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Date: September 2, 2021
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

EMERGENCY RELIABILITY ORDER INSTITUTING RULEMAKING

ERRATA TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
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ERRATA TESTIMONY

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CHAPTER 1
SUMMARY OF OPENING TESTIMONY IN PHASE 2 OF THE EMERGENCY RELIABILITY RULEMAKING

A. Introduction

Pacific Gas and Electric Company (PG&E) is pleased to provide this Summary of its Phase 2 Opening Testimony in the Reliability Rulemaking 20-11-003. Building on the momentum of Phase 1, PG&E is advancing a number of ideas for consideration by the California Public Utilities Commission (CPUC) in order to address grid reliability needs in 2022, 2023, and potentially beyond.

On Friday, July 30, 2021, Governor Newsom issued a Proclamation of a State of Emergency (Proclamation) in response to the significant and accelerating impacts of climate change in California. During the summers of 2020 and 2021 the West experienced multiple significant extreme heat events, resulting in stresses to the electrical grid system and rolling outages across California. PG&E supports California’s plan to build a safe, affordable, and reliable energy future that benefits all our hometowns and continues to meet procurement targets for a clean electricity system.

The ideas proposed herein include both programmatic options and policy matters for consideration by the CPUC. While PG&E addresses aspects of the Staff Concept Paper (SCP), it also advances additional ideas as part of a comprehensive suite of options for vetting by the CPUC. Moreover, the proposals are not limited to electric demand and supply issues identified in the Scoping Memo. For instance, PG&E advances action on the gas side of the business in order to support electric reliability.

Section B of this chapter summarizes PG&Es demand side options while section C summarizes supply side options. Lastly, section D advances a core gas proposal as part of PG&E’s “out of the box” thinking.

B. Demand Side

PG&E commends the CPUC for its SCP, which served as an impetus for ideation. PG&E observes that the SCP's core strength is based on the idea of expanding the Emergency Load Reduction Program (ELRP) to auto-enroll residential participants. To this end, PG&E provides its assessment and proposal for implementing a residential ELRP offering leveraging its prior proposal for the Power Saver Reward Pilot (PSRP). Similarly, the SCP identifies a number of enhancements for the existing non-residential ELRP offering, which in some cases PG&E supports and in other cases believes requires additional data or clarification before an informed decision can be made.[1]

In the spirit of continued optimization of its existing demand response (DR) portfolio, PG&E identifies a number of enhancements to its current DR programs. Specifically, the Base Interruptible Program, the Capacity Bidding Program, and the SmartAