential Rate Proposals in this Proceeding

In summary, PG&E's residential rate design proposals are as follows:

- **Baseline Quantities:**
  - Update residential electric baseline quantities, using 52.5 percent of average usage, with the most recently available four years of billing data and no changes to the current seasonal definitions (i.e., a 4-month summer season consisting of June through

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[2] A.17-12-011 (PG&E), A.17-12-012 (Southern California Edison (SCE)) and A.17-12-013 (San Diego Gas & Electric Company), which the CPUC consolidated into a single proceeding.

[3] This change to the DMBA was proposed by the Public Advocates Office at the California Public Utilities Commission (Cal Advocates). While PG&E believes a distribution minimum bill amount is an inferior rate design to one which includes a fixed charge, the distribution minimum bill amount would nevertheless represent an improvement over the current DMBA.

[4] Phase II of the 2018 RDW has been fully briefed and is pending a Proposed Decision, which is not expected until Q1 2020, with a Final Decision likely by April 2020.

[5] PG&E's $7.37 fixed charge proposal is based on marginal customer access cost estimates from its 2017 GRC Phase II testimony (A.16-06-013). If a fixed charge is approved in the 2018 RDW Phase III final decision, PG&E will update the $7.37 per customer-month figure to reflect its current estimates of marginal customer access costs in this proceeding.

September and an 8-month winter season consisting of January through May and October through December);[6] and

– Revise gas baseline quantities at the same percentage of average use as in previous GRC Phase II proceedings but incorporate the recently implemented segmentation of the gas winter season into a 2-month peak period of December and January and off-peak period of November, February, and March.[7]

- **Tiered Rates:** Establish rates for Schedule E-1 consistent with the tiered rate ratios specified by Decision (D.) 15-07-001 for the final year of the glidepath,[8] but then freeze those cent-per-kWh differentials to prevent further widening should Residential rates increase.
- **Time-of-Use Rates:** Establish rates for PG&E's default time-of-use (TOU) Schedule E-TOU-C, as well as PG&E's menu of optional TOU rates, consistent with D.19-07-004 in Phase IIB of the consolidated 2018 RDW proceeding and with D.15-11-013 in PG&E's 2015 RDW proceeding.[9]
- **CARE Rates:** Retain the 35 percent CARE discount level that will become effective on March 1, 2020, per the glidepath established in D.15-07-001,[10] but effectively apply that 35 percent discount to all rate components, including the DMBA, so that it represents a true, single-percentage, line-item discount.
- **FERA Rates:** Retain the current 18 percent FERA discount level, but effectively apply that 18 percent discount to all rate components,

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6 Schedule E-6 is the only residential rate that currently has different seasonal definitions, with a 6-month summer season consisting of May through October and a 6-month winter season consisting of January through April and November through December. Per D.15-11-013 in PG&E's 2015 RDW Proceeding (A.14-11-014), however, on January 1, 2021 the seasonal definitions for Schedule E-6 will change and match those of all of PG&E's other residential rates.

7 D.18-10-040, PG&E 2018 Gas Cost Allocation Proceeding, Decision Adopting Settlement Agreement on Residential Baseline Season Restructuring.

8 D.15-07-001 is the Phase 1 decision in the Commission's Residential Rate Reform Order Instituting Rulemaking (RROIR) proceeding, R.12-06-013.

9 A.14-11-014.

10 See D.15-07-001, p. 236, and PG&E Advice Letter (AL) 4697-E (approved by Energy Division on November 12, 2015), p. 2.

including the DMBA, so that it represents a true, single-percentage, line-item discount.

- **Medical Baseline Rates:** Retain the Medical Baseline structures approved by D.18-08-013 in PG&E's 2017 GRC Phase II proceeding, but increase the DMBA from $5 to $10 consistent with the amount paid by other non-CARE/FERA customers.
- **Electric Vehicle Rates:** Establish a Schedule EV rate transition for solar grandfathered customers (reducing the TOU differentials to better reflect current marginal costs).
- **SmartRate™:** Retain the SmartRate design approved by D.18-12-004 in Phase IIA of the 2018 RDW.
- **Master Meter Discounts:** Update the electric master meter discounts, line loss adjustment (LLA), and baseline diversity benefit adjustment (DBA) for Schedules ES, ESL, ET and ETL using recent data.
- **Rate Changes Between GRC Phase II Proceedings:** In D.18-08-013, the Commission approved rules for changing rates when revenue requirement changes occurred between GRC Phase II proceedings. PG&E proposes the same rules in this proceeding for any changes due to revenue requirement or reallocation of revenue, except as specifically noted below.

These proposed residential rate changes, if adopted, would provide more appropriate price signals for incenting more efficient energy usage across a wide range of residential customers.

The remainder of this chapter is organized as follows:

- Section B – Residential Class
- Section C – Baseline Quantities – Gas and Electric
- Section D – Schedule E-1 Tiered Rates
- Section E – Time-of-Use (TOU) Rates
- Section F – California Alternate Rates for Energy (CARE) Program
- Section G – Family Electric Rate Assistance (FERA) Program
- Section H – Medical Baseline Program
- Section I – SmartRate Program
- Section J – Study on Feasibility of Remote Dispatch of Residential Battery Storage

- Section K – Master-Meter Discounts
- Section L – Bill Comparisons

Appendix A of Exhibit (PG&E-4), titled 'Recorded Average Number of Customers and Sales,' provides recorded 2017 data for the residential class. Appendix C of Exhibit (PG&E-4), titled 'Present and Proposed Rates,' and Attachment B to this chapter, contain PG&E's present and proposed total and unbundled rates for the residential class. Appendix D of Exhibit (PG&E-4), titled "Illustrative Bill Impacts of Present Versus Proposed Rates," presents bill impacts of PG&E's proposed Schedule E-1 and EL-1 rates. Finally, Appendix F of Exhibit (PG&E-4), titled "Baseline Territory Study," presents PG&E's Baseline Territory Study required by D.18-08-013.

B. Residential Class

PG&E's Residential class encompasses Schedules E-1, E-TOU-A, E-TOU-B, E-TOU-C, E-TOU-D, E-6 (closed to new customers), EV-A, EV-B, EV2, EM, ES, ESR and ET.[11] Most of PG&E's residential customers are on the tiered, non-TOU Schedule E-1, which is currently the standard rate, open to any residential customer that is not master-metered. Specifically, as of November 2019, 87 percent of the approximately 4.8 million customers in PG&E's residential class are enrolled on E-1.

Customers who qualify for Schedule E-1 may also choose to take service on PG&E's optional TOU rates, E-TOU-A, E-TOU-B and E-TOU-C. The rate with the next largest enrollment after E-1 is Schedule E-TOU-A, which, as of November 2019, had a customer enrollment of about 223,000, which represents about five percent of PG&E's residential customer population.

PG&E's annual sales to the residential class are expected to be about 28,000 GWh (1 GWH = 1 million kWh) or 35 percent of PG&E's total retail electric sales in 2020. Income-qualified customers may enroll in either the CARE or FERA discounted rate programs. CARE customers comprise about 24 percent of PG&E's total residential customers, and FERA customers represent another 0.5 percent.

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11 Schedules E-6 and EV-A are closed to new customers but available on a grandfathered basis for legacy customers. Schedule E-TOU-A is expected to be eliminated effective September 30, 2020.

Residential customers with an electric vehicle can take service under either Schedule EV-A (1.1 percent of residential customers), EV-B (0.01 percent), or new Schedule EV2 (0.1 percent).

Schedule EM, which is closed to new installations, provides service to master metered multi-family Residential customers without submetering, including residential hotels as defined in PG&E's Electric Rule 1,[12] and recreational vehicle (RV) parks which rent at least 50 percent of their spaces on a month-to-month basis for at least nine months of the year to RV units used as permanent residences. Schedule ES is open to master-metered multi-family Residential customers that serve submetered tenants, excluding submetered mobile home parks. Schedule ESR is open to master-metered residential RV parks or marinas where spaces, slips, or berths are rented on a pre-paid monthly basis to RVs or boats used as permanent residences. Schedule ET is open to master-metered mobile home parks which serve submetered tenants. Schedules AM, ES, ESR and ET have the same energy and minimum charges as Schedule E-1.

As established by the Commission in the 2018 RDW proceeding, beginning in October 2020, PG&E is scheduled to begin its full roll-out of a default TOU rate program to eligible Residential customers.[13] Customers who receive notification of their impending default may opt-out of default TOU at any time, and will receive bill protection for their first year on the rate such that, if they would have been better off of E-1, they will receive a credit for the difference. Another part of the CPUC's already-adopted Residential rate reforms, provides that beginning in October 2020, Schedule E-TOU-C (the default TOU rate) will be considered PG&E's standard rate, although customer service representatives will discuss with all new and transferring customers their available rate options.

Because the CPUC has already put so much effort into its Residential rate reform decisions, PG&E is limiting its Residential rate design proposals in this GRC Phase II proceeding.

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12 PG&E's Electric Rule 1 can be found at the following link: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_1.pdf.

13 A.17-12-011 et seq., which thus far has resulted in the following CPUC decisions: D.18-05-011 (Phase 1), D.18-12-013 (Phase IIA), D.19-07-004 (Phase IIB).

C. Baseline Quantities – Gas and Electric

1. Introduction

Baseline quantities are the designated daily amounts of electricity and gas that are considered necessary to supply a significant portion of the reasonable energy needs of the average residential customer, pursuant to California Public Utilities Code (Pub. Util. Code) Section 739, as implemented by subsequent CPUC decisions. While residential and non-residential gas rate design issued are generally litigated in the gas Biennial Cost Adjustment Proceedings (BCAP), the proposed gas target baseline quantities applicable during the 2020 GRC cycle have been addressed in Phase II of the 2020 GRC, as ordered in D.89-12-057.

In this section, PG&E is proposing updated electric and gas Baseline quantities using a reversion to the previously-adopted methodology[14] to use weather-normalized rather than unadjusted historic usage. As with the prior method, under the proposed methodology PG&E averages the most recent four calendar years of bill frequency-derived Baseline quantities but uses normalized rather than unadjusted data. As in the past, the methodology also continues to exclude seasonal and vacation home usage, per D.04-02-057, as modified in D.07-09-004.

Thus, the updated electric and gas Baseline quantities proposed here are calculated using four years of normalized historic usage. PG&E also proposes updating the Gas Master Metered Multifamily Service Schedule End-Use Code W Baseline Allowance and moving future updates of gas baseline allowances to Gas Cost Allocation Proceedings (GCAP).

2. Normalization of Recorded Usage for Calculation of Proposed Electric and Gas Baseline Allowances Introduction

a. Overview

As mentioned above, PG&E's electric and gas Baseline allowances have historically been updated in prior GRC Phase II applications using four years of *unadjusted* historic customer usage. In this proceeding, PG&E proposes to weather-normalize recorded gas and electric

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[14] See D.02-04-026, which resolved the CPUC's Baseline Rulemaking, R.01-05-047.

Residential usage when calculating proposed Baseline allowances. This proposed change normalizes historic usage for any impacts caused by volatile temperatures during the historic period. It also incorporates non-temperature-related impacts on usage such as recent and forecast test period changes in usage caused by reduced sales, such as from customer employment of energy efficiency measures.

PG&E makes this proposal for two reasons: (1) to reduce unintended and undesirable fluctuations in Baseline allowance levels and resulting bill volatility adopted from one rate case Baseline update to the next; and (2) to better incorporate changes in customer usage in this era of increasing energy transformation as reflected in the adopted Residential gas and electric sales forecasts. This proposal supports Senate Bill (SB) 711 goals to consider bill volatility in gas and electric rate design applications and is one of the methods authorized by the Commission in D.04-04-026 for purposes of updating Baseline allowances.

b. Issues

Using four years of unadjusted recorded usage no longer provides a stable basis to calculate proposed gas and electric baseline allowances. Recorded Cooling Degree Days (CDD) and Heating Degree Days (HDD) can vary widely and inconsistently among 4-year historic periods. The change from one historic 4-year period used in a prior GRC Phase II application to the historic 4-year period used in the next GRC Phase II application has resulted in setting Baseline allowances using colder than normal[15] data for one case and warmer than normal data for another. To put it another way, total CDD’s or HDD’s in any given year are rarely close to normal. Furthermore, in the analysis presented below, even aggregating four years of data often results in average CDD’s or HDD’s that are significantly different than normal. This can be seen in the graphs Figure 3-1 and Figure 3-2 below.

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15 Normal temperature usage forecasts represent the expected usage by the class given the forecast number of customers under expected monthly Heating or Cooling Degree Days.”

Further, the average temperatures underlying usage for the historic 4-year period for the current Phase II case can be colder than normal while the temperatures underlying the usage data for the previous Phase II historic period can be warmer than normal. The opposite situation has also occurred. This results in baseline allowances, all else held equal, that can swing in an unintended manner with each update. While "normal" may be a moving target, there is significant fluctuation in the average temperatures between one 4-year period and the next 4-year period, making PG&E's proposal to use the allowed normalization method appropriate. This situation has occurred three times in the past five GRC Phase II proceedings for gas and electric Baseline allowances, as indicated by the arrows in Figures 3-1 and 3-2.[16] PG&E recently discovered this anomaly and is presenting its analysis and proposed solution at its first opportunity in this 2020 GRC Phase II.

Additionally, climate change and the impacts of both energy efficiency and electrification are transforming Residential gas and electric usage; that transformation can arguably be expected to take place at an increasing pace going forward, when all three factors are combined.[17] Therefore, it is important to have a forward-looking method for calculating Baseline allowances so that calculation of both gas and electric Baseline allowances use underlying usage data that are aligned with the assumptions otherwise built into the calculation of gas and electric rates in a way that does not contribute to bill volatility.

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16 For example, one historic four-year period, such as in the data used for the 2014 GRC Phase II setting of baseline allowances was warmer than normal, and the 4-year historic period used in the following 2017 GRC Phase II was colder than normal.

17 There is a long-term decline in adopted and actual per-customer residential gas usage, as each year some portion of customers replace the following: 25-35-year-old gas furnaces with more efficient furnaces, 10-to-20-year-old gas water heaters with more efficient gas water heaters, instant demand water heating, solar water heaters, or even electric water heaters. Additionally, there is a long-term trend of customers replacing washing machines with more water-efficient front-loading and top-loading models and use of detergents that perform using cold water instead of having to use warm or hot. Furthermore, with the recent drought some customers have installed lower flow shower heads. These latter changes reduce the level of usage of gas-fired water heaters.

FIGURE 3-1
HDD AVERAGE DURING 4-YEAR RECORDED PERIOD FOR EACH GRC PH II AS % DIFFERENCE FROM 20-YR MOVING AVERAGE HDD'S

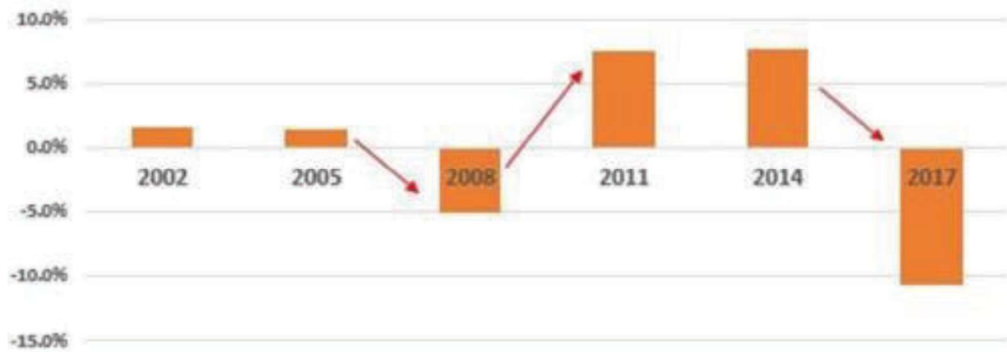
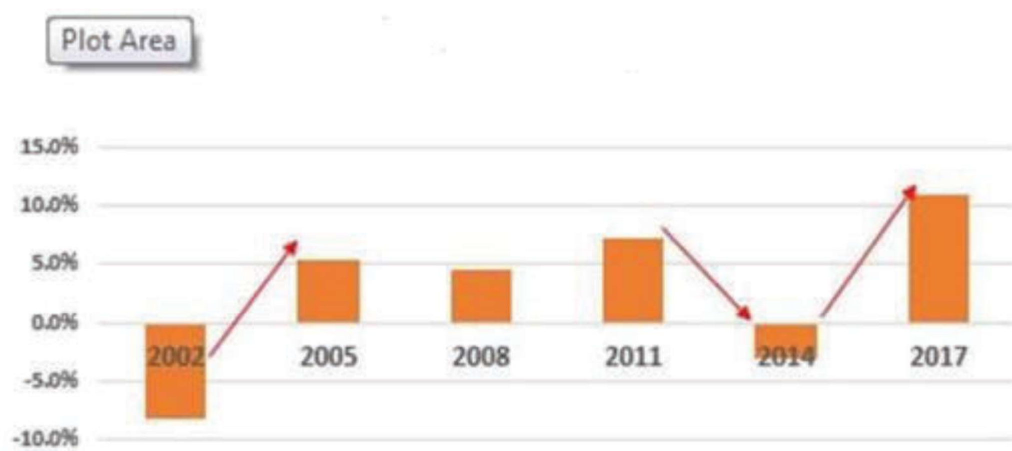


FIGURE 3-2
CDD AVERAGE DURING FOUR-YEAR RECORDED PERIOD FOR EACH GRC PH II AS % DIFFERENCE FROM 20-YR MOVING AVERAGE CDD'S



c. Proposal

To address the increasingly dynamic environment of weather and impacts from energy efficiency, water efficiency, and electrification on Residential gas and electric usage and appropriate baseline allowances, PG&E proposes to normalize the four years of historical data used to calculate gas and electric Baseline quantities. To normalize the recorded usage history PG&E determined (1) the average usage per residential customer segment (individually metered vs master metered) by month in the most recent forecast available[18]; (2) the historical average usage per customer by month; (3) the resulting monthly scaling factor by customer segment from dividing (1) by (2); and then, (4) applied that scaling factor by month by residential class segment to the historic usage by customer.

PG&E proposes to update the electric baseline allowances to reflect the adopted 2020 ERRA sales and customer forecast when it updates its billing determinants in the 2020 GRC Phase II proceeding. This would then allow the resulting billing determinants (percentage of volumes in Tier 1 and Tier 2) used in rate cases, such as the GRC Phase II electric proceeding or the GCAP to be consistent with the legislated ranges and the adopted CPUC targets. The normalization of historic usage would limit the volatility in tiered rates resulting from changes in baseline allowances between cases. Having allowances and tiered rates commensurate with near-term future usage will assist in meeting the goals of SB 711 by reducing bill volatility that is not the result of intended price signals. The normalization would align baselines with the adopted forecast of average usage per customer.

d. Other Methods Considered

PG&E's initial exploration of this issue was related purely to the CDD/HDD aspects impacting volatility of historic usage across updates. PG&E originally considered a method that included expanding the number of historic years used. However, to have a meaningful reduction in the variance of CDD/HDD's of the historic data sets between cases, ten years of historic usage data would be required for each update filing. Using the ten years of historical usage then presents a major problem in that it does not reflect the current trends in energy efficiency and hot water conservation. Furthermore, it would not reflect the continued energy efficiency impacts built into the usage forecast for

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18 For this 2020 GRC Phase II application, the most recent adopted gas throughput and customer forecast is from the 2019 Gas Transmission and Storage Rate Case that was adopted in PG&E's GCAP (D.19-10-036). For electric normalization, the most recently filed parallel forecasts are in PG&E's 2020 Energy Resource Recovery Account (ERRA) filed in June 2019.

the upcoming rate case period, during which time the allowances would be effective.

Ultimately, as PG&E continued to evaluate its proposal, it determined that the only way to simply and completely incorporate all the forces changing Residential gas and electric usage would be to normalize the recorded data to the most recent adopted forecast that is already being used for all other rate design calculations. While one year of historic usage data by customer could be used, using four years of normalized customer usage provides additional diversity of pre-normalized usage history among customers when determining baseline allowances.

e. Proposed[19] Baseline Allowances for Gas and Electric Residential Customers

PG&E's electric and gas Baseline quantities were last adjusted in D.18-08-013 (PG&E's 2017 GRC Phase II). The adopted electric allowances were implemented on January 1, 2019.[20] The adopted gas Baseline quantities were implemented on November 1, 2019[21] after incorporating the impacts of residential gas Baseline seasonal restructuring per D.18-10-040 and Advice Letter 4047-G. PG&E's proposed electric Baseline quantities are calculated using 52.5 percent and 62.5 percent tier 1 targets and using a 4-month summer season, as adopted in D.18-08-013, consistent with Pub. Util. Code Section 739(a)(1). Calculation of PG&E's proposed gas Baseline quantities retain the adopted 60 percent target for summer and 70 percent target for winter, including peak and off-peak months, also consistent with Pub. Util. Code Section 739(a)(1).

PG&E provides below tables of its proposed Baseline allowances for gas and electric residential customers, updated using the most recently available four years of normalized historic usage data (which is

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[19] As noted above, the electric Baseline allowances will be updated to use the adopted 2020 ERRA sales and customer forecast when PG&E updates its billing determinants for the ERRA decision.

[20] AL 5429-E.

[21] AL 4172-G.

October 2014 to September 2018 for electric and November 2014 to October 2018 for gas).[22] As discussed above, PG&E's proposal to use normalized customer usage will provide customers with a long-term stable trend of allowances for customers that reflect the usage levels the Commission adopts for cost allocation and rate design purposes. This mitigates allowance changes from update to update where the change is dominated by periods of volatile weather.

Below, PG&E first presents its updated gas baseline allowances and then presents the proposed electric baseline allowances, which include a few post-calculation manual adjustments.

i. Proposed Residential Gas Baseline Allowances (based on four years of normalized historic usage)

TABLE 3-1
NEW GAS BASELINE DAILY QUANTITIES
BASED ON NOV 2014 THRU OCT 2018 NORMALIZED DATA

	G-1, G-S, G-T - Basic			GM - Basic		
Baseline Territory	Summer	Peak Winter	Off-Peak Winter	Summer	Peak Winter	Off-Peak Winter
P	0.39	2.19	1.88	0.29	1.13	1.01
Q	0.56	2.00	1.48	0.56	0.77	0.67
R	0.36	1.81	1.24	0.33	1.16	0.87
S	0.39	1.94	1.38	0.29	0.65	0.61
T	0.56	1.68	1.31	0.56	1.10	1.01
V	0.59	1.71	1.51	0.59	1.32	1.28
W	0.39	1.68	1.14	0.26	0.87	0.71
X	0.49	2.00	1.48	0.33	0.77	0.67
Y	0.72	2.58	2.22	0.52	1.13	1.01

ii. Proposed Residential Electric Baseline Allowances for 4-Month Summer/8-Month Winter schedules (based on four years of normalized historic usage and including post-calculation proposed adjustments).[23]

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22 The historic periods used for each commodity are aligned with the beginning of a season change for that commodity.

23 The post-calculation proposed adjustments for the electric Baseline allowances are described in PG&E's electric Baseline workpapers to Exhibit (PG&E-3).

TABLE 3-2
NEW DAILY TARGET BASELINE QUANTITIES
BASED ON OCT 2014 THRU SEPT 2018 NORMALIZED TO FORECAST
52.5% TARGET: 4-MONTH SUMMER/8-MONTH WINTER

Individually-Metered

	Four-Year Average			
	Basic Electric		All-Electric	
Baseline Territory	Summer	Winter	Summer	Winter
P	12.7	10.6	14.1	23.9
Q	9.1	10.6	7.7	23.9
R	16.1	9.4	18.0	23.7
S	14.0	9.4	16.1	21.0
T	5.8	6.9	5.9	10.9
V	5.8	7.4	9.5	19.1
W	17.4	9.1	19.8	16.2
X	9.1	8.9	7.7	12.5
Y	9.8	10.6	10.9	22.0
Z	5.5	7.4	6.0	14.8

Master-Metered

	Four-Year Average			
	Basic Electric		All-Electric	
Baseline Territory	Summer	Winter	Summer	Winter
P	4.3	4.7	7.6	14.9
Q	4.8	4.7	6.2	14.9
R	6.9	4.8	8.4	11.0
S	6.1	4.9	9.0	11.9
T	3.2	3.9	4.1	7.5
V	3.7	4.3	4.7	9.9
W	7.5	4.8	9.9	10.0
X	4.8	5.3	6.2	10.9
Y	6.0	6.2	6.3	12.8
Z	3.4	4.4	5.0	8.6

3. Update Gas Master Metered Multifamily Service Schedule with End-Use Code W (GM-W) Baseline Allowance

PG&E proposes to update the GM-W Baseline allowance quantity for the 2020 GRC and in future proceedings. The GM-W tariff applies a subset of PG&E's master-metered customers, i.e., building owners, who supply only water heating from a central boiler to their tenants.[24] The GM-W

[24] Whether the master-metered customer receives the GM-W baseline quantities or the regular GM ("Basic") depends upon whether the tenants are individually metered by PG&E or not. If the tenants are individually metered, the landlord is assigned the GM-W designation. If the tenants do not have individual meters, the landlord is assigned the regular GM tariff and baseline allowance.

Baseline allowance was last updated to 0.5 therms per unit per day in 1984,[25] and was fixed at 0.5 therms per unit per day in D.93198.[26] PG&E proposes to update that 0.5 therms value because it is out of date and does not align with customer usage as of today, due to significantly increased energy efficiency and water conservation measures. Furthermore, the historically fixed 0.5 results in more customer usage being billed at the Tier 1 baseline rate than is appropriate under the ranges mandated for gas usage by the California Pub. Util. Code.[27]

The two graphs below (Figures 3-3 and 3-4) illustrate (1) what the GM-W allowances would have been in the previous four GRC Phase II proceedings if they had not been fixed at 0.5 therms per unit per day; and (2) how having the allowance fixed at 0.5 per therm per day has resulted in a far higher percentage of total usage for GM-W master meter owners being billed at the lower Tier 1 rates when compared to the Pub. Util. Code maximum target percentages.[28]

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[25] AL 1266-G and AL 1273-G, implementing D.83-12-068.

[26] PG&E's 1996 GRC Chapter 2 workpapers RD-2-4 notes "gas end-use W central water heating customers…receive a fixed baseline quantity of 0.5 therms per day."

[27] Pub. Util. Code 739 (a) (1) specifies that the targets adopted by the Commission for each gas utility should be based on 50-60 percent of summer usage being billed at Tier 1 rates, and 60-70 percent of winter usage being billed at Tier 1 rates.

[28] The Commission has adopted gas targets of 60 percent for summer months and 70 percent for winter months for PG&E.

FIGURE 3-3
ANNUAL BASELINE QUANTITIES "W" WITH ASSUMED GRC PH II DATA SET
DAILY THERMS PER UNIT

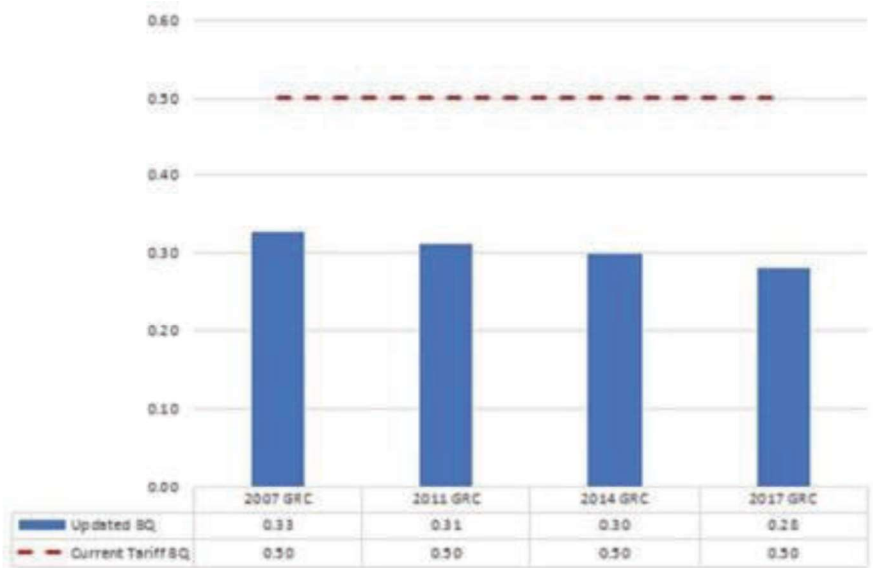

FIGURE 3-4
PERCENTAGE OF ANNUAL GM-W VOLUMES BILLED IN TIER 1
COMPARED TO PUB. UTIL. CODE MAXIMUM SEASONAL RANGES

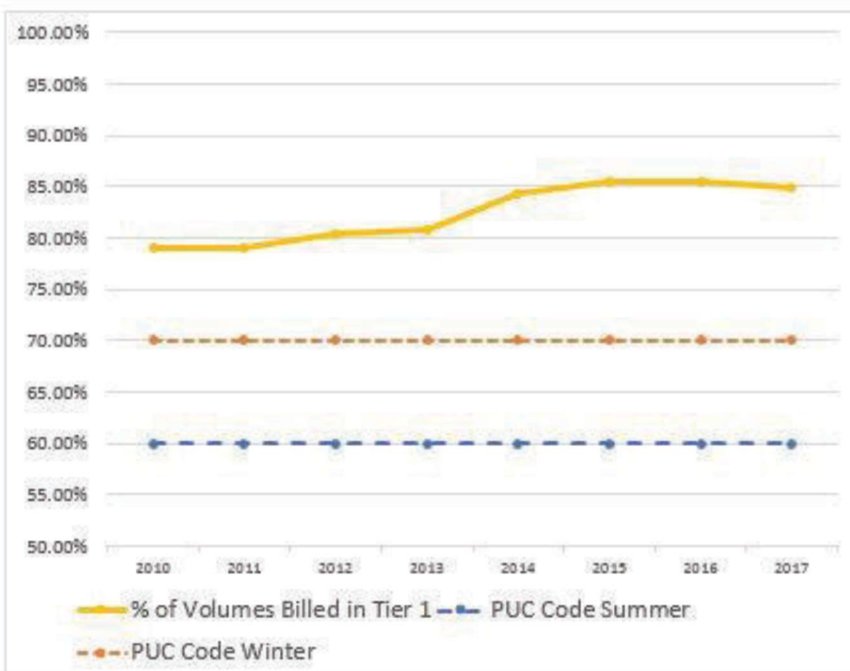

Table 3-3 below presents a distribution of the annual bill impacts on the owners of properties with service under tariff GM-W that would occur if the

Baseline allowance for GM-W were immediately updated. Over 53 percent of GM-W customers would experience an annual gas bill increase of 10 percent or more.

Given the annual bill impact distribution for the owners of properties receiving gas service under GM-W shown below, PG&E proposes to phase-in the GM-W Baseline allowance change over three years. The distribution of impacts by annual bill cost and annual bill percentage change under a 3-year phase-in are provided below in Table 3-4. With a 3-year phase-in, only 8.5 percent of building owners would experience a first-year bill impact of seven or eight percent, which would be the maximum impact experienced by any GM-W customer from this proposed update. The cumulative distribution of impacts in year three on customers of the proposed three-year phase-in is shown by Table 3-3.

TABLE 3-3
GM-W ANNUAL BILL IMPACT CUSTOMER SEGMENTATION %
YEAR 1 OF IMPLEMENTATION OF UPDATED GM-W BASELINE QUANTITY

	$ -	$ 25	$ 50	$ 75	$ 100	$ 125	$ 150	$ 175	$ 200	$ 225	$ 5,000	$ 10,000	Subtotals
0%	11.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	11.6%
1%	2.2%	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.7%
2%	1.6%	0.7%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.7%
3%	1.2%	0.7%	0.3%	0.2%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.0%	0.0%	2.7%
4%	0.6%	1.0%	0.4%	0.3%	0.1%	0.1%	0.1%	0.0%	0.0%	0.2%	0.0%	0.0%	2.9%
5%	0.3%	1.2%	0.5%	0.3%	0.1%	0.2%	0.3%	0.1%	0.1%	0.3%	0.0%	0.0%	3.4%
6%	0.1%	1.2%	0.5%	0.4%	0.2%	0.2%	0.5%	0.1%	0.1%	0.5%	0.0%	0.0%	3.8%
7%	0.1%	0.7%	0.9%	0.5%	0.4%	0.3%	0.7%	0.1%	0.1%	0.9%	0.0%	0.0%	4.7%
8%	0.1%	0.3%	1.4%	0.4%	0.4%	0.4%	0.9%	0.1%	0.2%	1.3%	0.0%	0.0%	5.5%
9%	0.1%	0.2%	1.4%	0.5%	0.4%	0.6%	1.2%	0.1%	0.2%	1.6%	0.0%	0.0%	6.3%
10%	0.1%	0.2%	0.5%	1.7%	0.6%	0.6%	1.9%	0.2%	0.3%	2.0%	0.0%	0.0%	8.0%
11%	0.1%	0.2%	0.3%	1.5%	0.9%	0.8%	2.1%	0.4%	0.3%	2.7%	0.0%	0.0%	9.3%
12%	0.1%	0.1%	0.2%	0.7%	1.9%	1.2%	2.3%	0.3%	0.5%	3.7%	0.0%	0.0%	11.1%
13%	0.1%	0.1%	0.2%	0.3%	1.4%	1.6%	2.1%	0.3%	0.4%	4.2%	0.0%	0.0%	10.8%
14%	0.1%	0.1%	0.1%	0.2%	0.4%	1.6%	1.6%	0.3%	0.4%	4.1%	0.0%	0.0%	9.0%
15%	0.1%	0.1%	0.1%	0.1%	0.2%	0.5%	0.8%	0.1%	0.2%	2.5%	0.0%	0.0%	4.6%
16%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.6%	0.0%	0.0%	0.9%
17%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
18%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
19%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
20%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Subtotals	18.4%	7.3%	6.9%	7.3%	7.2%	8.1%	14.8%	2.2%	2.9%	24.8%	0.1%	0.0%	100.0%

TABLE 3-4
GM-W ANNUAL BILL IMPACT CUSTOMER SEGMENTATION %
YEAR 1 OF 3-YEAR PHASE-IN OF UPDATED GM-W BASELINE QUANTITY

	$ -	$25.00	$50.00	$75.00	$100.00	$125.00	$150.00	$175.00	$200.00	$225.00	$5,000.00	Subtotals
0%	28.5%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	28.9%
1%	4.0%	0.9%	0.4%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	5.7%
2%	2.9%	1.6%	0.6%	0.5%	0.2%	0.1%	0.0%	0.1%	0.1%	0.2%	0.0%	6.2%
3%	1.2%	3.1%	1.1%	1.1%	0.3%	0.3%	0.1%	0.2%	0.1%	0.5%	0.0%	8.0%
4%	0.4%	3.9%	1.8%	2.4%	0.6%	0.6%	0.3%	0.4%	0.2%	1.0%	0.0%	11.7%
5%	0.4%	2.0%	4.0%	3.8%	1.0%	0.9%	0.5%	0.6%	0.4%	2.0%	0.0%	15.8%
6%	0.3%	0.6%	3.2%	4.3%	1.2%	1.2%	0.7%	0.7%	0.5%	2.5%	0.0%	15.2%
7%	0.2%	0.2%	0.9%	1.9%	0.6%	0.7%	0.5%	0.3%	0.4%	1.8%	0.0%	7.5%
8%	0.1%	0.0%	0.1%	0.2%	0.1%	0.1%	0.0%	0.0%	0.1%	0.3%	0.0%	1.0%
9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
10%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Subtotals	38.1%	12.7%	12.1%	14.4%	4.0%	3.9%	2.4%	2.3%	1.7%	8.3%	0.0%	**100.0%**

TABLE 3-5
BASELINE QUANTITY IN EACH PHASE-IN YEAR, BY SCENARIO

Baseline Quantity in Each Year by Scenario

Scenario	Year 0	Year 1	Year 2	Year 3
Implement Immediately	0.50	0.29		
Implement Over 1 GRC Rate Case	0.50	0.43	0.36	0.29

4. Move Gas Baseline Allowance Update to Gas Cost Allocation Proceeding (GCAP)

The issue of gas Baseline allowances has historically been updated in the GRC Phase II proceeding for PG&E, but PG&E believes it would be more appropriate if in the future, this issue resided in PG&E's GCAP. The GCAP is the mirror-image proceeding on the gas side of GRC Phase II dealing with cost allocation and rate design. PG&E proposes that the CPUC move the determination of future Baseline quantity updates to PG&E's GCAP, primarily to allow the CPUC to holistically consider it alongside the impacts of cost allocation and gas rate design proposals, especially when focusing on the tiered Residential gas rates and Residential rate design.[29]

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[29] In the 2018 GCAP (D.19-10-, PG&E's proposal that future GCAPs be filed every three to five years was adopted by the Commission. The pending final decision in the Rate Case Plan OIR would approve a Phase I cycle of four years.

However, PG&E proposes that any consideration of the potential future issue of Baseline territory boundary adjustments, as these territories are the same for gas and electric customers, should remain in the GRC Phase II.

5. Baseline Territory Study

In its decision on PG&E's 2017 GRC Phase II (D.18-08-013), the Commission ordered PG&E to present three versions of its Baseline territory boundaries (and corresponding Baseline allowances for each) in this application. This was done "in order to provide the Commission with the opportunity to consider new ways of defining Baseline territories that prioritize simplicity and fairness for customers."[30] PG&E has conducted the required study, which is presented in Exhibit (PG&E-4), Appendix F.

This study presents the three versions of Baseline territories required for study by D.18-08-013 and evaluates their accuracy and fairness in representing the relationship between microclimates and baseline allowances, as well as other metrics such as stability and implementability. Two of the three versions result in updates to PG&E's existing territories, while the third studies the status quo territories. Version 1 is an incremental remapping of PG&E's existing Baseline territories based on grouping customers by ZIP code and historical recorded data from nearby National Weather Service (NWS) stations; Version 2 is a simplified smaller set of territories created from scratch using the same set of ZIP code and NWS historical data. PG&E finds that both the Version 1 and 2 revised territories defined using the required ZIP-NWS analyses are unlikely to have greater climate precision or fairness than PG&E's existing Baseline territories. Furthermore, both Versions 1 and 2 would be difficult to implement and cause instability in customer rates during this transitional period when the Commission is already rolling out default TOU rates (and may also be implementing a fixed charge rollout). PG&E therefore proposes that the CPUC adopt the existing territories, while describing some of the needs for a robust and reliable microclimate-driven baseline territory recalculation should the CPUC wish to do so in PG&E's 2023 GRC Phase II proceeding.

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[30] D.18-08-013, pp. 76-78 and Ordering Paragraphs 17-20.

6. Conclusion

PG&E's proposals to use four years of normalized historic residential gas and electric usage data, update the GM-W Water Heating gas baseline allowance, determine future gas allowances in GCAPs, and retain existing baseline territory definitions are reasonable, supported by the testimony, and should be adopted by the Commission.

D. Schedule E-1 Tiered Rates

1. Introduction

In D.15-07-001, the decision in Phase I of the RROIR proceeding, the CPUC adopted a multi-year glide path that directed significant changes to the structure and rates to be charged for usage under PG&E's standard tiered rates, Schedules E-1 and EL-1. The final step in PG&E's glidepath implementation for E-1 rates occurred on March 1, 2019, and those rates now have three tiers that are defined as follows:

- Tier 1: Usage between zero and 100 percent of Baseline;
- Tier 2: Usage between 100 and 400 percent of Baseline; and
- High Usage Surcharge (HUS) Tier: Usage above 400 percent of Baseline.[31]

Per the final step of D.15-07-001's glidepath for tiered rates, the ratio of the Tier 2 rate to the composite Tier 1 rate is 1.25-to-1 and the ratio of the HUS rate to the composite Tier 1 rate is 2.19-to-1.[32]

In D.19-07-004 in Phase IIB of the 2018 RDW proceeding, the Commission determined that, beginning in October 2020, default TOU rate Schedule E-TOU-C will become the standard turn-on rate for PG&E's new and transfer Residential customers. These time of use rates are discussed in Section E of this chapter. Schedule E-1 will remain available as an

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[31] D.15-07-001 refers to this charge for usage above 400 percent of Baseline as the Super-User Electric Surcharge. However, on July 27, 2016, PG&E requested in AL 4722-E-B to modify the name of the surcharge to "High Usage Surcharge," which was approved by the CPUC's Energy Division on August 24, 2016.

[32] D.15-07-001, *mimeo*, p. 278. The composite Tier 1 rate is calculated by adding any revenues from a fixed charge and/or a minimum bill amount to the Tier 1 energy revenues, and then dividing by the Tier 1 sales.

optional rate, should a customer prefer to be served on a tiered non-TOU rate.

2. Schedule E-1 Rate Design

PG&E has designed illustrative E-1 rates based upon (a) its proposed revenue allocation in this proceeding; (b) the final steps of the glidepath for tiered rate ratios specified in D.15-07-001; and (c) forecasted billing determinants (i.e., sales by tier) based upon the Baseline quantities proposed in Section B. These rates are shown in Appendix C of Exhibit (PG&E-4).

3. Rules for Changing E-1 Rates Between GRC Proceedings

In GRC Phase II proceedings, the Commission typically adopts not only a rate design for each schedule, but also a set of rules for how rates should change during the period between when the rates are adopted and the following GRC Phase II proceeding (which, for PG&E, is anticipated to be the 2023 GRC Phase II). While PG&E is proposing that rates in this proceeding initially match the D.15-07-001 end-state glidepath ratios of 1.25-to-1 between Tier 2 and Tier 1 rates, and 2.12-to-1 between the HUS and Tier 1 rates, PG&E is concerned that adherence to these ratios may, over time, cause a widening of the cent per kWh differentials between the tiered rates. This is exactly what happened in the years after the energy crisis and was one of the main problems the Residential Rate Reform Proceeding (R.12-06-013) was opened to address.

PG&E's HUS rate today already exceeds 50 cents per kWh.[33] If it is constrained in the future to always be 2.12 times the composite Tier 1 rate, it could rapidly escalate to even higher levels in the future. To a somewhat lesser degree, constraining the Tier 2 rate to always be 1.25 times the composite Tier 1 rate might also cause a rapidly-widening cent-per-kWh difference between Tier 2 and Tier 1 rate. Both of these would adversely affect the high bill problem that already exists in the Central Valley, where an inclining block tier structure combines with high summer usage to create high bills and bill volatility.

[33] Effective October 1, 2019, the Schedule E-1 HUS rate is $0.50667 per kWh.

To mitigate against this potential problem in the future, PG&E proposes instead to change rates between GRCs by fixing the cent per kWh at their levels reached at the end of 2022. Under this proposal, the tiered rates would initially be set to match the end-state glidepath ratios, as described in the previous section. However, effective January 1, 2013, any increases or decreases in rates would be implemented by changing the rate levels in each tier by an equal cents per kWh amount. Thus, if, for example, rates needed to be increased by one cent per kWh to collect a future authorized revenue requirement, all three of the tiered rates would go up by that one cent amount, leaving the cent per kWh differentials between the tiered rates unchanged.[34]

E. Time-of-Use Rates

1. Introduction

PG&E's TOU rate offerings to Residential customers are in a process of transition. For many years, Residential TOU rates were voluntary and required customers to opt in if they wished to take service on a TOU rate. In October 2020, though, eligible customers on Schedule E-1 will begin being defaulted to PG&E's recently-approved default TOU rate, Schedule E-TOU-C, with the ability to opt-out back to E1 should they so desire. That rate will also become PG&E's standard turn-on rate for new customers or transfer customers (who have moved locations within PG&E's service area). The following sections describe PG&E's proposals for its various TOU rate options, some of which are now closed (or soon will be) to new and transfer customers but are still in place for customers on a grandfathered basis.

2. Default Schedule E-TOU-C

In its Phase IIB decision in the 2018 RDW, D.19-07-004, the Commission approved PG&E's proposed Schedule E-TOU-C as its default TOU rate. Schedule E-TOU-C has two tiers, with two TOU periods in summer (peak and off-peak) and two TOU periods in winter (peak and off-peak), as shown in Table 3-6. Per D.19-07-004, PG&E plans to begin

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[34] As described below in Sections F and G, E-1 customers who qualify for either CARE or FERA would continue to receive line-item discounts (35 percent for CARE, 18 percent for FERA) off their calculated E-1 bills.

transitioning non-excluded customers[35] to Schedule E-TOU-C beginning in October 2020, with the transition occurring in waves over a 13- to 18-month period.[36] Customers who do not wish to be defaulted to Schedule E-TOU-C can opt out and choose another available residential rate (e.g., tiered Schedule E-1, or another opt-in TOU rate). All customers who are defaulted to, and choose to remain on, Schedule E-TOU-C will receive 12 months of bill protection.[37]

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35 Customers to be excluded are as follows: Medical Baseline customers; customers requesting third-party notification pursuant to Pub. Util. Code Section 779.1(c); customers who the Commission has ordered cannot be disconnected without an in-person visit from a PG&E representative; customers with less than 12 months of metered interval data; customers for whom PG&E cannot complete the rate comparison analyses required pursuant to Pub. Util. Code Section 745; customers already on a TOU rate; customers who participated in PG&E's default TOU pilot; customers eligible for PG&E's CARE or FERA programs who reside in hot climate zones; master-metered customers; customers taking service on certain net energy metering (NEM) programs; participants in the Multifamily Affordable Solar Housing or the Solar on Multifamily Affordable Housing programs; or Transition Bundled Service customers. (D.19-07-004, Ordering Paragraph 27).

36 PG&E currently serves a small number of customers on Schedule E-TOU-C3, which was developed for PG&E's now-concluded Default TOU Pilot. At the conclusion of the Default TOU Pilot, PG&E kept the rate open for participating customers, as well as other customers who opted in to that rate. Schedule E-TOU-C3 has an identical structure and rate values as the Schedule E-TOU-C rates approved by D.19-07-004 (i.e., the same seasonal and TOU period definitions and the same peak vs. off-peak rate differentials). Effective March 1, 2020, PG&E plans to rename Schedule E-TOU-C3 as "Schedule E-TOU-C" so all E-TOU-C3 customers will automatically be on the new default TOU rate (E-TOU-C). Between March 1, 2020, and the October 2020 start of the default TOU transition period, customers can choose service on Schedule E-TOU-C by opting in to the rate.

37 Bill protection ensures that, over the 12-month period after being defaulted, the total E-TOU-C bill of a defaulted customer will be no higher than it would have been if the customers had opted out back to Schedule E-1. Customers who initially stay on E-TOU-C but then change their minds and opt out prior to the end of the 12-month bill protection period, will receive bill protection for the months during which they were on E-TOU-C.

TABLE 3-6
SCHEDULE E-TOU-C PERIOD DEFINITIONS

Effective March 1, 2020	Months	Weekdays	Weekends/ Holidays
Summer Peak	June - September	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.
Summer Off-Peak	June - September	Midnight - 4 p.m., 9 p.m. - Midnight	Midnight - 4 p.m., 9 p.m. - Midnight
Winter Peak	January - May, October - December	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.
Winter Off-Peak	January - May, October - December	Midnight - 4 p.m., 9 p.m. - Midnight	Midnight - 4 p.m., 9 p.m. - Midnight

In its Phase IIB decision, the Commission approved PG&E's proposal for "TOU Lite" peak versus off-peak (POPP) rate differentials, in order to ease the transition of customers onto the default TOU rate and increase the likelihood of their remaining on the rate after the bill protection period ends. Specifically, D.19-07-004 approved PG&E's proposal for a summer POPP of 6.3 cents per kilowatt-hour (kWh) and a winter POPP of 1.7 cents per kWh. The decision further specified that a portion of both the 6.3 cent summer and the 1.7 cent POPP differentials be included in the distribution rate component. Specifically, D.19-07-004 directs that at least 1 cent of the 6.3 cent summer POPP differential and exactly 0.23 cents of the 1.7 cent winter POPP differential be included in the distribution rate.[38] On October 9, 2019, PG&E filed Advice Letter 5653-E to implement this directive, effective March 1, 2020.[39] Finally, Ordering Paragraph 5 of D.19-07-004 also directed PG&E to include revised summer and winter POPP differentials in its 2020 GRC Phase II application for consideration by the parties and the Commission.

Per D.19-07-004, PG&E is scheduled to begin defaulting customers to E-TOU-C in waves starting in October 2020, a process which is expected to conclude within 18 months. That decision also directed that defaulted customers initially experience a "TOU Lite" rate design, with mild POPP differentials of 6.3 and 1.7 cents in summer and winter, respectively. Thus,

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38 D.19-07-004, Ordering Paragraphs 6 and 7.

39 PG&E's rate design proposes that exactly 1 cent of the total 6.3 cent summer POPP differential be in the distribution rate, with the other 5.3 cents in the generation rate.

in order for the last wave of defaulted customers to be able to experience a full twelve months of TOU Lite rates, and then receive their bill protection statement, these mild initial E-TOU-C POPP differentials need to be in place for at least 13 months after the last wave of customers are defaulted to E-TOU-C. This will ensure that all defaulted customers have had the opportunity to become accustomed to TOU after at least one year of TOU Lite rates and received their final bill protection notice (which shows the degree to which they saved, or did not save, on E-TOU-C). Thus PG&E proposes to maintain its approved TOU Lite rates through the end of 2022.[40]

Table 3-7 presents current (in yellow) and proposed (in blue) POPP differentials for Schedule E-TOU-C, as well as the underlying marginal generation and primary distribution costs (in orange). In summer, the current E-TOU-C POPP differentials are 5.3 and 1.0 cents for generation and distribution, respectively, compared to the marginal cost target differentials of 13.2 and 8.7 cents. PG&E's proposal is to gradually widen the current "TOU Lite" POPP differentials, effective no earlier than January 1, 2023, by increasing both the generation and distribution summer POPP differentials by 1.0 cents each. This would result in an increase in the total summer POPP differential of 2.0 cents. In winter, the current POPP differentials for generation and distribution are 1.5 and 0.2 cents, compared to marginal cost differentials of 4.3 and 0.3 cents. PG&E's proposal is to increase the winter generation POPP differential by 1.0 cents to 2.5 cents, and to increase the winter distribution POPP differential by 0.1 cents. This would result in a 1.1 cent increase to the total winter POPP differential. As noted above, these wider TOU price differentials would go into effect no sooner than 13 months after customers in the last wave have been defaulted to the E-TOU-C rate.

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40 In order to not alter the relative attractiveness of its menu of open rate options from which customers will be choosing, PG&E proposes no change to the design of Schedules E-TOU-C, E-1, and E-TOU-D until January 1, 2023, at the earliest. For closed legacy Schedules E-TOU-B, E-6, and EV, though, PG&E proposes to implement the design changes described herein effective January 1, 2022 (assuming a decision in this proceeding is issued in time to do so).

TABLE 3-7
SCHEDULE E-TOU-C RATE DIFFERENTIALS VS. FULL MARGINAL COST DIFFERENTIALS ($/KWH)

Schedule E-TOU-C	Current Rate Differentials			Proposed Rate Differentials			Full Marginal Cost Target Differentials		
	Generation	Distribution	Total	Generation	Distribution	Total	Generation	Distribution	Total
Summer Peak vs. Off-Peak	$0.053	$0.010	$0.063	$0.063	$0.020	$0.083	$0.132	$0.087	$0.219
Winter Peak vs. Off-Peak	$0.015	$0.002	$0.017	$0.025	$0.003	$0.028	$0.043	$0.003	$0.046

3. Optional Schedules E-TOU-B and E-TOU-D

a. Introduction

Currently, PG&E offers its customers, on an optional basis, a non-tiered TOU rate called Schedule E-TOU-B.[41] Schedule E-TOU-B has two TOU periods in summer (peak and off-peak) and two TOU periods in winter (peak and off-peak), as shown in Table 3-8 below.

TABLE 3-8
SCHEDULE E-TOU-B PERIOD DEFINITIONS

Current (Through October 1, 2025)	Months	Weekdays	Weekends/ Holidays
Summer Peak	June - September	4 p.m. - 9 p.m.	NA
Summer Off-Peak	June - September	Midnight - 4 p.m., 9 p.m. - Midnight	Midnight - Midnight
Winter Peak	January - May, October - December	4 p.m. - 9 p.m.	NA
Winter Off-Peak	January - May, October - December	Midnight - 4 p.m., 9 p.m. - Midnight	Midnight - Midnight

In Phase IIB of the 2018 RDW, PG&E proposed to narrow the peak period on Schedule E-TOU-B from the current five-hour period from 4 p.m.to 9 p.m., to a three-hour period from 5 p.m. to 8 p.m. D.19-07-004

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41 As of the date this testimony is being filed, PG&E also offers its Residential customers an optional tiered TOU rate, Schedule E-TOU-A. However, in its final decision in Phase IIB of PG&E's 2018 RDW, the Commission authorized PG&E to eliminate Schedule E-TOU-A in 2020 (*see* D.19-07-004, Ordering Paragraph 11, and subsequent PG&E AL 5654-E). PG&E plans to migrate all E-TOU-A customers to E-TOU-C (or, if the customer does not wish to take service on E-TOU-C, to any other residential rate option for which the customer is eligible) beginning with their July 2020 billing cycle, after which Schedule E-TOU-A will be eliminated. Consequently, PG&E has not designed rates for E-TOU-A in this proceeding.

approved PG&E's proposal to offer this revised TOU rate to new customers, but also directed PG&E to retain, the current Schedule E-TOU-B periods for "legacy" customers already taking service on the rate for a limited time period, until October 2025.[42]

To implement this decision, PG&E plans to close Schedule E-TOU-B to new customers on May 1, 2020. All customers who were on E-TOU-B as of April 30, 2020 may remain on the rate with unchanged TOU period definitions until it is eliminated on October 31, 2025. At that time, all remaining Schedule E-TOU-B customers will be defaulted to Schedule E-TOU-D, unless they opt out to a different available Residential rate option.

In order to avoid confusion with the legacy E-TOU-B rate for grandfathered customers, PG&E proposes to name the modified version of E-TOU-B approved by D.19-07-004 (with the narrower 3 p.m. – 8 p.m. peak period hours) "Schedule E-TOU-D." The Schedule E-TOU-D TOU period definitions are shown below in Table 3-9.

TABLE 3-9
SCHEDULE E-TOU-D PERIOD DEFINITIONS

Effective May 1, 2020	Months	Weekdays	Weekends/ Holidays
Summer Peak	June - September	5 p.m. - 8 p.m.	NA
Summer Off-Peak	June - September	Midnight - 5 p.m., 8 p.m. - Midnight	Midnight - Midnight
Winter Peak	January - May, October - December	5 p.m. - 8 p.m.	NA
Winter Off-Peak	January - May, October - December	Midnight - 5 p.m., 8 p.m. - Midnight	Midnight - Midnight

b. Schedule E-TOU-B

Since its inception, Schedule E-TOU-B has had time-differentiation only in the generation rate. While D.19-07-004 directed PG&E to include time-differentiation in Schedules E-TOU-C and E-TOU-D, it left

42 See D.19-07-004, Ordering Paragraph 12. On October 9, 2019, PG&E submitted AL 5655-E to implement these directives.

the design for the soon-to-be-closed Schedule E-TOU-B unchanged. Focusing on just the generation rate component in Table 3-10 below, the current summer and winter POPP differentials of 10.7 and 2.3 cents, respectively, are smaller than the corresponding marginal cost target differentials of 16.1 and 4.7 cents. Accordingly, PG&E is proposing to increase the summer and winter generation POPP differentials, respectively, by 2.0 cents each to 12.7 and 4.3 cents, effective January 1, 2022.[43] This achieves the objective of gradually moving the POPP differentials closer to their marginal cost targets, while mitigating potential rate shock.

TABLE 3-10
SCHEDULE E-TOU-B RATE DIFFERENTIALS VS. FULL MARGINAL COST DIFFERENTIALS ($/KWH)

Schedule E-TOU-B	Current Rate Differentials			Proposed Rate Differentials			Full Marginal Cost Target Differentials		
	Generation	Distribution	Total	Generation	Distribution	Total	Generation	Distribution	Total
Summer Peak vs. Off-Peak	$0.107	$0.000	$0.107	$0.127	$0.000	$0.127	$0.161	$0.069	$0.229
Winter Peak vs. Off-Peak	$0.023	$0.000	$0.023	$0.043	$0.000	$0.043	$0.047	$0.003	$0.050

c. Schedule E-TOU-D

Table 3-11 shows the current and proposed POPP differentials for non-tiered Schedule E-TOU-D, along with the associated marginal cost target differentials. D.19-07-004 approved summer generation and distribution POPP differentials of 8.5 and 1.0 cents, with much smaller winter generation and distribution POPP differentials of 1.5 and 0.2 cents. The table shows that PG&E's new marginal cost target differentials developed for this proceeding are all larger than these rate differentials. Accordingly, PG&E is proposing that, effective no earlier than January 1, 2023, the summer generation and distribution POPP differentials, as well as the winter generation POPP differential, all be increased by 2.0 cents. Because the winter distribution POPP

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43 PG&E generally changes its rates every January 1 to implement rate changes resulting from its Annual Electric True-Up (AET). Since PG&E anticipates the Commission will be issuing a final decision in this proceeding around mid-2021, this widening of the generation POPP differential would occur as part of the first AET-related rate change after the 2020 GRC Phase II decision is issued.

differential is less than 1.0 cents from its marginal cost target, PG&E proposes to increase this POPP differential by about 0.1 cents so that it hits the target. These proposals will gradually bring all the POPP differentials much closer to (and, in the case of the winter distribution POPP differential, exactly to) their marginal cost targets—allowing customers to gradually adjust to stronger price incentives to shift load, while offering another differentiated TOU option.

TABLE 3-11
SCHEDULE E-TOU-D RATE DIFFERENTIALS VS. FULL MARGINAL COST DIFFERENTIALS ($/KWH)

Schedule E-TOU-D	Current Rate Differentials			Proposed Rate Differentials			Full Marginal Cost Target Differentials		
	Generation	Distribution	Total	Generation	Distribution	Total	Generation	Distribution	Total
Summer Peak vs. Off-Peak	$0.085	$0.010	$0.095	$0.105	$0.030	$0.135	$0.119	$0.078	$0.197
Winter Peak vs. Off-Peak	$0.015	$0.002	$0.017	$0.035	$0.003	$0.038	$0.056	$0.003	$0.059

4. Optional Schedule E-6[44]

PG&E's Schedule E-6 is a legacy tiered TOU rate that has been closed to new customers since May 31, 2016, but remains open for grandfathered customers through 2022.[45] Schedule E-6 has two tiers, along with three TOU periods in summer (peak, partial-peak, and off-peak) and two TOU periods in winter (partial-peak and off-peak). In D.15-11-013, the Commission approved a settlement that will phase out Schedule E-6 at the end of 2022. The phase-out schedule will, over time, change the summer and winter seasonal definitions, as well as the TOU period hours, as shown in Table 3-12 below. Schedule E-6 will be eliminated at the end of 2022. All grandfathered customers still on Schedule E-6 at that time will be transitioned to PG&E's default TOU rate (Schedule E-TOU-C) unless they elect a different optional rate schedule.[46]

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44 The Schedule E-6 rate design also applies to master-metered Schedule EM TOU.

45 Grandfathered customers are those who took service on the rate on or before May 31, 2016.

46 The settlement adopted by D.15-11-013 states that remaining Schedule E-6 customers be transitioned to PG&E's then-existing default TOU rate. Since that decision, the Commission, in Phase IIB of the 2018 RDW proceeding, determined that PG&E's default TOU rate will be Schedule E-TOU-C. (*See* D.19-07-004.)

TABLE 3-12
SCHEDULE E-6 TOU PERIOD DEFINITIONS

Current (Through 2020)	Months	Weekdays	Weekends/ Holidays
Summer Peak	May - October	1 p.m. - 7 p.m.	NA
Summer Partial-Peak	May - October	10 a.m. - 1 p.m., 7 p.m. - 9 p.m.	5 p.m. - 8 p.m.
Summer Off-Peak	May - October	Midnight - 10 a.m., 9 p.m. - Midnight	Midnight - 5 p.m., 8 p.m. - Midnight
Winter Partial-Peak	January - April, November - December	5 p.m. - 8 p.m.	NA
Winter Off-Peak	January - April, November - December	Midnight - 5 p.m., 8 p.m. - Midnight	Midnight - Midnight

2021	Months	Weekdays	Weekends/ Holidays
Summer Peak	June - September	3 p.m. - 8 p.m	NA
Summer Partial-Peak	June - September	Noon - 3 p.m., 8 p.m. - 10 p.m.	5 p.m. - 8 p.m.
Summer Off-Peak	June - September	Midnight - Noon, 10 p.m. - Midnight	Midnight - 5 p.m., 8 p.m. - Midnight
Winter Partial-Peak	January - May, October - December	5 p.m. - 8 p.m.	NA
Winter Off-Peak	January - May, October - December	Midnight - 5 p.m., 8 p.m. - Midnight	Midnight - Midnight

2022	Months	Weekdays	Weekends/ Holidays
Summer Peak	June - September	4 p.m. - 9 p.m.	NA
Summer Partial-Peak	June - September	2 p.m. - 4 p.m., 9 p.m. - 10 p.m.	5 p.m. - 8 p.m.
Summer Off-Peak	June - September	Midnight - 2 p.m., 10 p.m. - Midnight	Midnight - 5 p.m., 8 p.m. - Midnight
Winter Partial-Peak	January - May, October - December	5 p.m. - 8 p.m.	NA
Winter Off-Peak	January - May, October - December	Midnight - 5 p.m., 8 p.m. - Midnight	Midnight - Midnight

For purposes of this proceeding, PG&E designed rates based on its 2021 seasonal and TOU period definitions.[47] Table 3-13 presents the current peak versus off-peak and part-peak versus off-peak rate differentials (in yellow, which correspond to today's TOU period definitions), along with the corresponding marginal cost differentials (in orange, which correspond to the 2021 TOU period definitions). For summer generation rates, the current peak versus off-peak price and part-peak versus off-peak differentials are 17.2 and 5.0 cents, respectively. In comparison, the analogous marginal cost differentials are 10.4 and 10.6 cents. So, PG&E is proposing to reduce the peak versus off-peak differential by 2.0 cents to 15.2 cents and increase the part-peak versus off-peak differential by 2.0 cents 7.0 cents, to bring both closer to their generation marginal cost target differentials. The current winter generation peak versus off-peak rate differential is 1.4 cents compared to the marginal generation cost differential of 5.6 cents. Here, PG&E is proposing a 2.0 cent increase to this differential, bringing it to 3.4 cents to better reflect marginal costs.

TABLE 3-13
SCHEDULE E-6 RATE DIFFERENTIALS VS. FULL MARGINAL COST DIFFERENTIALS
($/KWH)

Schedule E-6	Current Rate Differentials			Proposed Rate Differentials			Full Marginal Cost Target Differentials		
	Generation	Distribution	Total	Generation	Distribution	Total	Generation	Distribution	Total
Summer Peak vs. Off-Peak	$0.172	$0.242	$0.414	$0.152	$0.222	$0.374	$0.104	$0.088	$0.192
Summer Part-Peak vs. Off-Peak	$0.050	$0.061	$0.110	$0.070	$0.048	$0.118	$0.106	$0.048	$0.154
Winter Part-Peak vs. Off-Peak	$0.014	$0.039	$0.053	$0.034	$0.019	$0.053	$0.056	$0.003	$0.059

For summer distribution rates, the current peak versus off-peak differential of 24.2 cents vastly exceeds the 8.8 cent marginal cost target, so PG&E is proposing to decrease it by 2.0 cents to 22.2 cents. The 6.1 cent part-peak versus off-peak differential, though, only slightly exceeds the 4.8 cent marginal cost target, so PG&E is proposing to decrease it by 1.3 cents to match the target. For winter distribution rates, the 3.9 cent

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[47] Typically, it has taken at least 18 months from the time a GRC Phase II Application is filed for the Commission to issue a final decision. Since PG&E is filing this Application on November 22, 2019, a final decision is not anticipated any earlier than June 2021.

part-peak versus off-peak differential is 3.6 cents higher than the 0.3 cent marginal cost target, so PG&E proposes to decrease it by 2.0 cents to 1.9 cents. PG&E proposes that these changes take effect on January 1, 2022.

5. Optional Schedules EV and EV2 for Electric Vehicle Charging

PG&E currently maintains two non-tiered TOU rate schedules for electric vehicle charging: Schedules EV and EV2. Schedule EV was developed prior to when the influx of solar power shifted the high-cost generation hours from afternoon to later in the day. It has peak period hours from 2 p.m. to 9 p.m. on weekdays and from 3 p.m. to 7 p.m. on weekends and holidays, as shown in Table 3-14. Schedule EV customers can choose between two options: (1) a whole-house charging option on Rate A, where the household's entire usage is billed on the rate; or (2) a separately-metered option on Rate B, where the customer has a second meter on its EV charger (with the remainder of the household loads being metered and billed separately on a different Residential rate). Option A of Schedule EV is now closed to new customers, available only on a grandfathered basis to legacy customers, while Option B remains available to new enrollment.

TABLE 3-14
SCHEDULE EV TOU PERIOD DEFINITIONS

Current (Through November 2025)	Months	Weekdays	Weekends/ Holidays
Summer Peak	May - October	2 p.m. - 9 p.m.	3 p.m. - 7 p.m.
Summer Partial-Peak	May - October	7 a.m. - 2 p.m., 9 p.m. - 11 p.m.	NA
Summer Off-Peak	May - October	Midnight - 7 a.m., 11 p.m. - Midnight	Midnight - 3 p.m., 7 p.m. - Midnight
Winter Peak	January - April, November - December	2 p.m. - 9 p.m.	3 p.m. - 7 p.m.
Winter Partial-Peak	January - April, November - December	7 a.m. - 2 p.m., 9 p.m. - 11 p.m.	NA
Winter Off-Peak	January - April, November - December	Midnight - 7 a.m., 11 p.m. - Midnight	Midnight - 3 p.m., 7 p.m. - Midnight

With the closing of Option A of Schedule EV, PG&E now offers customers seeking a whole-house charging option a new Schedule EV2, approved by the Commission in D.18-08-013, with peak period hours every day from 4 p.m. to 9 p.m. This better reflects the times of day when PG&E's costs are now the highest. The Schedule EV2 TOU period definitions are shown in Table 3-15.

TABLE 3-15
SCHEDULE EV2 TOU PERIOD DEFINITIONS

Current	Months	Weekdays	Weekends/ Holidays
Summer Peak	May - October	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.
Summer Partial-Peak	May - October	3 p.m. - 4 p.m., 9 p.m. - Midnight	3 p.m. - 4 p.m., 9 p.m. - Midnight
Summer Off-Peak	May - October	Midnight - 3 p.m.	Midnight - 3 p.m.
Winter Peak	January - April, November - December	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.
Winter Partial-Peak	January - April, November - December	3 p.m. - 4 p.m., 9 p.m. - Midnight	3 p.m. - 4 p.m., 9 p.m. - Midnight
Winter Off-Peak	January - April, November - December	Midnight - 3 p.m.	Midnight - 3 p.m.

In this proceeding, PG&E recommends adjustments to the TOU rate differentials for Schedule EV, effective January 1, 2022, but not for Schedule EV2.

a. Schedule EV

In D.17-01-006, the Commission indicated that while solar customers could be grandfathered on the current TOU periods (both seasons and hours), the rates for those outdated legacy TOU periods may be adjusted to reflect the changing underlying marginal costs associated with those months and hours. This is provided, however, that the adjusted, cost-based rates could not result in the partial-peak rate exceeding the peak rate.[48]

[48] See D.17-06-001, p. 64, and fn 48.

The yellow and orange portions of Table 3-16 below show the current Schedule EV POPP differentials compared to the updated marginal costs developed by PG&E for this proceeding. As that table shows, the current summer generation and distribution differentials between peak and off-peak rates of 21.1 and 18.8 cents, respectively, are now substantially higher than the corresponding marginal cost differentials of 9.2 and 6.3 cents. To move the rates somewhat closer to these much smaller marginal costs, PG&E is proposing to reduce the peak versus off-peak price differentials for both generation and distribution by 2.0 cents, as shown in the blue portion of Table 3-16. A similar situation exists when comparing the current summer generation and distribution differentials between part-peak and off-peak rates (6.7 and 8.7 cents, respectively) to the corresponding marginal cost differentials (of 0.4 and 0.0 cents, respectively). PG&E is proposing to reduce these two differentials by 2.0 cents as well, again to bring TOU rate differentials somewhat more in line with the smaller marginal cost differentials.

TABLE 3-16
SCHEDULE EV RATE DIFFERENTIALS VS. FULL MARGINAL COST DIFFERENTIALS
($/KWH)

Schedule EV	Current Rate Differentials			Proposed Rate Differentials			Full Marginal Cost Target Differentials		
	Generation	Distribution	Total	Generation	Distribution	Total	Generation	Distribution	Total
Summer Peak vs. Off-Peak	$0.211	$0.188	$0.399	$0.191	$0.168	$0.359	$0.092	$0.063	$0.155
Summer Part-Peak vs. Off-Peak	$0.067	$0.087	$0.153	$0.047	$0.067	$0.113	$0.004	$0.000	$0.004
Winter Peak vs. Off-Peak	$0.034	$0.200	$0.234	$0.027	$0.180	$0.206	$0.027	$0.001	$0.028
Winter Part-Peak vs. Off-Peak	-$0.005	$0.092	$0.087	$0.000	$0.072	$0.072	$0.000	$0.000	$0.000

For winter, the current generation differentials between peak and off-peak rates, and between part-peak and off-peak rates, are not far from the corresponding marginal cost differentials. Here, PG&E proposes simply to set the proposed differentials equal to the target marginal cost differentials. However, the current distribution differentials between peak and off-peak rates, and between part-peak and off-peak rates, are greatly in excess of the corresponding marginal cost differentials. So here, too, PG&E is proposing to reduce each of those rate differentials by 2.0 cents to bring them somewhat closer to the much lower marginal cost differentials (which are zero or virtually zero).

b. Schedule EV2

In PG&E's 2017 GRC Phase II proceeding, the Commission approved new EV TOU periods and rates that were part of a settlement between PG&E and other parties, which subsequently became the new Schedule EV2.[49] That settlement provided that future changes to all EV2 TOU rates would be made on an equal cents per kWh basis until the rate design is re-evaluated in a future rate proceeding that occurs no sooner than PG&E's 2023 GRC Phase II. Accordingly, as shown in Table 3-17, in this proceeding PG&E is not proposing any changes to the EV2 TOU rate differentials from the differentials agreed upon by the settling parties and approved by the Commission in D.18-08-013.

TABLE 3-17
SCHEDULEV2 RATE DIFFERENTIALS VS. FULL MARGINAL COST DIFFERENTIALS
($/KWH)

Schedule EV2	Current Rate Differentials			Proposed Rate Differentials			Full Marginal Cost Target Differentials		
	Generation	Distribution	Total	Generation	Distribution	Total	Generation	Distribution	Total
Summer Peak vs. Off-Peak	$0.086	$0.227	$0.313	$0.086	$0.227	$0.313	$0.144	$0.092	$0.236
Summer Part-Peak vs. Off-Peak	$0.041	$0.161	$0.202	$0.041	$0.161	$0.202	$0.040	$0.014	$0.054
Winter Peak vs. Off-Peak	$0.036	$0.149	$0.185	$0.036	$0.149	$0.185	$0.049	$0.003	$0.052
Winter Part-Peak vs. Off-Peak	$0.023	$0.145	$0.169	$0.023	$0.145	$0.169	$0.023	$0.001	$0.023

6. Rules for Changing TOU Rates Between GRC Proceedings

After the TOU rates are set in this proceeding, PG&E proposes that all subsequent changes to rates on Residential TOU schedules, between this 2020 GRC Phase II and PG&E's 2023 GRC Phase II, be calculated on an equal cents per kWh basis. Doing so will maintain the marginal cost-based TOU rate differentials adopted in this proceeding.[50] Furthermore, given PG&E's proposal for rate changes between GRCs for Schedule E-1 described in Section D.3. above, which will also be made on an equal cents

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[49] *See* D.18-08-013, Ordering Paragraph 13.

[50] This is consistent with the rules for rate changes between GRCs approved by the Commission in D.18-08-083 for PG&E's 2027 GRC Phase II.

per kWh basis, the baseline credits on PG&E's tiered TOU rates (Schedules E-TOU-C and E-6) will remain unchanged when rates change.[51] As described below in Sections F and G, Residential customers on TOU rates who qualify for either CARE or FERA would continue to receive line-item discounts (35 percent for CARE, 18 percent for FERA) off their calculated TOU schedule bills.

F. CARE Program

D.15-07-001 prescribed a glidepath for gradually reducing PG&E's CARE discount percentage to the top end of the statutory range of 30 to 35 percent.[52] PG&E's CARE discount percentage is currently set at 35.5 percent, and it will reach the final step in the glidepath on March 1, 2020 when it will be reduced to 35 percent.[53]

In Phase IIA of the 2018 RDW proceeding, PG&E proposed to simplify how CARE rates are administered by eliminating its CARE rate schedules and instead provide the CARE discount via a line-item percentage discount off the customer's corresponding non-CARE rate schedule. The Commission approved PG&E's line-item CARE discount in D.18-12-004 and PG&E subsequently filed Advice Letters 5547-E and 5638-E with tariff changes to implement the line-item discount.[54] As a result, PG&E will eliminate Schedule EL-1 and all its other CARE tariffs on March 1, 2020, and provide CARE discounts as a partial line-item discount via newly-approved Schedule D-CARE.[55]

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[51] The Baseline credits on PG&E's two-tiered TOU rates E-TOU-C and E-6 are calculated based on the E-1 rates, as a sales-weighted average of (a) the difference between the E-1 Tier 2 and Tier 1 rates and (b) the difference between the E-1 HUS Tier and Tier 1 rates. Since neither (a) nor (b) will change under PG&E's proposal when rates are changed, the Baseline credit will remain the same so long as the sales weights do not change. However, if a rate change due to changing revenue requirements also involves a new sales forecast (for example, as typically occurs once per year, when the ERRA sales forecast is adopted), then the Baseline credit may change due to changing sales weights.

[52] See Pub. Util. Code Section 739.1(c)(1).

[53] See D.15-07-001, p. 236, and PG&E AL 4697-E (approved by Energy Division on November 12, 2015), p. 2.

[54] AL 5547-E was filed on May 22, 2019 and approved by Energy Division on June 13, 2019. AL 5638-E was filed on September 18, 2019.

[55] Schedule D-CARE acts as a rider on the customer's selected non-CARE schedule.

As noted above, the PG&E's overall average effective CARE discount is currently set at 35.5 percent and will be reduced to 35 percent on March 1, 2020. In this GRC Phase II proceeding, PG&E proposes that the CARE discount percentage remain at 35 percent.

PG&E does recommend one change to the CARE discount, though, pertaining to the DMBA. In proposing a line-item discount for CARE in Phase IIA of the 2018 RDW, one of PG&E's primary objectives was to make the discount simple for customers to understand. Another objective was to be able to implement the discounts via a single rider rate, Schedule D-CARE, and thus eliminate a significant number of stand-alone CARE rate schedules. PG&E's vision was that a CARE household could easily see it was receiving a 35 percent discount on the total bill if the bill were first calculated based on non-CARE rates and then, at the end, reduced by a 35 percent line-item CARE discount.

However, in D.15-07-001, the Commission specified that the DMBA for CARE customers be set at $5.[56] The fact that this is a 50 percent discount on that particular rate component compared to the $10 DMBA paid by non- CARE customers complicates matters and makes it difficult to achieve the intended benefit of a CARE bill that is simpler and easier to understand. This is because a rate design which discounts the DMBA by more than 35 percent can only achieve an overall average effective discount of 35 percent if the energy charges are discounted at a percentage lower than 35 percent. Specifically, PG&E estimates that energy rates would need to be discounted at about 34.8 percent so that, in combination with a 50 percent discount on the DMBA, they yield a 35 percent overall average effective discount.[57] So, rather than being able to give CARE customers a simple message that their bills are being discounted by 35 percent, PG&E must instead explain that the discounts for most CARE

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[56] See D.15-07-001, p. 227, and Conclusion of Law 21.

[57] This is just an estimate. The precise discount percentage for the energy charges is not known as of the date this testimony is being filed. It depends on the 2020 forecasted billing determinants (in particular, kilowatt-hours subject to the DMBA) and the residential revenue requirement that will be in place on March 1, 2020.

customers is only 34.8 percent, in order for a small percentage of very low-usage customers to receive discounts of up to 50 percent.[58]

D.15-07-001 did not permanently lock in a $5 DMBA, but rather allowed for future changes via each utility's GRC Phase II proceeding.[59] Accordingly, in this proceeding PG&E proposes that there no longer be a separate DMBA rate for CARE customers. Instead, the CARE discount would be provided as a 35.0 percent line-item discount for all customers regardless of their usage level.[60] This would eliminate the variation in percentage bill discounts received by customers with varying usage levels and allow for a much simpler customer outreach message: "Every CARE customer, regardless of rate schedule or usage, receives the identical 35 percent discount." It would have minimal effects on CARE customer bills, at most increasing a bill by $1.50 for a customer with zero usage, while also resulting in bill decreases for the vast majority of CARE customers.

G. FERA Program

PG&E currently provides an 18 percent discount to its residential customers on the FERA program. This 18 percent level is specified by statute,[61] and is currently provided via Schedule E-FERA, which acts as rider on the customer's selected rate schedule. In this proceeding, PG&E is proposing just one change to FERA rates, which mirrors PG&E's CARE proposal in the previous section. Currently, customers on Schedule E-FERA receive an 18 percent discount relative to standard, non-low income rates, but also receive a 50 percent discount on the DMBA rate component, if applicable (i.e., their DMBA is set at

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58 A customer with zero usage would see a discount of 50 percent. As a customer's usage increases, this discount percentage declines, reaching 34.8 percent at the threshold kWh amount at which the DMBA no longer applies.

59 D.15-07-001, at p. 227, stated that "the minimum bill shall be set at $10 for non-CARE customers and $5 for CARE customers starting with the 2015 rate changes to be implemented under this decision. The future minimum bill ... amounts shall be subject to review by the Commission and the parties through the IOU's GRC Phase II applications."

60 Mathematically, this is equivalent to discounting each and every rate component, including the DMBA, by 35 percent. So, although there would no longer be any stand-alone CARE rate schedules, the effective DMBA for CARE customers would be $6.50.

61 See Pub. Util. Code Section 739.12(b).

the same $5 level as for CARE).[62] This results in very low-usage customers subject to the DMBA receiving discounts in excess of 18 percent.[63] Because of that, the overall average FERA discount exceeds the 18 percent level codified in the statute.[64]

To correct this and bring the overall average effective FERA discount to 18 percent, PG&E is proposing here to eliminate the $5 DMBA for FERA customers and, instead, provide the FERA discount as a true 18 percent line-item discount for all customers regardless of usage level.[65] Like PG&E's CARE line-item discount proposal, this would eliminate the variation in percentage bill discounts received by FERA customers with varying usage levels and allow for a much simpler customer outreach message: "Every FERA customer, regardless of rate schedule or usage, receives the identical 18 percent discount mandated by statute." It, too, would have minimal effects on FERA customer bills, at most increasing a bill by $3.20 (for a customer with zero usage).

H. Medical Baseline Program

D.18-08-013 approved a settlement that included a number of reforms to PG&E's Medical Baseline program to be implemented in 2020:

- End the four-cent per kWh credit for non-CARE Medical Baseline customers for usage exceeding 200 percent of baseline;
- Change the methodology for calculating Tier 2 and Tier 3 usage for Medical Baseline customers to the same methodology used for non-Medical Baseline customers; and
- For non-CARE Medical Baseline, apply an equal cents per kWh discount to all usage by reducing the CIA by an amount equal to the Department of Water Resources bond charge, currently approximately 0.5 cents per kWh.

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62 See D.15-07-001, Conclusion of Law 21.

63 In fact, a zero-usage FERA household currently pays the same $5 monthly bill as an economically worse-off zero-usage CARE customer.

64 Pub. Util. Code Section 739.12(b) states: "The FERA program discount shall be an 18 percent line-item discount applied to an eligible customer's bill calculated at the applicable rate for the billing period."

65 Mathematically, this is equivalent to discounting each and every rate component, including the DMBA, by 18 percent, resulting in the effective DMBA for FERA customers being $8.20.

In addition, in D.18-09-013 the CPUC approved an uncontested settlement among PG&E and other parties specifying that Medical Baseline customers served by CCAs will have their PCIA exemption phased-out (or, as stated alternatively in the settlement, have their PCIA charge phased in) over a four-year period beginning as early as June 1, 2019.[66] PG&E expects to begin this phase-in late 2021.

PG&E is here proposing just one further change to Medical Baseline beyond those approved by D.18-08-013. Specifically, similar to its proposals for CARE and FERA customers, PG&E is proposing that Medical Baseline customers also be subject to a $10 DMBA instead of the current $5 amount. This will facilitate uniformity for all of PG&E's Residential schedules. All customers, including CARE, FERA and Medical Baseline, will be subject to a $10 DMBA. CARE and FERA customers will receive their discounts via line-item discounts and Medical Baseline customers will receive their discounts by receiving additional baseline allocations and thus being able to consume additional kilowatt-hours at the lower Tier 1 rate. This proposed change is unlikely to affect many Medical Baseline customers, since the DMBA only affects the bills of very low users and Medical Baseline customers typically are high users. Indeed, the whole rationale for providing such customers with additional baseline amounts is to mitigate the high bills they would otherwise face due to their medical needs causing their usage to increase into the upper tiers.

I. SmartRate Program

PG&E's SmartRate Program is designed to provide load relief during selected periods, typically on hot summer days when costs are particularly high. It is a voluntary opt-in program for Residential customers who see very high prices during a limited number of event hours, and thus have strong incentives to reduce load during those hours. Participating customers benefit from lower prices during non-event hours. The SmartRate Program is implemented via Schedule E-RSMART, which acts as a rider rate in conjunction with the customer's selected rate schedule.

In Phase IIB of the 2018 RDW, PG&E proposed a number of changes to the rate design of its SmartRate Program, including moving the event hours to later

66 D.18-09-013, p. 7.

in the day (from 2 p.m.-7 p.m. to 5 p.m.-8 p.m.) and modifying the way in which credits and charges are assigned to SmartRate customers. These changes were approved by the Commission in D.18-12-004, and PG&E proposes no further changes here.

J. Study on Feasibility of Remote Dispatch of Residential Battery Storage

In D.18-08-013, deciding PG&E's 2017 GRC Phase II (D.18-08-013), the Commission adopted the Settlement Agreement on Residential Rate Design, which requires PG&E to analyze the feasibility of programs for remote dispatch of residential battery storage:

> Prior to the next Phase II GRC, PG&E will analyze the feasibility of providing a program or programs for residential customers with battery storage that requires a minimum amount of remote dispatch of the storage unit at the direction of PG&E or the Independent System Operator. PG&E may conduct this analysis either for inclusion in the next Phase II or as part of another Commission proceeding. The analysis shall consider technical, economic, and ratemaking challenges along with identifying potential benefits to the grid, non-participating customers, and California's greenhouse gas goals. PG&E shall consult with interested stakeholders in conjunction with its analysis.[67]

Pursuant to this agreement, PG&E conducted the study based on multiple components, including PG&E's participation in the SGIP GHG Signal Working Group and two Electric Program Investment Charge (EPIC) projects. The Greenhouse Gas (GHG) Signal Working Group developed recommendations for the content and delivery of a GHG signal (e.g., dynamic information on marginal GHG impacts of load). The study also considered two EPIC Projects that focused respectively on the use of customer-sited storage to reduce peak load and absorb excess DER generation and on producing proof of concept software to control these remote resources. The results of this study are summarized in Attachment A to this chapter, "Feasibility of Remote Dispatch of Residential Energy Storage."

K. Master Meter Discounts

This section presents PG&E's electric master meter discount proposals for Electric Multifamily Service (Schedule ES) and Electric Mobile Home Park

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[67] D.18-08-013, Ordering Paragraph 13, relating to January 24, 2018 Motion for Adoption of Residential Rate Design Supplemental Settlement Agreement.

Service (Schedule ET).[68] Under both of these rate schedules, electricity is delivered to a single master meter at a residential development. Under Schedule ET, the electricity is then delivered through a private sub-metered distribution system to individual tenants within the master metered mobile home parks (MHP). Under Schedule ES, electricity is delivered to other multifamily residential accommodations. PG&E's end-use customers on the master meter schedules are the owners of the master-metered MHP or other master-metered multifamily residential developments such as apartment buildings or apartment complexes. The owners taking service from PG&E under these master meter rate schedules receive a discount to compensate them for utility avoided costs because the utility does not directly serve those tenants. These rate schedules have been closed to new customers since January 1, 1997.

The master meter discount methodology proposed in this application follows the methodology adopted in D.18-08-013 which dates back to D.11-12-053[69] with further guidance from D.04-04-043 and D.04-11-033. The next Master Meter discounts were set in D.15-08-005, PG&E's 2014 GRC Phase II, adopting an all-party settlement. The current Master Meter discounts were set in D.18-08-013, in PG&E's 2017 GRC Phase II, in which WMA contested many aspects of the master meter discounts proposed by PG&E, on many of the same grounds the Commission had already rejected in D.11-12-053. In all cases where applicable, D.18-08-013 upheld and reaffirmed the Commission's disposition of those contested master meter discount issues.[70]

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68 This 2014 GRC Phase II Application includes only PG&E's electric master meter proposals. Consistent with a prior Commission ruling, PG&E will continue to submit its gas master meter testimony in its BCAP. (*See* January 10, 2005 ALJ Ruling Granting WMA Motion to Consider Gas Master Meter Discount Issues in Application 04-07-044 and Modifying Scoping Memo in Application 04-07-044.)

69 D.11-12-053, pp. 36-53. The WMA timely filed a Petition to Modify and Application for Rehearing of Decision 11-12-053, both of which the CPUC denied. (See D.12-10-004 and D.12-08-046, respectively.) On September 21, 2012, WMA timely filed with the Court a Petition for Writ of Review. The CPUC, as well as The Utility Reform Network (TURN) and PG&E all opposed WMA's Petition, which was denied by the District Court of Appeal of the State of California in and for the First Appellate District, Division Three (No. A136617).

70 D.18-08-013, pp. 112-140.

PG&E's proposed rates under the methodology adopted in D.18-08-013 are a net discount of $1.95 for Schedule ET, and a net discount of $1.09 for Schedule ES, per space per month.

1. Marginal Cost Master Meter Discount Methodology

In the 2003 GRC Phase II, PG&E proposed a marginal cost-based approach for calculating the master meter discount, as opposed to the sampling method presented by PG&E in previous GRCs.[71] Discounts calculated using this method were adopted in the settlement approved in D.05-11-005. This same value was again adopted in D.07-09-004 for PG&E's 2007 GRC. In PG&E's 2011 GRC Phase II, the Company performed a thorough review of its master meter discount methodology and carefully evaluated proposals presented by TURN and WMA. In response to these proposals, PG&E further refined its methodology with parties agreeing to some but not all of PG&E's proposals. PG&E reached a settlement for the Schedule ES master meter discount that was approved by the Commission in D.11-12-053. No settlement could be reached, however, for the master meter MHP discount in Schedule ET, and the methodology was fully litigated. In D.11-12-053, the Commission adopted PG&E's MHP master meter discount methodology, which was consistent with the guidance provided in D.04-04-043 and D.04-11-033 .[72]

In reaching its decision on MHP master meter methodology in PG&E's 2011 GRC Phase II, the Commission resolved several highly contested issues that had been the subject of debate for some time. The CPUC decided: (1) to include replacement costs through application of the Real

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[71] 2003 GRC Phase II, Application 04-06-024, Exhibit (PG&E-10), Chapter 2B, "Residential Rates: Electric Master Meter Discounts."

[72] The 2004 Decisions, D. 04-04-043 and D. 04-11-033, were the decisions arising from Phase I and Phase II, respectively, of the MHP Sub-metering Discount Rulemaking 03-03-017/Investigation 03-03-018. These 2004 Decisions identified categories of costs avoided by electric and natural gas utilities when MHP tenants are served by a master meter owner. Specifically, D.04-04-043 "identified the categories of costs the electric and natural gas utilities incur when directly serving MHP tenants that are avoided by the utilities when the MHP is served through a distribution system owned and operated by the MHP owner." (See D.04-11-033, p. 2, citing D.04-04-043.) These 2004 decisions allowed utilities to use a marginal cost methodology for master meter discount calculations in addition to the prior existing method using a statistically valid random sample of directly served MHPs in a utility's service area.

Economic Carrying Cost (RECC) to new connection equipment costs; (2) to exclude any Equal Percentage of Marginal Cost factors; (3) to consider new connection costs to properly be the costs as capped by PG&E's line extension allowances under Rule 15 and 16 with application of the rental method; and (4) that PG&E's multifamily residential costs are a reasonable proxy for the average avoided costs to otherwise directly serve tenants in master metered MHPs. In this proceeding, PG&E proposes to continue using that same methodology consistent with what the CPUC adopted in D.11-12-053.

Similarly, in D.18-08-013, in Section 7.3, the Commission resolved and expressly rejected disputed issues related to various WMA allegations that: (1) the master meter discount failed to cover sub-metering system operating costs; (2) line-extension allowances should be used as the basis for master meter discounts; (3) several Schedule ET avoided cost and DBA dataset inputs or assumptions should be changed or recalculated; (4) Schedule ET should be its own separate revenue allocation class; (5) excavation and replacement costs should be explicitly included in the master meter discount; and (6) Schedule ET Special Condition 9 should be updated.

In this proceeding, PG&E proposes to continue using the same methodology adopted by the CPUC in D.18-08-013.

The basis of this methodology can be described by the formula below:

(master meter discount) = (base discount) – (diversity benefit adjustment) + (line loss adjustment)

The Master Meter Discount model calculates these discounts for two rate schedules available to the master meter owners: ET and ES. Schedule ET is available to owners of mobile home park's (MHP) and Schedule ES is available to owners of submetered multi-family dwellings that are not MHP's (such as apartment complexes).

The base discount represents the costs of transformers, service conductors, service drops, and meters that PG&E avoids in a master meter arrangement. The amount of the discount is different for ET and ES. The reason for this is that a master-meter arrangement (as opposed to an arrangement in which PG&E serves each individual dwelling) results in different cost savings for PG&E, depending on whether a master meter is used for an MHP or other type of multi-family dwelling. The list below summarizes the avoided costs that are different between MHP (ET) and other multi-family dwellings (ES). Avoided costs not listed are the same across the two schedules:

1. Transformer equipment costs;
2. Service equipment costs;
3. Transformer operations and maintenance costs;
4. Service operations and maintenance costs;
5. Secondary distribution capacity costs;
6. Line loss costs; and
7. Average number of residential units.

For Items 1 through 6 in the list above, PG&E does avoid costs under a master-meter arrangement for MHP's (ET), but avoids no costs in a master-meter arrangement for ES (multi-family). PG&E avoids costs for MHP's but not multi-family dwellings because a mobile home park owner must construct transformers and services to extend electric service from the master meter to the submeters, thus displacing PG&E's cost. However, in a multi-family dwelling that would be eligible for Schedule ES, all the submeters are clustered in one large "bank" of meters. This means that the owner of the multi-family dwelling does not construct transformers and services to extend electric distribution from the master meter to the submeters; rather, PG&E does. Therefore, PG&E saves no transformer and service costs in a master-meter arrangement for multi-family dwellings. Item 7 is needed because, on average, MHP's and other multi-family dwellings have different numbers of dwellings. PG&E's 2020 GRC proposed monthly base discount per residential unit is $3.74 for Schedule ET and $3.49 for Schedule ES.

The line loss adjustment increases the amount of the discount for MHP (ET) owners. It accounts for the fact that the MHP owners must purchase more electricity at the master meter than the total electricity that the tenants demand at their individual submeters. Additional power is needed because some power is lost in the distribution system between the master meter and the submeters. The line loss adjustment is calculated by multiplying the

Average Loss per residential unit by the Weighted Average Price per kWh. The Average Loss is equal to the Average Usage per residential unit multiplied by (one minus the Capacity Loss Adjustment Factor). The Capacity Loss Adjustment Factor is the proportion of energy that is lost due to line losses between the master meter and the submeters. The Weighted Average Price per kWh is calculated by multiplying the $/kWh price in each tier by the average monthly usage in that tier, and then dividing by the sum of the average monthly usage in all tiers.

For example, suppose that the submetered tenants wish to purchase a total of 95 kilowatt-hours of electricity from PG&E. This means that the owner must purchase more than 95 kWh to serve these customers, because some electricity is lost in transfer between the master meter and the tenant meters. If line losses are 5 percent, the owner will purchase 100 kWh, but will only transmit 100 – (100*0.05) = 95 kWh to the tenants. The line loss adjustment compensates those owners for the lost 5 kWh. PG&E's proposed line loss adjustment for the 2020 GRC is $2.35 per month per residential unit.

The diversity benefit adjustment (DBA) decreases the amount of master meter discount. The reason for this decrease is that the MHP owner receives a full baseline allowance for each of the submetered dwellings, even though some dwellings use less than the baseline allowance. If the DBA did not exist, the owner would face an artificially low rate for electricity because his baseline quantity would be too high, and as a result an excessive amount of usage would fall into the lower tiers. The diversity benefit adjustment will be discussed in detail in the next section.

2. Diversity Benefit Adjustment

a. Introduction

The Commission has repeatedly endorsed and adopted the master metered baseline DBA on a conceptual basis, at historical DBA values that reflected the residential tier structure in place at the time. In the discussion below, PG&E explains the impact that a residential fixed monthly customer charge would have on the DBA and offers analysis of three alternative approaches that account for CARE participation in different ways. Ultimately, PG&E recommends adoption of the Southern California Edison (SCE) CARE Strata method, which results in a proposed DBA value for PG&E of $4.14 per space per tenant.

b. Background

The Residential Baseline DBA for MHP service was first adopted by the Commission for PG&E in 1986, at a level of $3.00 per space per month for gas service and $1.59 per space per month for electric service.[73] The Commission stated as follows:

> A diversity benefit exists when a master metered customer has more sales billed at baseline rates and less at non-baseline rates than are actually used by his sub-metered customers. **PG&E deserves credit in addressing an inequity in the billing of sub-metered mobile home parks. PG&E has clearly demonstrated that a sub-metered mobile home park benefits when a sub-metered customer consumes less than his full baseline allowance while another customer consumes more.**[74]

The Commission later also defined the DBA as follows:

> The diversity benefit adjustment reduces the discount paid to the MHP owner to account for the fact that while the MHP owner receives a full baseline allowance for each space, some tenants use less than the baseline allowance, and some spaces may be vacant.[75]

In its 2003 GRC Phase II proceeding, PG&E proposed to increase the Schedule ET DBA to $3.48 per space per month to reflect the new five-tiered residential rate structure implemented June 1, 2001. However, in the 2003 GRC Phase II settlement, the DBA value of $0.56 per space per month was not changed, and PG&E agreed to work with TURN and the Western Manufactured Housing Communities Association (WMA) to conduct a new study to calculate the Schedule ET DBA.

This study was still in progress as of the filing date for PG&E's 2007 GRC Phase II Application. In the 2007 GRC Phase II settlement agreement, PG&E agreed to submit the study by August 1, 2007. After

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[73] D.86-12-091, pp. 35-36, in PG&E's 1986 Energy Cost Adjustment Clause proceeding.

[74] D.86-12-091, pp. 34-35, emphasis added.

[75] D.04-11-033, p. 10, fn 6.

submitting the study, PG&E agreed to certain refinements proposed by WMA. The resulting DBA was $4.24 per space per month, but was not implemented in the 2007 GRC Phase II due to the delay in submitting the study.

The agreed methodology for the Schedule ET DBA relies on a sample of approximately 206 directly metered electric MHP to represent a master metered population of approximately 1,350 master metered electric MHP served on Schedule ET. The sample of 206 MHP consists of tenant units and common area accounts individually metered directly by PG&E, generally served on Residential rate Schedules E-1 and EL-1, for Non-CARE and CARE tenants respectively. This directly metered sample is stratified by: (1) climate zone (four climate zones); (2) average tenant usage (under or over 400 kWh per tenant per month); and (3) size of park (under or over 50 tenant spaces), to statistically project from the sample an estimated average monthly diversity benefit for the overall master metered Schedule ET population.

c. 2017 GRC Phase II Proposed DBA

In PG&E's 2017 GRC Phase II proceeding, PG&E proposed an updated Schedule ET DBA value of $5.73 per space per month. This proposal was based on all previously adopted DBA models and methods, with the exception that PG&E included a new proposal that the diversity benefits of the residential delivery minimum bill be included in the DBA quantification. This is important because the park operator can collect one minimum bill from each tenant with very low usage, but at the central master meter level, PG&E can impose only one minimum bill.

In addition, in PG&E's 2017 GRC Phase II rebuttal testimony, PG&E noted that CARE participation in the directly-metered sample was just under 60 percent, and just above 30 percent in the master metered population, based on updated 2014 and 2015 sample and master metered population kWh usage per tenant and CARE status. As a result, the sample, with a much higher CARE saturation, will have a much lower DBA than the population. However, PG&E had failed to normalize for this important discrepancy between the sample and the population in all previously adopted Schedule ET DBA values for

PG&E.[76] In its 2017 GRC Phase II rebuttal testimony, PG&E therefore proposed that 45 percent of CARE tenants in the sample be treated as Non-CARE to match the level of CARE participation among the master metered population.

In D.18-08-013, the Commission adopted PG&E's originally proposed DBA after a $0.36 adjustment proposed by WMA, including the impact of the new minimum bill. PG&E's 2017 GRC Phase II D.18-08-018 was implemented with respect to the Schedule ET net master meter discount on March 1, 2019, in Advice 5429-E, at a value of net master meter discount = Base + LLA – DBA, or $1.88 = $5.08 + $2.18 - $5.37.

Although the Commission rejected PG&E's CARE Participation normalization proposal in D.18-08-013, PG&E believes the Commission did so primarily because the increased value of the DBA under the CARE Participation normalization method would have established a net *negative* Schedule ET master meter discount. However, for SCE, the Commission had adopted a similar methodology to account for differences in CARE participation rates between the sample versus the population, in which SCE replaced the strata for the size of the park by a CARE participation rate stratum, of under or over 40 percent.[77] In addition, in PG&E's 2018 GCAP, the Commission adopted PG&E's CARE normalization approach for the purpose of setting the DBA for master metered gas MHP.[78]

PG&E has investigated how the resulting proposed Schedule ET DBA would vary based on these three alternate approaches. First, under PG&E's old method, using no CARE adjustment as applied to

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[76] The fact that PG&E had never before accounted for the impacts of the residential minimum bill, or the higher CARE saturation in the sample, each *benefitted* WMA, during all applicable periods from 1986 to the present.

[77] See SCE's 2012 and 2016 GRC Phase II rate design testimony, Appendix G, footnote 6 of 2012 proceeding, and footnote 86 of its 2016 GRC Phase II. SCE's CARE Strata method was adopted in D.13-03-031, pp. 11-13, and D.16-03-030, p. 20.

[78] D.19-10-036, pp. 52-59. In both PG&E's 2017 GRC Phase II proceeding and 2018 GCAP proceeding, WMA alleged that the DBA was invalid and should be eliminated or set to zero. This position was rejected in both D.18-08-013 (p. 140) and D.19-09-036 (pp. 54, 56, 59).

current updated recorded usage data for 2017 and 2018 and proposed rates and baseline quantities, the Schedule ET DBA would be $4.20 per space per month. Second, the Schedule ET DBA would be $4.38 under PG&E's CARE Participation normalization approach. Third, the Schedule ET DBA would be $4.14 under the SCE CARE Strata approach.[79] PG&E proposes that the Commission adopt a Schedule ET DBA of $4.14 per space per month based on the SCE CARE Strata method, adopted in D.13-03-031 and D.16-03-030.

d. PG&E's Proposed 2020 GRC Phase II Diversity Benefit Adjustment

For this 2020 GRC Phase II proceeding, as noted above, PG&E's primary proposal is to adopt the Schedule ET DBA value of $4.14 based on the SCE Care Strata method. Accordingly, PG&E has once again updated the prior Schedule ET DBA study, using 2017 and 2018 sample and population[80] kWh usage per tenant, as well as the data base and all analytical methods authorized and adopted by the CPUC in prior GRC Phase II proceedings. However, PG&E has now stratified the sample by replacing the prior size of MHP strata with a strata for CARE participation, as under 70 percent participation versus over 70 percent participation.

More specifically, for this 2020 GRC Phase II DBA proposal, the sample of 206 directly served MHPs comprised of some 13,400 tenant units has been rerun based on updated 2017 and 2018 calendar year recorded usage. As before, the model has also been updated to re-tier

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79 While SCE used an under and over strata cutoff of 40 percent CARE participation for the CARE strata, PG&E used a 70 percent participation rate for the CARE strata cutoff. The 70 percent level provided larger sample sizes relative to the population than the 40 percent level, and also provided slightly lower standard deviations.

80 It should be noted that the master metered Schedule ET MHP population may be slightly decreasing over time as a result of the Commission mandated three-year statewide pilot program originating from D.14-03-021 to convert 10 percent of MHP spaces in California from master meter service to direct utility service. Under this program, PG&E converted thirteen Schedule ET master metered parks in 2016, 46 parks in 2017, and fourteen parks in 2018, to direct utility service. This MHP conversion program is discussed in PG&E's 2020 GRC Phase I testimony, Exhibit (PG&E-12), Chapter 13, Mobile Home Park Utility Upgrade Program, revised June 18, 2019, and in periodic progress reports, such as PG&E's Mobile Home Park Utility Upgrade Program CPUC 2018 Report, submitted February 1, 2019.

all recorded usage at the proposed 2020 GRC Phase II Schedule E-1 and Schedule EL-1 CARE rates[81] and Baseline quantities. In addition, PG&E deleted approximately ten directly metered solar NEM tenants from the sample, as NEM customers do not occur in the master metered population and have abnormal recorded kWh usage levels.

The resulting MHP DBAs proposed by PG&E for this 2020 GRC Phase II proceeding based on the adopted SCE CARE Strata approach are $4.14 per space per month for Schedule ET and $2.40 for Schedule ES.[82] The Schedule ET proposed value has decreased compared to the currently-adopted $5.37 value per D.18-08-013. PG&E attributes the decrease to reductions in proposed Baseline quantities, changes in tenant usage in 2017 and 2018 compared to 2014 and 2015, the residential Delivery Only Minimum Bill, use of the SCE CARE Strata approach, and tier flattening that will occur on Schedule E-1 compared to the 2017 GRC Phase II proceeding.

e. Impact of a Residential Fixed Monthly Charge on the DBA

The 2018 RDW (A.17-12-011) is a statewide proceeding on a variety of measures related to implementation of default Residential TOU and other Residential rate design issues addressed in D.15-07-001 in Residential Rate Reform OIR 12-06-013. One of the issues under consideration in A.17-12-011 is the possible implementation of a Residential fixed monthly customer charge. The impact of such a fixed monthly customer charge on the DBA has been the subject of a previous Residential Rate Design Settlement in PG&E's 2014 GRC

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81 In Advice 5547-E, effective October 1, 2019, the Commission approved the elimination of all separate CARE tariffs, replaced by a new rider Schedule D-CARE tariff to provide a line item CARE discount as a simple 35.5 percent reduction to the Non-CARE bill. In this 2020 GRC Phase II proceeding, the 35.5 percent reduction is revised to 35.0 percent to comply with Commission adopted requirements expected to become effective March 1, 2020. However, PG&E subsequently filed superseding Advice 5638-E, to be effective March 1, 2020, rather than October 1, 2019.

82 PG&E has calculated the ET DBA value under only the new Schedule E-1 4-month summer residential baseline seasonal structure that took effect October 1, 2019. This 2020 GRC Phase II proceeding maintains the 4-month residential summer baseline structure.

Phase II proceeding, as adopted in D.15-08-005, where Residential settlement Part III.A.1.b held as follows:

> b. Contingency for a Potential Future Monthly Service Fee
>
> The MMHP Settling Parties agree it is reasonable to adjust the Schedule ET billing method should the Commission adopt a Monthly Service Fee for residential customers on rate Schedules E-1 and EL-1 prior to the effective date of the rate change implementing the Commission's decision in PG&E's next GRC Phase II proceeding. A Monthly Service Fee, if adopted prior to implementation of a decision in PG&E's next GRC Phase II proceeding, will be added to the Schedule ET master meter bill as follows:

Schedule ET Master Meter Bill Monthly Service Fee **equals:** One central master meter Monthly Service Fee* **plus** (non-CARE Monthly Service Fee **multiplied by** number of non-CARE tenant units) **plus** (CARE Monthly Service Fee **multiplied by** number of CARE tenant units). - - - - - *The one central master meter Monthly Service Fee = The CARE Monthly Service Fee if the park is on Schedule ETL, or The non-CARE Monthly Service Fee if the park is on Schedule ET.

For Schedule ES, similar 2014 GRC Phase II Residential Settlement terms in Part III.A.2.b were agreed to as follows:

> **b. Contingency for a Potential Future Monthly Service Fee**
>
> The MMHP Settling Parties also agree that it is reasonable to adjust the Schedule ES billing method should the Commission adopt a Monthly Service Fee for residential rate Schedules E-1 and EL-1 prior to the effective date of the rate change implementing the Commission's decision in its next GRC Phase II proceeding. The formula for incorporating a Monthly Service Fee into the Schedule ES billing method is the same as for the Schedule ET billing method described above.[83]

For this 2020 GRC Phase II proceeding, PG&E proposes that the methodology outlined above from PG&E's 2014 GRC Phase II proceeding be implemented as appropriate. Should a Minimum Bill be adopted in the 2018 RDW, PG&E's DBA analysis already incorporates the impact of the Delivery Only Minimum Bill. However, should a Residential fixed monthly customer charge be adopted in 2018 RDW Phase III, the DBA analysis would be affected in two ways. First, if a

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[83] D.15-08-005, p. 10, Supplemental Residential Rate Design Settlement Agreement in PG&E's A.13-04-012, pp. v to ix.

fixed customer charge is implemented, PG&E would expect to discontinue the Delivery Only Minimum Bill. Second, the implementation of a fixed customer charge would facilitate a commensurate reduction in the residential tiered energy charges.

Under this fixed customer charge scenario, PG&E would need to rerun its Schedule ET DBA analysis without the Delivery Only Minimum Bill, and under the energy charges associated with a fixed customer charge. If the fixed customer charge requires a commensurate reduction only in the Tier 1 rate or price, consistent with prior Commission treatment of tier ratios under a composite Tier 1 rate,[84] the diversity benefit magnitude may increase since the absolute tier difference in cents per kWh is a key driver of the magnitude of the Schedule ET DBA. If the fixed customer charge reduction were applied to all volumetric tiered rates (not just Tier 1), the impact on the Schedule ET DBA would be less than under the composite tier ratio approach. In any event, PG&E would propose to rerun its DBA upon 2020 GRC Phase II implementation, at then effective residential and other applicable rates.

f. DBA Conclusion

The Schedule ET diversity benefit study submitted in Exhibit (PG&E-3) was based on the mutually agreed sample of 206 electric MHPs developed in 2007 where all tenant spaces and common area accounts are directly individually metered by PG&E. PG&E recommends that the Commission adopt SCE's CARE Strata method, rather than PG&E's CARE normalization method, to set an adopted value of $4.14 for the Schedule ET DBA based on PG&E data from 2017 and 2018 usage by tenants in the sample and in the ET population. PG&E proposes to continue to set the Schedule ES DBA at a ratio based on values calculated from random samples of MHPs and multi-family apartment buildings in the 2003 GRC Phase II, which was the basis for the 58 percent ratio adopted in D.11-12-053, D.15-08-005,

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84 The composite tier 1 rate is given by the sum of tier 1 energy charge revenues plus applicable minimum bill revenues, plus applicable customer charge revenues, all divided by the sum of tier 1 kWh usage and kWh usage associated with minimum bills.

and D.18-08-013. Those prior 2003 GRC Phase II proposed values were $3.48 per space for Schedule ET and $2.01 for Schedule ES.[85] Applying this 58 percent ratio to the proposed Schedule ET DBA of $4.14 produces a proposed Schedule ES DBA of $2.40 per space per month. These proposed values for the Schedule ES and ET DBAs are reflected below in the net master meter discounts proposed in Table 4-20.

These proposed DBA values are illustrative only and will be updated upon implementation after a final decision in this 2020 GRC Phase II proceeding based upon the rates and revenue requirements then in effect.[86] PG&E proposes that the DBA be set initially, and then subsequently remain unchanged throughout the three-year 2020 GRC Phase II cycle, as has typically been done in the past.

3. Proposed Master Meter Discounts

Table 3-7 shows the present and proposed master meter discounts, including PG&E's resulting proposed base discounts, diversity benefits and LLA.[87] PG&E's proposed base master meter discounts are summarized in Table 3-18 for Schedules ET and ES.

TABLE 3-18
2020 GENERAL RATE CASE PHASE II
PRESENT AND PROPOSED ELECTRIC MASTER METER DISCOUNTS
(PER MONTH, PER UNIT)

		Current Discount(a)		Proposed 2020 Test Year Discount				
Line No.	Rate Schedule	Net Discount	Daily Equivalent	Base Discount	Diversity Benefit (-) Adjustment	Line Loss (+) Adjustment	Net Discount	Daily Equivalent
1	ET – Mobilehome Park Service	$1.88	$0.06181	$3.74	$4.14	$2.35	$1.95	0.06396
2	ES – Multifamily Service	$0.95	$0.03115	$3.49	$2.40	–	$1.09	0.03588

(a) Electric Master Meter Discount Rate in effect October 1, 2019.

85 The adopted 58 percent figure equals $2.01 divided by $3.48.

86 See discussion in D.11-12-053, *mimeo*, p. 41, as well as Conclusion of Law 12, and Ordering Paragraph 13.

87 The LLA adds to the base discount to compensate the master meter customer for usage at the master meter that is lost when distributed to the tenant spaces.

TABLE 3-19
2020 GENERAL RATE CASE PHASE II
SCHEDULE ET – MASTER METER DISCOUNTS

Line No.	Schedule ET Master Meter Discount	Costs for Tenant Meter	Costs for Master Meter[(a)]
1	Transformer	$401.00	$22,845.82
2	Service	$354.00	$27,026.55
3	Meter	$175.00	$1,753.08
4	Transformer/Service/Meter (TSM) Equip. Cost	$930.00	$51,625.45
5	RECC	6.78%	6.78%
6	Annualized Connection Equipment Cost — Finance, Tax, Ins. & Depr.	$63.06	$3,500.44
7	Test Year Secondary Dist. ($/kW-Yr)	$2.04	
8	Test Year Ongoing Costs Per Residential Unit		
9	Meter Services	$11.30	$25.77
10	Transformer Maintenance	$0.66	$37.55
11	Service Maintenance	$2.32	$176.87
12	Meter Reading	$4.85	$8.42
13	Billing & Payments	$15.43	$18.77
14	Credit & Collections and Account Setup	$3.16	$7.19
15	Total Ongoing Costs Per Residential Unit	$37.73	$274.56
16	Total Connection Cost	$102.83	$3,775.00
17	Average Number of Residential Units		65
18	Master Meter Connection Cost Per Residential Unit		$58.08
19	Net Marginal Connection Cost Per Residential Unit	$44.75	
20	Uncollectibles Factor	0.3253%	
21	Uncollectibles	$0.15	
22	Net Base Discount Per Residential Unit — Annual	$44.90	
23	Base Master Meter Discount Per Residential Unit — Monthly	$3.74	
24	Diversity Benefit Adjustment (Illustrative)	$4.14	
25	Line Loss Adjustment	$2.35	
26	Net Discount (Monthly) (Illustrative)	$1.95	
27	Net Discount (Daily) (Illustrative)	$0.06396	

(a) Master Meter costs uses ML&P-S proxy meter for connection; SL&P proxy meter for ongoing costs except transformer and service maintenance; transformer and service maintenance calculated for Medium L&P proxy connection

TABLE 3-20
2020 GENERAL RATE CASE PHASE II
SCHEDULE ES – MASTER METER DISCOUNTS

Line No.	Schedule ES Master Meter Discount	Costs for Tenant Meter	Costs for Master Meter[(a)]
1	Transformer	–	–
2	Service	–	–
3	Meter	$175.00	$1,753.08
4	Transformer/Service/Meter (TSM) Equip. Cost	$175.00	$1,753.08
5	RECC	6.78%	6.78%
6	Annualized Connection Equipment Cost — Finance, Tax, Ins. & Depr.	$11.87	$118.87
7	Test Year Secondary Dist. ($/kW-Yr)	–	
8	Test Year Ongoing Costs Per Residential Unit		
9	Meter Services	$11.30	$25.77
10	Transformer Maintenance	–	–
11	Service Maintenance	–	–
12	Meter Reading	$4.85	$8.42
13	Billing & Collections	$15.43	$18.77
14	Credit & Collections and Account Setup	$3.16	$7.19
15	Total Ongoing Costs Per Residential Unit	$34.76	$60.14
16	Total Connection Cost	$46.62	$179.01
17	Average Number of Residential Units		37
18	Master Meter Connection Cost Per Residential Unit		$4.84
19	Net Marginal Connection Cost Per Residential Unit	$41.78	
20	Uncollectibles Factor	0.3253%	
21	Uncollectibles	$0.14	
22	Net Base Discount Per Residential Unit — Annual	$41.92	
23	Base Master Meter Discount Per Residential Unit — Monthly	$3.49	
24	Diversity Benefit Adjustment (Illustrative)	$2.40	
25	Line Loss Adjustment	–	
26	Net Discount (Monthly) (Illustrative)	$1.09	
27	Net Discount (Daily) (Illustrative)	$0.03588	

(a) Master Meter costs uses ML&P-S proxy meter for connection; SL&P proxy meter for ongoing costs except transformer and service maintenance; transformer and service maintenance calculated for Medium L&P proxy connection

L. Bill Comparisons

Appendix D of Exhibit (PG&E-4) presents illustrative bill comparisons for PG&E's residential tiered rates. As described in Chapter 1 of Exhibit (PG&E-3), the starting point rates are PG&E's Schedule E-1 and EL-1 rates effective July 1, 2019, after being adjusted to have a 4-month summer/8 -month winter seasonal definition. The proposed Schedule E-1 rates are shown in Appendix C of Exhibit (PG&E-4), with CARE customer bills first calculated at E-1 rates but then reduced via a 35.0 percent line-item discount. Because present rates for Schedule EL-1 were based on a 35.5 percent CARE discount, the bill comparison results shown for this schedule are slightly worse than what can be expected solely as a result of the initiatives proposed in this Phase II.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

ATTACHMENT A

FEASIBILITY OF REMOTE DISPATCH OF RESIDENTIAL ENERGY STORAGE

PACIFIC GAS AND ELECTRIC COMPANY CHAPTER 3 ATTACHMENT A FEASIBILITY OF REMOTE DISPATCH OF RESIDENTIAL ENERGY STORAGE

In the Final Decision on Pacific Gas and Electric Company's (PG&E or the Utility) 2017 General Rate Case (GRC) Phase II, the California Public Utilities Commission (CPUC or Commission) adopted the Settlement Agreement on Residential Rate Design,[1] which requires PG&E to analyze the feasibility of providing a program(s) for residential customers with battery storage that requires remote dispatch of the storage by PG&E or California Independent System Operator (CAISO).[2] PG&E has explored the feasibility of enabling remote dispatch of customer-sited energy storage in a number of forums, including (1) the Self-Generation Incentive Program (SGIP) GHG Signal Working Group,[3] and (2) two Electric Program Investment Charge (EPIC) projects: EPIC 2.19C (Customer Sited and Behind-the Meter Storage)[4] and EPIC 2.02 (Distributed Energy Resource

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1 Decision (D.) 18-08-013, Ordering Paragraph 13

2 Prior to the next Phase II GRC, PG&E will analyze the feasibility of providing a program or programs for residential customers with battery storage that requires a minimum amount of remote dispatch of the storage unit at the direction of PG&E or the Independent System Operator. PG&E may conduct this analysis either for inclusion in the next Phase II or as part of another Commission proceeding. The analysis shall consider technical, economic, and ratemaking challenges along with identifying potential benefits to the grid, non-participating customers, and California's greenhouse gas (GHG) goals. PG&E shall consult with interested stakeholders in conjunction with its analysis. (Settlement Agreement on Residential Rate Design, p. 13, attached to D.18-08-013.)

3 SGIP GHG Signal Working Group (GHG Signal WG) was established by Assigned Commissioner's Ruling (ACR) on December 29, 2017, and met regularly between January and May 2018. A Final Report from the GHG Signal WG was issued on June 15, 2018 with a Corrected version (the WG Corrected Final Report) issued on September 6, 2018. See https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/Customer_Gen_and_Storage/GHG%20Working%20Group%20Report%20-%2009.06.18%20-%20corrected.pdf, accessed October 1, 2019.

4 Final Report available at https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.19.pdf, (EPIC Project 2.19 Final Report), accessed October 1, 2019.

Management System (DERMS)).[5] This section describes PG&E's analyses and the status of the GHG Signal WG and EPIC projects referenced above.

In summary, PG&E believes that the time is not yet ripe for programs that require remote dispatch of Residential battery storage. PG&E and the Energy Storage (ES) industry have made significant progress in developing software and hardware and in forecasting and control algorithms required to implement utility or CAISO dispatch at scale. Yet there are still significant challenges in terms of forecasting and control software, consistent and accurate visibility into the state of the ES systems, and indeed customer interest. PG&E and other industry players plan to continue researching through EPIC 3,[6] and moving towards scalable solutions via the 2020 and 2023 GRC filing. In the meantime, price and GHG signaling efforts such as those developed through the SGIP proceeding (as well as already-developed Demand Response programs) can provide an alternate way for Residential customers to reduce grid costs and GHG emissions.

EPIC Project 2.19C

The first EPIC project (Project 2.19C, Customer Sited and Behind-the-Meter Storage) tested the use of customer-sited energy storage technologies to (1) reduce peak loading, especially of local circuits; and (2) absorb Distributed Energy Resources (DER) generation during peak solar production times to address the CAISO's "duck curve." Project 2.19C "sought to understand customer interest in and adoption of BTM storage technologies, as well as the technical feasibility for leveraging these assets as a resource for grid services."[7] Project 2.19C demonstrated both the technical potential of Behind-the-Meter (BTM) storage to provide grid reliability support and the challenges in customer acquisition and deployment and dispatching algorithms. PG&E partnered with one Residential and one Commercial energy storage vendor to deploy customer-sited BTM ES

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5 Final Report available at https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-2.02.pdf, (EPIC Project 2.02 Final Report). Accessed October 1, 2019.

6 EPIC 3.03 (DERMS – DER Headend Project), in particular, seeks to address the visibility and forecasting issues (also known as situational awareness), which will be required to monitor and control DERs deployed as part of Wildfire Mitigation Plan grid resilience initiatives.

7 EPIC 2.19C Final Report, p. 1.

resources, which were controlled and monitored individually and in aggregate by the project team.

Project 2.19C found that the Utility "will need to have additional hardware and software systems… to provide accurate visibility into asset performance and availability, and assurances that the BTM energy storage assets will consistently and reliably respond to dispatch signals."[8] In addition, the development of appropriate communication infrastructure, a full-featured DERMS, and improved data accuracy and communications uptime "would enable utilities to leverage BTM energy storage in system planning and operations and realize their full value and capabilities to benefit customers and reduce Greenhouse Gas (GHG) emissions."[9]

In terms of readiness for rollout beyond the demonstration stage, the team found a number of issues that would need to be resolved before BTM ES could be relied on to provide grid benefits in a wider scale production environment. Such expansion to a production environment would require additional software and hardware investments, a new integrated grid platform, and efficient targeting of potential customers, since even the promise of a free Residential battery was not enough to draw significant interest. Project 2.19C also demonstrated that the ability of BTM ES to serve both customer and grid needs is a two-edged sword: increasing the potential value streams, but requiring sophisticated (and not yet mature) control algorithms, while being limited by customers' desire to manage bills and provide backup power, which can get in the way of meeting systemwide or local grid needs and reducing GHGs.[10]

In summary, EPIC Project 2.19C found that while BTM ES could technically be managed to respond to utility signals to help meet grid needs, existing systems are far from scalable and "plug and play," and significant customer interest in utility signaling has not yet developed.

<u>EPIC Project 2.02</u>

The second EPIC Project (EPIC 2.02, Distributed Energy Resource Management System (DERMS), or the "DERMS Demo"),[11] focused on defining and

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8 *Ibid.*

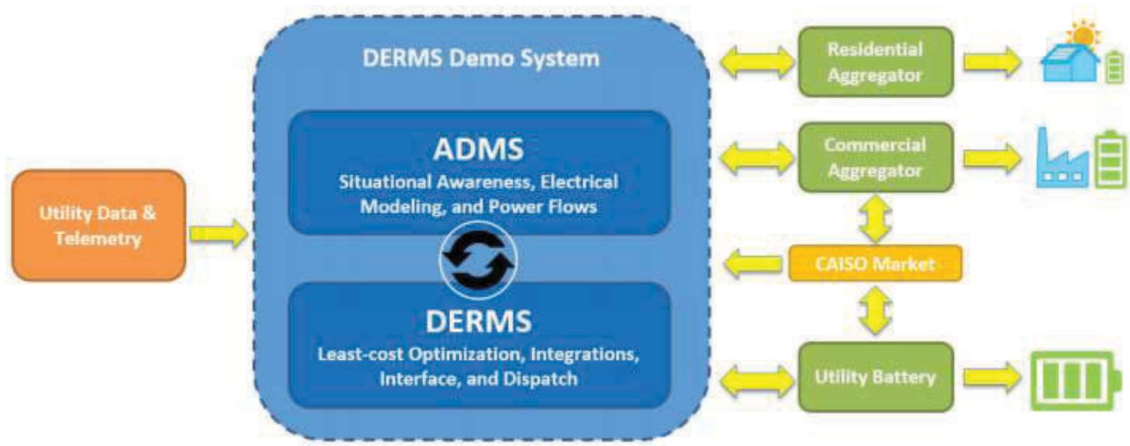
9 *Ibid.,* p. 2.

10 *Ibid.,* pp. 5-7.

11 EPIC Projects 2.19C and 2.02 shared the same DERMS and were conducted over the same timeframe on the same distribution feeder, in San Jose, California.

deploying proof of concept DERMS software, in "an industry leading field demonstration of optimized control of a portfolio of 3rd party aggregated behind-the-meter (BTM) solar and energy storage and utility front-of-the-meter (FTM) energy storage. These assets provided distribution capacity and voltage support services while also allowing for participation of these same DERs in the CAISO wholesale market … to test DER value stacking, often referred to as multiple use applications (MUA)."[12] As part of the Project, PG&E developed a scaled-down Advanced Distribution Management Systems (ADMS) to provide visibility and local distribution system power modeling. Figure 3A-1[13] provides a simplified overview of the DERMS Demo.

FIGURE 3A-1
SIMPLIFIED DERMS DEMO OVERVIEW



The main objective of the DERMS Demo was to "test and demonstrate that new technologies can provide the functionality to monitor and control DERs to manage system constraints and evaluate the potential value of DER flexibility to the grid. The DERMS Demo demonstrated that value from DERs to provide grid services could be realized."[14] That value included simulated participation in the CAISO market, including as a Proxy Demand Resource (PDR) to decrease load, and PG&E's Excess Supply DR Pilot[15] to increase load. However, the Project

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12 EPIC 2.02 Final Report, p. 2.

13 *Ibid.*, p. 3.

14 *Ibid.,* p. 5.

15 *See* https://olivineinc.com/services/our-work/xsp/.

concluded that "[t]o preserve distribution safety and reliability, distribution dispatch must have priority over wholesale market operations and visibility across both systems."[16]

The DERMS Demo project team concluded that the Project "successfully demonstrated the potential of DERMS technology, while creating key learnings that helped further the industry and identify ADMS and DERMS needs for PG&E . . . Through collaboration with the participating vendors, other PG&E demonstrations, and industry leaders, the DERMS Demo progressed the state of the industry."[17] However, "[o]utstanding policy, regulatory, and program ambiguity make it imprudent to implement a full-scale DERMS immediately."[18] PG&E is proposing further DERMS work in EPIC 3, and is pursuing more general technology investments through the Integrated Grid Platform Program as proposed in PG&E's 2020 GRC.[19]

GHG Signal WG

Finally, the GHG Signal WG[20] was tasked with developing "a 'GHG signal' provided to participants in advance [which] could help SGIP energy storage systems to operate (i.e., charge and discharge) to reduce net GHG emissions to at least zero."[21] Over a period of six months in 2018, the Working Group developed recommendations for the content and delivery mechanisms of a GHG signal (i.e., real-time estimates of marginal GHG impacts of load, as well as forecasts of same at various timescales). The Working Group also modeled the ability of the signal to reduce GHG emissions for both residential and non-residential customers under a wide variety of rates. These recommendations and modeling results were summarized in the WG Corrected Final Report, which was published along with a

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16 EPIC 2.02 Final Report, p. 8.

17 *Ibid.,* p. 10.

18 *Ibid.,* p. 11.

19 For an overall discussion of grid modernization efforts in California, including PG&E's Integrated Grid Platform, see https://www.utilitydive.com/news/pge-may-answer-the-billion-dollar-grid-modernization-question/561146/.

20 The GWG Signal WG was "facilitated by Alternative Energy Systems Consulting (AESC) and consisted of the SGIP program administrators (PAs) – Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), Southern California Gas Company (SoCalGas) and the Center for Sustainable Energy (CSE) – California Public Advocate's Office, solar and energy storage companies and trade associations, energy non-profits, and ED staff." See D.19-08-001, p. 6.

21 ACR filed December 29, 2017, p. 3.

CPUC Staff Proposal on September 6, 2018, followed by a Revised Staff Proposal on December 31, 2018, and a Final Decision (D.19-08-001, the GHG SGIP Decision) effective August 1, 2019.

Based on the extensive collaboration among interested stakeholders, including multiple rounds of comments, the GHG SGIP Decision specified a five-minute real-time GHG signal along with a 15-minute forecast, an hour-ahead forecast, and a day-ahead forecast. In addition, the SGIP PAs were directed to work with the GHG signal vendor and industry stakeholders to identify the type of longer-term forecasts that would be most useful (e.g., the probabilities of GHG emissions being in various ranges depending on time of day and year, and other factors). While the GHG SGIP Decision established incentive reductions based on poor GHG performance only for non-residential customers, the development of a robust GHG emissions forecasting infrastructure will enable residential customers with energy storage (many of whom have the desire to reduce their GHG emissions) to do so once both the GHG signal and control software from vendors are available.[22]

PG&E is continuing its efforts to enable signaling and potential remote dispatch of residential ES, either individually or via aggregators, along with ES industry partners and other stakeholders. These efforts are primarily through the EPIC 3 program, PG&E's proposed Integrated Grid Platform, and the GHG signal under development under SGIP (with rollout in 2020). PG&E anticipates that production-scale remote dispatch by the utility and/or CAISO will likely be possible in the mid-2020s, but is not yet a reality.

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22 The GHG SGIP Decision requires the PAs to contract with a qualified GHG signal vendor and to provide an interim GHG signal within 150 days of adoption (i.e., no later than December 30, 2019), and a final signal within 240 days of adoption (i.e., no later than March 29, 2020). The PAs selected the GHG signal vendor (WattTime) on November 1, 2019; development of the interim GHG signal is now underway.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

ATTACHMENT B

PRESENT AND ILLUSTRATIVE RESIDENTIAL RATE DESIGNS

E-1, EM, ES, ESR, ET

	PRESENT RATES							PROPOSED RATES						
	Distr	Gen	PPP	CIA	Other	Total		Distr	Gen	PPP	CIA	Other	Total	
ENERGY CHARGE (/kWh)														
Baseline Usage	0.09018	0.11757	0.01240	-0.03764	0.04137	0.22386		0.08623	0.12216	0.01257	-0.04220	0.04137	0.22012	
101% - 400% of Baseline	0.09018	0.11757	0.01240	0.02018	0.04137	0.28169		0.08623	0.12216	0.01257	0.01466	0.04137	0.27698	
Over 400% of Baseline	0.09018	0.11757	0.01240	0.23194	0.04137	0.49344		0.08623	0.12216	0.01257	0.22287	0.04137	0.48519	
MINIMUM CHARGE														
(/meter/day)	*		0.02519		0.00179	0.32854	10.00	*		0.02554	0.00000	0.00179	0.32854	10.00
(/kWh)					0.04132							0.04132		
ES DISCOUNT (/dwelling unit/day)	0.03115					0.03115	0.95	0.03581					0.03581	1.09
ES MARL (/kWh)		0.04417			0.00773	0.05190			0.04119			0.00773	0.04892	
ET DISCOUNT (/dwelling unit/day)	0.06181					0.06181	1.88	0.06407					0.06407	1.95
ET MARL (/kWh)		0.04417			0.00773	0.05190			0.04119			0.00773	0.04892	

* Calculated residually as total less sum of other charges. * Calculated residually as total less sum of other charges.

E-TOU-C (Tiered)

	PRESENT RATES							PROPOSED RATES						
	Distr	Gen	PPP	CIA	Other	Total		Distr	Gen	PPP	CIA	Other	Total	
SUMMER ENERGY CHARGE ($/kWh)														
Peak								0.12229	0.16098	0.01257	0.04194	0.04137	0.37915	
Off-Peak								0.10229	0.09754	0.01257	0.04194	0.04137	0.29571	
Baseline Credit											-0.08286		-0.08286	
WINTER ENERGY CHARGE ($/kWh)														
Peak								0.07547	0.09849	0.01257	0.04194	0.04137	0.26984	
Off-Peak								0.07243	0.07346	0.01257	0.04194	0.04137	0.24177	
Baseline Credit											-0.08286		-0.08286	
MINIMUM CHARGE														
(/meter/day)								*		0.02554	0.00000	0.00179	0.32854	10.00
(/kWh)												0.04132		

Note: Present rates for Schedule E-TOU-C do not yet exist.

* Calculated residually as total less sum of other charges.

E-TOU B (Non-Tiered)

	PRESENT RATES							PROPOSED RATES						
	Distr	Gen	PPP	CIA	Other	Total		Distr	Gen	PPP	CIA	Other	Total	
SUMMER ENERGY CHARGE ($/kWh)														
Peak	0.10791	0.22302	0.00699	0.00000	0.04137	0.37929		0.10962	0.21499	0.01257	0.00000	0.04137	0.37854	
Off-Peak	0.10791	0.11996	0.00699	0.00000	0.04137	0.27623		0.10962	0.08815	0.01257	0.00000	0.04137	0.25170	
WINTER ENERGY CHARGE ($/kWh)														
Peak	0.07728	0.11618	0.00699	0.00000	0.04137	0.24182		0.07263	0.11409	0.01257	0.00000	0.04137	0.24065	
Off-Peak	0.07728	0.09739	0.00699	0.00000	0.04137	0.22302		0.07263	0.07149	0.01257	0.00000	0.04137	0.19805	
MINIMUM CHARGE														
(/meter/day)	*		0.02519		0.00179	0.32854	10.00	*		0.02554	0.00000	0.00179	0.32854	10.00
(/kWh)					0.04132							0.04132		

* Calculated residually as total less sum of other charges. * Calculated residually as total less sum of other charges.

PRESENT RATES | **PROPOSED RATES**

E-TOU-D (Non-Tiered)

	Present Distr	Present Gen	Present PPP	Present CIA	Present Other	Present Total		Proposed Distr	Proposed Gen	Proposed PPP	Proposed CIA	Proposed Other	Proposed Total	
SUMMER ENERGY CHARGE (/kWh)														
Peak								0.13529	0.20794	0.01257	0.00000	0.04137	0.39716	
Off-Peak								0.10529	0.10298	0.01257	0.00000	0.04137	0.26220	
WINTER ENERGY CHARGE (/kWh)														
Peak								0.07547	0.11085	0.01257	0.00000	0.04137	0.24025	
Off-Peak								0.07220	0.07577	0.01257	0.00000	0.04137	0.20190	
MINIMUM CHARGE														
(/meter/day)								*		0.02554	0.00000	0.00179	0.32854	10.00
(/kWh)												0.04132		

Note: Present rates for Schedule E-TOU-D do not yet exist.

* Calculated residually as total less sum of other charges.

E-6 (Tiered)

	Present Distr	Present Gen	Present PPP	Present CIA	Present Other	Present Total		Proposed Distr	Proposed Gen	Proposed PPP	Proposed CIA	Proposed Other	Proposed Total	
SUMMER ENERGY CHARGE (/kWh)														
Peak														
Baseline Usage	0.26726	0.25500	0.01240	-0.19100	0.04137	0.38502		0.27445	0.22082	0.01257	-0.04092	0.04137	0.50829	
Over Baseline	0.26726	0.25500	0.01240	-0.10914	0.04137	0.46688		0.27445	0.22082	0.01257	0.04194	0.04137	0.59115	
Part-Peak														
Baseline Usage	0.10831	0.13656	0.01240	-0.03205	0.04137	0.26658		0.10022	0.13861	0.01257	-0.04092	0.04137	0.25185	
Over Baseline	0.10831	0.13656	0.01240	0.04981	0.04137	0.34844		0.10022	0.13861	0.01257	0.04194	0.04137	0.33471	
Off-Peak														
Baseline Usage	0.05533	0.08822	0.01240	-0.00595	0.04137	0.19135		0.05212	0.06872	0.01257	-0.04092	0.04137	0.13386	
Over Baseline	0.05533	0.08822	0.01240	0.07591	0.04137	0.27321		0.05212	0.06872	0.01257	0.04194	0.04137	0.21672	
WINTER ENERGY CHARGE (/kWh)														
Part-Peak														
Baseline Usage	0.10415	0.11506	0.01240	-0.06045	0.04137	0.21252		0.08896	0.10967	0.01257	-0.04092	0.04137	0.21165	
Over Baseline	0.10415	0.11506	0.01240	0.02141	0.04137	0.29438		0.08896	0.10967	0.01257	0.04194	0.04137	0.29451	
Off-Peak														
Baseline Usage	0.07022	0.10177	0.01240	-0.03005	0.04137	0.19569		0.07016	0.07595	0.01257	-0.04092	0.04137	0.15913	
Over Baseline	0.07022	0.10177	0.01240	0.05181	0.04137	0.27755		0.07016	0.07595	0.01257	0.04194	0.04137	0.24199	
MINIMUM CHARGE														
(/meter/day)	*		0.02519		0.00179	0.32854	10.00	*		0.02554	0.00000	0.00179	0.32854	10.00
(/kWh)					0.04132							0.04132		

* Calculated residually as total less sum of other charges. | * Calculated residually as total less sum of other charges.

PRESENT RATES / **PROPOSED RATES**

EVA (Electric Vehicles)

	Present Distr	Present Gen	Present PPP	Present CIA	Present Other	Present Total		Proposed Distr	Proposed Gen	Proposed PPP	Proposed CIA	Proposed Other	Proposed Total	
SUMMER ENERGY CHARGE (/kWh)														
Peak	0.18620	0.27845	0.01240	0.00000	0.04137	0.51841		0.19480	0.22142	0.01257	0.00000	0.04137	0.47016	
Part-Peak	0.09310	0.13419	0.01240	0.00000	0.04137	0.28106		0.09372	0.07691	0.01257	0.00000	0.04137	0.22457	
Off-Peak	0.01341	0.06744	0.01240	0.00000	0.04137	0.13461		0.02720	0.03004	0.01257	0.00000	0.04137	0.11118	
WINTER ENERGY CHARGE ($/kWh)														
Peak	0.19824	0.10405	0.01240	0.00000	0.04137	0.35605		0.17923	0.09767	0.01257	0.00000	0.04137	0.33083	
Part-Peak	0.09912	0.06501	0.01240	0.00000	0.04137	0.21789		0.07162	0.07104	0.01257	0.00000	0.04137	0.19659	
Off-Peak	0.01427	0.06984	0.01240	0.00000	0.04137	0.13788		-0.00050	0.07104	0.01257	0.00000	0.04137	0.12447	
MINIMUM CHARGE														
(/meter/day)	*		0.02519		0.00179	0.32854	10.00	*		0.02554	0.00000	0.00179	0.32854	10.00
(/kWh)					0.04132							0.04132		

* Calculated residually as total less sum of other charges. (Present rates)

* Calculated residually as total less sum of other charges. (Proposed rates)

EVB (Electric Vehicles)

	Present Distr	Present Gen	Present PPP	Present CIA	Present Other	Present Total		Proposed Distr	Proposed Gen	Proposed PPP	Proposed CIA	Proposed Other	Proposed Total	
SUMMER ENERGY CHARGE (/kWh)														
Peak	0.18023	0.27845	0.01240	0.00000	0.04137	0.51245		0.19190	0.22142	0.01257	0.00000	0.04137	0.46726	
Part-Peak	0.09012	0.13419	0.01240	0.00000	0.04137	0.27808		0.09082	0.07691	0.01257	0.00000	0.04137	0.22167	
Off-Peak	0.01298	0.06744	0.01240	0.00000	0.04137	0.13418		0.02430	0.03004	0.01257	0.00000	0.04137	0.10828	
WINTER ENERGY CHARGE ($/kWh)														
Peak	0.19189	0.10405	0.01240	0.00000	0.04137	0.34970		0.17633	0.09767	0.01257	0.00000	0.04137	0.32793	
Part-Peak	0.09595	0.06501	0.01240	0.00000	0.04137	0.21471		0.06872	0.07104	0.01257	0.00000	0.04137	0.19369	
Off-Peak	0.01382	0.06984	0.01240	0.00000	0.04137	0.13742		-0.00340	0.07104	0.01257	0.00000	0.04137	0.12157	
CUSTOMER CHARGE (/meter/day)	0.04928					0.04928	1.50	0.04928					0.04928	1.50
MINIMUM CHARGE														
(/meter/day)	*		0.02519		0.00179	0.32854	10.00	*		0.02554	0.00000	0.00179	0.32854	10.00
(/kWh)					0.04132							0.04132		

* Calculated residually as total less sum of other charges. (Present rates)

* Calculated residually as total less sum of other charges. (Proposed rates)

EV2A (Electric Vehicles)

	Present Distr	Present Gen	Present PPP	Present CIA	Present Other	Present Total		Proposed Distr	Proposed Gen	Proposed PPP	Proposed CIA	Proposed Other	Proposed Total	
SUMMER ENERGY CHARGE (/kWh)														
Peak	0.23512	0.18605	0.01240	0.00000	0.04127	0.47484		0.31804	0.16708	0.01257	0.00000	0.04127	0.53895	
Part-Peak	0.16934	0.14134	0.01240	0.00000	0.04127	0.36435		0.25226	0.12237	0.01257	0.00000	0.04127	0.42846	
Off-Peak	0.00847	0.10020	0.01240	0.00000	0.04127	0.16234		0.09139	0.08123	0.01257	0.00000	0.04127	0.22645	
WINTER ENERGY CHARGE (/kWh)														
Part-Peak	0.16488	0.12918	0.01240	0.00000	0.04127	0.34773		0.24116	0.10111	0.01257	0.00000	0.04127	0.39610	
Part-Peak	0.16067	0.11669	0.01240	0.00000	0.04127	0.33103		0.23695	0.08862	0.01257	0.00000	0.04127	0.37940	
Off-Peak	0.01546	0.09321	0.01240	0.00000	0.04127	0.16234		0.09174	0.06514	0.01257	0.00000	0.04127	0.21071	
MINIMUM CHARGE														
(/meter/day)	*		0.02519		0.00179	0.32854	10.00	*		0.02554	0.00000	0.00179	0.32854	10.00
(/kWh)					0.04132							0.04132		

* Calculated residually as total less sum of other charges. (Present rates)

* Calculated residually as total less sum of other charges. (Proposed rates)

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

COMMERCIAL AND INDUSTRIAL RATE DESIGN

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COMMERCIAL AND INDUSTRIAL RATE DESIGN

A. Introduction

In this chapter Pacific Gas and Electric Company (PG&E) proposes rates for the Commercial and Industrial (C&I) customers. In this proceeding, PG&E is proposing changes to generation, distribution and Public Purpose Program (PPP) revenue allocation and rate design. PG&E is not making any proposals for revenue allocation and rate design for other components of rates.[1] Generation, distribution and PPP revenue allocation, as well as PPP rate design,[2] is described in Chapter 2. In this chapter, PG&E summarizes its proposals for generation and distribution rate design.

Under the transition plan adopted by Decision (D.) 18-08-013, rates with new Time-of-Use (TOU) periods became available on an opt-in basis for C&I customers beginning in November 2019. From the date when the rates with new TOU periods became available on an opt-in basis, until November 1, 2020, PG&E will retain all C&I rates on both the old TOU structure (referred to herein as “legacy rates”) as well as the new TOU structure (rates with new TOU periods, or “B Series” rates). On November 1, 2020, PG&E will begin the mandatory transition of customers to the rates with new TOU periods for those customers who have not opted-in. In the table below, PG&E provides a summary of the rate schedules that are addressed in this chapter.

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1 Rate design includes rate components for transmission, distribution, generation, PPP, Nuclear Decommissioning, Department of Water Resources (DWR) Bond Charge, New System Generation Charges, the Energy Cost Recovery Amount, Competition Transition Charges, and the Power Charge Indifference Adjustment.

2 PPP rates are designed in accordance with the guidelines described in Chapter 1 using the revenue allocation provided in Chapter 2.

TABLE 4-1
PG&E'S COMMERCIAL AND INDUSTRIAL RATE SCHEDULES

Line No.	Section	Legacy Rate Schedule (Short Name)	Rate With New TOU Periods (Short Name)
1	C	A-1/A-1TOU	B-1
2	C	A-6	B-6
3	C	A-15	B-15
4	C	TC-1	N/C
5	C	N/A	B-1Store
6	D	A-10/A-10TOU	B-10
7	E	E-19/E-19V	B-19/B-19V
8	E	E-19/E-19V Option R	B-19/B-19V Option R
9	E	N/A	B-19/B-19V Option S
10	E	E-20	B-20
11	E	E-20 Option R	B-20 Option R
12	E	N/A	B-20 Option S
13	F	S	SB

Also beginning on November 1, 2020, rates with grandfathered TOU periods will become available for solar customers that have met the grandfathering requirements under D.17-01-006 and successor decisions.[3] D.18-08-013 adopted the Settlement Agreement on TOU Rates for Grandfathered Solar Customers, which established transition plans through 2023 for Schedules A-6, E-19V Option R, E-19 Option R and E-20 Option R. PG&E is not seeking a change to those transition plans in this proceeding.[4] In addition, the Settlement adopted adjustments for solar grandfathered rates for Schedules A-1TOU, A-10TOU and the non-Option R versions of Schedules E-19V, E-19 and E-20 that would occur in one step (that is, no transition plan was required) beginning when these rates would be used exclusively by grandfathered solar customers. This is expected to begin November 1, 2020. While adjustments to the solar grandfathered rates for Schedules A-1TOU, A-10TOU and the non-Option R versions of Schedules E-19V, E-19 and E-20 could be considered in this proceeding, PG&E has concluded that no changes are necessary and that the provisions of the Settlement Agreement on TOU Rates for Grandfathered Solar Customers should continue until the 2023 General Rate Case (GRC) Phase II.

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[3] D.17-01-006 was later modified by D.17-02-017 and D.17-10-018.

[4] In addition, pursuant to D.18-08-013, the transition plan for rate changes for eligible grandfathered solar customers served under Schedule RES-BCT was filed as Advice Letter 5379-E-A and subsequently approved by the California Public Utilities Commission (Commission). PG&E is not proposing a modification to the transition plan for Schedule RES-BCT in this proceeding.

Accordingly, PG&E is not proposing any changes in this proceeding to the rates and methodologies set forth in the Settlement Agreement on TOU Rates for Grandfathered Solar Customers approved by D.18-03-013.

The remainder of this chapter is organized as follows:

- Section B – Summary of Proposals
- Section C – Small Light and Power Rate Design
- Section D – Rate Design for Schedules A-10 and B-10
- Section E – Rate Design for Schedules E-19, E-20, B-19 and B-20
- Section F – Rate Design for Standby (Schedules S and SB)
- Section G – Rate Design Illustrations Requested in D.18-08-013
- Section H – Conclusion

Appendix A of Exhibit (PG&E-4) provides recorded 2017 data for the customer classes presented in this chapter. Appendix C, “Present and Proposed Rates,” of Exhibit (PG&E-4), and Attachment B to this chapter, contain PG&E’s present and proposed total and unbundled rates for each customer class. Appendix D, “Illustrative Bill Impacts,” of Exhibit (PG&E-4), presents the bill comparison impacts of PG&E’s proposed rates. Finally, Appendix G of Exhibit (PG&E-4) presents illustrative rates designs for C&I rate schedules as required by D.18-08-013.

B. Summary of Proposals

As discussed in Chapter 1 of this exhibit, a key objective in PG&E’s C&I rate design proposal is to retain the rate designs adopted by PG&E’s 2017 GRC Phase II proceeding (D.18-08-013) as customers are being transitioned to rates with new TOU periods. The following proposals are discussed in greater detail in the remaining sections of this chapter:

- For the revenue allocation changes in this proceeding, as well as revenue requirement changes for rate changes between GRCs, continue to apply the rules for rate changes between GRCs adopted by D.18-08-013, except as noted below for Schedules B-6 and SB;
- Revise Schedule B-6 to provide a greater TOU differentiation in 2022, no later than November 1;
- Eliminate the voluntary TOU meter charges on legacy rate Schedules A-6 and E-19 voluntary; and

- Mitigate the rate changes to Schedule SB at primary and secondary service voltages by limiting the distribution increase at these service voltages and reducing the reduction that would otherwise have been assigned to transmission voltage service. Revise generation charges for Schedule SB to better reflect cost, and adjust the basis for changing rates for revenue allocation and revenue requirement changes in the future.

C. Small Light and Power Rate Design

As noted above, Small Light and Power (SLP) includes Schedules A-1, A-1TOU, A-6, A-15, B-1, B-6, B-15, B-1Store and TC-1. PG&E's eligibility boundary between SLP and Schedules A-10 and B-10 is 75 kilowatts (kW). Customers that have demands in excess of 75 kW may not take service on the SLP rate schedules. In general, these rate schedules consist of a customer charge and volumetric energy charges.

1. Overview

PG&E proposes the following rate design for the SLP:

- Retain the current 75 kW eligibility threshold;
- Retain the seasons and TOU periods adopted by D.18-08-013;
- For all rate schedules, except as specifically proposed for Schedule B-6, continue the existing rate structures and rules for changes between GRCs in order to implement the revenue allocation results determined in this proceeding and for revenue requirement changes before the next GRC Phase II proceeding to ensure rate stability during the transition to rates with new TOU periods;
- Increase the Schedule B-6 TOU price differentials in 2022, no later than November 1; and
- Eliminate the voluntary TOU meter charges on legacy Schedule A-6.

2. Rate Design

As discussed above, in this proceeding PG&E proposes to continue the seasons, TOU periods and rate design established by D.18-08-013 for all SLP rate schedules except noted below for Schedule B-6.

PG&E proposes to continue the customer charges on Schedules A1-TOU, A-6, B-1, B-1 Store and B-6: $10 for single-phase and $25 for poly-phase service. In addition, PG&E proposes to eliminate the current

TOU meter charge applicable on Schedule A-6.[5] Currently, Schedule B-1 has TOU differentials in only the generation component of the rate. The prescribed differential in the summer is approximately seven cents per kilowatt-hour (¢/kWh) (on-peak versus off-peak). This design compares to a fully time-differentiated, fully-scaled Equal Percent of Marginal Cost (EPMC) rate differential of about 34 ¢/kWh. PG&E recommends retaining these moderate TOU differentials for this GRC cycle during the transition of customers to the new TOU periods and consider increasing the TOU differential on this rate schedule in the 2023 GRC Phase II proceeding.

The design authorized for Schedule B-6 in D.18-08-013 provides for an on-peak versus off-peak differential in the summer of about 12 ¢/kWh with no summer partial-peak period. This rate features time differentiation in both the generation and distribution rate components. In this proceeding, PG&E proposes to retain the TOU differential adopted by D.18-08-013 during the transition of customers to the mandatory TOU rates. Once the transition is complete, PG&E proposes to increase the TOU differentials for Schedule B-6. Specifically, PG&E proposes to set the TOU differential at the mid-point between fully-time-differentiated rates (with a 32 ¢/kWh differential) and the currently authorized rates, resulting in an on-peak versus off-peak differential in the summer of about 22 ¢/kWh. By adopting revised rate design for Schedule B-6, a beneficial rate is available to customers that can shift load that has a much wider TOU differential than Schedule B-1. By waiting to make this change until 2022, customers are not impacted by a change to pricing during the mandatory transition to the new TOU period hours and rates.

PG&E proposes to continue the current structure for both Schedules TC-1 and B-15. Energy rates for Schedule B-15 will be equal to the seasonally differentiated, non-TOU equivalent of Schedule B-1.

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[5] PG&E proposes to eliminate the voluntary TOU meter charges on the legacy Schedules A-6 and E-19 V. Voluntary TOU meter charges were first approved to recover the incremental cost of the TOU meter and TOU program administrative cost. As interval meters have been installed, these meter charges have only been applied to customers still served with legacy TOU meters. These charges no longer serve their original purpose because TOU meters and TOU service are now standard. For that reason, voluntary TOU meter charges were not included in the B Series schedules.

Schedule B-15 will be subject to the single-phase customer charge for Schedule B-1 and will continue to include a $25 facility charge. Schedule TC-1 will continue in its current form as a non-time differentiated rate. Schedule TC-1 will continue to include a $15 customer charge.

Schedules A-1, A-6 and A-15 will retain the same customer charge and facility charge as their B Series counterpart rates. As discussed above, PG&E proposes to eliminate the voluntary TOU meter charge on legacy Schedule A-6. Rate design changes will be implemented as provided in Section 3 below until these rates are available only to solar grandfathered customers.

In D.18-08-013, the Commission adopted a new SLP schedule, Schedule B1-Store, for eligible customers with storage systems. PG&E expects Schedule B1-Store will available for enrollment in August 2020. PG&E proposes that the design adopted by D.18-08-013 be continued subject to the rules for changing generation and distribution charges described in Section 3.

3. Changes to Distribution and Generation Rates

Changes to legacy rates and the B Series rates would continue to use the existing rules for changes between GRCs adopted by D.18-08-013 in order to implement the revenue allocation adopted in this proceeding and for revenue requirement changes before the next GRC Phase II proceeding. These rules are summarized for the SLP customer class in Attachment A, Part A.

4. Meet and Confer With Small Business Utility Advocates and the Public Advocates Office at the California Public Utilities Commission

The Settlement Agreement on SLP Rate Design adopted by D.18-08-013 required that PG&E schedule a 'meet and confer' with the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) and Small Business Utility Advocates (SBUA) six months prior to filing its next GRC Phase II application. The purpose of the meet and confer was to discuss whether A-1 DMD or other rate schedules should be proposed in the next GRC Phase II proceeding, for the purpose of providing a meaningful rate option for small businesses to manage energy costs. The Settlement further provided that PG&E would submit testimony in this GRC Phase II proceeding on the results of that meet and confer.

On February 5, 2019, PG&E held a conference call with SBUA and Cal Advocates. After PG&E reviewed the settlement requirement, SBUA indicated that they were generally in favor of options for small commercial customers and had requested the meet and confer to consider the possibility of additional options in the 2020 GRC Phase II. PG&E agreed that the reference to A-1-DMD was intended as an example of one such possible rate option. SBUA said that they had been in favor of A-1-DMD, but that was not the only possibility. The parties discussed the benefits and drawbacks of a rate with a low TOU differential. PG&E described the options that came out of the 2017 GRC II proceeding, including default A-1TOU (currently Schedule B-1) with a low 7 cent differential and A-6 (currently Schedule B-6) with a higher differential. PG&E indicated that while generally in favor of a demand charges, PG&E was not currently planning additional rate options for the next Phase II. In addition, PG&E indicated that changing designs radically in Phase II would disrupt the transition to the new TOU periods which will likely occur while the 2020 GRC Phase II was pending.

In response to an inquiry from Cal Advocates regarding the decision's reference to a wider TOU differential for A-6 (currently Schedule B-6), PG&E asked if a somewhat higher TOU differential on A-6 (currently Schedule B-6) would be a benefit. Both CAL Advocates and SBUA indicated that they would need to study the question. PG&E stated that illustrative rates would certainly be filed in the proceeding for consideration by the Commission and the Parties.

On April 3, 2019, SBUA, Cal Advocates, and PG&E held a follow-up conference call. SBUA indicated that they were in favor of considering a wider TOU differential for A-6 (currently Schedule B-6). Cal Advocates preferred to wait to widen the TOU differential for A-6 (currently Schedule B-6) until it could be reviewed further. SBUA asked about changes to TOU hours. PG&E stated that it was unlikely to attempt to change TOU hours in the 2020 GRC, although future changes to TOU periods would be reviewed as part of the filing. SBUA indicated that they were concerned with small business customers adjusting to TOU hours and suggested considering alternative rate structures. PG&E said it would prefer not to add a new rate schedule. No consensus with regard to additional rate options or alternative structures was reached during the meet and confer.

5. Schedule E-CARE and the Food Bank Discount

Schedule E-CARE is the California Alternate Rates for Energy (CARE) program for non-profit group living facilities served on non-Residential rates. The E-CARE discount is implemented as a dollar per kWh discount where the customer's bill is equal to its otherwise applicable commercial charges, less a discount equal to the product of its total kWh usage and the Schedule E-CARE discount rate per kWh. The Schedule E-CARE discount rate per kWh is designed to provide approximately the same percentage discount relative to Non-CARE rates, on average, as Residential rates.

The Schedule E-CARE total rate per kWh discount is unbundled into three parts: (1) the waiver of the CARE surcharge component of PPP rates; (2) a distribution discount; and (3) the exemption to the California DWR Bond Charge. By providing the distribution CARE discount in the distribution function, PG&E allows all customers, whether CCA, Direct Access or bundled service, to receive the same CARE discount. PG&E proposes to retain the current E-CARE design and update the rate discounts as the overall residential CARE discount changes.

The Commission authorized a 20 percent discount to eligible food banks in D.18-08-013. PG&E proposes to continue the food bank discount in this GRC.

D. Rate Design for Schedules A-10 and B-10

This section includes rate design for Schedules A-10, A-10 TOU and B-10. Customers with demand less than 500 kW may take service on these rate schedules. These schedules generally consist of a customer charge, a maximum (non-coincident) demand charge and energy charges.

1. Overview

PG&E proposes the following rate design for Schedules A-10 and B-10:

- Retain the seasons and TOU periods adopted by D.18-08-013; and

- Continue the existing rate structures and rules for changes between GRCs in order to implement the revenue allocation results determined in this proceeding and for revenue requirement changes before the next GRC Phase II proceeding to ensure rate stability during the transition to rates with new TOU periods.

2. Rate Design

As discussed above, in this proceeding, PG&E proposes to continue the rate design established by D.18-08-013 for Schedules A-10 and B-10. PG&E's proposal retains the rules for changing the customer charge authorized by D.18-08-013 with changes in revenue allocation in this proceeding and revenue requirement changes.

D.18-08-013 adopted a TOU differential for Schedule B-10 only in the generation component of the rate. The prescribed differential in the summer is approximately 9.4 ¢/kWh (on-peak to off-peak at secondary voltage). This design compares to a fully-time-differentiated, fully-scaled EPMC rate differential of about 33 ¢/kWh (distribution and generation). PG&E recommends retaining this moderate TOU differential for this GRC cycle during the transition of customers to the new TOU periods; increases to the TOU differential on this rate schedule in should instead be considered in PG&E's 2023 GRC Phase II proceeding. PG&E proposes to retain the current level of non-coincident demand charge, subject to the revenue allocation changes in this proceeding, to recover a portion of distribution costs that do not vary by time of day. Customers whose demand is less than 500 kW also have the choice of electing voluntary service under Schedule B-19. Schedule B-19V offers a much wider TOU differential in both the generation and distribution components of the rate than Schedule B-10 and provides a beneficial option to customers that can shift load.

Under this proposal, Schedule A-10 will retain the same customer charge as the B Series counterpart rate. Rate design changes will be implemented as provided in Section 3, below, until these rates are available only to solar grandfathered customers.

3. Changes to Distribution and Generation Rates

Changes to legacy rates (A-10) and the new B Series rates (B-10) would use the existing rules for changes between GRCs adopted by D.18-08-013 in order to implement the revenue allocation adopted in this proceeding and for revenue requirement changes before the next GRC Phase II proceeding. These rules are summarized for Schedules A-10 and B-10 in Attachment A, Part B.

E. Rate Design for Schedules E-19, E-20, B-19, and B-20

This section includes rate design for Schedules E-19, E-19V, E-20, B-19, B-19V, and B-20. Customers with demands less than 500 kW may elect to take service on Schedules E-19V and B-19V. Customers with demands between 500 kW and 1,000 kW must take service on Schedules E-19 and B-19. Customers with demand greater than 1,000 kW are required to take service on Schedules E-20 and B-20. The basic rates for B-19 and B-20 are among PG&E's most cost-based rates as they recover costs in customer, demand (TOU and non-coincident) charges and TOU energy charges. Schedules E-19V, E-19 and E-20 also include Option R for qualifying customers with photovoltaic (PV) systems. Similarly, Schedules B-19V, B-19 and B-20 also include Option R for qualifying customers with PV systems. In addition, these B Series schedules include Option S, for qualifying customers with storage systems.

1. Overview

PG&E proposes the following rate design for Schedules E-19, E-19V, E-20, B-19, B-19V, and B-20:

- Retain the seasons and TOU periods adopted by D.18-08-013;
- Continue the existing rate structures and rules for changes between GRCs in order to implement the revenue allocation results determined in this proceeding and for revenue requirement changes before the next GRC Phase II proceeding to ensure rate stability during the transition to rates with new TOU periods; and
- Eliminate the voluntary TOU meter charges on legacy rate Schedule E-19V.

2. Rate Design

As discussed above, PG&E proposes to continue the rate design established by D.18-08-013 for all rate schedules in this group. Like Schedule B-10, PG&E's proposal retains rules for changing the customer charge authorized by D.18-08-013 with changes in revenue allocation in this proceeding and revenue requirement changes. In addition, as described in the SLP rate design section for Schedule A-6, PG&E proposes to eliminate the current TOU meter charge applicable on Schedule E-19V.

PG&E has reviewed the overall level of TOU differentials adopted by D.18-08-013 relative to TOU differentials that are fully scaled based on EPMC relationships. In general, PG&E believes the proposed rates are consistent with the EPMC scaled rates and are suitable for application during the transition to new TOU periods in this GRC cycle. PG&E recommends that the rate design adopted by D.18-08-013 be continued for that purpose in this proceeding.

Schedules E-19V, E-19 and E-20 (and the related Option R) will retain the same customer charge as the B Series counterpart rate. As discussed above, PG&E proposes to eliminate the voluntary TOU meter charge on legacy Schedule E-19V. Rate design changes will be implemented as provided in Section 3, below, until these rates are available only to solar grandfathered customers.

3. Changes to Distribution and Generation Rates

As with Schedule A-10 and B-10, changes to legacy rates (E-19V, E-19, E-20) and the new B Series rates (B-19V, B-19 and B-20) would use the existing rules for changes between GRCs adopted by D.18-08-013 to implement the revenue allocation adopted in this proceeding and for revenue requirement changes before the next GRC Phase II proceeding. These rules are summarized for this customer class in Attachment A, Part C.

F. Rate Design for Standby (Schedules S and SB)

PG&E provides standby service under Schedule S or Schedule SB to customers whose non-utility source of generation is capable of regularly and completely serving their entire electrical load. The largest portion of the load currently served by PG&E under Schedule S is comprised of customers who take service at transmission service voltages. Schedule S will be eliminated on the date that the new Schedule SB with later TOU periods becomes mandatory. Schedules S and SB include customer charges, reservation and TOU energy charges, and all applicable utility charges, terms and conditions for those customers whose non-utility source of generation is capable of regularly and completely serving their entire electrical load.

A limited number of customers require "supplemental" standby service from PG&E. Supplemental standby service is provided to customers who rely on non-utility sources of generation for only a portion of their total load. These customers pay all other charges under the terms and conditions of the otherwise-applicable rate schedule. In addition, under this type of standby service, the customer pays the standby reservation charge from Schedule S (or Schedule SB) only for that portion of its load that is ordinarily supplied by the non-utility generation resource.[6]

1. Overview

PG&E proposes the following rate design for Standby:

- Retain the seasons and TOU periods adopted by D.18-08-013;
- Mitigate the changes to Schedule SB at primary and secondary service voltage by limiting the distribution increase at these service voltages and reducing the reduction that would otherwise have been assigned to transmission service;
- Revise generation charges for Schedule SB to better reflect the capacity cost assignment; and
- Revise the method to change rates for revenue allocation and revenue requirement changes in the future to adjust demand rates and energy rates by an equal percent change, but implement the equal percent change to energy charges on an equal ¢/kWh basis.

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[6] Demand charges billed under the terms of the otherwise-applicable rate schedule are reduced by the amounts paid for reservation capacity under Schedule S or SB, in those instances where it is demonstrated that the maximum demand during a given billing cycle was attributable to non-operation of the customer's generator.

2. Rate Design

Standby distribution costs will be collected through a combination of customer charges, energy and reservation charges. Customer charges are set at the levels adopted for the otherwise applicable rate schedule. Consistent with long established practice and to maintain stable relationships across voltages, PG&E combines the billing determinants and marginal costs for standby loads served at primary and secondary distribution voltages before designing distribution energy and reservation charges for these customers. In this proceeding, PG&E proposes to mitigate the impact of fully allocating distribution costs to primary and secondary service customers by reducing the distribution reduction that would otherwise be assigned to the transmission service voltage. Distribution reservation charges and energy rates are changed by the equal percent change necessary to recover the assigned revenue after changes to customer charges are considered. However, PG&E proposes that the equal percentage change to distribution energy rates will be implemented by change each energy rate on an equal ¢/kWh basis.

Standby generation costs will be collected through a combination of energy and reservation charges. Like distribution rate design, PG&E proposes to combine the billing determinants and marginal costs for standby loads served at primary and secondary distribution voltages before designing generation energy and reservation charges for these customers. PG&E proposes to collect the energy-related share of the total generation revenue assigned to Schedule SB in TOU energy charges. As in past, PG&E proposes to use the capacity-related share of the assigned generation revenue for Schedule SB to set the generation component of the standby reservation charge. Because the capacity related share of generation costs have increased significantly relative to the level of those costs currently recovered in the reservation charge, PG&E proposes to increase the reservation charge in this proceeding, with commensurate reductions to proposed energy rates, in order to better reflect the cost of service to this class.

With regard to future changes to generation rates (i.e., after the adjustment described above) due to changes in revenue allocation and subsequent revenue requirement changes, PG&E proposes to change generation reservation and energy charges by the equal percentage necessary to collect the assigned revenue. However, PG&E proposes that the equal percentage change to generation energy rates will be implemented by changing each energy rate on an equal ¢/kWh basis.

3. Changes to Distribution and Generation Rates

Schedule SB was implemented on an opt-in basis in November 2019. Schedule S will remain in effect until the new "B" series rates become mandatory, which is expected in November 2020. At that time, customers taking service on Schedule S will be transferred to the new Schedule SB and Schedules S will be eliminated. Therefore, PG&E expects that Schedule S will be eliminated before decision in this proceeding is rendered. PG&E proposes that changes to rates for the new Schedule SB to implement the revenue allocation adopted in this proceeding as well as for revenue requirement changes will be governed by the guidelines set forth for changing generation rates and distribution rates that are as described above. Rules for changing distribution and generation rates, subject to the initial adjustments described above, are set forth in Attachment A, Part D.

G. Rate Design Illustrations Requested in D.18-08-013

D.18-08-013 also required that PG&E file a number of illustrations of rate designs to give the Commission and the other parties the fullest opportunity consider other approaches to rate design.[7] To this end, PG&E has provided three illustrative rate designs for C&I customers. Each rate design illustration is provided in Exhibit (PG&E-4), Appendix G.

The first illustration is required by D.18-08-013 and provides rates with TOU differentials scaled to provide full EPMC differentials. Customer charges for this illustration were set at the proposed levels. In the prior rate design discussion, PG&E compared its rate proposal to this rate design illustration.

In the second illustration, PG&E has fully scaled the customer charge based on EPMC while also fully scaling the TOU differentials by EPMC as shown in the first illustration. PG&E is providing this illustration to show the impact on energy charges if customer charges were set at full cost.

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[7] D. 18-08-013, Ordering Paragraph (OP) 5, pp. 47-51.

In the third (and last) illustration, D.18-08-013 also requires that PG&E provide an illustration of rates with TOU differentials that fall in between those approved by D.18-08-013 and fully EPMC scaled TOU differentials.[8] Since PG&E does not propose to increase customer charges to the extent shown in the second illustration, PG&E has utilized fully-scaled TOU differentials provided in the first illustration as one bound in this mid-point analysis. Rates were then set to move half-way from the PG&E's proposed rates, which are based on the rate design adopted in D.18-08-013, and the rates provided in the first illustration. This illustration provides the rates proposed to be implemented in 2022 for Schedule B-6.

Illustrative designs were prepared for Schedules B-1, B-6, B-10, B-19 and B-20.

TABLE 4-2
ILLUSTRATIVE RATE DESIGNS

Line No.	Rate Design	Description
1	Illustration 1	Fully scaled TOU differentials with no change to customer charge
2	Illustration 2	Fully scaled TOU differentials with a fully-scaled customer charge
3	Illustration 3	Rate design established at the mid-point between the rates adopted by D.18-08-013 and Illustration 1

H. Conclusion

In this chapter, PG&E has proposed rates for C&I customers that will apply prior to the next GRC Phase II proceeding. PG&E's rate design proposals seek to minimize rate design changes, thereby providing a reasonable degree of stability in rates during the period when customers are transitioned to rates with new, later TOU periods. In addition, minimizing rate design changes will also reduce the potential compounding effects that can be caused by making rate design changes while also adjusting revenue allocation as described in

8 OP 5 of D.18-08-013 provides that "PG&E shall also propose an alternate set of rates that, while not based on full EPMC scaling, are more cost based than those approved by this decision."

Chapter 2 of this exhibit. PG&E respectfully requests that the Commission approve the rate design proposals contained in this chapter.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT A

DETAILED GUIDELINES FOR CHANGING RATES FOR REVENUE CHANGES

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
ATTACHMENT A
DETAILED GUIDELINES FOR CHANGING RATES FOR REVENUE CHANGES

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ATTACHMENT A
DETAILED GUIDELINES FOR CHANGING RATES FOR REVENUE CHANGES

A. Small Light and Power Customer Class

Changes to Small Light and Power legacy rates and the B Series rates will continue to utilize the existing rules for changes between General Rate Cases (GRC) adopted by Decision (D.)18-08-013 in order to implement the revenue allocation adopted in this proceeding as well as for revenue requirement changes before the next GRC Phase II proceeding. Rules for changes to distribution and generation rates are set forth below.

1. Distribution Rate Design

The distribution revenue requirement will be allocated to each rate schedule as provided in Chapter 2 of Exhibit (PG&E-3). Distribution rates will then be designed to collect the allocated revenue. Pacific Gas and Electric Company (PG&E) proposes to retain the approved customer charges until the levels of those charges are revisited in its 2023 GRC Phase II. With the exception of the proposed change to increase the Time-of-Use (TOU) differentials for Schedule B-6 in 2022, demand and energy charges each will be designed to change by the same percentage change in rate necessary to collect the required revenue. However, the change in energy charges will be determined by the equal cents per kilowatt-hour (kWh) adder that is required to collect the necessary change in energy charge revenue. This approach to setting the distribution energy charges will ensure that the differential in rates between seasons and TOU periods remains the same on a cents per kWh basis.

2. Generation Rate Design

The generation revenue requirement will be allocated to each rate schedule as provided in Chapter 2 of Exhibit (PG&E-3). Generation rates will then be designed to collect the allocated revenue. With the exception of the proposed change to increase the TOU differentials for Schedule B-6 in 2022, demand and energy charges will be designed to each change by the same percentage amount as necessary to collect the required revenue. However, the change in energy charges will be determined by the equal cents per kWh adder that is required to collect the necessary change in energy charge revenue. This approach to setting the generation energy charges will ensure that the differential in rates between seasons and TOU periods remains the same on a cents per kWh basis.

B. Schedules A-10 and B-10

Changes to legacy rates (A-10) and the B Series rates (B-10) will continue to utilize the existing rules for changes between GRCs adopted by D.18-08-013 in order to implement the revenue allocation adopted in this proceeding as well as for revenue requirement changes before the next GRC Phase II proceeding. Rules for changing distribution and generation rates are set forth below.

1. Distribution Rate Design

The distribution revenue requirement will be allocated to each rate schedule as provided in Chapter 2 of Exhibit (PG&E-3). Distribution rates will then be designed to collect the allocated revenue. For Schedules B-10 and A-10, customer charges, demand charges, and energy charges will be designed to change by the same percentage change in rate necessary to collect the required revenue. However, the change to energy charges will be determined by the equal cents per kWh adder required to collect the necessary change in energy charge revenue. This approach to setting the distribution energy charges for Schedules A-10 and B-10 will ensure that the differential in energy rates between seasons and TOU periods remains the same on a cents per kWh basis for these schedules.

2. Generation Rate Design

The generation revenue requirement will be allocated to each rate schedule as provided in Chapter 2 of Exhibit (PG&E-3). Generation rates will then be designed to collect the allocated revenue. Demand and energy charges will be designed to each change by the same percentage change in rate necessary to collect the required revenue for Schedules A-10 and B-10. However, the change in energy rates will be determined by the equal cents per kWh adder required to collect the necessary change in energy charge revenue. This approach to setting the generation energy charges for

Schedules A-10 and B-10 will ensure that the differential in rates between seasons and TOU periods remains the same on a cents per kWh basis.

C. Schedules E-19V, E-19, E-20, B-19V, B-19 and B-20

Changes to legacy rates (E-19V, E-19, E-20) and the B Series rates (B-19V, B-19 and B-20) will continue to utilize the existing rules for changes between GRCs adopted by D.18-08-013 in order to implement the revenue allocation adopted in this proceeding as well as for revenue requirement changes before the next GRC Phase II proceeding. Rules for changing distribution and generation rates are set forth below.

1. Distribution Rate Design

The distribution revenue requirement will be allocated to each rate schedule as provided in Chapter 2 of Exhibit (PG&E-3). Distribution rates will then be designed to collect the allocated revenue. For Schedules E-19V and B-19V, the customer charge will be set to the customer charge for Schedules A-10 and B-10. All remaining customer charges and demand charges on these schedules will be changed by an equal percentage change to collect the required revenue. Customer charge changes resulting from the method described above for Schedule E-20 T will be limited to ensure that the residual distribution maximum demand charge collects the revenue associated with the CPUC Fee.

For Option R, distribution rates will be designed by converting 75 percent of the distribution revenue derived from peak and part-peak distribution demand charges to energy charges. Energy charges will be designed to change by the equal cents per kWh adder required to collect the necessary change in energy charge revenue. This approach to setting the distribution energy charges for Option R will ensure that the differential in energy rates between seasons and TOU periods remains the same on a cents per kWh basis. In some cases, application of the rule described above resulted in illustrative Option R energy rates that were slightly negative. PG&E does not expect this to occur with actual rate changes required to implement this decision.

Option S will begin from the Option R design for B-19V, B-19 and B-20 only. Revenue associated with the non-coincident demand charges for

Option R will be converted to a daily demand charge applicable in the peak period (80 percent share), and to a special non-coincident demand charge applicable in all hours except 9 a.m. to 2 p.m. (20 percent share). Revenue associated with the peak and partial peak demand charges on Option R will be converted to peak and partial-peak daily demand charges.

2. Generation Rate Design

The generation revenue requirement will be allocated to each rate schedule as provided in Chapter 2 of Exhibit (PG&E-3). Generation rates will then be designed to collect the allocated revenue. Demand and energy charges for schedules E-19V, E-19, E-20, B-19V, B-19, and B-20 will be designed to each change by the same percentage change in rate necessary to collect the required revenue.

For Option R, generation rates will be designed by converting 100 percent of the generation revenue derived from peak and part-peak generation demand charges and converting that revenue to energy charges. Energy charges will be designed to change by the equal cents per kWh adder required to collect the necessary change in energy charge revenue. This approach to setting the generation energy charges for Option R will ensure that the differential in energy rates between seasons and TOU periods remains the same on a cents per kWh basis. Generation rates for Option S will be the same as the generation rates for Option R for Schedules B-19V, B-19 and B-20.

D. Schedule SB

Changes to Schedule SB will utilize the following rules to implement the revenue allocation adopted in this proceeding as well as for revenue requirement changes before the next GRC Phase II proceeding. Rules for changing distribution and generation rates, after the initial rate adjustments described in Chapter 4 of Exhibit (PG&E-3) are implemented, are set forth below.

1. Distribution Rate Design

The distribution revenue requirement will be allocated to each rate schedule as provided in Chapter 2 of Exhibit (PG&E-3). Distribution rates will then be designed to collect the allocated revenue. Customer charges will be set based on the rate for the otherwise applicable schedule.

For Schedule SB, reservation and energy charges will be designed to change by the same percentage change in rate necessary to collect the required revenue. However, the change to energy charges will be determined by the equal cents per kWh adder required to collect the necessary change in energy charge revenue. This approach to setting the distribution energy charges for Schedule SB will ensure that the differential in energy rates between seasons and TOU periods remains the same on a cents per kWh basis for these schedules.

2. Generation Rate Design

The generation revenue requirement will be allocated to each rate schedule as provided in Chapter 2 of Exhibit (PG&E-3). Generation rates will then be designed to collect the allocated revenue. Reservation and energy charges will be designed to change by the same percentage change in rate necessary to collect the required revenue. However, the change to energy charges will be determined by the equal cents per kWh adder required to collect the necessary change in energy charge revenue. This approach to setting the generation energy charges for Schedule SB will ensure that the differential in energy rates between seasons and TOU periods remains the same on a cents per kWh basis for these schedules.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT B

COMMERCIAL AND INDUSTRIAL PRESENT AND PROPOSED RATES

	PRESENT RATES						PROPOSED RATES					
B-1	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
ENERGY CHARGE (/kWh)												
Summer												
Peak	.08785	.17700	.01317	.03481	.31283		.10095	.17290	.01333	.03481	.32198	
Part-Peak	.08785	.12777	.01317	.03481	.26360		.10095	.12367	.01333	.03481	.27275	
Off-Peak	.08785	.10696	.01317	.03481	.24279		.10095	.10286	.01333	.03481	.25194	
Winter												
Peak	.06767	.12175	.01317	.03481	.23740		.08077	.11765	.01333	.03481	.24655	
Off-Peak	.06767	.10563	.01317	.03481	.22128		.08077	.10153	.01333	.03481	.23043	
Super Off-Peak	.06767	.08921	.01317	.03481	.20486		.08077	.08511	.01333	.03481	.21401	
CUSTOMER CHARGE (/meter/day)												
Single-phase	.32854				.32854	10.00	.32854				.32854	10.00
Polyphase	.82136				.82136	25.00	.82136				.82136	25.00

B1-STORAGE	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
DEMAND CHARGE (/kW)												
Summer	3.32				3.32		3.91				3.91	
Winter	3.32				3.32		3.91				3.91	
ENERGY CHARGE (/kWh)												
Summer												
Peak	.15223	.18180	.01317	.03481	.38201		.16261	.17769	.01333	.03481	.38845	
Part-Peak	.05339	.13934	.01317	.03481	.24071		.06377	.13523	.01333	.03481	.24715	
Off-Peak	.04181	.10359	.01317	.03481	.19338		.05219	.09948	.01333	.03481	.19982	
Winter												
Peak	.10486	.13122	.01317	.03481	.28406		.11524	.12711	.01333	.03481	.29050	
Part-Peak	.08770	.11888	.01317	.03481	.25456		.09808	.11477	.01333	.03481	.26100	
Off-Peak	.02065	.09688	.01317	.03481	.16551		.03103	.09277	.01333	.03481	.17195	
Super Off-Peak	.02065	.08046	.01317	.03481	.14909		.03103	.07635	.01333	.03481	.15553	
CUSTOMER CHARGE (/meter/day)												
Single-phase	.32854				.32854		.32854				.32854	10.00
Polyphase	.82136				.82136		.82136				.82136	25.00

B-6	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
ENERGY CHARGE (/kWh)												
Summer												
Peak	.11702	.18199	.01181	.03481	.34563		.13044	.18024	.01333	.03481	.35882	
Off-Peak	.07025	.11083	.01181	.03481	.22770		.08367	.10908	.01333	.03481	.24089	
Winter												
Peak	.07293	.11847	.01181	.03481	.23802		.08635	.11672	.01333	.03481	.25121	
Off-Peak	.07025	.10142	.01181	.03481	.21829		.08367	.09967	.01333	.03481	.23148	
Super Off-Peak	.07025	.08500	.01181	.03481	.20187		.08367	.08325	.01333	.03481	.21506	
CUSTOMER CHARGE (/meter/day)												
Single-phase	.32854				.32854	10.00	.32854				.32854	10.00
Polyphase	.82136				.82136	25.00	.82136				.82136	25.00

E-CARE	Distr	Gen	PPP	Other	Total	Distr	Gen	PPP	Other	Total
Discount (/kWh)										
B-1/A-1	(.07270)		(.00699)	(.00503)	(.08472)	(.07454)		(.00691)	(.00503)	(.08648)
B-6/A-6	(.06911)		(.00699)	(.00503)	(.08113)	(.07162)		(.00691)	(.00503)	(.08356)
B-15/A-15	(.07270)		(.00699)	(.00503)	(.08472)	(.07454)		(.00691)	(.00503)	(.08648)
B-10/A-10	(.06384)		(.00699)	(.00503)	(.07586)	(.06106)		(.00691)	(.00503)	(.07300)
B-19/E-19	(.05606)		(.00699)	(.00503)	(.06808)	(.05328)		(.00691)	(.00503)	(.06522)
B-20/E-20	(.04384)		(.00699)	(.00503)	(.05586)	(.04223)		(.00691)	(.00503)	(.05417)

B-10

	PRESENT RATES						PROPOSED RATES					
	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
DEMAND CHARGE (/kW)												
Transmission												
Summer	1.35			7.67	9.02		1.39			7.67	9.06	
Winter	1.35			7.67	9.02		1.39			7.67	9.06	
Primary												
Summer	4.08			7.67	11.75		3.81			7.67	11.48	
Winter	4.08			7.67	11.75		3.81			7.67	11.48	
Secondary												
Summer	4.28			7.67	11.95		4.54			7.67	12.21	
Winter	4.28			7.67	11.95		4.54			7.67	12.21	
ENERGY CHARGE (/kWh)												
Transmission												
Summer												
Peak	.00658	.17957	.01129	.01119	.20863		.00676	.17344	.00910	.01120	.20050	
Part-Peak	.00658	.12283	.01129	.01119	.15189		.00676	.11670	.00910	.01120	.14376	
Off-Peak	.00658	.09276	.01129	.01119	.12182		.00676	.08663	.00910	.01120	.11369	
Winter												
Peak	.00658	.12652	.01129	.01119	.15558		.00676	.12039	.00910	.01120	.14745	
Off-Peak	.00658	.09368	.01129	.01119	.12274		.00676	.08755	.00910	.01120	.11461	
Super Off-Peak	.00658	.05734	.01129	.01119	.08640		.00676	.05121	.00910	.01120	.07827	
Primary												
Summer												
Peak	.04215	.18751	.01158	.01119	.25243		.04016	.18218	.01200	.01120	.24554	
Part-Peak	.04215	.12921	.01158	.01119	.19413		.04016	.12388	.01200	.01120	.18724	
Off-Peak	.04215	.09837	.01158	.01119	.16329		.04016	.09304	.01200	.01120	.15640	
Winter												
Peak	.02393	.13288	.01158	.01119	.17958		.02194	.12755	.01200	.01120	.17269	
Off-Peak	.02393	.09925	.01158	.01119	.14595		.02194	.09392	.01200	.01120	.13906	
Super Off-Peak	.02393	.06291	.01158	.01119	.10961		.02194	.05758	.01200	.01120	.10272	
Secondary												
Summer												
Peak	.04204	.20025	.01181	.01119	.26529		.04388	.19068	.01235	.01120	.25810	
Part-Peak	.04204	.13856	.01181	.01119	.20360		.04388	.12899	.01235	.01120	.19641	
Off-Peak	.04204	.10600	.01181	.01119	.17104		.04388	.09643	.01235	.01120	.16385	
Winter												
Peak	.02382	.14221	.01181	.01119	.18903		.02566	.13264	.01235	.01120	.18184	
Off-Peak	.02382	.10673	.01181	.01119	.15355		.02566	.09716	.01235	.01120	.14636	
Super Off-Peak	.02382	.07039	.01181	.01119	.11721		.02566	.06082	.01235	.01120	.11002	
CUSTOMER CHARGE (/meter/day)	4.59959				4.59959	140.00	4.87372				4.87372	148.34

B-15

	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
ENERGY CHARGE (/kWh)												
Summer	.08785	.12734	.01317	.03481	.26317		.10095	.12324	.01333	.03481	.27233	
Winter	.06767	.10820	.01317	.03481	.22385		.08077	.10410	.01333	.03481	.23301	
CUSTOMER CHARGE (/meter/day)	.32854				.32854	10.00	.32854				.32854	10.00
FACILITY CHARGE (/meter/day)	.82136				.82136	25.00	.82136				.82136	25.00

B-19 Secondary	PRESENT RATES						PROPOSED RATES					
	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
DEMAND CHARGES (/kW)												
Summer												
Peak	9.93	15.01			24.94		8.98	14.35			23.33	
Part-Peak	2.87	2.18			5.05		2.60	2.08			4.68	
Maximum	11.46			8.09	19.55		10.36			8.09	18.45	
Winter												
Peak	.00	1.78			1.78		.00	1.70			1.70	
Maximum	11.46			8.09	19.55		10.36			8.09	18.45	
DEMAND CHARGES - OPTION R ($/kW)												
Summer												
Peak	2.48				2.48		2.25				2.25	
Part-Peak	.72				.72		.65				.65	
Maximum	11.46			8.09	19.55		10.36			8.09	18.45	
Winter												
Peak	.00						.00				.00	
Maximum	11.46			8.09	19.55		10.36			8.09	18.45	
DEMAND CHARGES - OPTION S												
Summer												
Peak ($/kW/day)	.49				.49		.47	.00			.47	
Part Peak ($/kW/day)	.03				.03		.03	.00			.03	
Maximum ($/kW)				8.09	8.09			.00		8.09	8.09	
Maximum ($/kW applied to all hours except 9 am to 2 pm)	2.32				2.32		2.10	.00			2.10	
Winter ($/kW mo)												
Peak ($/kW/day)	.42				.42		.38	.00			.38	
Maximum ($/kW)				8.09	8.09			.00		8.09	8.09	
Maximum ($/kW applied to all hours except 9 am to 2 pm)	2.32				2.32		2.10	.00			2.10	
ENERGY CHARGES (/kWh)												
Summer												
Peak	.00000	.13955	.01129	.01112	.16196		.00000	.13340	.01301	.01113	.15754	
Part-Peak	.00000	.10960	.01129	.01112	.13201		.00000	.10477	.01301	.01113	.12891	
Off-Peak	.00000	.08841	.01129	.01112	.11082		.00000	.08451	.01301	.01113	.10865	
Winter												
Peak	.00000	.12053	.01129	.01112	.14294		.00000	.11522	.01301	.01113	.13935	
Off-Peak	.00000	.08833	.01129	.01112	.11074		.00000	.08444	.01301	.01113	.10857	
Super Off-Peak	.00000	.04513	.01129	.01112	.06754		.00000	.04314	.01301	.01113	.06728	
ENERGY CHARGES - OPTION R (/kWh)												
Summer												
Peak	.07226	.26656	.01129	.01112	.36123		.07016	.26158	.01301	.01113	.35587	
Part-Peak	.02399	.13099	.01129	.01112	.17739		.02189	.12601	.01301	.01113	.17203	
Off-Peak	.00203	.09249	.01129	.01112	.11693		(.00007)	.08751	.01301	.01113	.11157	
Winter												
Peak	.00000	.13473	.01129	.01112	.15714		.00000	.12975	.01301	.01113	.15389	
Off-Peak	.00000	.09242	.01129	.01112	.11483		.00000	.08744	.01301	.01113	.11158	
Super Off-Peak	.00000	.05660	.01129	.01112	.07901		.00000	.05162	.01301	.01113	.07576	
ENERGY CHARGES - OPTION S (/kWh)												
Summer												
Peak	.07226	.26656	.01129	.01112	.36123		.07016	.26158	.01301	.01113	.35587	
Part-Peak	.02399	.13099	.01129	.01112	.17739		.02189	.12601	.01301	.01113	.17203	
Off-Peak	.00203	.09249	.01129	.01112	.11693		(.00007)	.08751	.01301	.01113	.11157	
Winter												
Peak	.00000	.13473	.01129	.01112	.15714		.00000	.12975	.01301	.01113	.15389	
Off-Peak	.00000	.09242	.01129	.01112	.11483		.00000	.08744	.01301	.01113	.11158	
Super Off-Peak	.00000	.05660	.01129	.01112	.07901		.00000	.05162	.01301	.01113	.07576	
CUSTOMER CHARGE (/meter/day)												
B-19	23.65503				23.65503	720.00	21.69512				21.69512	660.35
Rate V	4.59959				4.59959	140.00	4.87372				4.87372	148.34
POWER FACTOR ADJUSTMENT (/kWh)	.00005				.00005		.00005				.00005	

per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%

B-19 Primary

	PRESENT RATES						PROPOSED RATES					
	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
DEMAND CHARGES (/kW)												
Summer												
Peak	9.33	12.75			22.08		8.38	12.72			21.10	
Part-Peak	2.66	1.86			4.52		2.39	1.86			4.25	
Maximum	8.00	.00		8.09	16.09		7.19			8.09	15.28	
Winter												
Peak	.00	1.31			1.31			1.31			1.31	
Maximum	8.00	.00		8.09	16.09		7.19			8.09	15.28	
DEMAND CHARGES - OPTION R ($/kW)												
Summer												
Peak	2.33				2.33		2.10				2.10	
Part-Peak	.67				.67		.60				.60	
Maximum	8.00			8.09	16.09		7.19			8.09	15.28	
Winter												
Peak	.00				.00							
Maximum	8.00			8.09	16.09		7.19			8.09	15.28	
DEMAND CHARGES - OPTION S												
Summer												
Peak ($/kW/day)	.42				.42		.39				.39	
Part Peak ($/kW/day)	.03				.03		.04				.04	
Maximum ($/kW)				8.09	8.09					8.09	8.09	
Maximum ($/kW applied to all hours except 9 am to 2 pm)	1.63				1.63		1.47				1.47	
Winter ($/kW mo)												
Peak ($/kW/day)	.32				.32		.30				.30	
Maximum ($/kW)				8.09	8.09					8.09	8.09	
Maximum ($/kW applied to all hours except 9 am to 2 pm)	1.63				1.63		1.46				1.46	
ENERGY CHARGES (/kWh)												
Summer												
Peak	.00000	.12290	.01059	.01112	.14461		.00000	.12262	.01258	.01113	.14632	
Part-Peak	.00000	.10029	.01059	.01112	.12200		.00000	.10006	.01258	.01113	.12376	
Off-Peak	.00000	.08064	.01059	.01112	.10235		.00000	.08045	.01258	.01113	.10416	
Winter												
Peak	.00000	.11064	.01059	.01112	.13235		.00000	.11039	.01258	.01113	.13409	
Off-Peak	.00000	.08077	.01059	.01112	.10248		.00000	.08058	.01258	.01113	.10429	
Super Off-Peak	.00000	.03825	.01059	.01112	.05996		.00000	.03816	.01258	.01113	.06186	
ENERGY CHARGES - OPTION R (/kWh)												
Summer												
Peak	.07623	.24289	.01059	.01112	.34083		.07391	.24266	.01258	.01113	.34028	
Part-Peak	.02503	.11935	.01059	.01112	.16609		.02271	.11912	.01258	.01113	.16554	
Off-Peak	.00337	.08395	.01059	.01112	.10903		.00105	.08372	.01258	.01113	.10848	
Winter												
Peak	.00000	.12172	.01059	.01112	.14343		.00000	.12149	.01258	.01113	.14520	
Off-Peak	.00000	.08406	.01059	.01112	.10577		.00000	.08383	.01258	.01113	.10754	
Super Off-Peak	.00000	.04824	.01059	.01112	.06995		.00000	.04801	.01258	.01113	.07172	
ENERGY CHARGES - OPTION S (/kWh)												
Summer												
Peak	.07623	.24289	.01059	.01112	.34083		.07391	.24266	.01258	.01113	.34028	
Part-Peak	.02503	.11935	.01059	.01112	.16609		.02271	.11912	.01258	.01113	.16554	
Off-Peak	.00337	.08395	.01059	.01112	.10903		.00105	.08372	.01258	.01113	.10848	
Winter												
Peak	.00000	.12172	.01059	.01112	.14343		.00000	.12149	.01258	.01113	.14520	
Off-Peak	.00000	.08406	.01059	.01112	.10577		.00000	.08383	.01258	.01113	.10754	
Super Off-Peak	.00000	.04824	.01059	.01112	.06995		.00000	.04801	.01258	.01113	.07172	
CUSTOMER CHARGE (/meter/day)												
B-19	36.13963				36.13963	1100.00	32.54948				32.54948	990.72
Rate V	4.59959				4.59959	140.00	4.87372				4.87372	148.34
POWER FACTOR ADJUSTMENT (/kWh)	.00005				.00005		.00005				.00005	

per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%

(PG&E-3)

B-19 Transmission	PRESENT RATES						PROPOSED RATES					
	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
DEMAND CHARGES (/kW)												
Summer												
Peak	.00	9.66			9.66		.00	9.72			9.72	
Part-Peak	.00	2.42			2.42		.00	2.43			2.43	
Maximum	2.81	.00		8.09	10.90		1.88			8.09	9.96	
Winter												
Peak	.00	.93			.93		.00	.94			.94	
Maximum	2.81	.00		8.09	10.90		1.88			8.09	9.96	
DEMAND CHARGES - OPTION R ($/kW)												
Summer												
Peak	.00	.00			.00		.00					
Part-Peak	.00	.00			.00		.00					
Maximum	2.81	.00		8.09	10.90		1.88			8.09	9.96	
Winter												
Part-Peak	.00	.00			.00		.00					
Maximum	2.81	.00		8.09	10.90		1.88			8.09	9.96	
DEMAND CHARGES - OPTION S												
Summer												
Peak ($/kW/day)	0.13				.13		.08				.08	
Part Peak ($/kW/day)					.00		.00				.00	
Maximum ($/kW)				8.09	8.09		.00			8.09	8.09	
Maximum ($/kW applied to all hours except 9 am to 2 pm)	0.58				.58		.38				.38	
Winter ($/kW mo)												
Peak ($/kW/day)	0.13				.13		.08				.08	
Maximum ($/kW)				8.09	8.09					8.09	8.09	
Maximum ($/kW applied to all hours except 9 am to 2 pm)	0.58				.58		.39				.39	
ENERGY CHARGES (/kWh)												
Summer												
Peak	.00000	.10869	.01059	.01112	.13040		.00000	.10932	.01176	.01113	.13221	
Part-Peak	.00000	.09955	.01059	.01112	.12126		.00000	.10012	.01176	.01113	.12301	
Off-Peak	.00000	.08009	.01059	.01112	.10180		.00000	.08055	.01176	.01113	.10344	
Winter												
Peak	.00000	.10991	.01059	.01112	.13162		.00000	.11054	.01176	.01113	.13343	
Off-Peak	.00000	.08035	.01059	.01112	.10206		.00000	.08081	.01176	.01113	.10370	
Super Off-Peak	.00000	.03686	.01059	.01112	.05857		.00000	.03707	.01176	.01113	.05996	
ENERGY CHARGES - OPTION R (/kWh)												
Summer												
Peak	.00000	.20761	.01059	.01112	.22932		.00000	.20818	.01176	.01113	.23107	
Part-Peak	.00000	.12611	.01059	.01112	.14782		.00000	.12668	.01176	.01113	.14957	
Off-Peak	.00000	.08396	.01059	.01112	.10567		.00000	.08453	.01176	.01113	.10742	
Winter												
Peak	.00000	.11785	.01059	.01112	.13956		.00000	.11842	.01176	.01113	.14131	
Off-Peak	.00000	.08417	.01059	.01112	.10588		.00000	.08474	.01176	.01113	.10763	
Super Off-Peak	.00000	.04835	.01059	.01112	.07006		.00000	.04892	.01176	.01113	.07181	
ENERGY CHARGES - OPTION S (/kWh)												
Summer												
Peak	.00000	.20761	.01059	.01112	.22932		.00000	.20818	.01176	.01113	.23107	
Part-Peak	.00000	.12611	.01059	.01112	.14782		.00000	.12668	.01176	.01113	.14957	
Off-Peak	.00000	.08396	.01059	.01112	.10567		.00000	.08453	.01176	.01113	.10742	
Winter												
Peak	.00000	.11785	.01059	.01112	.13956		.00000	.11842	.01176	.01113	.14131	
Off-Peak	.00000	.08417	.01059	.01112	.10588		.00000	.08474	.01176	.01113	.10763	
Super Off-Peak	.00000	.04835	.01059	.01112	.07006		.00000	.04892	.01176	.01113	.07181	
CUSTOMER CHARGE (/meter/day)												
B-19	45.99589				45.99589	1400.00	33.01601				33.01601	1004.92
Rate V	4.59959				4.59959	140.00	4.87372				4.87372	148.34
POWER FACTOR ADJUSTMENT (/kWh)	.00005				.00005		.00005				.00005	

per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%

B-20 Secondary

	PRESENT RATES						PROPOSED RATES					
	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
DEMAND CHARGES (/kW)												
Summer												
Peak	10.17	14.85			25.02		9.05	14.07			23.12	
Part-Peak	2.92	2.15			5.07		2.60	2.04			4.64	
Maximum	10.65	.00		8.86	19.51		9.48			8.86	18.34	
Winter												
Peak	.00	1.89			1.89		.00	1.79			1.79	
Maximum	10.65	.00		8.86	19.51		9.48			8.86	18.34	
DEMAND CHARGES - OPTION R ($/kW)												
Summer												
Peak	2.54	.00			2.54		2.26				2.26	
Part-Peak	.73	.00			.73		.65				.65	
Maximum	10.65	.00		8.86	19.51		9.48			8.86	18.34	
Winter												
Peak	.00	.00			.00		.00				.00	
Maximum	10.65	.00		8.86	19.51		9.48			8.86	18.34	
DEMAND CHARGES - OPTION S												
Summer												
Peak ($/kW/day)	.49				.49		.43				.43	
Part Peak ($/kW/day)	.03				.03		.03				.03	
Maximum ($/kW)				8.86	8.86					8.86	8.86	
Maximum ($/kW applied to all hours except 9 am to 2 pm)	2.20				2.20		1.93				1.93	
Winter ($/kW mo)												
Peak ($/kW/day)	.41				.41		.34				.34	
Maximum ($/kW)				8.86	8.86					8.86	8.86	
Maximum ($/kW applied to all hours except 9 am to 2 pm)	2.21				2.21		1.93	.00			1.93	
ENERGY CHARGES (/kWh)												
Summer												
Peak	.00000	.13445	.01107	.01085	.15637		.00000	.12737	.01204	.01085	.15027	
Part-Peak	.00000	.10711	.01107	.01085	.12903		.00000	.10147	.01204	.01085	.12437	
Off-Peak	.00000	.08552	.01107	.01085	.10744		.00000	.08102	.01204	.01085	.10392	
Winter												
Peak	.00000	.11816	.01107	.01085	.14008		.00000	.11194	.01204	.01085	.13484	
Off-Peak	.00000	.08535	.01107	.01085	.10727		.00000	.08086	.01204	.01085	.10375	
Super Off-Peak	.00000	.04138	.01107	.01085	.06330		.00000	.03920	.01204	.01085	.06210	
ENERGY CHARGES - OPTION R (/kWh)												
Summer												
Peak	.07291	.26005	.01107	.01085	.35488		.07069	.25437	.01204	.01085	.34796	
Part-Peak	.02283	.12730	.01107	.01085	.17205		.02061	.12162	.01204	.01085	.16513	
Off-Peak	.00126	.08984	.01107	.01085	.11302		(.00096)	.08416	.01204	.01085	.10610	
Winter												
Peak	.00000	.13344	.01107	.01085	.15536		.00000	.12776	.01204	.01085	.15066	
Off-Peak	.00000	.08971	.01107	.01085	.11163		.00000	.08403	.01204	.01085	.10693	
Super Off-Peak	.00000	.05396	.01107	.01085	.07588		.00000	.04828	.01204	.01085	.07118	
ENERGY CHARGES - OPTION S (/kWh)												
Summer												
Peak	.07291	.26005	.01107	.01085	.35488		.07069	.25437	.01204	.01085	.34796	
Part-Peak	.02283	.12730	.01107	.01085	.17205		.02061	.12162	.01204	.01085	.16513	
Off-Peak	.00126	.08984	.01107	.01085	.11302		(.00096)	.08416	.01204	.01085	.10610	
Winter												
Peak	.00000	.13344	.01107	.01085	.15536		.00000	.12776	.01204	.01085	.15066	
Off-Peak	.00000	.08971	.01107	.01085	.11163		.00000	.08403	.01204	.01085	.10693	
Super Off-Peak	.00000	.05396	.01107	.01085	.07588		.00000	.04828	.01204	.01085	.07118	
CUSTOMER CHARGE												
(/meter/day)	42.71047				42.71047	1300.00	38.01766				38.01766	1157.16
POWER FACTOR ADJUSTMENT (/kWh)	.00005				.00005		.00005				.00005	

per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%

	PRESENT RATES						PROPOSED RATES					
B-20 Primary	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
DEMAND CHARGES (/kW)												
Summer												
Peak	9.26	16.08			25.34		8.76	15.67			24.43	
Part-Peak	2.61	2.21			4.82		2.47	2.15			4.62	
Maximum	8.73	.00		8.86	17.59		8.26			8.86	17.12	
Winter												
Peak	.00	1.85			1.85		.00	1.80			1.80	
Maximum	8.73	.00		8.86	17.59		8.26			8.86	17.12	
DEMAND CHARGES - OPTION R ($/kW)												
Peak	2.31	.00			2.31		2.19				2.19	
Part-Peak	.65	.00			.65		.62				.62	
Maximum	8.73	.00		8.86	17.59		8.26			8.86	17.12	
Winter												
Peak	.00	.00			.00		.00				.00	
Maximum	8.73	.00		8.86	17.59		8.26			8.86	17.12	
DEMAND CHARGES - OPTION S												
Summer												
Peak ($/kW/day)	.39				.39		.38				.38	
Part Peak ($/kW/day)	.03				.03		.03				.03	
Maximum ($/kW)				8.86	8.86					8.86	8.86	
Maximum ($/kW applied to all hours except 9 am to 2 pm)	1.77				1.77		1.67				1.67	
Winter ($/kW mo)												
Peak ($/kW/day)	.32				.32		.30				.30	
Maximum ($/kW)				8.86	8.86					8.86	8.86	
Maximum ($/kW applied to all hours except 9 am to 2 pm)	1.77				1.77		1.67				1.67	
ENERGY CHARGES (/kWh)												
Summer												
Peak	.00000	.12883	.01033	.01079	.14995		.00000	.12552	.01166	.01079	.14798	
Part-Peak	.00000	.10028	.01033	.01079	.12140		.00000	.09771	.01166	.01079	.12016	
Off-Peak	.00000	.08036	.01033	.01079	.10148		.00000	.07830	.01166	.01079	.10075	
Winter												
Peak	.00000	.11066	.01033	.01079	.13178		.00000	.10782	.01166	.01079	.13027	
Off-Peak	.00000	.08042	.01033	.01079	.10154		.00000	.07836	.01166	.01079	.10081	
Super Off-Peak	.00000	.03751	.01033	.01079	.05863		.00000	.03655	.01166	.01079	.05900	
ENERGY CHARGES - OPTION R (/kWh)												
Summer												
Peak	.06176	.24758	.01033	.01079	.33046		.06081	.24499	.01166	.01079	.32826	
Part-Peak	.01949	.11869	.01033	.01079	.15930		.01854	.11610	.01166	.01079	.15710	
Off-Peak	.00163	.08398	.01033	.01079	.10673		.00068	.08139	.01166	.01079	.10453	
Winter												
Peak	.00000	.12410	.01033	.01079	.14522		.00000	.12151	.01166	.01079	.14397	
Off-Peak	.00000	.08403	.01033	.01079	.10515		.00000	.08144	.01166	.01079	.10390	
Super Off-Peak	.00000	.04828	.01033	.01079	.06940		.00000	.04569	.01166	.01079	.06815	
ENERGY CHARGES - OPTION S (/kWh)												
Summer												
Peak	.06176	.24758	.01033	.01079	.33046		.06081	.24499	.01166	.01079	.32826	
Part-Peak	.01949	.11869	.01033	.01079	.15930		.01854	.11610	.01166	.01079	.15710	
Off-Peak	.00163	.08398	.01033	.01079	.10673		.00068	.08139	.01166	.01079	.10453	
Winter												
Peak	.00000	.12410	.01033	.01079	.14522		.00000	.12151	.01166	.01079	.14397	
Off-Peak	.00000	.08403	.01033	.01079	.10515		.00000	.08144	.01166	.01079	.10390	
Super Off-Peak	.00000	.04828	.01033	.01079	.06940		.00000	.04569	.01166	.01079	.06815	
CUSTOMER CHARGE												
(/meter/day)	42.71047				42.71047	1300.00	40.41729				40.41729	1230.20
POWER FACTOR ADJUSTMENT (/kWh)	.00005				.00005		.00005				.00005	

per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%

B-20 Transmission	PRESENT RATES Distr	Gen	PPP	Other	Total		PROPOSED RATES Distr	Gen	PPP	Other	Total	
DEMAND CHARGES (/kW)												
Summer												
Peak	.00	18.08			18.08		.00	17.90			17.90	
Part-Peak	.00	4.31			4.31		.00	4.27			4.27	
Maximum	.89	.00		8.86	9.75		.31			8.86	9.17	
Winter												
Peak	.00	2.41			2.41		.00	2.39			2.39	
Maximum	.89	.00		8.86	9.75		.31			8.86	9.17	
DEMAND CHARGES - OPTION R ($/kW)												
Summer												
Peak	.00	.00			.00		.00			.00	.00	
Part-Peak	.00	.00			.00		.00			.00	.00	
Maximum	.89	.00		8.86	9.75		.31			8.86	9.17	
Winter												
Peak	.00	.00			.00		.00			.00	.00	
Maximum	.89	.00		8.86	9.75		.31			8.86	9.17	
DEMAND CHARGES - OPTION S												
Summer												
Peak ($/kW/day)	.03				.03		.01				.01	
Part Peak ($/kW/day)					.00		.00				.00	
Maximum ($/kW)				8.86	8.86					8.86	8.86	
Maximum ($/kW applied to all hours except 9 am to 2 pm)	.19				.19		.06				.06	
Winter ($/kW mo)												
Peak ($/kW/day)	.03				.03		.01				.01	
Maximum ($/kW)				8.86	8.86					8.86	8.86	
Maximum ($/kW applied to all hours except 9 am to 2 pm)	.19				.19		.06				.06	
ENERGY CHARGES (/kWh)												
Summer												
Peak	.00000	.10930	.00913	.01073	.12916		.00000	.10824	.01052	.01073	.12949	
Part-Peak	.00000	.09180	.00913	.01073	.11166		.00000	.09091	.01052	.01073	.11216	
Off-Peak	.00000	.07227	.00913	.01073	.09213		.00000	.07157	.01052	.01073	.09282	
Winter												
Peak	.00000	.10845	.00913	.01073	.12831		.00000	.10740	.01052	.01073	.12865	
Off-Peak	.00000	.06874	.00913	.01073	.08860		.00000	.06807	.01052	.01073	.08932	
Super Off-Peak	.00000	.02906	.00913	.01073	.04892		.00000	.02878	.01052	.01073	.05003	
ENERGY CHARGES - OPTION R (/kWh)												
Summer												
Peak	.00000	.24555	.00913	.01073	.26541		.00000	.24463	.01052	.01073	.26588	
Part-Peak	.00000	.12693	.00913	.01073	.14679		.00000	.12601	.01052	.01073	.14726	
Off-Peak	.00000	.07668	.00913	.01073	.09654		.00000	.07576	.01052	.01073	.09701	
Winter												
Peak	.00000	.12678	.00913	.01073	.14664		.00000	.12586	.01052	.01073	.14711	
Off-Peak	.00000	.07376	.00913	.01073	.09362		.00000	.07284	.01052	.01073	.09409	
Super Off-Peak	.00000	.04096	.00913	.01073	.06082		.00000	.04004	.01052	.01073	.06129	
ENERGY CHARGES - OPTION S (/kWh)												
Summer												
Peak	.00000	.24555	.00913	.01073	.26541		.00000	.24463	.01052	.01073	.26588	
Part-Peak	.00000	.12693	.00913	.01073	.14679		.00000	.12601	.01052	.01073	.14726	
Off-Peak	.00000	.07668	.00913	.01073	.09654		.00000	.07576	.01052	.01073	.09701	
Winter												
Peak	.00000	.12678	.00913	.01073	.14664		.00000	.12586	.01052	.01073	.14711	
Off-Peak	.00000	.07376	.00913	.01073	.09362		.00000	.07284	.01052	.01073	.09409	
Super Off-Peak	.00000	.04096	.00913	.01073	.06082		.00000	.04004	.01052	.01073	.06129	
CUSTOMER CHARGE												
(/meter/day)	49.28131				49.28131	1500.00	32.03285				32.03285	975.00
POWER FACTOR ADJUSTMENT (/kWh)	.00005				.00005		.00005				.00005	

per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%

	PRESENT RATES						PROPOSED RATES					
LS-1	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
ENERGY CHARGE (/kWh)	.04698	.09373	.00579	.02873	.17522		.03575	.11082	.00583	.02873	.18113	
LS-2	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
ENERGY CHARGE (/kWh)	.04698	.09373	.00579	.02873	.17522		.03575	.11082	.00583	.02873	.18113	
LS-3	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
ENERGY CHARGE (/kWh)	.04698	.09373	.00579	.02873	.17522		.03575	.11082	.00583	.02873	.18113	
CUSTOMER CHARGE (/meter/day)	.24641				.24641	7.50	.24641				.24641	7.50
TC-1	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
ENERGY CHARGE (/kWh)												
Summer	.03777	.10455	.00584	.03481	.18297		.05226	.10827	.00624	.03481	.20159	
Winter	.03777	.10455	.00584	.03481	.18297		.05226	.10827	.00624	.03481	.20159	
CUSTOMER CHARGE (/meter/day)	.49281				.49281	15.00	.49281				.49281	15.00
OL-1	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
ENERGY CHARGE (/kWh)	.04698	.09373	.01278	.02873	.18221		.03575	.11082	.01274	.02873	.18804	

Standby (SB) Secondary

	PRESENT RATES Distr	Gen	PPP	Other	Total	PROPOSED RATES Distr	Gen	PPP	Other	Total
RESERVATION CHARGE (/kW)	6.42	.31		1.01	7.74	6.93	.70		1.01	8.63
(per kW per month applied to 85% of the Reservation Capacity)										
ENERGY CHARGE (/kWh)										
Summer										
Peak	.44176	.11509	.01364	.03520	.60569	.44486	.10209	.01275	.03520	.59490
Part-Peak	.19170	.10303	.01364	.03520	.34357	.19480	.09003	.01275	.03520	.33278
Off-Peak	.00568	.08962	.01364	.03520	.14414	.00878	.07662	.01275	.03520	.13335
Winter										
Peak	.00978	.11027	.01364	.03520	.16889	.01288	.10101	.01275	.03520	.16184
Off-Peak	.00568	.09076	.01364	.03520	.14528	.00878	.08150	.01275	.03520	.13823
Super Off-Peak	.00568	.04745	.01364	.03520	.10197	.00878	.04506	.01275	.03520	.10179
POWER FACTOR ADJUSTMENT (/kWh)	.00005				.00005	.00005				.00005
per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%										
MAXIMUM REACTIVE DEMAND CHRG (/kVAR)					.35	.35				.35

Standby (SB) Primary

	PRESENT RATES Distr	Gen	PPP	Other	Total	PROPOSED RATES Distr	Gen	PPP	Other	Total
RESERVATION CHARGE (/kW)	6.42	.31		1.01	7.74	6.93	.70		1.01	8.63
(per kW per month applied to 85% of the Reservation Capacity)										
ENERGY CHARGE (/kWh)										
Summer										
Peak	.44176	.11509	.01444	.03520	.60649	.44486	.10209	.01665	.03520	.59880
Part-Peak	.19170	.10303	.01444	.03520	.34437	.19480	.09003	.01665	.03520	.33668
Off-Peak	.00568	.08962	.01444	.03520	.14494	.00878	.07662	.01665	.03520	.13725
Winter										
Peak	.00978	.11027	.01444	.03520	.16969	.01288	.10101	.01665	.03520	.16574
Off-Peak	.00568	.09076	.01444	.03520	.14608	.00878	.08150	.01665	.03520	.14213
Super Off-Peak	.00568	.04745	.01444	.03520	.10277	.00878	.04506	.01665	.03520	.10569
POWER FACTOR ADJUSTMENT (/kWh)	.00005				.00005	.00005				.00005
per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%										
MAXIMUM REACTIVE DEMAND CHRG (/kVAR)	.35				.35	.35				.35

Standby (SB) Transmission

	PRESENT RATES Distr	Gen	PPP	Other	Total	PROPOSED RATES Distr	Gen	PPP	Other	Total
RESERVATION CHARGE (/kW)	.25	.17		1.01	1.43	.15	.69		1.01	1.85
(per kW per month applied to 85% of the Reservation Capacity)										
ENERGY CHARGE (/kWh)										
Summer										
Peak	.00000	.10139	.01069	.03520	.14728	.00000	.09503	.00870	.03520	.13893
Part-Peak	.00000	.08979	.01069	.03520	.13568	.00000	.08343	.00870	.03520	.12733
Off-Peak	.00000	.07687	.01069	.03520	.12276	.00000	.07051	.00870	.03520	.11441
Winter										
Peak	.00000	.09684	.01069	.03520	.14273	.00000	.09422	.00870	.03520	.13812
Off-Peak	.00000	.07808	.01069	.03520	.12397	.00000	.07546	.00870	.03520	.11936
Super Off-Peak	.00000	.03521	.01069	.03520	.08110	.00000	.03902	.00870	.03520	.08292
POWER FACTOR ADJUSTMENT (/kWh)	.00005				.00005	.00005				.00005
per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%										
MAXIMUM REACTIVE DEMAND CHRG (/kVAR)	.35				.35	.35				.35

PRESENT RATES | **PROPOSED RATES**

Standby Customer Charges

	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
Residential	.16427				.16427	5.00	.16427				.16427	5.00
Agriculture	.91565				.91565	27.87	.91565				.91565	27.87
Small Light and Power												
(Reservation Capacity ≤ 50 kW)												
Single Phase Service	.32854				.32854	10.00	.32854				.32854	10.00
PolyPhase Service	.82136				.82136	25.00	.82136				.82136	25.00
Medium Light and Power												
(Reservation Capacity > 50 kW and < 500 kW)												
	4.59959				4.59959	140.00	4.87372				4.87372	148.34
Medium Light and Power												
(Reservation Capacity ≥ 500 kW and < 1000 kW)												
Transmission	45.99589				45.99589	1400.00	33.01601				33.01601	1004.92
Primary	36.13963				36.13963	1100.00	32.54948				32.54948	990.72
Secondary	23.65503				23.65503	720.00	21.69512				21.69512	660.35
Large Light and Power												
(Reservation Capacity ≥ 1000 kW)												
Transmission	49.28131				49.28131	1500.00	32.03285				32.03285	975.00
Primary	42.71047				42.71047	1300.00	40.41729				40.41729	1230.20
Secondary	42.71047				42.71047	1300.00	38.01766				38.01766	1157.16

Standby Reduced CUSTOMER CHARGES (where applicable)

	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
Small Light and Power												
(Reservation Capacity < 75 kW)												
SINGLEPHASE	.32854				.32854	10.00	.32854				.32854	10.00
POLYPHASE	.39359				.39359	11.98	.39359				.39359	11.98
Medium Light and Power												
(Reservation Capacity > 75 kW and < 750 kW)												
PRIMARY	4.59959				4.59959	140.00	4.59959				4.59959	140.00
SECONDARY	1.23433				1.23433	37.57	1.23433				1.23433	37.57
Medium Light and Power												
(Reservation Capacity > 500 kW and < 1000 kW)												
PRIMARY	11.72698				11.72698	356.94	11.72698				11.72698	356.94
SECONDARY	7.91556				7.91556	240.93	7.91556				7.91556	240.93
TRANSMISSION	18.68945				18.68945	568.86	18.68945				18.68945	568.86
Large Light and Power												
(Reservation Capacity ≥ 1000 kW)												
PRIMARY	8.44583				8.44583	257.07	8.44583				8.44583	257.07
SECONDARY	10.75515				10.75515	327.36	10.75515				10.75515	327.36
TRANSMISSION	24.52271				24.52271	746.41	24.52271				24.52271	746.41

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

AGRICULTURAL RATE DESIGN

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A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) proposes rates for the Agricultural (AG) class of customers. The AG class includes Small AG (Schedules AG-A1, AG-A2, and AG-FA), Medium AG (Schedules AG-B and AG-FB), and Large AG (Schedules AG-C and AG-FC). Six of these seven rate schedules were adopted by the California Public Utilities Commission (Commission) in Decision (D.) 18-08-013 in PG&E's 2017 General Rate Case (GRC) Phase II case. Modifications to all six of those rates, as well as the addition of new Schedule AG-A2 for higher load factor small AG customers, were also adopted in PG&E's 2019 Rate Design Window (RDW) proceeding in D.19-05-010.

The default Agricultural rates are Time-of-Use (TOU) Schedules AG-A1, AG-A2, AG-B and AG-C. Flexible off-peak hours are available on a voluntary opt-in basis on TOU Schedule AG-F, on options AG-FA, AG-FB, and AG-FC. All of the new Agricultural TOU rates have on-peak hours of 5 p.m. to 8 p.m., with no partial-peak or super-off-peak periods, to respond to the needs of agricultural customers for rates that are simple to understand, and that better reflect the logistical and operational needs of farming and other agricultural operations.[1]

Rate design for these Agricultural schedules includes rate components for transmission, distribution, generation, Public Purpose Programs (PPP), Nuclear Decommissioning, Department of Water Resources Bond Charge, New System Generation Charges, the Energy Cost Recovery Amount, and the Power Charge Indifference Adjustment. In this proceeding, PG&E is proposing changes to AG generation, distribution and PPP revenue allocation and rate design. PG&E is not making any proposals for revenue allocation and rate design for other components of AG rates. Accordingly, PG&E's current approach to revenue allocation and rate design for these components is set forth in Chapter 1, "Revenue Allocation and Rate Design Introduction." Generation, distribution,

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1 D.18-08-013, pp. 35-36, 87-88.

and PPP revenue allocation, as well as PPP rate design,[2] is addressed in Chapter 2. Agricultural rate design for generation and distribution is set forth in this chapter.

As discussed in Chapter 1 of Exhibit (PG&E-3), a key objective of PG&E's Agricultural rate design proposal is to retain the rate designs adopted in PG&E's 2017 GRC Phase II (D.18-08-013) and 2019 RDW (D.19-05-010) proceedings because AG customers are being transitioned to rates with new TOU periods. To that end, PG&E's generation and distribution AG rate proposals in this proceeding include:

- For the revenue allocation change in this proceeding, as well as revenue requirement changes for rate changes between GRCs, continue to apply the rules for rate changes between GRCs adopted by D.18-08-013, but revise for the initial and each subsequent electric rate change as necessary to preserve Agricultural intra-class rate schedule relationships; and
- Eliminate any remaining instances of voluntary TOU meter charges, as these charges are no longer appropriate.

Attachment A to this chapter presents the proposed Agricultural rates that PG&E is sponsoring for adoption in this chapter. In addition, in this chapter, PG&E also presents and discusses proposals for illustrative rate designs that D.18-08-013[3] required be presented in this proceeding. These illustrative rates are presented in Appendix H to Exhibit 4.

The remainder of this chapter is organized as follows:

- Section B – Background
- Section C – Agricultural Rate Design
- Section D – Conclusion

Various other Appendices in Exhibit 4 present the following information. Appendix A provides recorded 2017 data for the customer classes presented in this chapter. Appendix B presents PG&E's proposed revenue allocation results from Chapter 2. Appendix C, "Present and Proposed Rates," contains PG&E's present and proposed total and unbundled rates for the AG customer class.

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2 PPP rates for the agricultural class are designed in accordance with the guidelines described in Chapter 1, using the revenue allocation provided in Chapter 2.

3 D.18-08-013, p. 51, and Ordering Paragraph (OP) 5.

Appendix D, "Illustrative Bill Impacts," presents the bill comparison impacts of PG&E's proposals on agricultural customers.

B. Background

1. Transition to New TOU Periods

Under the plan adopted in D.18-08-013, rates with new TOU periods will become available on an opt-in basis for AG customers in the first quarter of 2020, by no later than March 2020. Then, on March 1, 2021, PG&E will begin the mandatory transition of all remaining AG customers to the rates with new TOU periods. From the date when the rates with new TOU periods become available on an opt-in basis, until March 1, 2021, PG&E will retain all Agricultural rates on both the old TOU structure (referred to herein as 'legacy rates') as well as the new TOU structures (or rates with new TOU periods). Also, beginning on March 1, 2021, rates with grandfathered legacy TOU periods will become available for solar customers that have met the grandfathering requirements under D.17-01-006. PG&E is working toward these deadlines and currently expects to meet this schedule.

2. Distribution and Generation Cost of Service Principles

PG&E's cost of service considerations for distribution and generation were described in Chapter 1. While PG&E's primary proposal in this proceeding is to continue the current approach to changing rates and to make very few changes to the Agricultural rate relationships established by D.18-08-013 and D.19-05-010, PG&E has utilized the rate principles articulated in Chapter 1 to prepare proposed and illustrative compliance rates which are discussed below.

3. Other Rate Design Principles

In addition to cost of service principles, PG&E's rate design recommendations also consider other rate design objectives. As discussed in Chapter 1, they include balancing cost of service considerations with rates that offer stability, are understandable and transparent, offer meaningful rates to customers and are practical to implement. In this 2020 GRC Phase II, PG&E believes that stability is extremely important due to the timing of this case in relation to the initial opt-in roll out and mandatory transition of customers to rates with new TOU periods.

C. Agricultural Rate Design

As noted above, the Agricultural class includes new default Schedules AG-A1, AG-A2, AG-B and AG-C, and voluntary opt-in Schedules AG-FA, AG-FB and AG-FC.[4] The new Agricultural rates are based on a threshold of 35 kilowatts (kW) to separate smaller AG-A customers from larger AG-B and AG-C customers.

In addition, the "legacy" Agricultural rates include small customer Schedules AG-1A, AG-4A, AG-5A, AG-RA and AG-VA; medium customer Schedules AG-1B, AG-4B, AG-4C, AG-RB and AG-VB; and large customer Schedules AG-5B and AG-5C.[5] PG&E's legacy boundary between the small Agricultural class and the medium to large Agricultural class is 35 horsepower (hp), or 15 hp for customers with multiple pumps. D.18-08-013 established rules through the end of 2023 governing the rate design for legacy agricultural rates, for qualifying grandfathered solar or other customers, and therefore is not addressed in detail here. In this proceeding, PG&E proposes to retain the current legacy and new eligibility thresholds within the AG customer class.

1. Overview

PG&E proposes the following rate design for the Agricultural class:

- Continue the existing rate structures and rules for changes between GRCs, but revise for the initial and each subsequent electric rate change as necessary to preserve Agricultural intra-class rate schedule relationships, in order to implement the revenue allocation results determined in this proceeding, and for revenue requirement changes before the next GRC Phase II proceeding, to support rate stability during the transition to rates with new TOU periods; and

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[4] In December 2019, PG&E plans to submit by advice letter proposed tariff sheets and illustrative rates for new Schedule AG, and for new Schedule AG-F, to be effective beginning with the March 1, 2020 voluntary opt-in date, to specify the tariff terms and conditions of service and rates for all four main new default Schedule AG Agricultural electric rate options, as well as the three rate options available under voluntary Schedule AG-F.

[5] In December 2019, PG&E plans to submit a second advice letter addressing proposed tariff sheet revisions for all twelve legacy Agricultural rate schedules, to be effective beginning with the March 1, 2020 voluntary opt-in date, to specify the modifications to legacy tariffs necessary to describe the transition from legacy to new rates, and all other applicable terms and conditions of service.

- Eliminate voluntary TOU meter charges.

2. Distribution Rate Design

In D.18-08-013, Ordering Paragraph 27 stated as follows:

> PG&E must propose in its next GRC Phase II application agricultural rates (along with all other non-residential Time-of-Use rates) that better reflect time-differentiation of marginal distribution costs, and contain peak-to-off-peak price differentials that encourage agricultural customers to invest in energy management technology and practices that allow them to respond to peak price signals.

However, PG&E already complied with the above order through the rate design modifications proposed and approved in PG&E's 2019 RDW, as adopted in D.19-05-010.

Except as noted below, changes to legacy rates and to rates with new TOU periods will be governed by the rules for rate changes between GRCs as determined by D.18-08-013, as applied to the Agricultural rates adopted in D.19-05-010. Changes to distribution rates are set forth below. Revenue requirements will be allocated to each rate schedule as provided in Chapters 1 and 2.

Agricultural fixed monthly customer charges will not change for legacy rates, or from the levels initially set for rates with new TOU periods as of the date when rates with new TOU periods become available on an opt-in basis. Customer charges will not change from those levels until the 2023 GRC Phase II.

Demand and energy charges each will be designed to change by the same percentage change in rates necessary to collect the required revenue. Demand charges will each be changed by the same percentage, and energy charges in total will also be changed by the same percentage amount, except as required to recover Demand Charge Rate Limiter (DCRL) shortfalls.[6] PG&E has re-estimated the revenue shortfalls attributable to the adopted 50 cent per kWh DCRL, and proposes to recover the shortfall through an equal cent per kWh adder to all Schedule AG-C TOU distribution energy charges in both seasons, per the adopted methodology.

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6 The DCRL applies only to default Schedule AG-C. As adopted in D.18-08-013 and D.19-05-010, a 50 cent per kilowatt-hour (kWh) charge shall limit the monthly sum of demand charges and energy charges, excluding the fixed monthly customer charge.

However, the change in distribution energy charges will be determined by whatever equal cents per kWh adder is required to collect the necessary change in distribution energy charge revenue. This approach to setting the distribution energy charges will ensure that the differential in rates between seasons and TOU periods remains the same on a cents per kWh basis.

For schedules that are designed together (such as schedules that are designed on a revenue neutral basis, or where rate schedule relationships are to be preserved), the system average percentage change by function will be applied to the combined rate design group. For example, the percentage change applied to the allocated distribution revenue on AG-B and AG-C was set to the same percentage,[7] in order to preserve the traditional 1,500 annual break-even pumping hours where the Agricultural rates for larger customers are generally better for customers than the rates for medium customers.

3. Generation Rate Design

Except as noted below, changes to legacy rates and to rates with new TOU periods will be governed by the rules for rate changes between GRCs as determined by D.18-08-013.[8] Rates will be designed to collect the generation revenue requirement allocated to each rate schedule as provided in Chapters 1 and 2. Changes to generation rates are set forth below.

Demand and energy charges for the generation component of rates will be designed to each change by the same percentage amount as necessary to collect the required allocated generation revenue. That is, generation demand charges will be changed by the same percentage and generation

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7 For the initial rate change to implement 2020 GRC Phase II rates, the percentage change to AG-B was set approximately two to three percentage points higher than the percentage change to AG-C, for distribution, and for generation, in order to offset the impact of the DCRL equal cent per kWh adder on AG-C distribution and total energy charges and preserve 1,500 break-even pumping hours. Going forward with interim GRC rate changes, the percentage change on distribution, and the percentage change on generation, will be equivalent across AG-B and AG-C.

8 D.18-08-013, Supplemental Settlement Agreement in PG&E's General Rate Case Phase II (Application 16-06-013) on Agricultural Rate Design, Term V.H., Rate Changes Between GRC Phase II Proceedings, pp. A-13 to A-14, as well as Settlement Agreement in Phase II of Pacific Gas and Electric Company's 2017 General Rate Case on Marginal Cost and Revenue Allocation Issues, Term VIII. 3., Rate Changes Between General Rate Cases, pp. 16 to 19.

energy charges in total will also be changed by the same percentage amount.

However, the change in generation energy charges will be determined by whatever equal cents per kWh adder that is required to collect the necessary change in generation energy charge revenue. This approach to setting the generation energy charges will ensure that the differential in rates between seasons and TOU periods remains the same on a cents per kWh basis.

For schedules that are designed together (such as schedules that are designed on a revenue neutral basis, or where rate schedule relationships are to be preserved), the system average percentage change by function will be applied to the combined rate design group. As with distribution, the percentage change applied to the allocated generation revenue on AG-B and AG-C was set to the same percentage, in order to preserve the traditional 1,500 annual break-even pumping hours where AG-C is generally better for customers than AG-B.

4. Proposed Rates

As noted above, PG&E's proposal is generally to minimize the changes to Agricultural rate design that were approved by D.18-08-013 and D.19-05-010. Appendix C provides illustrative proposed Agricultural rates under the revenue allocation and rate design that PG&E is sponsoring for implementation. At the point in time that this 2020 GRC Phase II proceeding is implemented in rates, the new mandatory Agricultural rates scheduled to be implemented in March 2021 will have been in place for less than one year. This strongly suggests that PG&E's proposal to carry forward the Agricultural rate designs adopted in PG&E's 2019 RDW with as little revision as possible is advisable to smooth customer transitions to the new Agricultural rates with later TOU hours.

5. Eliminate Voluntary TOU Meter Charges

PG&E's current legacy Agricultural rates may still retain varying levels of ongoing monthly TOU meter charges for those relatively few meter sites where an interval meter has not been installed. In legacy Agricultural tariffs, AG-A rates carry a $6.80 per month "TOU Meter Charge" if applicable, with a lower charge of only $2.00 per month for related AG-D rates for those AG-A customers who paid an up-front "TOU Meter Installation Charge" to cover the incremental cost of a TOU meter over a standard non-TOU meter. Similarly, legacy AG-B and AG-C rates carry a $6.00 per month TOU Meter Charge, if applicable, and a lower ongoing AG-E or AG-F monthly TOU Meter Charge of $1.20 per month.

The lower ongoing Monthly TOU Meter Charge was designed to cover the prior incremental costs of meter reading, billing, and education and outreach associated with the earlier days of metering and billing of voluntary TOU service. PG&E proposes to eliminate these incremental ongoing legacy TOU meter charges as obsolete, since TOU service is now the mandatory or standard basis for service.

6. Optimal Billing Period Program

PG&E proposes no changes to the modifications to the Optimal Billing Period Program revisions adopted in D.18-08-013. Those revisions left the program cap of 50 participants in place, retained the option on Schedule AG-5C until AG-5C expires, transferred agricultural eligibility to the new AG-C, expanded the program to Schedule E-19 above 500 kW and to Schedule E-20, and expanded eligibility to direct access and community choice aggregation. D.18-08-013 adopted revisions which established that 36 of the 50 participation slots would be assigned to AG customers, and 14 to medium and large Commercial or Industrial customers.[9]

7. Rates for Solar Grandfathered Customers

Legacy rates for qualifying solar grandfathered customers were subject to rate transition plans established in D.18-08-013 through the end of 2023. While this 2020 GRC Phase II proceeding may update the cost-basis for rates for solar grandfathered customers that were not subject to transition

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9 As of late October 2019, there were 31 Agricultural customers, and seven Commercial and Industrial customers, participating in the Optimal Billing Period program. Pursuant to D.18-08-013, PG&E filed Advice 5470-E to expand program eligibility to qualifying E-19 and E-20 Commercial and Industrial customers, and to Direct Access and Community Choice Aggregation (CCA) customers, effective February 9, 2019. Subsequently, seven Commercial customers joined the program, five of whom were CCA customers. All seven of the new commercial participants appear to be involved in fruit or vegetable canning operations.

plans adopted by D.18-08-013, there were none in the Agricultural class. Instead, for all legacy TOU Agricultural rates, D.18-08-013 adopted a phase-in plan to flatten the on-peak versus off-peak rate differentials applicable under the old legacy TOU periods and seasons. As a result, PG&E proposes to simply implement the solar grandfather rate designs specified in D.18-08-013. However, revenue allocation changes will still apply to legacy grandfathered Agricultural rates. The associated legacy schedule level revenue allocation percentage changes have been set to the same schedule level revenue allocation percentage changes as the new Agricultural TOU rates to which each legacy Agricultural rate schedule maps, in order to preserve rate schedule relationships.

8. Agricultural Data Reporting Requirements

In D.18-08-013, the Settlement Agreement on Marginal Cost and Revenue Allocation, Attachment 2, Agricultural Data Reporting Requirements, Section D, page 5, paragraph 3, states as follows:

> 3) Annual reports for the Tracking period from 2016 through the latest year available (likely to be 2017) will be provided as part of PG&E's 2020 GRC Phase II application.

The various reporting requirements set forth in Attachment 2 were quite voluminous, and include many reports. Further reports covering 2019 data will also be required during 2020. However, for inclusion with this 2020 GRC Phase II application, the latest year available and applicable at the time this testimony was prepared covers Agricultural data reporting requirements through 2018. By agreement with Agricultural Energy Consumers Association and California Farm Bureau Federation, PG&E is providing copies of these reports as part of the workpapers supporting this application.

9. Illustrative Agricultural Rate Designs

D.18-08-013 required that a number of illustrative Agricultural rate designs be provided in this proceeding to give the Commission and the other parties the fullest opportunity to consider other approaches to rate design, as follows:

> PG&E shall propose more cost-based rates, based on full equal percent of marginal cost (EPMC) scaling of all marginal cost components, for its

> non-residential Time-of-Use (TOU) customers in its next GRC Phase II proceeding. PG&E shall also propose an alternative set of rates that, while not based on full EPMC scaling, are more cost-based than those approved by this decision. (D.18-08-013, OP 5.)

To this end, PG&E has provided the following illustrative cases in Appendix H, "Illustrative Rate Designs for Agricultural Customers":

a) **Illustrative Full EPMC Rates per D.18-08-013:** Traditional full EPMC rates based on full scaling of applicable distribution and generation marginal cost revenues, as discussed at pages 12 through 55 of D.18-08-013, including setting customer charges at higher full EPMC levels.

b) **Illustrative Full EPMC Rates, but With Customer Charges Set at PG&E's Sponsored Proposed Lower Levels, Below Full EPMC Levels:** Because higher full EPMC customer charges are not realistic for fixed monthly customer charges, PG&E has instead set illustrative customer charges at the same level as in PG&E's main proposal. This also better facilitates comparisons across the rate design scenarios.

c) **Partial EPMC Rates per D.18-08-013:** While not based on full EPMC scaling, PG&E has instead used unscaled Marginal Costs to develop the final rate design scenario ordered by D.18-08-013, again retaining customer charges only at PG&E's sponsored proposed lower levels.

Comparison of PG&E's sponsored proposed rates to these three above illustrative compliance sets of rates shows varying levels of customer charges, demand charges, and TOU price differentials. In the full EPMC scenario, customer charges set at full EPMC levels would result in differential bill comparison results and would not be acceptable for reasons of rate stability stated herein. Further, as stated earlier, at the time this 2020 GRC Phase II proceeding is implemented in rates, the new mandatory Agricultural rates scheduled to be implemented in March 2021 will have been in place for less than one year. This strongly suggests that PG&E's proposal to carry forward the Agricultural rate designs adopted in PG&E's 2019 RDW with as little revision as possible is advisable, to smooth customer transitions to the new Agricultural rates with later TOU hours. Therefore, PG&E does not propose that any of the three sets of illustrative rates be adopted. However, they are provided as a compliance item for the convenience and reference of the Commission and parties.

D. Conclusion

In this chapter, PG&E has presented the background supporting the new Agricultural rates with later TOU hours adopted in PG&E's 2017 GRC Phase II and 2019 RDW proceedings. PG&E proposes to preserve the Agricultural rates adopted in the GRC as modified by the 2019 RDW by applying "interim GRC rules" to the slate of new default and voluntary Agricultural rates adopted in the 2019 RDW, as modified to preserve intra-class rate schedule relationships such as the 1,500 pumping hour break-even level where AG-C is generally better for customers than AG-B. This will stabilize the rates with later TOU hours as AG customers adapt to the new later TOU hours of 5 p.m. to 8 p.m. that will become mandatory beginning in March 2021. Changes to grandfathered legacy rates for solar customers will occur under the rules adopted in D.18-08-013, but are subject to updated revenue allocation to preserve legacy and new schedule level percentage changes.

In addition, PG&E provided a compliance showing to illustrate rates under alternative rate design approaches. However, PG&E does not support the adoption of these alternative rate designs. Finally, PG&E proposes to eliminate obsolete voluntary TOU meter charges, and proposes no changes to the Optimal Billing Period Program.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

ATTACHMENT A

PRESENT AND PROPOSED AGRICULTURAL RATES

PACIFIC GAS AND ELECTRIC COMPANY
2020 GRC PHASE II
EXHIBIT 3, CHAPTER 5, ATTACHMENT A
PRESENT AND PROPOSED AGRICULTURAL RATES

	PRESENT RATES						PROPOSED RATES					
AG-A1	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
DEMAND CHARGE (/kW)												
Summer	5.42	.00		.00	5.42		5.69	.00		.00	5.69	
Winter	5.42	.00		.00	5.42		5.69	.00		.00	5.69	
ENERGY CHARGE (/kWh)												
Summer												
Peak	.12078	.22699	.01403	.02910	.39090		.12442	.23580	.01403	.02910	.40335	
Off-Peak	.07452	.10731	.01403	.02910	.22496		.07816	.11612	.01403	.02910	.23741	
Winter												
Peak	.06747	.10399	.01403	.02910	.21459		.07111	.11280	.01403	.02910	.22704	
Off-Peak	.06463	.07754	.01403	.02910	.18530		.06827	.08635	.01403	.02910	.19775	
CUSTOMER CHARGE (/meter/day)	.68895				.68895	20.97	.68895				.68895	20.97

	Present						Proposed					
AG-B	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
DEMAND CHARGE (/kW)												
Secondary												
Summer Max Peak Period												
Summer Maximum	6.02	.00		.00	6.02		7.36	.00		.00	7.36	
Winter Max Peak Period												
Winter Maximum	6.02	.00		.00	6.02		7.36	.00		.00	7.36	
Primary												
Summer Max Peak Period												
Summer Maximum	5.20	.00		.00	5.20		6.35	.00		.00	6.35	
Winter Max Peak Period												
Winter Maximum	5.20	.00		.00	5.20		6.35	.00		.00	6.35	
Transmission												
Summer Max Peak Period												
Summer Maximum	2.02	.00		.00	2.02		2.47	.00		.00	2.47	
Winter Max Peak Period												
Winter Maximum	2.02	.00		.00	2.02		2.47	.00		.00	2.47	
ENERGY CHARGE (/kWh)												
Summer												
Peak	.10650	.25076	.01299	.02910	.39935		.11976	.25452	.01299	.02910	.41636	
Off-Peak	.05672	.12769	.01299	.02910	.22650		.06998	.13145	.01299	.02910	.24351	
Winter												
Peak	.05799	.12235	.01299	.02910	.22243		.07125	.12611	.01299	.02910	.23944	
Off-Peak	.05493	.09615	.01299	.02910	.19317		.06819	.09991	.01299	.02910	.21018	
CUSTOMER CHARGE (/meter/day)	.91565				.91565	27.87	.91565			.00000	.91565	27.87

	Present						Proposed					
AG-C	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
DEMAND CHARGE (/kW)												
Secondary												
Summer Max Peak Period	5.95	13.16			19.11		7.12	13.35			20.47	
Summer Maximum	10.81				10.81		12.95				12.95	
Winter Max Peak Period					.00		.00				.00	
Winter Maximum	10.81				10.81		12.95				12.95	
Primary												
Summer Max Peak Period	5.95	13.16			19.11		7.12	13.35			20.47	
Summer Maximum	9.68				9.68		11.60				11.60	
Winter Max Peak Period					.00		.00				.00	
Winter Maximum	9.68				9.68		11.60				11.60	
Transmission												
Summer Max Peak Period	5.95	13.16			19.11		7.12	13.35			20.47	
Summer Maximum	2.79				2.79		3.35				3.35	
Winter Max Peak Period					.00		.00				.00	
Winter Maximum	2.79				2.79		3.35				3.35	
ENERGY CHARGE (/kWh)												
Summer												
Peak	.01791	.12042	.01128	.02910	.17870		.02428	.12169	.01128	.02910	.18635	
Off-Peak	.00795	.09094	.01128	.02910	.13926		.01432	.09221	.01128	.02910	.14691	
Winter												
Peak	.00476	.10578	.01128	.02910	.15091		.01113	.10705	.01128	.02910	.15856	
Off-Peak	.00459	.08026	.01128	.02910	.12522		.01096	.08153	.01128	.02910	.13287	
CUSTOMER CHARGE (/meter/day)	1.43343				1.43343	43.63	1.43343			.00000	1.43343	43.63

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PRESENT AND PROPOSED AGRICULTURAL RATES

	PRESENT RATES						PROPOSED RATES					
AG-A2	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
DEMAND CHARGE (/kW)												
Summer	9.53	.00		.00	9.53		10.00	.00		.00	10.00	
Winter	9.53	.00		.00	9.53		10.00	.00		.00	10.00	
ENERGY CHARGE (/kWh)												
Summer												
Peak	.06454	.22699	.01403	.02910	.33466		.06578	.23580	.01403	.02910	.34471	
Off-Peak	.01829	.10731	.01403	.02910	.16873		.01953	.11612	.01403	.02910	.17878	
Winter												
Peak	.02850	.10399	.01403	.02910	.17562		.02974	.11280	.01403	.02910	.18567	
Off-Peak	.02566	.07754	.01403	.02910	.14633		.02690	.08635	.01403	.02910	.15638	
CUSTOMER CHARGE (/meter/day)	.68895				.68895	20.97	.68895				.68895	20.97

	PRESENT RATES						PROPOSED RATES					
AG-F	Distr	Gen	PPP	Other	Total		Distr	Gen	PPP	Other	Total	
DEMAND CHARGE ($/kW)												
Rate A												
Summer	5.42	.00		.00	5.42		5.69	.00		.00	5.69	
Winter	5.42	.00		.00	5.42		5.69	.00		.00	5.69	
DEMAND CHARGE ($/kW)												
Rate B												
Secondary												
Summer												
Peak	.00	.00		.00	0.00		.00	.00		.00	0.00	
Maximum	6.02	.00		.00	6.02		7.36	.00		.00	7.36	
Winter												
Maximum	6.02	.00		.00	6.02		7.36	.00		.00	7.36	
Primary												
Summer												
Peak	.00	.00		.00	0.00		.00	.00		.00	0.00	
Maximum	5.20	.00		.00	5.20		6.35	.00		.00	6.35	
Winter												
Maximum	5.20	.00		.00	5.20		6.35	.00		.00	6.35	
Transmission												
Summer												
Peak	.00	.00		.00	0.00		.00	.00		.00	0.00	
Maximum	2.02	.00		.00	2.02		2.47	.00		.00	2.47	
Winter												
Maximum	2.02	.00		.00	2.02		2.47	.00		.00	2.47	
Rate C												
Secondary												
Summer												
Peak	5.95	13.16		.00	19.11		7.12	13.35		.00	20.47	
Maximum	10.81	.00		.00	10.81		12.95	.00		.00	12.95	
Winter												
Maximum	10.81	.00		.00	10.81		12.95	.00		.00	12.95	
Primary												
Summer												
Peak	5.95	13.16		.00	19.11		7.12	13.35		.00	20.47	
Maximum	9.68	.00		.00	9.68		11.60	.00		.00	11.60	
Winter												
Maximum	9.68	.00		.00	9.68		11.60	.00		.00	11.60	
Transmission												
Summer												
Peak	5.95	13.16		.00	19.11		7.12	13.35		.00	20.47	
Maximum	2.79	.00		.00	2.79		3.35	.00		.00	3.35	
Winter												
Maximum	2.79	.00		.00	2.79		3.35	.00		.00	3.35	
ENERGY CHARGE ($/kWh)												
Rate A												
Summer												
Peak	.20460	.19252	.01646	.02910	.44268		.21379	.20133	.01403	.02910	.45825	
Off-Peak	.06820	.11539	.01646	.02910	.22914		.07126	.12420	.01403	.02910	.23859	
Winter												
Peak	.11880	.10501	.01646	.02910	.26937		.12540	.11382	.01403	.02910	.28234	
Off-Peak	.05940	.07856	.01646	.02910	.18352		.06270	.08736	.01403	.02910	.19319	
Rate B												
Summer												
Peak	.17845	.21767	.01507	.02910	.44029		.21572	.22172	.01299	.02910	.47953	
Off-Peak	.05099	.13635	.01507	.02910	.23151		.06163	.14041	.01299	.02910	.24413	
Winter												
Peak	.09908	.12351	.01507	.02910	.26676		.12282	.12756	.01299	.02910	.29247	
Off-Peak	.04954	.09706	.01507	.02910	.19077		.06141	.10111	.01299	.02910	.20461	
Rate C												
Summer												
Peak	.02890	.12200	.01507	.02910	.19508		.04885	.12326	.01128	.02910	.21248	
Off-Peak	.00723	.09199	.01507	.02910	.14339		.01221	.09324	.01128	.02910	.14583	
Winter												
Peak	.00842	.10761	.01507	.02910	.16019		.02005	.10886	.01128	.02910	.16928	
Off-Peak	.00421	.08116	.01507	.02910	.12954		.01002	.08241	.01128	.02910	.13281	
CUSTOMER CHARGE ($/meter/day)												
Rate A	.68895					20.97						20.97
Rate B	.91565					27.87						27.87
Rate C	1.43343					43.63						43.63

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

STREETLIGHTING RATE DESIGN

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STREETLIGHTING RATE DESIGN

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CHAPTER 6
STREETLIGHTING RATE DESIGN

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E) 2020 General Rate Case (GRC) Phase II rate design proposals for the Streetlight customer class. Rate design for the Streetlight customer class includes rate components for transmission, distribution (including facility charges), generation, Public Purpose Programs (PPP), Competition Transition Charges, Nuclear Decommissioning, Department of Water Resources Bond Charge, New System Generation Charges, the Energy Cost Recovery Amount, and the Power Charge Indifference Adjustment. In this proceeding, PG&E is proposing changes to generation, distribution and PPP revenue allocation and rate design. PG&E is not making any proposals for revenue allocation and rate design for other components of streetlight rates. Accordingly, PG&E's current approach to revenue allocation and rate design for these components is set forth in Chapter 1, "Revenue Allocation and Rate Design Introduction." Generation, distribution and PPP revenue allocation, as well as PPP rate design,[1] is described in Chapter 2 of Exhibit (PG&E-3).

PG&E's updates to streetlight rate design proposals for the Streetlight customer class are described in the following testimony and include adjustments to facility charge rates to reflect updated costs as well as determination of the total monthly streetlight charges. Consistent with PG&E's Revenue Allocation proposal in Chapter 2, PG&E's goal is to transition allocations to full cost of service over a period of six years. Accordingly, PG&E proposes to adjust the facility charge 1/6th the way towards the full revenue requirement each year for the next three years. PG&E would then reassess costs in its 2023 GRC Phase II and propose the continuation of its transition plan in that proceeding.

The remainder of this chapter is organized as follows:

- Section B – Background

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1 PPP rates for the streetlighting customers are designed in accordance with the guidelines described in Chapter 1 using the revenue allocation provided in Chapter 2.

- Section C – Non-Energy Facility Charge Calculation for Schedules LS-1, LS-2, OL-1, and CCSF Streetlights
- Section D – Energy Charge and Total Streetlight Rates for Schedules LS-1, LS-2, and OL-1
- Section E – Rate Design for Schedule LS-3
- Section F – City and County of San Francisco (CCSF) Streetlight Rates
- Section G – Light-Emitting Diode (LED) Streetlight Conversion Program
- Section H – Network-Controlled Dimmable Streetlight
- Section I – Conclusion

B. Background

In this chapter, PG&E addresses rate design for Schedules LS-1, LS-2, LS-3, OL-1, and CCSF streetlights. Schedules LS-1 and LS-2 provide options for illuminating public streets, highways, and other outdoor ways and places and are designed as a fixed monthly charge. Schedule OL-1 is also designed as a fixed charge per month for private outdoor lighting. PG&E also develops fixed monthly charges for CCSF's streetlights. Schedule LS-3, however, is a metered schedule with a customer charge and an energy rate that does not vary by time of day or season.

Schedules LS-1, LS-2, OL-1 and CCSF streetlights include a fixed monthly charge per lamp based on the most common type and size of lamp within each rate schedule and the type of service provided by PG&E (e.g., LS-1A, LS-1C, etc.). The monthly charge for Schedules LS-1, LS-2 and OL-1 consists of a non-energy facility portion and an energy portion based on the estimated usage per lamp and an average energy rate. The average energy rate includes all applicable components as set forth in Section A, above, and is derived in the process of developing the revenue allocation. The average energy rate is the same for Schedules LS-1, LS-2, LS-3 and OL-1, except that Schedule OL-1 pays the full PPP charge.[2]

In addition to the standard rates, this chapter includes PG&E's proposals for the LED Streetlight Conversion Program. The California Public Utilities Commission (CPUC or Commission) approved this program to encourage

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2 Rates for Schedules LS-1, LS-2 and LS-3 do not include the California Alternate Rates for Energy surcharge component of the PPP rate.

conversion of LS-1, OL-1, and CCSF lamps to LED lamps. Under the adopted program, PG&E assesses an Incremental Facility Charge (IFC) in addition to the facility rate for the standard lamp type (which originally was not an LED fixture).

C. Non-Energy Facility Charge Calculation for Schedules LS-1, LS-2, OL-1, and CCSF Streetlights

In this proceeding, PG&E continues to base its non-energy facility charge proposal on a simplified non-energy streetlight rate design model. This type of simplified model was first introduced in PG&E's 2003 GRC Phase II (D.05-11-005) and has continued to be used in PG&E's GRC Phase II proceedings since that time. The method proposed herein was most recently adopted in the settlement approved by the CPUC in D.18-08-013 (PG&E's 2017 GRC Phase II decision), and is the basis for the currently effective non-energy facility charges for these rate schedules.

Consistent with PG&E's Revenue Allocation proposal in Chapter 2, PG&E proposes to transition allocations to full cost of service over a period of 6 years. Specifically, PG&E is proposing that streetlight facility charges be adjusted 1/6th the way towards the full revenue requirement each year for the next three years. PG&E would then reassess costs in its 2023 GRC Phase II and propose the continuation of its transition plan in that proceeding. PG&E's proposed facility rates at full cost (that is, in year six of the transition) are provided in Table 6-2 at the end of this chapter.

The three components of the non-energy facility charge, using the simplified model, are:

- Universal Charge;
- Remaining operations and maintenance (O&M) Expense Charge; and
- Plant-Related Charge.

Table 6-1, below, provides a summary of the applicability of these non-energy facility charge components to each streetlight rate schedule:

TABLE 6-1
APPLICABILITY OF NON-ENERGY FACILITY CHARGE COMPONENTS

Line No.	Streetlight Rate Schedule	Universal Charge	O&M Charge	Plant-Related Charge
1	LS-1A through LS-1F	Yes	Yes	Yes
2	LS-2A	Yes	No	No
3	LS-2C	Yes	Yes	No
4	OL-1	Yes	Yes	Yes
5	CCSF	Yes	Yes	Yes

1. Universal Charge

The Universal Charge is imposed on all LS-1, LS-2, OL-1, and CCSF streetlight customers regardless of whether the streetlight is owned by the customer or by PG&E. The Universal Charge covers recovery of O&M, Customer Accounts, and Administrative and General (A&G) expenses.

The O&M portion of the Universal Charge includes Distribution Maps and Records, as well as Supervision costs. The Customer Accounts portion of the Universal Charge includes the Streetlight Inventory Program. The A&G portion of the Universal Charge is calculated by multiplying the test year (TY) electric distribution A&G loader by the O&M expense.

a. O&M Expense

For its 2020 streetlight rates, PG&E uses 2018 actual costs and 2020 TY estimates for the streetlight O&M account shown in the Federal Energy Regulatory Commission (FERC) Account 596 (Distribution Maintenance of Streetlights and Signal Systems).

As it did in the prior GRC Phase II proceedings beginning 2007, PG&E has continued to separate the O&M streetlight expenses into the Universal Charge (Distribution Maps and Records, and Supervision) and the Remaining O&M Expense Charge (group replacements and burnouts). However, Supervision costs are no longer included in FERC Account 596. Instead, PG&E uses 2018 actual Supervision costs escalated to 2020 dollars. This separation enables PG&E to unbundle the expense for group lamp replacements and burnouts.

b. Customer Accounts Expense

Similar to the 2017 GRC Phase II, in this 2020 GRC Phase II, PG&E proposes to include the Streetlight Inventory Program cost in the Universal Charge. This cost is specifically related to the lamp inventory for Schedules LS-1, LS-2 and OL-1, and is driven by record keeping for each streetlight in the streetlight inventory.

c. A&G Expenses

For this 2020 GRC Phase II, PG&E proposes to continue to calculate the A&G expenses by multiplying the TY electric distribution A&G loader by the O&M expenses in the Universal Charge.[3] The electric distribution A&G loader for this 2020 GRC Phase II, is equal to 24.17 percent, as described in Exhibit (PG&E-2), Chapter 10, "Marginal Cost Loaders and Financial Factors."

2. Remaining O&M Expense Charge

O&M expenses that were not incorporated into the Universal Charge, such as group replacement and burnouts, appear in the Remaining O&M Expense Charge. For this 2020 GRC Phase II, PG&E proposes to continue to calculate the A&G expenses for this component by applying the TY electric distribution A&G loader discussed in the previous paragraph.

3. Plant-Related Charge

The Plant-Related charge is developed first by determining the revenue requirement for the capital cost of the streetlights and then separately determining the replacement cost for each type of lamp in order to allocate the revenue requirement among all lamp types in Schedules LS-1, OL-1, and CCSF streetlights.

a. Plant Revenue Requirements

The Plant-Related charge is based on a revenue requirement that is derived using the year-end balances of the streetlight plant accounts. The revenue requirement is based on the cost of owning the streetlight facilities for Schedules LS-1, OL-1, and CCSF and includes costs for

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[3] A&G Loader is already embedded within the customer account expenses portion of the Universal Charge.

depreciation, uncollectibles, franchise fees, income taxes, property taxes and return. In this proceeding, PG&E is proposing to collect the revenue requirement in the plant-related charge, to reallocate that revenue to reflect updated replacement costs and to reflect a change to the "most common lamp type" as discussed in more detail below.

b. Replacement Costs

The revenue requirement is allocated to each streetlight rate schedule according to the replacement cost of each lamp type. There are four basic lamp types currently in use on PG&E's system: (1) High Pressure Sodium Vapor; (2) Mercury Vapor (MV); (3) incandescent; and (4) newer technologies like LED street lamps. For non-decorative CCSF and PG&E lamps, LED lamps are the most common streetlight lamp type. PG&E expects that, by 2020, the most common OL-1 lamp type will be an LED lamp. Accordingly, PG&E proposes to change rates to make LED the most common lamp type in this proceeding for all non-decorative lamps as described further below.

For this 2020 GRC Phase II, PG&E updates the streetlight replacement cost on most lamp types with 2019 data, the most up-to-date data available. PG&E continues to use the materials and labor categories that were used to determine the rates in the Streetlight rate Design Settlement adopted in D.18-08-013.[4] MV and incandescent lamps are old, obsolete technologies that are not supported by manufacturers and/or for which spare parts/supplies are no longer available. Therefore, as these lamps fail or burn out, the luminaire (and not just the lamp itself) is replaced by LED luminaire with the equivalent number of lumens. As a result, PG&E derived the replacement cost for these obsolete lamps based on the replacement cost for LED lamps with the equivalent number of lumens.[5]

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4 PG&E obtained the cost data for materials and labor (e.g., for each lamp type) to install the replacement lamp from standard estimating tools that are routinely used in most construction projects.

5 MV and incandescent lamps make up less than 600 of the approximately 196,000 PG&E-owned streetlights encompassed by the Plant-Related Charge.

c. **Plant Revenue Requirement Allocation**

Once the total replacement costs are determined, the Plant Revenue Requirement, or in this case the total current plant-related facility charge revenue, is allocated to each lamp type in a three-step process. First, PG&E calculates the Revenue Allocation Factors (RAF), which is the ratio of the embedded revenue requirements compared to the total replacement costs for all lamps under Schedules LS-1, OL-1, and CCSF. Second, PG&E multiplies the RAF by the replacement cost on each of the most common lamp type in Schedules LS-1, OL-1, and CCSF to yield an annualized plant related charge rate. Lastly, the annualized charge rates are then scaled to equal to the total required revenue.

D. Energy Charge and Total Streetlight Rates for Schedules LS-1, LS-2 and OL-1

The total monthly charge per lamp for Schedules LS-1, LS-2, and OL-1 is the sum of the non-energy facility charge and the product of the energy usage per lamp and a volumetric (per kilowatt-hour (kWh)) rate which includes all other costs allocated to these customers. Since Schedules LS-1, LS-2 and OL-1 are not metered, energy usage for these rate schedules is derived based on the type and size of lamp and lamp ballast, and the estimated number of hours during which the lamp would operate each month. For this GRC Phase II, PG&E proposes no change in the estimated hours of operation. Lamps are assumed to be operated for approximately 11 hours per night on average, but not to exceed 4,100 hours per year for all-night rates.

The volumetric energy rate is determined by subtracting non-energy facility charge revenues from Schedules LS-1, LS-2, OL-1, and CCSF lamps, as well as the applicable Schedule LS-3 basic service fee from the total revenue allocated to the streetlight class, and then dividing the difference by the applicable sales, in kWh. The energy rate is the same for Schedules LS-1, LS-2, LS-3 and OL-1, except that Schedule OL-1 pays the full PPP charge.

E. Rate Design for Schedule LS-3

As noted in the Background section of this testimony, Schedule LS-3 includes a customer charge and an energy rate that does not vary by season or by time of use. PG&E is not proposing to change the LS-3 customer charge in this proceeding.

F. City and County of San Francisco Streetlight Rates

PG&E provides O&M services to the streetlights that are located in San Francisco. These CCSF streetlights obtain their energy from the city's Hetch Hetchy Project and not from PG&E. In this proceeding, PG&E proposes to set rates for CCSF's streetlights using the same approach adopted in the settlement approved by the CPUC in D.18-08-013 (PG&E's 2017 GRC Phase II decision), subject to the adjusting the facility charge 1/6th of the way towards the full revenue requirement each year for the next three years as proposed for non-CCSF lamps. PG&E's proposed non-energy facility charges for the CCSF rate schedules are shown in Table 6-2 at the end of this chapter.

G. LED Streetlight Conversion Program

1. Non-Decorative Lamps

The IFC was eliminated for non-decorative LS-1 lamps in the in the last GRC and replaced with a rate for a standard LED lamp. In this proceeding, PG&E proposes to eliminate the LED Streetlight Conversion Program for PG&E *non-decorative* streetlights where more than half of the lamps have already been converted to LED, or where PG&E expects more than half of the lamps will be converted to LED by 2020. Specifically, PG&E proposes to eliminate the IFC on Schedules OL-1 and CCSF non-decorative lamps, and replace the rate with an LED streetlight facility charge rate. The revision will eliminate the need for the IFC adder on these schedules. That is, rather than calculating an LED conversion adder, PG&E will calculate the facilities cost for OL-1 and CCSF using an LED replacement cost.

2. Decorative Lamps

Pursuant to Public Utilities Code Section 384.5,[6] PG&E filed and the Commission approved the LED Streetlight Conversion Program for decorative lamps in Advice 4661-E (PG&E-owned decorative lamps) and in Advice Letter 4662-E (CCSF decorative lamps). Like the similar program for non-decorative lamps, customers are required to pay an IFC in addition to their otherwise applicable streetlight rate. The approved IFC of $12.768 per month for decorative CCSF lamps and for decorative lamps served under Schedule LS-1D has been in effect since 2016. PG&E's experience with the program to date has been that only 13.5 percent of PG&E lamps that would be eligible for the program have been converted and only 13.5 percent of CCSF lamps have been converted. In this proceeding, PG&E has reviewed the calculations for the decorative IFC based on more recent data and proposes to reduce the adder from its current level to $6.226.[7] As is the case with the current decorative IFC, the proposed IFC would be applied in the addition to the facility rate for the standard lamp type (which originally was not an LED fixture). PG&E is hopeful that the revised IFC for decorative streetlights will encourage greater customer adoption of LED lighting during this GRC cycle.

H. Network-Controlled Dimmable Streetlight

1. Pilot Program

A Pilot Program for Network-Controlled Dimmable Streetlights (Pilot) was established as part of the Streetlight Settlement Agreement approved

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6 384.5. (a) On or before March 1, 2014 the commission shall order electrical corporations to submit, on or before July 1, 2015, a tariff to be used, at the discretion of local governments, to fund energy efficiency improvements in street light poles owned by the electrical corporations to ensue reduced energy consumption for local governments who are streetlight customers covered by these tariffs.

(b) The tariff shall be designed to allow local governments to remit the cost of the improvement through the tariff over time, resulting in reduced energy consumption, without shifting costs to nonparticipating ratepayers. The cost of the improvement shall be identified separately rather than included within the charge for electrical service.

7 CCSF's historical Golden Triangle and Dragon lights are not eligible for the decorative LED conversion program due to the highly specialized nature of these lights.

by the CPUC in PG&E's 2011 GRC Phase II (D.11-12-053).[8] The Pilot was revised in the Streetlight Settlement Agreement approved by the CPUC in PG&E's 2014 GRC Phase II (D.15-08-005).[9] As compared with the 2011 Dimmable Pilot Program, which is now closed to new enrollment, the 2014 Dimmable Pilot Program was expected to provide dimmable streetlight service as an option to Schedule LS-2 that was simpler and offered participants some certainty that they would benefit from related energy savings in a timely and mutually-workable way. To date, there is only one participant in the 2011 pilot and there are no participants on the 2014 pilot program.

In Phase II of the 2017 GRC proceeding, the Commission adopted the Streetlight Rate Design Settlement as part of D.18-08-013. Among other things, the Settlement Agreement required that PG&E hold a workshop to discuss the feasibility of a fully-automated, dimmable streetlight and ancillary device billing system. In addition, the settlement required that PG&E develop a report including a work plan and cost estimate for such a system and include the report in Phase I of the 2020. Accordingly, the Compliance Report was filed in Phase I of the 2020 GRC proceeding.[10] As part of the Compliance Report, PG&E stated that it:

> …does not recommend the Commission pursue a fully integrated metering and billing option for dimmable streetlights at this time in light of the relative costs to both customer and to PG&E.[11]

In that same proceeding, California City-County Street Light Association recommended that the Commission approve a fully-integrated billing and metering solution for dimmable streetlights that utilized customer-owned meters.[12]

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8 See D.11-12-053, *mimeo*, pp. 55-58, adopting, without modification, the uncontested Amended Streetlight Settlement Agreement attached to that decision as Appendix D, Attachment 3. See also Resolution E-4421 approving the necessary Special Contract that would allowing participants' billing to deviate from PG&E's existing LS-2 streetlight rate schedule, to allow for reductions due to dimmable LED streetlights under this pilot.

9 See the Streetlight Rate Design Settlement, p. 5.

10 Application (A.) 16-12-009, Exhibit (PG&E-7), WP 8-163 to WP 8-188.

11 A.16-12-009, Exhibit (PG&E-7), WP 8-169 to WP 8-170; Exhibit (PG&E-28), p. 9-4.

12 A.16-12-009, CALSLA-01, p. 1, lines 21-24; p. 9, line 27 to p. 10, line 9.

In Rebuttal Testimony, PG&E expanded on why the Commission should not approve a fully-automated billing and metering at this time. First, whether the meters would be customer-owned or owned by PG&E, the Information Technology costs of the programs would be considerable and the potential costs that would be incurred by customers to achieve the desired benefit are uncertain. While the pilot program has demonstrated that for a subset of pilot locations, the concept of utilizing measured usage to calculate an energy credit for dimming was valid, the pilot has not provided an adequate demonstration that customer-owned meters and data delivery systems are capable of providing the information to PG&E that is necessary billing in a timely and complete manner.[13] Instead, PG&E proposed to continue the pilot program for customers that had installed dimming equipment, and consider revisions to make the program more in line with customer needs. Continuation of the pilot program would provide, at a minimum, benefits of a basic dimming schedule while providing an opportunity to participating customers to improve the capability of their systems. PG&E plans to initiate a discussion with interested parties to determine whether the pilot program should be revised or enhanced.

2. Rate Design for a Fully-Integrated Metered and Billing Solution for Dimmable Streetlights

In anticipation that a fully-integrated metering and billing solution could be approved in Phase I of the 2020 GRC, D.18-08-013 also requires that PG&E provide a rate design in this Phase II proceeding for dimmable streetlights that could be employed with such a system if approved in Phase I. As of the date this testimony was filed, a decision Phase I of the 2020 GRC has not been issued. Accordingly, in compliance with D.18-08-013, PG&E had intended to provide the required rate design proposal as Appendix I of Exhibit (PG&E-4). However, PG&E was unable to complete the proposal in time to be included with this opening testimony. PG&E will supplement this testimony with Appendix I by January 17, 2020.

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[13] A.16-12-009, Exhibit (PG&E-28), pp. 9-6 and 9-7.

I. Conclusion

PG&E requests that the Commission adopt its proposed rate design for non-energy facility charges for Schedules LS-1, LS-2, OL-1, and CCSF streetlights, and its proposed energy charges for all streetlight rate schedules. PG&E also requests revisions to the LED Streetlight Conversion Program as noted above and continuance of a Dimmable Streetlight Pilot Program subject to input from the parties in this proceeding.

TABLE 6-2
FACILITY CHARGES FOR STREETLIGHT RATES

			Lamp Counts			Monthly Rate				Annual Revenues - Full Cost ($000)	
	Rate Schedule	Service	Plant Charge	Universal Charge	O&M Charge	Plant Charge	Universal Charge	O&M Charge	Total Monthly Facility Charge	Per Schedule	Per Class
1	LS-1A	PG&E owns and maintains luminaire, control facilities, support arm, and service wiring on its existing distribution pole, and all lights. Most common lamp type: LED 29W.	60,630	60,630	60,630	$8.778	$0.141	$1.363	$10.282	$ 7,481	
2	LS-1B	PG&E owns and maintains luminaire, control facilities, support arm, pole or post, foundation and service connection and where customer has paid the estimated installed cost of the luminaire, support arm and control facilities. Most common lamp type: MV 175W (HPSV 70W equivalent).	42	42	42	$9.582	$0.141	$1.363	$11.086	$ 6	
3	LS-1C	PG&E owns and maintains its standard luminaire, control facility, internal pole wiring as required. (Ownership of pole or post, support arm and foundation by customer where light is the only light on a pole or where this schedule is applied to all lights on the customer owned pole. Also applies to second and all multiple lights on poles or posts owned by PG&E. Most common lamp type: LED 29W.	19,992	19,992	19,992	$4.642	$0.141	$1.363	$6.146	$ 1,474	
4	LS-1D	PG&E owns and maintains its standard post top luminaire, control facility, internal post wiring, standard galvanized steel post (20-foot mounting height or less) and foundation where customer pays for the estimated and installed cost of the post, support arm (if any) and foundation. Most common lamp type: HPSV 70W.	18,830	18,830	18,830	$9.175	$0.141	$1.363	$10.679	$ 2,413	
5	LS-1E	PG&E owns and maintains its standard luminaire, control facility, internal pole wiring, service connection, galvanized steel pole and foundation where the customer has paid to PG&E the estimated installed cost of the pole, support arm and foundation. Most common lamp type: LED 29W.	43,390	43,390	43,390	$8.546	$0.141	$1.363	$10.050	$ 5,233	
6	LS-1F	PG&E owns and maintains a standard luminaire, control facility, support arm, and service connection on its standard pole or post, installed solely for the luminaire. Most common lamp type: LED 29W.	16,864	16,864	16,864	$9.256	$0.141	$1.363	$10.760	$ 2,177	$ 18,784
7	LS-2A	City Owned and Maintained		575,662			$0.141		$0.141	$ 976	
9	LS-2C	City Owned and PG&E Maintained		5,876	5,876		$0.141	$1.363	$1.504	$ 106	$ 1,082
10	OL-1	Outdoor area lighting service where street lighting schedules are not applicable and where PG&E installs, owns, operates and maintains the complete lighting installation on PG&E's existing wood distribution poles or on customer-owned poles acceptable to PG&E installed by the customer on his private property.	18,174	18,174	18,174	$9.582	$0.141	$1.363	$11.086	$ 2,418	$2,418
	CCSF Standard:										
11		CCSF Rate Schedule No. 1 (LS-1A LED 53W)	15,189	15,189	15,189	$9.485	$0.141	$1.363	$10.989	$ 2,003	
12		CCSF Rate Schedule No. 3 (LS-1A HPSV 150W)	19	19	19	$8.141	$0.141	$1.363	$9.645	$ 2	
13		CCSF Rate Schedule No. 4E (LS-1E LED 53W)	1,507	1,507	1,507	$9.819	$0.141	$1.363	$11.323	$ 205	
14		CCSF Rate Schedule No. 7									
	CCSF Non-Standard										
		CCSF Rate Schedule No. 4A:									
15		Incandescent 405W	6	6	6	$49.086	$0.141	$1.363	$50.590	$ 4	
		CCSF Rate Schedule No. 5:									
16		HPSV 100W	687	687	687	$16.964	$0.141	$1.363	$18.468	$ 152	
17		Incandescent 405W	10	10	10	$49.086	$0.141	$1.363	$50.590	$ 6	
		CCSF Rate Schedule No. 6A (Chinatown Area) - HSPV 250W	43	43	43	$87.142	$0.141	$1.363	$88.646	$ 46	
		CCSF Rate Schedule No. 9 (Triangle District)									
		HPSV:									
18		150W 16,000 LUMENS DUPLEX (1)	193	193	193	$74.570	$0.141	$1.363	$76.074	$ 176	
19		150W 16,000 LUMENS DUPLEX (2)	193	193	193	$1.692	$0.141	$1.363	$3.196	$ 7	
20	CCSF Subtotal		17,847	17,847	17,847	$10.642	$0.141	$1.363	$12.146	$ 2,601	$ 2,601
21	Lamp Count Totals		195,769	777,307	201,645						
22	Annual Revenues ($000)		$20,270	$1,317	$3,298					$ 24,885	$24,885

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

THE ECONOMIC DEVELOPMENT RATE

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THE ECONOMIC DEVELOPMENT RATE

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E) proposal for its Economic Development Rate (EDR) in the 2020 General Rate Case (GRC) Phase II. Public Utilities Code Section 740.4(a) provides that the California Public Utilities Commission (CPUC or Commission) shall authorize public utilities to engage in programs to encourage economic development. PG&E proposes to continue offering its EDR to attract jobs and companies to locate in California when they have out-of-state choices and to retain companies considering leaving California. PG&E proposes to continue its current EDR until December 31, 2023 (or until a decision is rendered in Phase II of the 2023 GRC, whichever is later), and to establish an increase of 150 megawatts (MW) for large businesses and 5 MW for small businesses to the current program cap of 145 MW. Also, while PG&E proposes to retain the existing rate reduction percentages of the current program, PG&E proposes to revise the proportions used to allocate the rate reduction to distribution and generation components of the bill.

B. Overview of the EDR Program

1. History of the EDR Program

On November 13, 2012, PG&E filed Application 12-03-001, *Application for Approval of Economic Development Rate for 2013-2017* to extend and revise its EDRs. On October 3, 2013, the Commission issued Decision (D.) 13-10-019 which authorized PG&E to offer an EDR tariff with a 200 MW cap and a maximum rate reduction of 30 percent to help compete for out-of-state business. The EDR Program offered the discounted electric rate over a 5-year period to help with attraction, expansion, and retention activities. On August 9, 2018, in the decision on PG&E's Proposed Rate Designs and Related Issues, the CPUC adopted an all-party settlement, a renewed program with some changes agreed to by the settling parties, as described below.

a. Parameters of the 2018-2020 EDR Program

This section outlines the parameters and qualification process of the current 2018-2020 EDR Program for each customer applying for the EDR.

- Qualification Criteria

  To qualify, a company must:

  - Have out-of-state options for a new facility or an expansion facility or have a current operation in California that is at risk of ceasing operations;
  - Supply documentation to show out-of-state choices or other operational scenarios;
  - Sign an affidavit attesting to the fact that but for this incentive rate, either on its own or in combination with a package of offerings, the customer would not have retained or expanded its load within California or would not have located in California;
  - Pass an eligibility review with the California Governor's Office of Business and Economic Development;
  - Be a relocatable type of business, e.g., a retail store is not a relocatable business because it is locally tied to its consumer base; and
  - Submit an annual report that includes the number of jobs, types of jobs, and average wages and benefits for the jobs created or retained.

- Rate Reduction Tiers

  The EDR has three rate reduction tiers which are dependent on the annual average of local unemployment rate at the city or county level, in comparison to the annual average unemployment across California. The current rate reduction tiers respectively provide 12 percent, 18 percent, or 25 percent off the monthly electricity bill, with the greater discounts going to projects in cities and counties with higher unemployment rates. Specifically, PG&E's mid-enhanced tier (Tier 2) makes available an 18 percent rate reduction for those cities and counties that have an annual unemployment rate between 130 and 150 percent of California's average. Tier 3, the 25 percent rate reduction, is only available in those cities and counties that have an annual unemployment rate above 150 percent of California's average. For all other areas of PG&E's service territory, qualifying customers are eligible for the standard 12 percent rate reduction under Tier 1.

- Program Cap and Allocation

  The current program (2018-2020) has cap space of about 80 MW that has been rolled over from the 2014-2017 program. This unused cap space will be allocated as follows:

TABLE 7-1
UNUSED CAP SPACE

Tier	Allocation of Remaining CAP
1 – Standard EDR (12% rate reduction)	20%
2 – Mid-enhanced EDR (18% rate reduction)	20%
3 – Enhanced EDR (25% rate reduction)	20%
4 – Unrestricted (Tiers 1-3)	40%

An additional 60 MW of additional cap space was allowed within the 2018-2020 EDR Program, allocated as indicated below:

TABLE 7-2
ADDITIONAL CAP SPACE

Tier	Allocated Load
1 – Standard EDR (12% rate reduction)	20 MW
2 – Mid-Enhanced EDR (18% rate reduction)	20 MW
3 – Enhanced EDR (25% rate reduction)	20 MW

This leaves a total of about 140 MW available in the 2018-2020 program for projects with an electricity load of at least 150 kilowatts (kW) of demand. Another new feature agreed upon in the settlement is an additional small business cap of 5 MW provided for projects with demand below 150 kW.

As projects are signed onto the EDR, the projected load is allocated to the applicable restricted tier. Once the cap from a tier has been used up, the EDR participant's load can be allocated to either the unrestricted tier or to a lower tier which provides a lower rate reduction percentage at PG&E's discretion.

b. Parameters of the 2014-2017 EDR Program

The 2014-2017 program was similar to the 2018-2020 program, with the main differences being:

- There used to be two tiers instead of three tiers, at 12 percent and 30 percent;
- The 200 MW cap did not have different allocations based on the percentage tier and no separate small business cap;
- The minimum threshold was 200 kW instead of 150 kW, with no exemptions for small businesses; and
- Renewals were allowed in certain cases.

C. Success of the EDR Program Since D.13-10-019

Since the inception of the EDR Program and PG&E's active efforts to attract and retain qualified businesses in California, from 2014 to July 2019, the program has achieved the results below. The jobs and wage numbers are listed in the annual compliance reports that have been reported to the CPUC.

TABLE 7-3
EDR PROGRAM RESULTS

Line No.	Metric	2014-2017 EDR Program(a)	2018-2020 EDR Program(a)
1	Projects signed	57	13
2	Total energy load per tier	12%: 54.6 MW 30%: 85.5 MW *Total: 140.1 MW*	12%: 7.2 MW 18%: 0.027 MW 25%: 16.4 MW *Total: 23.6 MW*
3	Projected jobs created	10,187	4,046
5	Actual Jobs created	8,843	N/A
6	Actual Wages created	$76,899,978.30	N/A
7	Contribution to Margin	$18.4 Million	N/A
8	Projects signed by region	Bay Area: 14 Central Coast: 5 Greater Sacramento: 4 Northern California: 2 Northern Sacramento Valley: 4 San Joaquin Valley: 28	Bay Area: 3 Central Coast: 4 Central Sierra: 1 San Joaquin Valley: 4
9	Unused cap (MW)	80.6 MW (rolled over)	116.4 MW (as of July 2019)

(a) The 2018-2020 EDR Program launched in October 2018. The 2014-2017 program ran from 2014 through September 2018, and the 2018-2020 program is running from October 2018 through present. Data in table is updated as of July 2019.

Since 2014, the EDR Program has provided such benefits as:

- Over $88 million of new annual recurring revenue to PG&E to help lower the bills of all customers, because this is incremental electric revenue that would have gone out-of-state or not come to California;
- Over $18 million of Contribution to Margin (CTM) after full non-bypassable charges (NBC) are applied; and
- Support for small businesses:
  - Since adding the small business cap into the 2018-2020 program, PG&E has been able to support struggling small businesses in our service area. One recent example is a small manufacturer of electronics in Santa Maria, CA with 20 kW of electric load, whose owner was considering moving the business (which included ten jobs) to Texas due to recent high import tariffs and the anticipation of a higher minimum wage in California. PG&E was able to approve the EDR at a 25 percent rate reduction, which helped lower costs for them to continue operating in Santa Maria.

The EDR is a powerful tool, along with other local and statewide incentives, to keep California on the consideration list for siting new businesses or for the expansion of facilities by existing businesses. For example, Zodiac Aerospace (with permission from the company to disclose that they are on the EDR), is a French-owned company with manufacturing facilities in Europe and in Mexico. Their Santa Maria, California location employs 1,200 workers and makes seat shells for airliners. When the parent company initially made a decision to eliminate this facility and shift its remaining California operations to Mexico, PG&E and the Governor's Office of Business and Economic Development worked to expedite a package of incentives, including the EDR along with other incentives, that persuaded Zodiak Aerospace to change that decision and keep its operations in Santa Maria, California instead.

The EDR has also been successful at tipping the decision to site regional facilities, such as large telecom data centers or logistics fulfillment centers in California, when they could have sited in Arizona or Nevada. For reference, the price of electricity in Arizona is $0.11 per kilowatt-hour (kWh) and $0.07 in Nevada on average, compared to California's average of $0.15.

When selecting sites, companies engage in a methodical search and eliminate sites in various rounds based on their business needs. When the cost of utilities is a top ten factor on the list, the EDR Program is an important tool for keeping California within the consideration set.

D. Revenue Evaluation

The EDR allows PG&E to attract and retain customers, resulting in revenue that otherwise would not have located or remained in California. This results in sales that are higher than they would be, absent these customers. When PG&E can retain or attract sales at a rate that is lower than the tariffed rate but higher than the marginal cost of service, it helps to maintain or add to CTM. This CTM can be used to keep rates to non-participating customers lower than they otherwise would be by allowing PG&E to spread its costs over more units of sales, thus benefiting all ratepayers.

In the 2018-2020 EDR Program, the CTM is determined on a total portfolio basis and reported under existing confidentiality rules. This applies for retention, attraction, and expansion projects. However, for retention EDR customers, a before-the-fact CTM calculation is done before approving the rate, in order to confirm that retention customers with negative CTM are not enrolled in the program. PG&E proposes to continue this rule in the 2021-2023 program.

1. Contribution to Margin Program Results: 2014-2017 Program

PG&E compared the revenue from EDR participants to the marginal cost consisting only of marginal economic costs applicable to customers receiving the EDR over a short term: Marginal Generation Energy costs (Marginal Generation Capacity costs are excluded pursuant to D.13-10-019); Transmission Charges; Marginal Customer Access Costs; Marginal Distribution Capacity Costs to the extent the customer is located within a constrained Distribution Planning Area; and NBCs.[1] All marginal cost values were used as adopted for contract evaluation purposes in the Marginal Cost and Revenue Allocation Settlement adopted by D.15-08-005 in PG&E's 2014 GRC Phase II. Under this analysis, the participants contributed positive CTM in the amount of $18.4 million for the EDR Program from 2014 through 2017.

The EDR Program, from 2014 to 2017, has had a large, positive CTM even though there has been a handful individual projects whose CTM, on average, was somewhat negative, but those have been limited. Specifically, out of 52 total EDR projects, six of them had a negative contribution to margin. Of these, most of the negative CTM was due to $1.1 million from one large customer. The majority of negative CTM projects come from customers either on a transmission rate, or those that are on DA or CCA Service. Overall the portfolio has been overwhelmingly positive at $18.4 million (see table below—data updated through July 2019), so ratepayers have benefitted significantly from this program.

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[1] Non-bypassable charges include: Public Purpose Program charges, the Department of Water Resources Bond charges, Nuclear Decommissioning, Competition Transition Charges, the New System Generation Charge, the Energy Cost Recovery Amount and the Power Charge Indifference Adjustment (PCIA), as applicable for customers electing Direct Access (DA) and Community Choice Aggregation (CCA) service.

TABLE 7-4
CONTRIBUTION TO MARGIN, 2014-2017 EDR PROGRAM RESULTS

Project	Contract Start Date	EDR Margin – With Full NBCs
1	7/29/2014	$1,439,810.17
2	8/3/2014	1,187,946.38
3	9/2/2014	866,057.62
4	9/29/2014	538,961.43
5	9/30/2014	(1,124,020.08)
6	10/12/2014	255,236.00
7	10/12/2014	1,568,720.46
8	1/4/2015	1,120,149.20
9	1/31/2015	(321,721.77)
10	3/19/2015	347,160.97
11	3/26/2015	127,196.85
12	6/4/2015	416,379.67
13	6/22/2015	(83,289.42)
14	6/28/2015	428,823.05
15	9/16/2015	6,999,818.15
16	11/30/2015	93,321.28
17	12/8/2015	142,958.65
18	1/1/2016	(115,356.41)
19	1/10/2016	139,361.05
20	2/8/2016	60,408.50
21	3/13/2016	145,939.27
22	3/13/2016	30,980.75
23	4/6/2016	177,357.39
24	5/12/2016	10,277.83
25	5/12/2016	373,547.98
26	5/12/2016	248,278.74
27	5/12/2016	216,738.81
28	5/15/2016	31,139.22
29	5/31/2016	77,306.93
30	6/13/2016	8,354.41
31	12/4/2016	37,444.09
32	12/8/2016	253,072.48
33	12/22/2016	61,681.73
34	12/29/2016	262,776.07
35	12/29/2016	175,736.98
36	4/30/2017	(331,583.77)
37	5/4/2017	117,099.72
38	5/11/2017	12,087.19
39	5/23/2017	97,644.12
40	5/25/2017	70,287.41
41	5/25/2017	217,728.74
42	6/11/2017	1,160,297.81
43	10/31/2017	351,373.74
44	12/12/2017	63,732.22
45	12/28/2017	125,390.29
46	1/5/2018	336,809.71
47	2/5/2018	10,040.92
48	3/4/2018	8,385.48
49	3/4/2018	46,251.80
50	7/16/2018	2,090.39
51	8/31/2018	(95,495.85)
52	9/18/2018	1,844.16
53	Total	$18,392,538.53

2. Contribution to Margin Program Results: 2018-2020 Program

The 2018-2020 program started enrolling participants in October 2018. At the time of this submission, most of the contracts since October 2018 had less than a year of billing data on the EDR. Therefore, it was not possible to get complete CTM calculations, since partial year's contribution would not be representative of a full year including all seasonality, etc. In calculating CTM, one would expect to see a similarly positive contribution across the portfolio, taking into account that PG&E is not signing retention projects with a projected negative CTM. PG&E will be able to run an additional CTM calculation in January 2020, which would provide analysis for projects that have completed a year of billing data at the end of 2019.

E. Economic Conditions and Keeping California Competitive

1. California's Economic Conditions

Since D.18-08-013, the economy in California has so far continued to improve with solid Gross Domestic Product growth and declining unemployment rates. Still, the economic recovery has not been equal across the state. While certain counties in the Bay Area, for example, had less than 2.6 percent average annual unemployment rates in 2018,[2] parts of PG&E's territory such as Fresno County still had high unemployment over twice as high at 7.5 percent.[3] Nearly 70 percent of job growth from 2010-2018 came from coastal areas, whereas the inland areas such as San Joaquin Valley have faced, and continue to see, higher structural unemployment and created fewer jobs in the state's fastest growing industries.[4]

Although it is clear that California's inland areas are places of great potential, they have not had the same job growth or investment activity as the state's coastal areas. As a result, there have recently been multiple initiatives across California that have focused on lifting inland regions to match the prosperity seen in other parts of the state. In 2019, California's Governor's Office of Business and Economic Development launched a new initiative, Regions Rising Together, to build a comprehensive plan seeking to bring more of California's fast-growing prosperity into inland regions

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2 https://www.labormarketinfo.edd.ca.gov/file/lfhist/18aacou.pdf.

3 *Id.*

4 https://www.pe.com/2019/05/10/regions-rise-together-building-a-plan-for-inclusive-sustainable-growth-across-california/.

through investment, policy, and sustainable development. Other inland initiatives have also been launched, such as Inland California Rising,[5] a broad coalition of leaders and organizations in the business, philanthropic, non-profit, and public sectors which have formed to improve progress for the inland counties.

PG&E's EDR aligns very well with these recent initiatives, since the EDR is structured to only provide a higher rate reduction to those counties with higher unemployment rates, which are largely located in inland areas. Out of the 31 counties in California that had above-statewide average unemployment rates in 2018, 27 of them are in PG&E's service area. Of those 27 counties, 18 are eligible for either the Mid-Enhanced (18 percent) or Enhanced (25 percent) rate reduction. California-wide, PG&E's service area includes almost all the counties with unemployment rates higher than the statewide average, which was 4.2 percent as of December 2018. (See Table 7-5 and Figure 7-1).

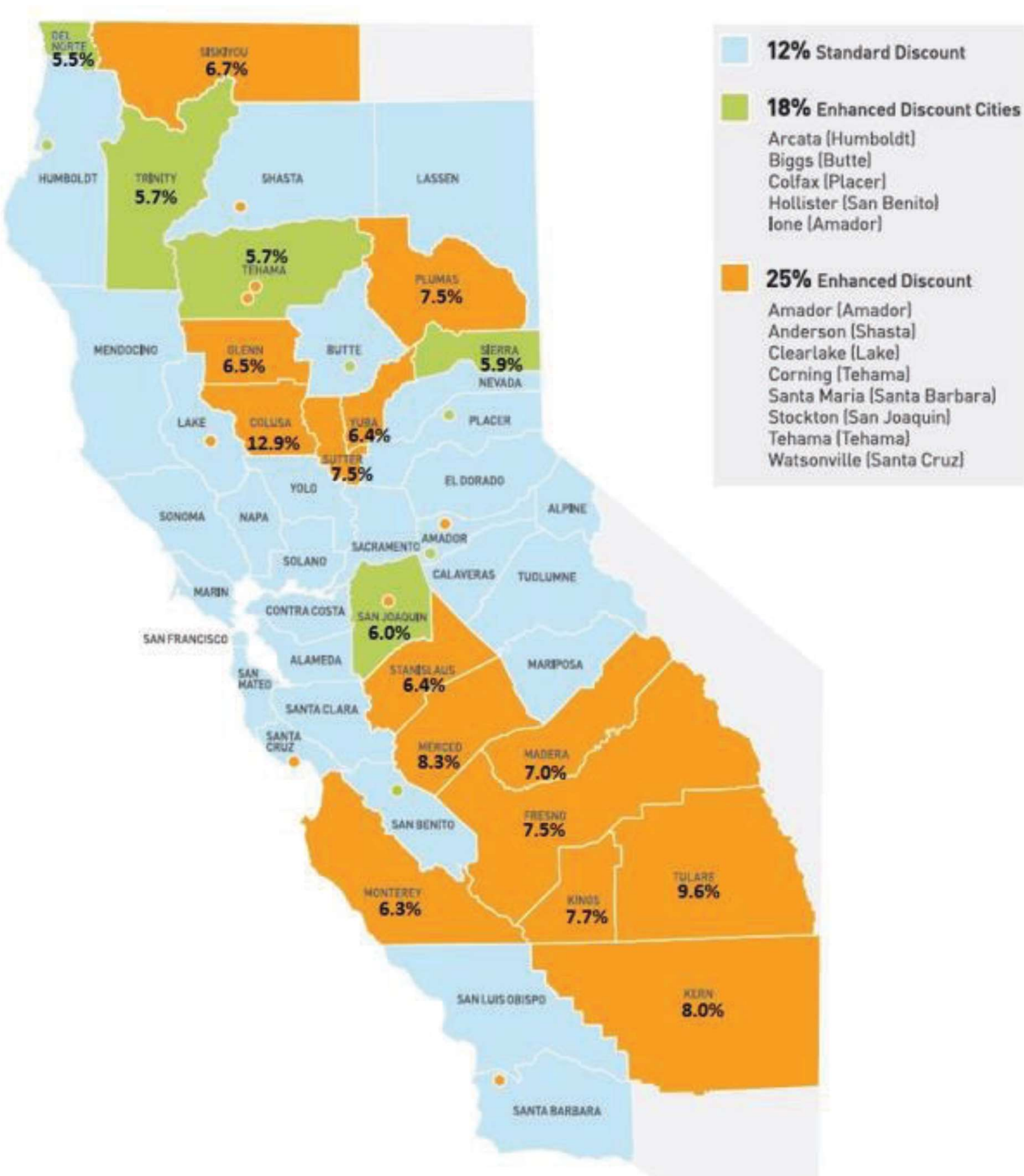
5 http://inlandrising.org/.

TABLE 7-5
2018 CALIFORNIA STATEWIDE UNEMPLOYMENT RATES BY COUNTY

Ranking	County	Unemployment Rate	% Tier	Utility
1	Imperial County	18.1%	25%	Other
2	Colusa County	12.9%	25%	PGE
3	Tulare County	9.6%	25%	PGE
4	Merced County	8.3%	25%	PGE
5	Kern County	8.0%	25%	PGE
6	Kings County	7.7%	25%	PGE
7	Fresno County	7.5%	25%	PGE
8	Modoc County	7.5%	25%	Other
9	Plumas County	7.5%	25%	PGE
10	Sutter County	7.5%	25%	PGE
11	Madera County	7.0%	25%	PGE
12	Siskiyou County	6.7%	25%	PGE
13	Glenn County	6.5%	25%	PGE
14	Stanislaus County	6.4%	25%	PGE
15	Yuba County	6.4%	25%	PGE
16	Monterey County	6.3%	25%	PGE
17	San Joaquin County	6.0%	18%	PGE
18	Sierra County	5.9%	18%	PGE
19	Tehama County	5.7%	18%	PGE
20	Trinity County	5.7%	18%	PGE
21	Del Norte County	5.5%	18%	Other
22	Mariposa County	5.3%	12%	PGE
23	Lake County	5.2%	12%	PGE
24	San Benito County	5.1%	12%	PGE
25	Butte County	4.9%	12%	PGE
26	Shasta County	4.9%	12%	PGE
27	Santa Cruz County	4.9%	12%	PGE
28	Lassen County	4.8%	12%	PGE
29	Los Angeles County	4.7%	12%	Other
30	Alpine County	4.6%	12%	PGE
31	Tuolumne County	4.6%	12%	PGE

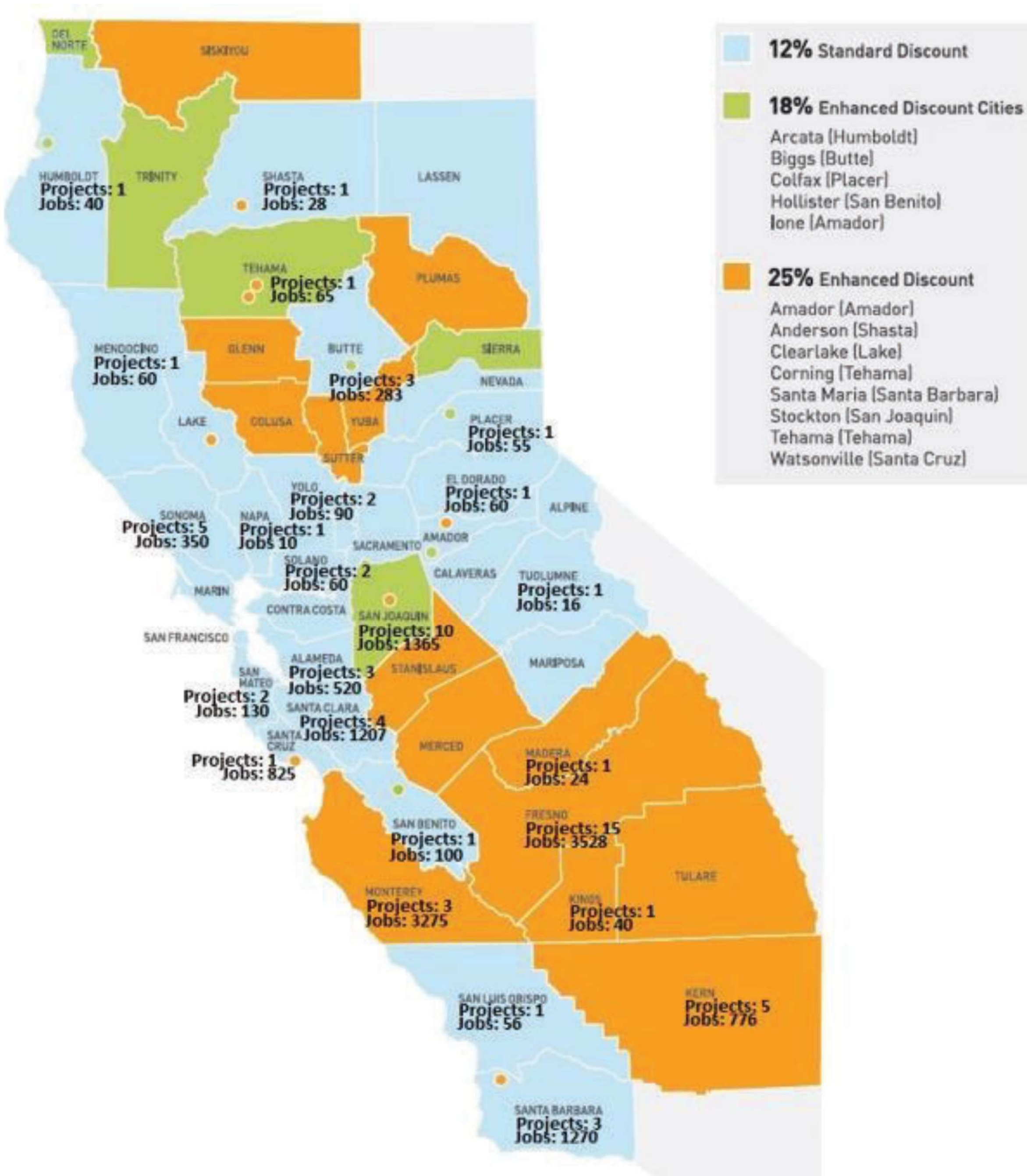
Note: California Average (2018), 4.2%.
(State of California Employment Development Department)

FIGURE 7-1
2018 CALIFORNIA STATEWIDE UNEMPLOYMENT RATES BY COUNTY
(FROM STATE OF CALIFORNIA EMPLOYMENT DEVELOPMENT DEPARTMENT)



The EDR has been very successful in supporting Governor Newsom's Office of Business and Economic Development's goal of bringing or retaining jobs and business investment into the inland regions. Out of 70 projects signed through the EDR Program through July 2019, 43 have been in inland counties, creating or retaining 5,710 jobs. The map below, which shows where EDR jobs and projects have been located, makes it clear that a significant number of jobs have been brought to inland counties with support from the EDR Program.

FIGURE 7-2
EDR PROGRAM MAP AS OF JULY 2019 – NUMBER OF PROJECTS AND JOBS CREATED (FROM PG&E EDR 2014-2017 AND 2018-2020 PROJECT DATA)



The EDR incentive is a critical part of the state of California's strategy to support the economic vitality of the inland region. These areas rely on incentives such as the EDR to be able to compete with other states and other countries. Removing or reducing the ability to provide an appropriate rate reduction on electricity would make any overall incentive package less competitive, and would harm the efforts spearheaded by the Governor's Office of Business and Economic Development. Therefore, PG&E proposes to continue the EDR Program under its previously-approved terms.

2. The State of Competition at National Utilities

Most larger utilities in the United States (U.S.) have a robust economic development program, because it strengthens the communities that they serve, but also, it is an effort with either high return-on-investment where a utility's profits depend on load, or CTM helping cover rates for all customers in states like California cost-of-service decoupled ratemaking. Other large utilities in the U.S. have economic development groups with 26-40 employees, marketing a variety of incentives, rebates, and other programs. By comparison, PG&E's Economic Development Program has achieved its results with only five employees.

The state of competition for California's customers has become more intense since 2014, with print advertisements by other utilities featured in airplane magazines serving California routes, to radio ads targeting high-energy use commercial and industrial customers. Another large out-of-state investor-owned utility has hired permanent staff in San Francisco for the purpose of attracting PG&E commercial and industrial customers to relocate to their territory in the Midwest and East Coast, where the per kWh price of electricity is almost half of California's, even though overall bill in California might be lower due to the state's moderate climate and focus on energy efficiency.

While the continuing EDR Program will not match other states on a cost basis, it will however, continue to help achieve the purpose of not eliminating California as a part of the site selection process when there are out-of-state options. It remains clear that PG&E's EDR is part of a comprehensive package of incentives and initiatives that encourages investment into

California, with an emphasis on areas that need it most, such as the inland cities and counties.

The current EDR Program, which resulted from an all-party settlement, has been carefully designed to work both during economic recession cycles and in expansionary cycles, either of which can happen within a 3-year regulatory cycle. During a recession, the EDR helps retain companies in California that are seeking to move to lower-cost areas of the U.S. On the other hand, during times of economic expansion, it helps level the playing field with neighboring states when attracting new facilities or expansions to site in California. As economic activity increases across the U.S., California must continue to find ways to be more competitive in order to attract the growth that will be needed when the inevitable economic recession occurs, especially in the inland areas of the state.

F. Proposal for the 2021-2023 Program

1. Program Characteristics

As described above, the all-party EDR settlement approved In D.18-08-013 moved the program to a three-tiered system, as well as introduced some new terms and conditions.

In practice, PG&E believes that many of the new features of the program to be of great benefit, such as the prohibition against renewals of the EDR at the same facility and the mandated energy reduction requirement. Therefore, for the 2021-2023 EDR, PG&E proposes to keep all parameters of the 2018-2020 program, including the three-tier system of discounts based on unemployment level, along with the following additions:

- A 150 MW cap increase that can be used towards all three rate reduction tiers (unrestricted) for businesses with 150 kW of demand or more;
- A 5 MW cap for small businesses with under 150 kW of demand; and
- Any unused load space from the 2018-2020 program will be rolled over into the new program and applied using the same tiered bucket rules from the 2018-2020 program.

Since the start of PG&E's EDR Program, between 20 and 44 MW per year have signed onto the program (see below).

TABLE 7-6
PG&E EDR PROGRAM – MW SIGNED PER YEAR

Line No.	Year	MW Signed Into the EDR Program (2014 – July 2019)
1	2014	20.3
2	2015	19.1
3	2016	20.1
4	2017	43.7
5	2018	41.9
6	2019 (YTD as of July)	23.2

Assuming an optimistic scenario, under which 50 MW per year would enter the program in the future, PG&E anticipates using almost 100 MW of total cap through 2020 from the 2018-2020 program. This would leave almost zero load space to be rolled-over after the 2020 program ends. This would still leave a need for roughly 150 MW of additional capacity for the 2021-2023 program. Therefore, PG&E is requesting an increase of 150 MW for large businesses and 5 MW for small businesses with electricity load under 150 kW, beyond the current program's cap of 145 MW. This will ensure that the program continues to have adequate capacity to support the state's important economic policy initiatives, while providing benefits to ratepayers.

2. Contribution to Margin Analysis

As noted in Section D above, the analysis of revenue from participating customers fully supports continuation of this important job-promoting program. To be sustainable going forward, however, the new program must be supported by an evaluation of current marginal cost and rates. PG&E's analysis of the program on a forward-looking basis utilizes schedule-average rates (based on rates effective July 1, 2019) and marginal costs proposed in this proceeding.[6]

PG&E calculated the maximum rate reduction that could be applied to each rate schedule on a schedule average basis for bundled customers using a conservative set of assumptions, meaning assumptions that would

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6 PG&E's analysis includes several representative rate schedules as in the past. In addition, PG&E has added the Small Light and Power (SLP) rate schedules reflecting their current eligibility for the program.

tend to reduce the level of the maximum potential rate reduction. Specifically, PG&E calculated the maximum available rate reduction by subtracting the following components from the bundled bill: transmission charges,[7] generation marginal energy costs, constrained distribution capacity costs,[8] marginal customer access costs, and non-bypassable charges. In addition, consistent with separately allocating the PCIA cost for bundled customers (and reflecting the PCIA in tariffs for bundled customers), PG&E has calculated the CTM by assuming that the bundled customer PCIA is a non-bypassable charge. As shown in Table 7-7, the maximum achievable rate reduction was less than 25 percent maximum rate reduction only in the case of SLP. Significantly, while the CTM is generally positive when the 25 percent rate reduction is applied, the CTM would be much greater for customers located in distribution areas that were not subject to distribution capacity constraints (yielding a lower marginal cost) or in cases where the lower 12 or 18 percent rate reduction are applied. Thus, PG&E believes that the discounts approved by the Commission as a part of D.18-08-013 are still reasonable should be continued.

TABLE 7-7
MAXIMUM POTENTIAL EDR RATE REDUCTION

Line No.	Customer Class	Maximum Potential Rate Reduction
1	SLP	20.0%
2	A-10/B-10S	28.0%
3	E-19P/B-19P	27.9%
4	E-19S/B-19S	34.9%
5	E-20T/B-20T	27.7%
6	E-20P/B-20P	28.0%
7	E-20S/B-20S	32.3%

One enhancement to the EDR Program required by D.13-10-019 was to provide for specific treatment of rate reductions for Direct Access and Community Choice Aggregation (DA/CCA) customers. As implemented,

7 Fully transmission charges are used as a substitute for marginal transmission costs in this calculation.

8 A local distribution planning area is considered constrained, for purposes of evaluating CTM for individual EDR participants, if it has planned capacity-related capital projects in excess of $1 million.

rate reductions were applied separately to bundled customers and DA/CCA customers by allocating the rate reduction to distribution and generation charges. Schedule EDR currently provides the proportions that will be used to allocate the rate reductions to the generation and distribution portions of the bills. PG&E continues to believe this approach to deriving the rate reductions to participating customers is appropriate. However, the original proportions adopted in 2013 do not compare favorably with the CTM analysis provided herein. In particular, the contribution of generation to the total CTM calculation at the secondary service voltage level has increased compared to the original values. Accordingly, PG&E proposes to revise those allocation factors in this proceeding. The revised allocation factors are shown in Table 7-8, together with the current values.

TABLE 7-8
REVISED ALLOCATION FACTORS OF EDR RATE REDUCTIONS TO GENERATION AND DISTRIBUTION

Line No.	Rate Reduction Component	Transmission	Primary	Secondary
1	Generation Current	95%	70%	60%
2	Generation Proposed	93%	70%	70%
3	Distribution Current	5%	30%	40%
4	Distribution Proposed	7%	30%	30%

G. Compliance With EDR D.18-08-013 Requirements

- Energy Usage Reduction Requirement and Audit

The 2018-2020 EDR tariff states that during the third year of such EDR agreements, such customers will be subject to an audit to determine whether the energy usage reduction requirement has been met (see text below). PG&E will be conducting these audits for projects that are in their third year on the current EDR rate, which would occur in 2021 at the earliest.

> Applications shall implement such measures such as those presented by PG&E, to achieve a 5% energy usage reduction during the life of EDR agreement. This energy usage reduction will be determined by PG&E through an audit conducted by PG&E during the third year of the agreement. If the audit shows Applicant has not yet achieved a 5% energy reduction, PG&E may discontinue the rate reduction benefit for the remainder of the agreement, in PG&E's discretion, or PG&E may establish an action plan for the Applicant to achieve the required 5%

> energy usage reduction, including an additional audit early in year five of the Agreement to ensure the requirement was met.

- Third-Party Verification

  The 2018-2020 EDR tariff states that customers on the EDR that are projected to receive over $100,000 in savings will be subject to an annual, after-the-fact economic impact audit by a third-party (see text below). As of September 2019, none of the projects signed on the current EDR program had projected savings greater than $100,000. PG&E will continue to monitor each project for this $100,000 savings threshold and, in such instances, have an economic impact audit conducted after one year on the rate. The earliest this is anticipated to occur would be at the end of 2020, if any applicable project is signed by the end of 2019.

  > EDR applicants who are projected by PG&E to receive over one hundred thousand (100,000) dollars of savings per year from the EDR program are subject to, and must agree to an annual, third-party, after-the-fact EDR audit. The purpose of the audit is to verify contribution to margin, the number of jobs created, wages and benefit information, and document other indirect economic benefits to the community. The third-party EDR audit will be conducted no sooner than one (1) year after the customer's EDR discount starts.

H. Conclusion

Since 2014, the EDR Program has helped create or retain over 14,000 jobs for California and added over $80 million of incremental, annual revenue (including about $18.5 million of CTM) to lower the cost of the grid to all ratepayers. The program's rate reductions are also self-funding due to its positive CTM. To date, PG&E's EDR Program has resulted in over $75 million of combined wages and salary contribution to support California's economy. Because past program results show that the EDR has been beneficial to all stakeholders within California, the Commission should therefore adopt PG&E's proposal to continue the EDR Program through 2023 presented herein.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

RATE PROGRAMS

FEES FOR SERVICES TO COMMUNITY CHOICE AGGREGATION AND DIRECT ACCESS ELECTRIC SERVICE PROVIDERS

PACIFIC GAS AND ELECTRIC COMPANY
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RATE PROGRAMS
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
RATE PROGRAMS
FEES FOR SERVICES TO COMMUNITY CHOICE AGGREGATION AND DIRECT ACCESS ELECTRIC SERVICE PROVIDERS

A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) sets forth its proposals for changes to fees and respective Rate Schedules in the 2020 General Rate Case (GRC) Phase II for incremental services[1] rendered to principal energy providers under two alternative energy provider programs. The remainder of this chapter is organized as follows:

- Section B – Background
- Section C – Proposed Fees and Rate Schedule Changes
- Section D – Implementation and On-going Maintenance
- Section E – Conclusion
- Attachment A – Summary matrix of proposed fee changes per applicable Rate Schedule in comparative format with current respective fees including sample costs based on current labor rates and hour required for each proposed “at cost” service and the methodology by which they would be applied.
- Attachment B – Recommended revisions to Schedule E-CCA.
- Attachment C – Recommended revisions to Schedule E-ESP.
- Attachment D – Recommended revisions to Schedule E-ESPNDSF.

B. Background

The idea of having independent non-utility entities as alternative electric supply providers directly available to retail customers began to take shape in the 1990’s as part of the California’s interest to promote customer choice by expanding market competition within the energy industry.

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[1] In D.04-12-046, the California Public Utilities Commission (Commission) held that “individual CCAs should not assume the cost of developing the CCA program’s basic infrastructure,” but that individual CCAs should be charged for the cost of “specific specialized services.” (pp. 11-12).

The Direct Access (DA) electric services program launched in 1998 and allowed Energy Service Providers (ESP) to supply electric power directly to a limited number of customers. The program currently has approximately 9,300 enrolled participants and is expected to grow. The program was recently reopened to new customers under Decision (D.) 19-09-043. Terms and conditions applicable to the DA program are contained primarily under PG&E's Electric Rule No. 22 with related program service fees authorized primarily under Electric Schedule E-ESP and E-ESPNDSF.

The first Community Choice Aggregation (CCA) electric service provider was established in 2010 and there are now 12 CCAs in operation as of June 2019 serving approximately 3.0 million electric customers within PG&E's service territory. The number of CCA customers is expected to exceed 3.3 million by the end of 2020. Terms and conditions applicable to the CCA program are reflected primarily under PG&E's Electric Rule No. 23, with related program service fees authorized primarily under Electric Schedule E-CCA.

Within each referenced Rate Schedule under both DA and CCA programs, fees for services rendered to DA and CCA providers can be grouped into two categories: (1) account-based, i.e., fees assessed based on the number of accounts serviced, and (2) event-based, i.e., fees assessed based on completing and/or delivering a specified task or product as requested by a DA or CCA provider.

With the establishment of the DA and CCA programs at different inception dates over a span of nearly twenty years and over the course of their combined operational history of over 28 years from inception to date, updates to the applicable Rate Schedules and respective fees for which PG&E is requesting revisions in this proceeding, have been infrequent and limited. In 2001, PG&E filed an application to reassess its DA and CCA service fees, Application 11-12-009. PG&E reached a settlement agreement with participating parties in that docket, which was approved by the Commission by D.13-04-020. That Settlement included a consolidated and simplified fee structure for selected account-based services, with provisions for yearly escalations in fees. In the 2017 GRC Phase II proceeding, the Commission adopted a settlement which revised the Meter Data Management Agent (MDMA) fee, DA/CCA rate ready and bill ready billing fees and fees for DA meter services. That 2017 DA/CCA fees settlement primarily enabled the alignment of similar account-based billing and MDMA services with similar fees between the DA and CCA programs while also adjusting them downward due to the overall customer growth with respect to the programs which enabled efficiencies to be implemented.

In this proceeding, PG&E is proposing changes to the DA/CCA event-based fees that were not updated in the 2017 GRC Phase II proceeding. While updates to the service fees presented in this application have been limited over the programs' operational history, service delivery developments such as technological advancements, process maturity, and procedural streamlines have evolved over the years. These evolving developments in service delivery and program maturity are the principal factors driving the fee changes proposed in this chapter in an effort to capture the impacts to cost of services and to make them current and sustainable for the future.

C. Proposed Fees and Rate Schedule Changes

The fee changes PG&E proposes here are primarily limited to certain "event-based" services and are intended to standardize practices to support tracking and billing based on actual labor costs incurred to perform each service for each event. Proposed changes within Schedule E-ESPNDSF include several fees related to "Account Analysis" services provided to ESPs currently assessed on a per account, per report, or per occurrence basis. PG&E also proposes to remove these variations by grouping them all as "Account Assistance" services using the "at-cost" actual labor approach consistent with how similar services are grouped and priced for CCA services within Schedule E-CCA. This approach will support fees that are more sustainable given cost fluctuations over time. Adoption of an "at cost" pricing approach for the referenced services will not only reduce fee variations between the two programs, effectively streamlining fees for similar services. It will also minimize fee update/maintenance requirements and ultimately enable a more accurate accounting and billing of services based on actual labor costs.

If approved, implementation of this "at cost" approach will require PG&E to utilize standardized documented procedures and practices that require each servicing personnel to track/record their respective time spent on each service event. This ultimately enables real time cost management locally while ensuring only standard labor rates that are centrally maintained, current, and specific to the servicing contributor(s) are applied to each service event on an ongoing basis; that, in turn, will support a more accurate method to account and bill for the respective services. Section D “Implementation and On-going Maintenance” below discusses how we propose to implement this “at cost” approach, including procedures for tracking and billing event based services using actual labor cost of service. Event based services previously established with specific hourly fees will effectively achieve realignment with this proposed “at cost” methodology.

Service fees under each Schedule for which a change is not being proposed are not included. Fees not proposed for change are primarily account-based fees, of which the related services are usually provided on a recurring cycle basis and are accounted for and billed to the ESPs and CCAs programmatically without the need to track separately, as labor rate and time are not major factors.

Specific fee change proposals are presented below in a 6-columnar table format to show for each applicable service, the respective rate schedule reference, the current fee, proposed (“at-cost”) sample fee, and an example of the actual labor cost calculated based on current factors such as 2019 standard labor rates (consistent with approved GRC cost funding mechanisms) for each applicable servicing line of business(s), applied to current estimated labor hours to fulfill each service, and are organized by fee schedule under each program as follows:

<u>Community Choice Aggregation Program</u>

- Table 8-1: Electric Schedule E-CCA

<u>DA ESP Program</u>

- Table 8-2: Electric Schedule E-ESP. Table 8-2 also reflects the deletion of certain rate programs for Electric Schedule E-ESP, 6.A.5 which has never been used.
- Table 8-3: Electric Schedule E-ESPNDSF. Proposed changes to this schedule also reflects the consolidation of certain rate programs for Electric Schedule E-ESPNDSF 3A. See Attachment D.

While the tables presented below provide a comparative view between the current fee and the proposed change including estimated cost impact for each applicable service, the matrix provided by Attachment A of this chapter offers more details to support the illustrative costs estimated for each service using the proposed fee methodology, including estimated labor hours required to perform each service as well as the 2019 standard labor rate specific for the department personnel that performs each service. This Attachment A will also be used (and expanded on as necessary) as part of the supporting workpapers to this chapter. PG&E's recommended changes to the affected rate schedules are provided as attachments to this chapter: Schedule E-CCA is provided as Attachment B; Schedule E-ESP is provided as Attachment C; and Schedule E-ESPNDSF is provided as Attachment D.

COMMUNITY CHOICE AGGREGATION PROGRAM
TABLE 8-1
ELECTRIC SCHEDULE E-CCA

Line No.	Service Description	Tariff Reference	Fee Type	Current Fee	Proposed "At Cost" Labor Per Hour[(a)]	Effective Cost Example[(a)]
1	CCA Service Establishment	Sheet 1: 1	Per Hour	$119.58 to $149.48	$109.50 to $154.03	N/A
2	Customer List Development	Sheet 2: 2c	Per Data Extract	$2,596	$109.50	$438
3	Mass Enrollment	Sheet 2: 3	Per Event	$4,475	$154.03	$3,081
4	<u>MDMA Services</u>					
5	Reposting Monthly Meter Data	Sheet 5: 6c	Per Meter Read	$20.84	$137.94	(b)
6	Reposting of Account Usage (12-month history)	Sheet 5: 6d	Per Hour	$104.25	$137.94	N/A
7	Account Assistance	Sheet 5: 6e	Per Hour	$104.25	$133.63	N/A
8	<u>Other Billing Services</u>					
9	CCA Rate Schedule Value Usage	Sheet 6: 6b	Per Event	N/A	$153.03	N/A
10	Programming for Consolidated Billing	Sheet 7: 9a	Per Hour	$97.84	$154.03	N/A
11	Account Assistance	Sheet 7: 9d	Per Hour	$69.30	$112.20 to $137.94	N/A
12	<u>CCA Termination of Service</u>					
13	Voluntary Termination	Sheet 8: 10a	Per Event	$4,475	$154.03	$6,161
14	Standard Phase-in Services	Sheet 8: 11	Per Phase-in	$4,475	$154.03	$5,391

(a) Labor rates and effective costs are presented as examples using applicable 2019 data. The labor rates presented vary by service because they are specific to the cost unit that performs each service. A range is provided if the service requires performance by more than one cost unit. See Attachment A of this chapter for sample calculation supporting these examples including estimated labor hours to complete a typical request of each applicable service. Also see Section D "Implementation and On-going Maintenance" below for discussion of proposed cost tracking and update procedures.

(b) Effective cost for these services as proposed will be based on total labor hours required per event, which may include servicing multiple accounts or reports.

DIRECT ACCESS ENERGY SERVICE PROVIDER PROGRAM
TABLE 8-2
ELECTRIC SCHEDULE E-ESP

Line No.	Service Description	Tariff Reference	Fee Type	Current Fee	Proposed "At Cost" Labor Per Hour[(a)]	Effective Cost Example[(a)]
1	<u>Consolidated PG&E Billing - Rate Ready Billing Set-Up Charges</u>					
2	Programming for Consolidated Billing Set-Up	Sheet 3: 6A5a	Per Hour	$123.80	$154.03	N/A
3	Programming for ESP's Rate Schedules - Standard Rate Structure	Sheet 3: 6A5b	Per Hour	$123.80	$154.03	N/A
4	Programming for ESP's Rate Schedules - Custom Rate Structure	Sheet 3: 6A5c	Per Hour	$146.15	(See Attachment C)	N/A
5	Programming for ESP's Bill Messages	Sheet 3: 6A5d	Per Hour	$123.80	$154.03	N/A
6	<u>Consolidated PG&E Billing - Bill Ready Billing Set-Up Charges</u>					
7	Programming for Consolidated Billing Set-Up	Sheet 4: 6B4a	Per Hour	$123.80	$154.03	N/A
8	Programming for ESP's Bill Messages	Sheet 4: 6B4b	Per Hour	$123.80	$154.03	N/A

(a) Labor rates and effective costs are presented as examples using applicable 2019 data. The labor rates presented vary by service because they are specific to the cost unit that performs each service. A range is provided if the service requires performance by more than one cost unit. See Attachment A of this chapter for sample calculation supporting these examples including estimated labor hours to complete a typical request of each applicable service. Also see Section D "Implementation and On-going Maintenance" below for discussion of proposed cost tracking and update procedures.

DIRECT ACCESS ENERGY SERVICE PROVIDER PROGRAM
TABLE 8-3
ELECTRIC SCHEDULE E-ESPNDSF

Line No.	Service Description	Tariff Reference	Fee Type	Current Fee	Proposed "At Cost" Labor Per Hour[(a)]	Effective Cost Example[(a)]
1	Full Consolidated ESP Billing					
2	Billing Set-Up and Ongoing Support	Sheet 1: 1A	Per Hour	$134.57	$154.03	N/A
3	Exception Fees - Account Analysis					
4	Retrieval of Account Information	Sheet 2: 3A1	Per Account	$5.00	$112.20	(b)
5	Routine Account Analysis	Sheet 2: 3A2	Per Account	$15.83	$112.20	(b)
6	Complex Account Analysis	Sheet 2: 3A3	Per Hour	$63.81	$133.63	N/A
7	Resend File/Report	Sheet 2: 3A4	Per Report	$15.00	$112.20	(b)
8	Investigate EDI Duplicate Payments	Sheet 2: 3A5	Per Occurrence	$134.57	$137.94	$137.94
9	Refund Account Credits Due to Overpayment	Sheet 2: 3A6	Per Account	$5.00	$112.20	(b)

(a) Labor rates and effective costs are presented as examples using applicable 2019 data. The labor rates presented vary by service because they are specific to the cost unit that performs each service. A range is provided if the service requires performance by more than one cost unit. See Attachment A of this chapter for sample calculation supporting these examples including estimated labor hours to complete a typical request of each applicable service. Also see Section D "Implementation and On-going Maintenance" below for discussion of proposed cost tracking and update procedures.

(b) Effective cost for these services as proposed will be based on total labor hours required per event which may include servicing multiple accounts or reports.

D. Implementation and On-going Maintenance

If approved, this methodology of applying current labor rates to bill for services will require implementation of new procedures. The required procedures will include at minimum, each department responsible for performing a service to track the actual time it takes to complete each task using internal tracking order numbers established for each service. Standard labor rates maintained by our SAP system will automatically apply to generate monthly bills which will be quality reviewed prior to transmitting to respective CCA and DA providers. In addition, Commission authorized advice letter filings will be used as needed to propose additional updates. PG&E proposes that the new rates could go into effect no later than the beginning of the third calendar month after the supporting business processes and systems are in place to enable the new procedures to be implemented into operational practice.

E. Conclusion

For all of the foregoing reasons, PG&E requests that the Commission adopt its proposed DA and CCA Service Fees, for all applicable rate schedules. In addition, PG&E acknowledges the need for regular reassessments of these fees on an ongoing schedule to ensure program sustainability and thus anticipates that updates may be required in future rate design proceedings or Tier 2 advice letter filings.

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
ATTACHMENT A
FEES FOR SERVICES TO CCA AND
DA ELECTRIC SERVICE PROVIDERS

Attachment A
Rate Programs - Chapter 8: Fees for Services to CCA and DA Electric Service Providers

Rate Schedule	Sheet & Section Reference	Service Fee Item	(Current) Current Service Fee	Current Fee Type	Sample Cost Calculation (Proposed) Proposed "At Cost" Rate Per Hour (as of Q3 2019)[a]	Labor Hrs Required (Typical Request)[a]	Proposed Extended Cost Per Service
E-CCA	Sheet 1: 1	CCA Service Estab (Range)	119.58 to 149.48	Per Hour	$109.50	N/A	N/A
					$154.03	N/A	N/A
	Sheet 2: 2c	Cust. Notification - List Dev.	$2,596	Per Extract	$109.50	4	$438
	Sheet 2: 3	Mass Enrollment	$4,475	Per Event	$154.03	20	$3,081
	Sheet 5: 6c	MDMA - Repost Monthly Meter Data	$20.84	Per Meter	$137.94	(b)	(b)
	Sheet 5: 6d	MDMA - Repost Account Usage	$104.25	Per Hour	$137.94	N/A	N/A
	Sheet 5: 6e	MDMA - Acct Assistance	$104.25	Per Hour	$133.63	N/A	N/A
	Sheet 7: 9a	Programming - Bill Rdy Billing	$97.84	Per Hour	$154.03	N/A	N/A
	Sheet 7: 9d	Account Assistance	$69.30	Per Hour	$112.20	N/A	N/A
	Sheet 8: 10a	Voluntary Termination	$4,475	Per Event	$154.03	40	$6,161
	Sheet 8: 11	Standard Phase-in	$4,475	Per Phase-in	$154.03	35	$5,391
E-ESP	Sheet 3: 6A5a	Programming - Rate-Rdy Set-up	$123.80	Per Hour	$154.03	N/A	N/A
	Sheet 3: 6A5b	Programming Std ESP Rates	$123.80	Per Hour	$154.03	N/A	N/A
	Sheet 3: 6A5c	Programming Cust. ESP Rates	$146.15	Per Hour	$154.03	N/A	N/A
	Sheet 3: 6A5d	Programming Bill Msg	$123.80	Per Hour	$154.03	N/A	N/A
	Sheet 4: 6B4a	Programming - Bill-Rdy Set-up	$123.80	Per Hour	$154.03	N/A	N/A
	Sheet 4: 6B4b	Programming Bill Msg	$123.80	Per Hour	$154.03	N/A	N/A
E-ESPNDSF	Sheet 1: 1A	Programming Full ESP Consol.	$134.57	Per Hour	$154.03	N/A	N/A
	Sheet 2: 3A1	Retrieval of Account Information	$5.00	Per Account	$112.20	(b)	(b)
	Sheet 2: 3A2	Routine Account Analysis	$15.83	Per Account	$112.20	(b)	(b)
	Sheet 2: 3A3	Complex acct analysis	$63.81	Per Hour	$133.63	N/A	N/A
	Sheet 2: 3A4	Resend file/report	$15.00	Per Report	$112.20	(b)	(b)
	Sheet 2: 3A5	Investigate EDI duplicate payments	$134.57	Per Occurrence	$137.94	1	$137.94
	Sheet 2: 3A6	Refund Account Credits Due to Overpayment	$5.00	Per Account	$112.20	(b)	(b)

[a] Labor rates and effective costs are presented as examples where applicable using 2019 data. Actual cost will differ based on real time labor rates consistent with approved GRC rate mechanisms as appropriate for the service period. The labor rates presented vary by service because they are specific to the cost unit that performs each service. A range is provided if the service requires performance by more than one cost unit. Labor hours required for applicable services are estimated based on a typical request.

[b] Effective cost for these services as proposed will be based total labor hours required per event which may include servicing multiple accounts or reports.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

ATTACHMENT B

RECOMMENDED REVISIONS TO

ELECTRIC SCHEDULE E-CCA –

SERVICES TO COMMUNITY CHOICE AGGREGATORS

ELECTRIC SCHEDULE E-CCA Sheet 1

SERVICES TO COMMUNITY CHOICE AGGREGATORS

APPLICABILITY: This schedule applies to Community Choice Aggregators (CCAs) who participate in Community Choice Aggregation Service (CCA Service) and to customers who receive CCA Service, pursuant to California Public Utilities Commission Decision 05-12-041 and electric Rules 1 and 23.

TERRITORY: The entire PG&E service territory.

RATES:

1. CCA SERVICE ESTABLISHMENT

This fee will apply when a CCA establishes service. This fee will cover the cost of establishing a new business relationship with the CCA and will include activities such as establishing a CCA account in PG&E's customer information system for customer switching, meter reading, and billing services, EDI testing and processing forms and agreements, including but not limited to: the CCA Service Agreement, the CCA Information Form, the Credit Application, the Electronic Funds Transfer Agreement, and provides for a review of a CCA's credit worthiness. Charges are based on an hourly rate required to perform the activities.

Fee .... ~~$119.58 $149.48 per hour~~Labor (I)

2. CUSTOMER NOTIFICATION (OPTIONAL SERVICE)

a. CUSTOMER NOTIFICATION – DIRECT MAIL

This service provides a direct mail customer notification service (labeling and mailing of notifications). This service will be applicable to the initial customer notifications and to follow-up notifications.

Fee .... Labor and Material

b. CUSTOMER NOTIFICATION – NOTIFICATION IN MONTHLY PG&E BILL

The CCA may request PG&E to mail the CCA notices in PG&E's monthly bills to the customers. PG&E will perform this service and charge the CCA based on labor and material costs, and any additional postage required to mail the monthly bills. This service shall be subject to advance notice and scheduling requirements, PG&E's normal bill insert business practices, and operational specifications. CCA customer notices inserted in PG&E's billing envelope shall include a disclaimer prominently displayed in font no smaller than the title or heading of the customer notices stating: "This notice was prepared and paid for by [CCA name] and not PG&E." Information contained in such notices shall be limited to that required by PU Code Section 366.2(c)(13)(A).

Fee .... Labor and Material

Postage .... Additional Postage

(Continued)

ELECTRIC SCHEDULE E-CCA Sheet 2
SERVICES TO COMMUNITY CHOICE AGGREGATORS

RATES: (Cont'd.)

2. CUSTOMER NOTIFICATION (OPTIONAL SERVICE) (Cont'd.)

c. CUSTOMER LIST DEVELOPMENT

PG&E will perform a data extract to provide a list of customers with a standard set of data elements. Based upon the CCA's specific criteria, the list can be refined and finalized to specify the customers that will receive a notification. This fee is calculated based upon a per event basis and is based on labor costs to perform a data extract with a standard set of data elements. No material costs are included in this fee.

Fee...~~$2,596 per data extract~~Labor (I)

d. DESIGN CUSTOMIZED CUSTOMER NOTIFICATION

This service provides special design or customization for the customer notifications as specified by the CCA.

Fee..Labor and Material

3. MASS ENROLLMENT

This fee will apply to a CCA. Upon completion of the initial customer notification and opt-out period, PG&E will initiate a mass transfer of the eligible customers (who have not opted-out) onto CCA Service over one-billing cycle period on the customer's regularly scheduled meter read date (assuming no metering work is required), and send a confirmation to the CCA through the CCASR process.

Fee ....~~$4,475 per event~~Labor (I)

4. OPT-OUT REQUESTS

These service fees will apply to a CCA and are associated with processing customer requests for opting-out of the CCA program. PG&E will offer two options to process responses by customers to the "opt-out" notifications: Internet and Automated Telephone service.

a. INTERNET OPT-OUT – This fee will apply when a customer opts out of a CCA's Program using the Internet through PG&E's website.

Internet Opt-out... .$0.49 per account

b. AUTOMATED TELEPHONE (IVRU) OPT-OUT – This fee will apply when a customer opts out of a CCA's program using PG&E's Interactive Voice Response Unit (IVRU).

Automated Telephone (IVRU) Opt-Out ....$0.42 per account

(Continued)

ELECTRIC SCHEDULE E-CCA Sheet 3
SERVICES TO COMMUNITY CHOICE AGGREGATORS

RATES: (Cont'd.)

5. COMMUNITY CHOICE AGGREGATION SERVICE REQUEST (CCASR)

   a. CCASR

      This fee will apply to a CCA when a Connect or Disconnect CCASR is submitted by a CCA.

      Per account per CCASR submittal..$0.79 (I)

   b. CUSTOMER RE-ENTRY

      This charge is imposed on the customer. This fee covers the cost of processing customer requests to switch back to PG&E Bundled Service after the Opt-Out period has expired.

      Fee.. .$4.24 account (I)

   c. NEW CUSTOMER

      This fee will apply to a CCA to cover PG&E's cost to enroll a new account onto CCA Service after mass enrollment has occurred.

      Fee.. $0.49 per account
      ....

(Continued)

RATES: (Cont'd.)

6. METER DATA MANAGEMENT AGENT (MDMA) SERVICES

a. METER DATA POSTING

This service provides meter data to the CCA. Meter data will be made available to the CCA in EDI 867 format, and will be posted for retrieval by the CCA on PG&E's Data Exchange Server (DES).

Composite MDMA fee per meter per month .... $0.14 (N)

b. UNSCHEDULED METER READ

This fee will apply when a CCA requests cumulative reads or interval usage data for an account for a period outside the normal PG&E meter reading schedule. PG&E will attempt to accommodate requests for unscheduled reads. In no case will PG&E provide cumulative reads and/or interval usage data for a period greater than 33 contiguous days.

Per unscheduled meter read per cumulative meter .... no charge

Per unscheduled meter read per interval meter .... no charge

ELECTRIC SCHEDULE E-CCA Sheet 5
SERVICES TO COMMUNITY CHOICE AGGREGATORS

RATES: (Cont'd.)

6. METER DATA MANAGEMENT AGENT (MDMA) SERVICES (Cont'd.)

c. REPOSTING MONTHLY METER DATA

This fee will apply when a CCA requests that PG&E repost previously posted meter reads and/or usage data to the DES. As requested, PG&E will provide this data with meter reads and/or interval usage data framed to the standard billing cycle period (as published in PG&E's applicable year meter reading schedule).

Per meter read per billing period.................................... ~~$20.84~~ Labor (I)

d. REPOSTING OF ACCOUNT USAGE

This fee will apply when a CCA requests that PG&E repost previously posted account usage history to the DES. Reposted service account usage history will consist of the most recent 12-month usage history, or for the portion available if the customer's account has been open for less than 12 months, framed to standard billing cycle period.

Fee .... ~~$104.25 per hour~~Labor (I)

e. ACCOUNT ASSISTANCE

This fee will apply when a CCA requests assistance on an account. The fee covers services such as:

– Account switch date corrections;

– Subsequent supplying of meter reads/usage data for the corrected period; and

– Reconciliation of meter reads and/or usage quantities.

Fee .... ~~$104.25 per hour~~Labor (I)

(Continued)

Pacific Gas and Electric Company®
U 39 San Francisco, California

	Revised	Cal. P.U.C. Sheet No.	41758-E
Cancelling	Revised	Cal. P.U.C. Sheet No.	35802-E

ELECTRIC SCHEDULE E-CCA Sheet 6
SERVICES TO COMMUNITY CHOICE AGGREGATORS

RATES: (Cont'd.)

7. CONSOLIDATED BILL-READY BILLING SERVICES

a. CONSOLIDATED PG&E BILLING

Composite Bill-Ready Billing Fee

This fee covers the cost to present the CCA's energy and customer charges. It also includes cost to process the CCA's energy charges and customer payments.

Per account per billing cycle..$0.21 (R)

8. CONSOLIDATED RATE-READY BILLING SERVICES

a. CONSOLIDATED PG&E BILLING

Composite Rate-Ready Billing Fee

This fee covers the cost to present the CCA's energy and customer charges on an additional bill page. It also includes cost to process the CCA's energy charges and customer payments, and respond to CCA calls regarding billing issues.

Bill presentation and processing of CCA's energy charges and customer payments, per account per billing cycle ....$0.21 (R)

b. CCA RATE SCHEDULE VALUE CHANGE

This fee will apply to a CCA when they request PG&E to change the CCA's price on a particular rate schedule or change the rate schedule assigned to a particular CCA customer.

Fee .... ~~no charge~~Labor

(Continued)

Advice	5225-E	Issued by	Date Filed	February 9, 2018
Decision	18-01-013	***Robert S. Kenney***	Effective	March 1, 2018
		Vice President, Regulatory Affairs	Resolution	

RATES: (Cont'd.)

9. OTHER BILLING SERVICES

a. PROGRAMMING FOR CONSOLIDATED BILLING

This fee will apply to a CCA when they request PG&E to provide additional billing services requiring programming such as text messages on the page of the bill presenting the CCA's charges.

Fee .... ~~$97.84 per hour~~Labor (I)

b. BILL ADJUSTMENT

This fee will apply when a CCA requests PG&E to adjust a CCA customer's bill for reason unrelated to the CCA's charges, such as the following:

– Goodwill gesture or promotional discounts

– Recourse adjustments as a result of dispute resolution

– Policy adjustment to satisfy a customer's complaint

Fee .... no charge

c. CCA RETURN PAYMENT

This fee will apply to a CCA when a CCA's check is returned for payment of any of PG&E's service charges.

Fee .... $8.00 per event

d. ACCOUNT ASSISTANCE

This fee will apply to a CCA when a CCA requests PG&E to perform other types of account assistance. For example: switch date corrections, reconciliation of balances and statements, duplicate bills, routine or complex account analyses, retrieval of account information, reproduction/resending of file/report, investigating EDI duplicate payments, and refunding account credits due to overpayments. ~~and account analysis.~~ (I)

Fee .... ~~$69.30 per hour~~Labor

ELECTRIC SCHEDULE E-CCA Sheet 8
SERVICES TO COMMUNITY CHOICE AGGREGATORS

RATES: (Cont'd.)

10. CCA TERMINATION OF SERVICE

a. VOLUNTARY TERMINATION

This charge will apply when a CCA terminates its entire program on a voluntary basis as described in Rule 23. If the CCA requests PG&E to provide the required notifications, then a separate CCA Customer Notification Fee will be applicable. The Voluntary Termination Fee would be assessed on a per event basis.

Fee...~~$4,475 per event~~Labor (I)

b. INVOLUNTARY TERMINATION

This fee will apply under conditions associated with Involuntary Service Changes as defined in Rule 23. All associated costs will be assessed to the CCA on a time and material basis in the event of such a circumstance.

Fee.. Labor and Material

11. STANDARD PHASE-IN SERVICES

This charge will apply when a CCA requests Phase-In Services as set forth in Rule 23. A CCA may select one of the following phase-in options: customer class, rate class, incorporated city, county, or zip code. The Phase-In requires the affected customers in each phase to be mass enrolled in CCA Service on the customer's regularly scheduled meter read date over one-billing cycle and requires the CCA to conclude its phase-in plan within one CRS period beginning with the first phase-in event. A CCA may also select a customized phase-in which would be provided under Specialized Services.

Fee ....~~$4,475 per phase-in~~Labor (I)

12. SPECIALIZED SERVICES

This charge will apply when a CCA requests Specialized Services, including Phase-In Services as set forth in Rule 23. This fee will also apply in the event a CCA requests Boundary Metering as set forth in Rule 23. This service will be provided on terms mutually agreeable to PG&E and the CCA. The fee will be calculated on a time and material basis.

Fee .... Labor and Material

SPECIAL CONDITIONS:

1. DEFINITIONS

a. Account – In PG&E's customer information system, a service account is called a service agreement and is defined as the customer's service identification number linking the customer's service with a specific meter.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

ATTACHMENT C

RECOMMENDED REVISIONS TO

ELECTRIC SCHEDULE E-ESP – SERVICES TO ELECTRIC SERVICE PROVIDERS

ELECTRIC SCHEDULE E-ESP Sheet 1
SERVICES TO ELECTRIC SERVICE PROVIDERS

APPLICABILITY: This schedule applies to Electric Service Providers (ESPs) who provide direct access service to Customers, as defined in electric Rule 1 and Rule 22.

TERRITORY: The entire PG&E service territory.

RATES:

1. METER INSTALLATION

   If an ESP requests that PG&E install a meter for its Direct Access Customer, the rates will be as set forth in Schedule E-EUS.

2. METER TESTING

   If an ESP requests that PG&E test a meter for its Direct Access Customer, the rates will be as set forth in Schedule E-EUS.

3. METER REMOVAL

   If an ESP requests that PG&E remove the existing PG&E meter, as set forth in Rule 22, the charge shall be as set forth in Schedule E-EUS.

4. INSPECTION OF ESP-INSTALLED METERING EQUIPMENT

   If PG&E inspects ESP-installed metering equipment pursuant to Rule 22 and the ESP Service Agreement, the charge shall be as set forth in Schedule E-EUS.

5. METER DATA MANAGEMENT AGENT (MDMA) SERVICES

   a. MDMA services include meter reading setup, if required, to ensure the ESP's meter communication system is compatible with PG&E's meter reading system, data validation, editing and estimating to settlement quality form, data reads and data transfer to the MDMA Server.

      If PG&E performs MDMA services for an ESP the charge shall be:

      MDMA Composite Fee per meter per month .... $0.14 (R) (T)

(Continued)

ELECTRIC SCHEDULE E-ESP Sheet 2
SERVICES TO ELECTRIC SERVICE PROVIDERS

RATES: (Cont'd.)

6. CONSOLIDATED PG&E BILLING

A. Rate-Ready Billing

If an ESP requests that PG&E calculate the charge and bill the ESP's Direct Access Customers for the energy supply portion of the Customer's bill, the prices shall be:

1) Composite Billing Fee, per service account per billing cycle...... $0.21 (R)

If PG&E is billing the ESP's Direct Access Customers for the energy supply portion of the Customer's bill, the ESP may request that PG&E provide the following additional billing-related services (Items 2 to 4) at no additional charge and is included in the Composite Billing Fee.

2) Duplicate Bill Request from ESP

3) Bill Adjustment

An ESP may request PG&E to adjust a Customer's bill for reasons unrelated to PG&E's calculation of the ESP's charges, such as the following:

a) ESP requested adjustment for reasons unrelated to the bill, such as a goodwill gesture or promotional discount.

b) Recourse adjustment as a result of dispute resolution.

c) Policy adjustment to satisfy a Customer's complaint.

(Continued)

ELECTRIC SCHEDULE E-ESP Sheet 3
SERVICES TO ELECTRIC SERVICE PROVIDERS

RATES: (Cont'd.)

6. CONSOLIDATED PG&E BILLING (Cont'd.)

A. Rate-Ready Billing (Cont'd.)

4) ESP Rate Schedule Changes

An ESP may request to change the price on a particular rate schedule or change the rate schedule assigned to the customer.

5) Rate-Ready Billing Set-Up Charges:

a) Programming for consolidated billing set-up, per hour…~~$123.80~~Labor (I)

b) Programming for ESP's rate schedules values, standard rate structure, per hour .... …~~$123.80~~Labor (I)

~~c) Programming for ESP's rate schedules, custom rate structure, per hour................................ …$146.15~~ ~~(I)~~

c~~d~~) Programming for ESP's bill messages, per hour………~~$123.80~~Labor (I)

d~~e~~) ESP bill message text, per character...................... ……. no charge

e~~f~~) Central Processing Unit (CPU) charge for consolidated bill programming, flat fee per ESP ……. no charge

f~~g~~) Computer Storage Device, per service account being billed based on hourly interval metering data……. no charge

ELECTRIC SCHEDULE E-ESP
SERVICES TO ELECTRIC SERVICE PROVIDERS

RATES: (Cont'd.)

6. CONSOLIDATED PG&E BILLING (Cont'd.)

B. Bill-Ready Billing

If an ESP requests that PG&E bill the ESP's Direct Access Customers for the energy supply portion of the Customer's bill as calculated by the ESP, the prices shall be:

1) Composite Billing Fee, per service account per billing cycle .... $0.21 (R)

Per additional page per service account per billing cycle .... no charge

2) Duplicate Bill Request, per bill per account .... no charge

3) Bill Adjustment, per adjustment per service account .... no charge

An ESP may request PG&E to adjust a previously billed Customer's bill due to the following reasons:

a. Recourse adjustment as a result of a dispute resolution

b. Policy adjustment to satisfy a Customer's complaint

4) Bill-Ready Billing Set-Up Charges

a. Programming for consolidated bill set-up, per hour .... ~~$123.80~~Labor

b. Programming for ESP's bill message, per hour .... ~~$123.80~~Labor

c. ESP bill message text, per character .... no charge

d. Central Processing Unit (CPU) charge for consolidated bill programming, flat fee per ESP .... no charge

e. Computer Storage Device, per service account being billed based on hourly interval metering data .... no charge

(Continued)

ELECTRIC SCHEDULE E-ESP Sheet 5
SERVICES TO ELECTRIC SERVICE PROVIDERS (T)

RATES: (Cont'd.)

7. DELIVERY OF MANDATED NOTICES

   A. Electronic transmission of text (electronic mail) for mandated notice .... no charge

8. LATE PAYMENT FEE

   a. If an ESP is performing Consolidated ESP billing and the bill to PG&E is not paid within 17 calendar days of transmittal of PG&E's customer charges, PG&E will assess late charges at the rate of one percent per month of the outstanding balance owed to PG&E, as set forth in the ESP Service Agreement.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

ATTACHMENT D

ELECTRIC SCHEDULE E-ESPNDSF –

ELECTRIC SERVICE PROVIDER

NON-DISCRETIONARY SERVICE FEES

ELECTRIC SCHEDULE E-ESPNDSF Sheet 1

ELECTRIC SERVICE PROVIDER NON-DISCRETIONARY SERVICE FEES (T)

APPLICABILITY: This schedule applies to Electric Service Providers (ESPs) who provide direct access service to Customers, as set forth in Rule 22. (T)

TERRITORY: The entire PG&E service territory.

RATES:

1. FULL CONSOLIDATED ESP BILLING

The following fees apply to ESPs performing Full Consolidated Billing when assistance is requested from PG&E.

A. Billing set up and ongoing support (labor), per hour.............. ~~$ .... 134.57~~cost

B. Billing set up and ongoing support (non-labor)...................... cost

2. PARTIAL CONSOLIDATED ESP BILLING

A. ESPs Using VAN Transmission

The following fees apply to ESPs performing Partial Consolidated Billing that are using VAN transmission.

Charge per account, per month	$ 0.12
Charge per ESP, per month	$63.00

B. ESPs Not Using VAN Transmission

The following fees apply to ESPs performing Partial Consolidated Billing that are not using VAN transmission.

Charge per ESP, per month	$60.80

(Continued)

ELECTRIC SCHEDULE E-ESPNDSF Sheet 2

ELECTRIC SERVICE PROVIDER NON-DISCRETIONARY SERVICE FEES (T)

RATES: (Cont'd.)

3. EXCEPTION FEES

The following fees apply to ESPs for services provided by PG&E.

A. Account ~~Analysis~~Assistance

This fee will apply to an ESP when an ESP requests PG&E to perform other types of account assistance. For example, switch date corrections, reconciliation of balances and statements, duplicate bills, routine or complex account analyses, retrieval of account information, reproduction/resending of file/report, investigating EDI duplicate payments, and refunding account credits due to overpayments.

Fee……………………………………………………………………………Labor

~~1) Retrieval of account information, per account ....$ 5.00~~

~~2) Routine account analysis, per account ....$ 15.83~~

~~3) Complex account analysis, per hour .... $ 63.81~~

~~4) Resend file/report, per report ....$ 15.00~~

~~5) Investigate EDI duplicate payments, per occurrence........ $134.57~~

~~6) Refund account credits due to overpayment, per account ..$ 5.00~~

B. Involuntary Billing Change

Billing/Accounts switch, per account...$ 8.00

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

ELECTRIC ESSENTIAL USE STUDY FOR RESIDENTIAL CUSTOMERS

PACIFIC GAS AND ELECTRIC COMPANY
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ELECTRIC ESSENTIAL USE STUDY FOR RESIDENTIAL CUSTOMERS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
ELECTRIC ESSENTIAL USE STUDY FOR RESIDENTIAL CUSTOMERS

A. Introduction

Ordering Paragraph (OP) 14 of California Public Utilities Commission (Commission) Decision (D.) 18-08-013, issued August 17, 2018, directed Pacific Gas and Electric Company (PG&E):

> "to develop a study plan (including budget) for developing a model of what constitutes essential use for its residential customers. This model must be developed using research, both existing (information sources such as the Residential Appliance Saturation Survey (RASS) and Experian data) and new direct customer surveys, to collect information on household size (in terms of both square footage and number of residents), building features (age, construction materials, insulation, etc.), and appliances (efficiency and usage) in order to better evaluate the essential electricity needs of PG&E's residential customers. This model of essential usage must be able to specify the amount of essential usage in both summer and winter for residential customers separately in each of the hot climate zone (baseline territories R, S, W, and P), the warm climate zone (baseline territories X and Y), and the cool climate zone (baseline territories T, V, and Z)."[1]

The decision also required that the plan be submitted with PG&E's next General Rate Case (GRC) Phase II application, scheduled to be filed November 22, 2019."[2]

B. Joint Investor-Owned Utilities (IOU) Recommend Conducting a Single Electric Essential Use Study

The Commission issued a similar requirement to quantify the amount of electricity usage that should be deemed essential for the residential customers of Southern California Edison Company (SCE) in D.18-11-027, issued

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1 D.18-08-013, p. 179.

2 D.18-08-013 ordered that "[t]he study plan for the development of this model must be submitted with PG&E's next GRC Phase II application. PG&E shall consult with parties to this proceeding, if a party expresses interest, when developing this study plan. If the development of a model of essential usage is included in the scope of Rulemaking 18-07-006 before PG&E files its next GRC Phase II application, PG&E is not required to file the study plan in its next GRC Phase II application." (D.18-08-013, OP 14, p. 179.)

November 29, 2018. The Commission issued a similar requirement to develop an essential usage study for the residential customers of San Diego Gas & Electric Company (SDG&E), consistent with the directions as provided to PG&E in D.18-03-013, in a Ruling issued November 1, 2019.[3]

In OP 14 of D.18-08-013, the Commission required PG&E to consult with parties when developing its Essential Use Study (Study) plan. In OP 14 of D.18-03-013, the Commission required SCE to consult with parties, including PG&E, when developing its essential use study plan. In its Administrative Law Judge (ALJ) Ruling issued on November 1, 2019, the Commission required SDG&E to participate in PG&E's and SCE's stakeholder participation process for developing a model of what constitutes essential use for its residential customers.

To date, PG&E, SCE, and SDG&E (collectively, the Joint IOUs) have conducted two workshops (on August 28, 2019 and September 6, 2019) regarding the design of the Study. Notice of these workshops was provided to parties on the service lists in: Rulemaking (R.) 18-07-006 (Affordability Rulemaking), R.12-06-013 (Residential Rate Reform), and Application (A.) 16-06-013 (PG&E GRC Phase II). The Joint IOUs expect that this study plan will evolve as Commission guidance is received and further stakeholder workshops are held.

The Joint IOUs have agreed that conducting the Essential Use Study jointly will provide several benefits, including: cost sharing, cost-effectiveness, stakeholder involvement, and consistency in methodology. The Joint IOUs have created a proposed interim Study plan and process incorporated into this filing as Attachment A. Attachment A also contains a preliminary cost estimate for conducting the Study.

C. Cost-Tracking for the Electric Essential Use Study

PG&E's primary proposal is to move the Essential Use Study to a special bifurcated, expedited proceeding as described in Section F of Attachment A to this testimony. If the Commission does not approve PG&E's primary proposal, PG&E requests that, upon Commission approval of the Study plan in its GRC

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3 See ALJ's Ruling in A.19-03-002, Directing SDG&E to File/Serve Addition Information, issued November 1, 2019.

Phase II decision, the Commission authorize PG&E to create a memorandum account to track its portion of actual costs related to the Study. Upon completion of the Study, PG&E proposes to file a Tier 2 advice letter with details of the actual costs as compared to the estimated costs. With the Commission's approval of the advice letter, PG&E would then recover its portion of the actual costs in distribution rates through its Annual Electric True-up advice letter.

D. Conclusion

PG&E requests Commission approval of the Joint IOU Study as described further in Attachment A and approval of PG&E's cost recovery proposal as described above.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

ATTACHMENT A

PROPOSED INTERIM JOINT INVESTOR-OWNED UTILITIES STUDY PLAN AND PROCESS FOR IDENTIFYING ELECTRIC ESSENTIAL USAGE FOR RESIDENTIAL CUSTOMERS

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PROPOSED INTERIM JOINT INVESTOR-OWNED UTILITIES STUDY PLAN AND PROCESS FOR IDENTIFYING ELECTRIC ESSENTIAL USAGE FOR RESIDENTIAL CUSTOMERS

A. Introduction

Ordering Paragraph (OP) 14 of California Public Utilities Commission (CPUC or Commission) Decision (D.) 18-08-013, issued August 17, 2018, directed Pacific Gas and Electric Company (PG&E) "to develop a study plan (including budget) for developing a model of what constitutes essential use for its residential customers." The Commission also issued a nearly identical requirement to Southern California Edison (SCE) in OP 14 of D.18-11-027, issued November 29, 2018. Finally, an Administrative Law Judge (ALJ) Ruling issued on November 1, 2019 directed San Diego Gas & Electric Company (SDG&E) "to participate in PG&E and SCE's stakeholder process for developing a model of what constitutes essential use for its residential customers, and to develop such a model consistent with the specific directions provided to PG&E in D.18-08-013."[1] That Ruling directed SDG&E to file and serve a document that details SDG&E's timeline for completing development of its essential use model.

This document presents the required plan to identify the essential usage of electricity for residential customers for PG&E, SCE, and SDG&E (collectively, the Joint IOUs). To facilitate consistency across the Joint IOU territories and to accommodate a streamlined approach to engaging with stakeholders, the Joint IOUs propose conducting a coordinated statewide study, hereinafter referred to as the Essential Use Study (Study).

The proposed Joint IOU Study plan incorporates comments received from stakeholders to date. The Joint IOUs continue to work with interested stakeholders to develop this plan further.

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[1] ALJ Ruling in Application (A.) 19-03-002 Directing SDG&E to File/Serve Supplemental Information, Issued November 1, 2019.

We are also proposing that the CPUC issue a ruling creating an expedited, bifurcated Joint Study proceeding. In addition, the Joint IOUs are seeking approval from the Commission with respect to their proposals to:

- Execute a statewide Essential Use Study;
- Contract with the 2019 Residential Appliance Saturation Survey (RASS) consultant to administer the Study on a directed-award basis; and
- Provide a preliminary estimate of cost[2] of between $500,000 and $750,000 to complete the Study, depending on its final design.

Provided that the Joint IOUs receive Commission approval to proceed with the development of this Study plan, the Joint IOUs will host a minimum of two public Study design meetings. These meetings will be noticed to the appropriate service lists, including: the most recent PG&E, SCE, and SDG&E[3] General Rate Case (GRC) Phase II proceedings, SCE's 2019 Rate Design Window (RDW) application, and the CPUC's Affordability Rulemaking proceeding, (R.) 18-077-006. Following these public meetings, the Study design will be finalized considering stakeholder feedback.[4]

B. How Should Essential Use Be Defined?

While the Scoping Memo in the Affordability Rulemaking determined that the Essential Use Study for PG&E, and consequently for SCE, should remain in their respective GRC Phase II/RDW proceedings rather than within the scope of R.18-07-006,[5] the Affordability Rulemaking aims to define both essential service and, more specifically, energy essential service, as the level of energy use needed for essential services. The Joint IOUs recommend that the definition of

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[2] OP 14 of D.18-08-013, issued August 17, 2018, directed PG&E "to develop a study plan (including budget)" for the Study. Similarly, OP 14 of D.18-11-027, issued November 29, 2018, directed SCE "to develop a study plan (including budget)" for the Study. This is referenced in this document as a "preliminary estimate of cost."

[3] SDG&E is using two service lists for its 2019 GRC Phase II proceeding: the service list for its 2016 GRC Phase II proceeding (A.15-04-012) and the service list for its 2019 Electric Sales Forecast proceeding (A.18-03-003).

[4] To ensure ongoing collaboration with interested parties, further public meetings will be held (and continue to be noticed to the above-referenced service lists) as the Study is underway. These public meetings will provide additional opportunities for stakeholders to provide comments and suggestions and to ask questions regarding the Study as it progresses.

[5] See Scoping Memo in R.18-07-006, dated November 19, 2018, at p. 5.

essential use for the Essential Use Study being discussed herein utilize the definition of energy essential service being determined in R.18-07-006.

On April 12, 2019, an ALJ Ruling (April Ruling) was issued in the Affordability Rulemaking inviting comments and responses to questions presented in an attachment (Attachment J) containing background information and a summary of several proposals. Attachment J of the April Ruling included the following discussion regarding the definition of essential service quantity:

> Across the water and energy industries, various conceptions of an essential service quantity already exist. The Public Utilities Code has provided for "an adequate supply of healthful water…at an affordable cost" since as early as 1993,[6] and tiered rate structures common in both the water and energy spaces reflect the idea of an essential baseline. With that said, the notion of an essential service quantity can differ greatly across utilities, in part based on differing assumptions of what is adequate or reasonable. An appropriate definition for essential services should be flexible, applicable to all Commission-regulated utilities, and set a common baseline for the assumptions behind the definition. The following definition reflects input received from parties via comments and information from the January 22, 2019 workshop pertaining to this OIR:
>
> An essential service quantity of utility service is that quantity which is necessary for health, comfort, and safety.

One of the questions posed in Attachment J was how this definition of essential service could be refined. Parties provided several responses.

On August 20, 2019, an ALJ Ruling in the Affordability Rulemaking was issued inviting comments on the *Staff Proposal on Essential Service and Affordability Metrics* (Staff Proposal). In this proposal, Commission staff from its Water, Energy, and Communications Divisions proposed the following high-level definition:

> <u>Essential Service</u>: service that meets a household's basic needs and is reasonably necessary for that household's health, safety, and full participation in society.[7]

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[6] Public Utilities Code § 739.8.

[7] August 20, 2019 ALJ Ruling in R.18-07-006, Staff Proposal, p. 5.

The Staff Proposal also provides a proposal for a more specific definition for energy essential service:[8]

> Energy Essential Service: service required for home heating and cooling; lighting; cooking; personal hygiene; medical care; and meaningful participation in society, such as operating a computer or charging a mobile device. These amounts vary seasonally and regionally.[9]

A workshop concerning the Staff Proposal took place on August 26, 2019. Parties subsequently provided opening and reply comments to the Staff Proposal on September 10 and 20, 2019, respectively.

A Commission decision concerning the Staff Proposal and the proposed definitions of electric essential service and energy essential service is still pending as of the date of the preparation of this proposed interim Joint Study plan.

C. What Specific Uses Warrant Inclusion in Essential Use?

The Staff Proposal currently identifies the following uses in its proposed definition for energy essential service:

- Home heating and cooling;
- Lighting;
- Cooking;
- Personal hygiene;
- Medical care; and
- Meaningful participation in society, such as operating a computer or charging a mobile device.

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8 In the first public meeting for the Essential Use Study, the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) noted that this Staff Proposal, which was referenced in the presentation deck for the meeting in relation to "essential use quantities" and affordability metrics, is in the public comments phase and is preliminary. Home Energy Analytics Inc. (HEA) commented that Lawrence Berkeley National Labs has conducted research that identifies electricity-using devices that provide life-safety, health, and security functions to residential customers (EPIC Project EPC-15-024) that may be of value to this project. Specifically, HEA notes that this study identifies base loads from items like GFCI outlets and garage door backup batteries and concludes that the new California building code will result in a minimum of 80-continuous-watts (700 kilowatt-hour/year) for all new homes that will impact residential essential use.

9 August 20, 2019 ALJ Ruling in R.18-07-006, *Staff Proposal*, p. 5.

The Joint IOUs recommend that the uses to be addressed in the Essential Use Study align with definition of energy essential service expected to be resolved in R.18-07-006.

D. What Customer Segments Should Be Included in This Study?

In D.18-08-013 and D.18-11-027, the Commission states that the model for determining essential use must be able to specify essential usage based on the needs of residential customers uniquely within the following geographic areas:

- Hot climate zone – summer and winter (for PG&E, this represents Baseline Territories R, S, W, and P; for SCE, this represents California Climate Zones 10, 13, 14, and 15, and for SDG&E, this represents Mountain and Desert Climate Zones);
- Warm climate zone – summer and winter (for PG&E, this represents Baseline Territories X and Y; for SCE, this represents California Climate Zones 5 and 9, and for SDG&E, this represents the Inland Climate Zone); and
- Cool climate zone – summer and winter (for PG&E, this represents Baseline Territories T, V, and Z; for SCE, this represents California Climate Zones 6, 8, and 16, and for SDG&E, this represents the Coastal Climate Zone).

Given that current baseline quantities for electricity are dependent upon service type (i.e., basic/dual-service and all-electric) in addition to season and climate zone,[10] the Joint IOUs recommend that the segmentation also include differentiation by service type. Other unique segments may be identified over the course of the Study.

E. Joint IOUs Recommend Conducting a Single Essential Use Study

Per OP 14 of D.18-08-013, PG&E is required to submit the plan for an Essential Use Study as part of its next GRC Phase II application. SCE is required to submit such a study plan with its next RDW or GRC Phase II application, whichever comes first.[11] SDG&E is required to "file and serve a document that details SDG&E's timeline for completing development of its

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10 The Center for Accessible Technologies emphasized during the second public meeting that weather variations within climate zones—typically referred to as microclimates—can affect the amounts of electricity required for essential uses and requests that these differences be assessed in this Study.

11 OP 14 per D.18-11-027, p. 74.

essential use model."[12] While PG&E, SDG&E and SCE will satisfy their requirements to file plans for an Essential Use Study in their respective GRC Phase II or RDW proceedings, the Joint IOUs recommend that an Essential Use Study be conducted jointly by PG&E, SCE, and SDG&E. The Joint IOUs believe that conducting an Essential Use Study jointly will provide for several benefits including cost sharing, cost-effectiveness, and consistency in methodology. The Joint IOUs are seeking the ability to track costs associated with the undertaking (detailed in their respective testimonies for PG&E, SCE and SDG&E) and recommend the following cost allocation:

- PG&E, 45 percent
- SCE, 43 percent
- SDG&E, 12 percent[13]

F. The Joint IOUs Recommend Consolidation Into a Single Joint IOU Study Proceeding

The Joint IOUs recommend that, following approval of the proposed study plan detailed herein, the Essential Use Study be addressed in a single proceeding. This approach would be an efficient means for allowing all interested parties to participate in the development of the Essential Use Study for the Joint IOUs. Consolidation will allow interested parties to address issues related to essential use for the Joint IOUs once in a single proceeding. Given the merits of a single, coordinated statewide study of essential use, the Joint IOUs recommend the establishment of a special, expedited, consolidated Joint Study proceeding including only PG&E, SCE, and SDG&E, that will be focused on the Essential Use Study as defined herein.

As discussed, the Scoping Memo in the Affordability Order Instituting Rulemaking (OIR) determined that the essential use study plans should be filed in PG&E's GRC Phase II and SCE's RDW, respectively, and both PG&E and

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[12] See ALJ Ruling, dated November 1, 2019, Directing SDG&E to File/Serve Supplemental Information, in R.18-07-006.

[13] These cost-sharing ratios are consistent with the allocation of expenditures for the statewide residential rate reform marketing, education, and outreach campaign established in OP 8 in D.17-12-023.

SCE will do so.[14] However, with the Joint IOUs' proposal for a single Essential Use Study, the Joint IOUs respectfully request that the Commission consider addressing the Essential Use Study in the Affordability OIR, R.18-07-006. The Joint IOUs acknowledge that the Scoping Memo in the Affordability OIR[15] states that, even though the concept of essential usage is closely related to the concept of affordability, the primary issues in the Affordability Rulemaking "are to identify and define affordability criteria and to develop a framework for assessing affordability impacts across Commission proceedings and utility services." The discussion of essential use also continues to be a critical component to the discussion of affordability, however. In fact, essential use is a key component to the definition of affordability as put forward in the Staff Proposal:

> Affordability: the degree to which a household can regularly pay for essential service of each public utility type on a full and timely basis without substantial hardship.

There are several ways the CPUC could accommodate conducting the Essential Use Study. For instance, the Commission could establish a special separate proceeding focused solely on examining essential usage for electricity, which could be done as new, second phase of the Affordability OIR proceeding or as a separate multi-utility proceeding. PG&E proposes that the CPUC bifurcate this issue from PG&E's utility-specific GRC Phase II, to expedite its consideration (since a final decision in this GRC Phase II as a whole is not expected until mid-2021). One benefit of establishing a separate expedited track within the Affordability OIR with a primary focus on the Essential Use Study is that doing so would provide all of the parties who are already involved in the Affordability OIR with the opportunity to weigh in on the Study without having to become a party to a special bifurcated multi-utility proceeding or separate utility-specific proceedings such as PG&E's GRC Phase II and/or SCE's 2019 RDW. As to the latter, even if the Study issue is bifurcated and allowed to proceed quickly in each of these two proceedings, it seems inefficient to have the same study reviewed in multiple, separate utility-specific proceedings. Moreover, the newly-established, bifurcated Joint Study proceeding can move forward at a

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14 At the time the Scoping Memo was issued in the Affordability OIR, SDG&E had not been required to conduct an Essential Use Study.

15 See Scoping Memo in R.18-07-006, dated November 19, 2018, at p. 6.

more expedited pace, to be determined by the Commission. If the Study is not bifurcated from myriad issues being considered in PG&E's 2020 GRC Phase II proceeding, there would be a significant delay in starting execution of the Study, when compared to PG&E's proposed expedited schedule below, because the ultimate 2020 GRC Phase II decision is not expected until at least mid-2021.

G. Leveraging the 2019 Residential Appliance Saturation Survey

In both D.18-08-013 and D.18-11-027, the Commission recognizes the critical role that the 2019 RASS would play in the development of an Essential Use Study. OP 14 of D.18-08-013 states that the Essential Use Study:

> …must be developed using research, both existing (information sources such as the Residential Appliance Saturation Survey and Experian data) and new direct customer surveys, to collect information on household size (in terms of both square footage and number of residents), building features (age, construction materials, insulation, etc.), and appliances (efficiency and usage) in order to better evaluate the essential electricity needs of PG&E's residential customers.[16]

The 2019 RASS is a large-scale, statewide study that has been conducted periodically over the past few decades to estimate the saturation of typical residential appliances and energy consumption tied to a wide range of common end uses of energy. Utilities participating in the 2019 RASS include: Los Angeles Department of Water and Power, PG&E, SCE, SDG&E, Southern California Gas Company, and the Sacramento Municipal Utilities District. Using both mail- and e-mail-based respondent recruitment techniques, the forecasted completed sample size for the 2019 RASS is approximately 77,000 California households, over 45,000 of which will be in Joint IOU service territories and is the most comprehensive survey of California residents of its kind.

The 2019 RASS will estimate unit energy consumption of specific end-uses of electricity using a conditional demand analysis (CDA), which has been refined over the past 30 years. CDA combines meter data from utilities, survey data on

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[16] D.18-08-013, p. 179. Comparable language about the Essential Use Study can also be found in OP 14 of D.18-11-027 for SCE. "The SCE study plan must consider a model that uses research, both existing (information sources such as the Residential Appliance Saturation Survey and Experian data) and new direct customer surveys, to collect information on household size (in terms of both square footage and number of residents), building features (age, construction materials, insulation, etc.), and appliances (efficiency and usage) in order to better evaluate the essential electricity needs of SCE's residential customers." (D.18-11-027, p. 74.)

appliances in homes and household demographics, temperature data, and engineering models to estimate average energy usage for specific appliances or end-uses. Household members are surveyed to obtain demographic information, end-use appliances and equipment in the dwelling, and occupant usage habits. This information is combined with end-use engineering estimates to create a bottom-up estimate of each household's energy consumption profile. The results of the statistically-adjusted end-use usage estimates, aggregated over the sample population, produce the segment- and population-level end-use average usage estimates. The 2019 RASS is expected to be completed by March 2020.

The Commission in D.18-08-013 and D.18-11-027 determined that, to better evaluate the essential electricity needs of residential customers, the model for determining essential use must collect information on the geographic segments listed in Section D above and on the following customer attributes:

- Household size (in terms of both square footage and number of residents);
- Building features (age, construction materials, insulation, etc.); and
- Appliances (efficiency and usage).

Most of these requirements are met with the 2019 RASS questionnaire. A complete listing of the 2019 RASS questions is provided as Table 9A-2 to this document. Table 9A-3 provides cross-references between the 2019 RASS questions and household size and building features. Table 9A-4 provides cross-references between the 2019 RASS questions and appliances.

Further, the Joint IOUs wish to build upon the 2019 RASS by using its respondent pool to fill in any gaps in the existing questionnaire and as the source for new survey respondents for follow-on surveys,[17] when practical.

H. Preliminary Cost Estimate

The California Energy Commission (CEC) used a competitive solicitation process to award the administration of the 2019 RASS Study (initially referred to by the CEC as the "2017 RASS" due to a delay in issuing the contract) to the consultant DNV GL (doing business as KEMA Inc.) based on this firm's

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17 In the public meeting, Cal Advocates requested that all new data collected for the Joint IOUs' Essential Use Study be open for inspection by the stakeholders so that it can be validated, can provide for continued engagement, and its interpretation can include multiple perspectives.

experience in conducting prior versions of the RASS study and on the knowledge and skills of the firm's staff in conducting in-depth analyses of household energy consumption patterns. Based in part on DNV GL's deep expertise with administering RASS studies, and based in part on the prior experience that the Joint IOUs have contracting with DNV GL on other research projects, the Joint IOUs intend to issue a directed award for the preliminary design of the Essential Use Study to this consultant, provided that the Commission has no objections.[18] In doing so, the survey design, data collection, and conditional demand estimates performed for the RASS can be leveraged to expedite the implementation and reduce the costs of producing the Essential Use Study, and ensure the quality of essential energy use estimates.

Based on this proposal and prior studies of similar scope and magnitude, the cost estimate range for the Essential Use Study is between $500,000 and $750,000. The final cost of the Study will be dependent on the extent of stakeholder collaboration, the characteristics of the final Study design, and the timetable for its execution. Proposals for cost recovery would be incorporated in the respective testimonies of PG&E, SCE, and SDG&E.

I. Stakeholder Engagement for Developing the Study Plan

OP 14 of D.18-08-013, and OP 14 of D.18-11-027, require that PG&E and SCE, respectively, "consult with parties to this proceeding, …when developing this study plan,"[19] referencing both PG&E and SCE's GRC Phase II proceedings. The ALJ Ruling issued November 1, 2019 in A.19-03-011, directs SDG&E "to participate in PG&E and SCE's stakeholder process for developing a model of what constitutes essential use for its residential customers, and to

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18 During the public meeting, TURN questioned how a direct award of a contract to DNV GL to conduct the study would benefit stakeholders. The Joint IOUs explained that DNV GL analysts have demonstrated expertise in demand modeling and have knowledge of both the data structure of 2019 RASS and the content of the surveys. Further, the Joint IOUs explained that contracting with a different vendor without familiarity with the data and its modeling would result in having to begin anew and ratepayers being required to pay more to execute the Essential Use Study. After discussion, Cal Advocates and TURN had no major objections to the hiring of DNV GL or to the Joint IOU effort, provided that stakeholders are given information about the scope, scale and cost of the project prior to the awarding of any contracts.

19 OP 14 of D.18-08-013, p. 179; OP 14 of D.18-11-027, p. 76.

develop such a model consistent with the specific directions provided to PG&E in D.18-08-013."[20]

The Joint IOUs have conducted two public meetings to date, one on August 28, 2019 and another on September 6, 2019. Both of these meetings were noticed to parties on the service lists for R.18-07-006 as well as for PG&E and SCE's respective GRC Phase II proceedings.

Parties were also invited to provide comments directly to the study plan through an online document. This Joint IOU interim Study plan proposal reflects comments received to date from stakeholders, and the Joint IOUs intend to continue to work with stakeholders further to develop and finalize this Study plan.

Once the Commission approves the proposed Study plan, as detailed herein, the Joint IOUs intend to host a minimum of two public Study design meetings.[21] These meetings will be noticed to the service lists referenced in Section A, above. Following these public meetings, the final Study design will be determined in coordination with interested stakeholders. Further public meetings will be planned and noticed in the same manner as above as the Study is underway. These public meetings will provide additional opportunities for stakeholders to provide comments and suggestions and to ask questions.

J. Study Timeline

This same proposal is being submitted as part of PG&E's November 22, 2019 GRC Phase II application, as part of SCE's 2019 RDW application, and as part of SDG&E's GRC Phase II proceeding. PG&E is requesting that the Commission issue a ruling bifurcating the Essential Use Study issue from the rest of the issues in its 2020 GRC Phase II proceeding. Bifurcating will allow the Essential Use Study plan to be developed and finalized jointly, for consideration and approval in a special, separate, expedited consolidated proceeding that can result in the Joint Study moving forward faster and more efficiently than it otherwise would. Recommendations or any remaining issues concerning the final Study design should also be received and incorporated into the record in

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[20] ALJ Ruling in A.19-03-001, dated November 1, 2019, p. 2.

[21] The Utility Consumers' Action Network (UCAN) commented that the initial two public meetings were helpful for understanding the requirements for the Essential Use Study and suggests that additional meetings will be helpful for further discussions.

that expedited, consolidated Study proceeding. The Commission would then approve a final Study plan in such an expedited joint proceeding. The Joint IOUs provide the following draft timeline, which aims to facilitate a timely, joint implementation of the Commission's envisioned Essential Use Study.

The Joint IOUs are uncertain what the Commission might decide should be the schedule for the Joint Study process, but the following provisional timeline is based on experience with typical public proceedings for such a study, based on the assumption that the Commission approves the Joint IOU request for a bifurcated, consolidated, and expedited process.

TABLE 9A-1
ILLUSTRATIVE SCHEDULE FOR CONSIDERATION OF BIFURCATED JOINT ESSENTIAL USE STUDY

Line No.	Study Activity	Approximate Timeline
1	Ruling Granting Bifurcation	Mid-February 2020
2	Public Study Design Workshops	Mid-March to Mid-May 2020 (3 months after Ruling)
3	Submittal of Final Joint Study Design	Mid-August 2020 (1 month after Design Workshops)
4	Hearings and Briefs (or Public Workshops and Comments)	Mid-November 2020 (3 months after Final Joint Study Design Submittal)
5	Proposed Decision on Study and Cost Recovery Mechanisms	Mid-February 2021 (2 months after Reply Briefs or Reply Comments)
6	Final Decision on Special Expedited, Bifurcated Proceeding on the Study	Mid-March 2021 (1 month after Proposed Decision)
7	Preparation for Study Initiation and Contracting	Mid-June 2021 (3 months after Final Decision)
8	Joint Study Execution	Mid-December 2021 (6 months after Joint Study Initiation)
9	Preparation of Draft Report	Mid-February 2022 (2 months after Joint Study Execution)
10	Public Comments on Draft Report	Mid-March 2022 (1 month after Draft Report Completion)
11	Completion of Final Report and Submittal of Tier 2 Advice Letter	Mid-April 2022 (1 month after Public Comment Period)
12	Approval of Advice Letter	Mid-May 2022 (1 month after Advice Letter Submittal)

The estimated dates in the timeline above are dependent upon the following assumptions: (1) the RASS Study is completed by March 2020; (2) the CPUC issues a ruling authorizing the Essential Use Study to be conducted as a bifurcated, expedited single, statewide study; (3) consensus can be timely reached among the stakeholders regarding the final Joint Study design; (4) the

CPUC timely approves the directed award to the contractor completing the RASS Study; and (5) the CPUC timely approves the final Study design proposed by the Joint IOUs. If there are changes in any of these assumptions, the estimated schedule above could be lengthened.

TABLE 9A-2
2019 RASS QUESTION LIST

Home and Lifestyle	
A1	What type of building exists at the service address on the front cover of this survey?
A2	Do you own or rent this home?
A3	How long have you lived at this address?
A4	Which of the following best describes this residence? (permanent/vacation)
A5	If this is a partial-year or vacation home, please indicate the months this home is typically occupied.
A6	Approximately what year was this residence built?
A7	How many bedrooms are in your home?
A8	How many square feet of living space are there in your residence
A9	Are your home's exterior (outside) walls insulated?
A10	Is your home's attic/ceiling insulated?
A11	If yes estimate the number of inches of attic/ceiling insulation.
A12	Choose the statements that best describe your windows.
A13	Has your home been remodeled in the past 12 months?
A14	If yes, what type of remodel did you do?
A15	For each of the following age groups, how many people including yourself usually live in this home?
A16	Generally speaking, how often does a member of this household use any major electrical appliances or equipment (e.g. clothes washer, electric range, dishwasher, air conditioner etc.) on weekdays from 12 noon to 6 pm?
A17	Is natural gas service from underground pipes from the gas utility available in your neighborhood?
A18	Do you have a natural gas line or hook-up to any part of your home?
A19	What utility do you pay for natural gas service to your home?
Electric Vehicles	
A20	Does anyone in your household currently own or lease a plug-in battery electric vehicle or plug-in hybrid electric vehicle?
A21	How many electric vehicles does your household own or lease?
A22	On an average day, how many total miles do you drive your electric vehicles?
A23	How often do you charge your electric vehicle(s) at home work or somewhere else?
A24	Is your primary charger used at home a level 1 (120V) or level 2 (240V)?
A25	When is/are the EV(s) normally charged using this primary charger?

TABLE 9A-2
2019 RASS QUESTION LIST
(CONTINUED)

Space Heating	
B1	Do you pay to heat your home?
B2	What type of heating system do you use to heat this home?
B3	If your heating system(s) uses natural gas for fuel indicate whether it has a pilot light(s).
B4	How old is your main heating system?
B5	What type of thermostat does your main heating system(s) use?
B6	If your main heating system is controlled by a thermostat what is the average thermostat temperature usually set for each time period during the heating season?
B7	Has maintenance been performed on your main heating system in the past
B8	How many electric (plug-in) portable heaters do you use?
B9	How often do you use any additional heating system(s)
Space Cooling	
	CENTRAL AIR CONDITIONING/COOLING
C1	Do you pay for central air conditioning/cooling for your home?
C2	What type and how many central air conditioning/cooling system(s) do you have in your home?
C3	How old is your main central air conditioning/cooling unit?
C4	What type of thermostat does your main air conditioning/cooling system(s) use?
C5	What is the typical thermostat temperature setting of your main central cooling system for each time period during the cooling season?
C6	Has maintenance been performed on your central air conditioning system in the past 12 months?
	ROOM AIR CONDITIONING/COOLING (Window/Wall Units)
C7	Please tell us the characteristics of each room air conditioning/cooling unit below.
C8	Please indicate how often your room air conditioning/cooling unit(s) is/are turned on during the cooling season.
Water Heating	
D1	Do you pay for heating water at your residence?
D2	What type of water heating systems do you use in your home?
D3	What is the typical hot water heater temperature setting?

TABLE 9A-2
2019 RASS QUESTION LIST
(CONTINUED)

Space Heating	
D4	How old is your primary water heating system?
D5	How many total showers and baths are taken in your home on a typical day?
D6	Do you have low-flow showerheads installed in the shower(s)?
D7	Do the faucets in your home have water-saving aerators?
Laundry	
E1	Do you have the use of laundry equipment in your home?
E2	What type of clothes washer do you have?
E4	For each wash temperature below, how many loads of clothes do you wash in your home during a typical week?
E5	What type of clothes dryer do you have?
E6	How old is your clothes dryer?
E7	For each dry temperature below how many loads of clothes do you dry in your home during a typical week?
Food Preparation	
F1	Which of the following cooking appliances are used in your home?
F2	During a typical week how often do you use the following cooking appliances?
F3	Do you have a dishwasher?
F4	How old is your dishwasher?
F5	How many dishwasher loads are run in a typical week?
Refrigerators	
G1	How many refrigerators do you have plugged in?
G2	Please tell us the characteristics of each refrigerator in the table below.
	Door Style
Freezers	
H1	How many stand-alone freezers do you have plugged in?
H2	Please tell us the characteristics for each stand-alone freezer in the table below. (Style, size, age)
Spas and Hot Tubs	
I1	Do you have the use of a spa or hot tub at your home?
I2	What fuel do you use to heat the spa or hot tub?
I3	How large is the spa or hot tub?
I4	Where is the spa located?

TABLE 9A-2
2019 RASS QUESTION LIST
(CONTINUED)

Spas and Hot Tubs	
I5	Do you have an insulated cover on your spa or hot tub?
I6	How often do you run the filter pump on your spa or hot tub?
I7	Please indicate how often you heat your spa or hot tub in the winter and summer.
Pools	
J1	Do you have the use of a swimming pool at your home?
J2	How large is your pool? (An average-size pool is about 5 ft. deep by 40 ft. long by
J3	How many hours per day do you operate your swimming pool filter?
J4	Which fuel do you use to heat your pool?
J5	Please indicate how often you heat your pool in the summer and winter.
J6	Which of the following attributes does your pool have? (Choose all that apply.)
Entertainment and Technology	
K1	How many televisions and accessories do you use in this home?
K2	How many combined total hours are your televisions on each day?
K3	How many personal computer(s) (PC, Macintosh, etc.) do you use in this home?
K4	If you have one or more computer(s) in this home how many combined total hours are they turned on each day?
K5	Do you or someone else in your home operate a business and/or work from your home?
K7	How many of the following products do you use in this home?
	Printer, Scanner, Copier or Multifunction machine
	Tablet computer or e-reader (iPad or Kindle)
	Hubs controllers (Amazon Echo, Google home, Apple HomeKit)
	Smart home devices
	“Smart” cell phone (iPhone or Android)
	Other cell phone (flip phone candy bar phone)
	High-speed modem for Internet (DSL/cable/satellite)
	Home network (wired or wireless)
	Uninterrupted Power Supply (UPS power backup)

TABLE 9A-2
2019 RASS QUESTION LIST
(CONTINUED)

Lighting	
L1	What portion of light bulbs installed in the ceiling fixtures and lamps inside your home are the following types?
L2	How many lights inside your home are turned on during the following times of day?
L3	How many of the following lighting products do you use inside your home?
L4	How many of the following lighting products do you use outside your home?
Misc. Appliances	
M1	How many of each of the following appliances or equipment do you use in your home?
M2	Do you use an electric well water pump to provide water for your home?
M3	Does your home also have access to city/county water?
M4	How do you use your well water?
M5	Select fuel type for any of the equipment that is used three or more hours per week
	Sump pump, Shop tools, Electric welding equipment, Electric air compressor, Charger for large battery, Kiln for ceramics and pottery, Medical equipment (e.g., respirator)
M6	Do you have an electric bicycle, skateboard, wheelchair or golf cart at your home?
M7	Do you charge your electric wheelchair, cart, skateboard or bicycle at home?
M8	Do you use any other equipment or large appliance that consumes a significant amount of electricity or natural gas in your home?
M9	Please indicate if you have added any of the following appliances in the past 12 months. If the new item replaced an existing unit
M10	Please indicate if you have discarded any of the following appliances in the past 12 months. Include both items that were replaced and those that were discarded without being replaced.
Renewable Energy Technologies	
M11	Which of the following renewable energy technologies are currently used at this residence?
	No renewable energy technologies
	Solar electricity/photovoltaic (PV) cells
	Solar water heating (In-home water heated)
	Battery storage connected to solar
	Wind generator

TABLE 9A-2
2019 RASS QUESTION LIST
(CONTINUED)

Renewable Energy Technologies	
	Fuel cells
M12	In the next two years do you plan to install any of the following renewable technologies?
Household Information	
N1	In addition to the home described in this survey do you own any other home in California that is occupied on a part-time basis by your family or as a vacation rental?
N2	Please provide the following information for your seasonal or vacation home that you own in California?
N3	What was the highest level of education completed by any head of household in the home?
N4	What is the primary language spoken in this home?
N5	Are any of the occupants of your home permanently disabled?
N6	Which of the following ethnic groups are represented by your head(s) of household?
N7	Please check the range that best describes your household’s total annual income.

TABLE 9A-3
2019 RASS DWELLING CLASSIFICATION QUESTIONS

Essential Use Model Decision Guidelines					
Household Size					
		Square Footage	Number of residents		Additional
A7	How many bedrooms are in your home?				X
A8	How many square feet of living space are there in your residence	X			
A15	For each of the following age groups, how many people including yourself usually live in this home?		X		
Building Features					
		Age	Construction Materials	Insulation	Additional
A9	Are your home’s exterior (outside) walls insulated?			X	
A10	Is your home’s attic/ceiling insulated?			X	
A11	If yes estimate the number of inches of attic/ceiling insulation.		X		
A12	Choose the statements that best describe your windows. [PANE TYPE (number of layers of glass)]		X		
A6	Approximately what year was this residence built?	X			

TABLE 9A-4
2019 RASS QUESTION MATRIX

	2019 RASS Survey Questions	Essential Use Model Decision Guidelines Appliances	
		Efficiency	Usage
	Electric Vehicles		
A21	How many electric vehicles does your household own or lease?		X
	Space Heating		X
B2	What type of heating system do you use to heat this home?		X
B4	How old is your main heating system?	X	
B5	What type of thermostat does your main heating system(s) use?	X	
	Space Cooling		
	CENTRAL AIR CONDITIONING/COOLING		X
C2	What type and how many central air conditioning/cooling system(s) do you have in your home?		X
C3	How old is your main central air conditioning/cooling unit?	X	
C4	What type of thermostat does your main air conditioning/cooling system(s) use?	X	
	ROOM AIR CONDITIONING/COOLING (Window/Wall Units)		X
C7	Please tell us the characteristics of each room air conditioning/cooling unit below.		X
	Water Heating		
D2	What type of water heating systems do you use in your home?		X
D4	How old is your primary water heating system?	X	
	Laundry		
E2	What type of clothes washer do you have?		X
E5	What type of clothes dryer do you have?		X
E6	How old is your clothes dryer?	X	
	Food Preparation		
F1	Which of the following cooking appliances are used in your home?		X
F3	Do you have a dishwasher?		X
F4	How old is your dishwasher?	X	
	Refrigerators		
G1	How many refrigerators do you have plugged in?		X
	Age of your Refrigerator	X	

TABLE 9A-4
2019 RASS QUESTION MATRIX
(CONTINUED)

	2019 RASS Survey Questions	Essential Use Model Decision Guidelines: Appliances – Efficiency	Usage
	Freezers		
H1	How many stand-alone freezers do you have plugged in?		X
	Age of your Freezer	X	
	Spas and Hot Tubs		X
I1	Do you have the use of a spa or hot tub at your home?		X
I5	Do you have an insulated cover on your spa or hot tub?	X	
	Pools		
J1	Do you have the use of a swimming pool at your home?		X
	Entertainment and Technology		
K1	How many televisions and accessories do you use in this home?		X
K3	How many personal computer(s) (PC, Macintosh, etc.) do you use in this home?		X
K7	How many of the following products do you use in this home?		
	Printer, Scanner, Copier or Multifunction machine		X
	Tablet computer or e-reader (iPad or Kindle)		
	Hubs controllers (Amazon Echo, Google home, Apple HomeKit)		X
	Smart home devices		X
	“Smart” cell phone (iPhone or Android)		X
	Other cell phone (flip phone candy bar phone)		X
	High-speed modem for Internet (DSL/cable/satellite)		X
	Home network (wired or wireless)		X
	Uninterrupted Power Supply (UPS power backup)		X
	Lighting		
L1	What portion of light bulbs installed in the ceiling fixtures and lamps inside your home are the following types?		
	Incandescent	X	
	CFLs	X	
	LEDs	X	

TABLE 9A-4
2019 RASS QUESTION MATRIX
(CONTINUED)

	2019 RASS Survey Questions	Essential Use Model Decision Guidelines Appliances	
		Efficiency	Usage
L2	How many lights inside your home are turned on during the following times of day?		
	Morning		X
	Day		X
	Evening		X
	Night		
L3	How many of the following lighting products do you use **inside** your home?		
	Fixtures on timers		X
	Fixtures on motion detectors or occupancy sensors		X
	Fixtures on a dimming switch		X
	"Smart" (connected) light bulbs		X
	HID (sodium vapor, metal halide) fixture		X
	Night lights		
L4	How many of the following lighting products do you use **outside** your home?		
	Exterior incandescent fixtures		X
	Exterior compact fluorescent fixtures		X
	Exterior LED fixtures		X
	Low voltage landscape lighting system		X
	HID (sodium vapor, metal halide) fixture		X
	Fixtures on timers		X
	Fixtures on dusk-to-dawn sensors		X
	Fixtures on motion detectors		X
	Miscellaneous Appliances		
M1	How many of each of the following appliances or equipment do you use in your home?		X

TABLE 9A-4
2019 RASS QUESTION MATRIX
(CONTINUED)

	2019 RASS Survey Questions	Essential Use Model Decision Guidelines — Appliances: Efficiency	Essential Use Model Decision Guidelines — Appliances: Usage
M2	Do you use an electric well water pump to provide water for your home?		X
M5	Select fuel type for any of the equipment that is used three or more hours per week		
	Sump pump, Shop tools, Electric welding equipment, Electric air compressor, Charger for large battery, Kiln for ceramics and pottery, Medical equipment (e.g., respirator)		X
M6	Do you have an electric bicycle, skateboard, wheelchair or golf cart at your home?		X
M7	Do you charge your electric wheelchair, cart, skateboard or bicycle at home?		X
	Renewable Energy Technologies		
M11	Which of the following renewable energy technologies are currently used at this residence?		X
	No renewable energy technologies		X
	Solar electricity/photovoltaic (PV) cells		X
	Solar water heating (In-home water heated)		X
	Battery storage connected to solar		X
	Wind generator		X
	Fuel cells		X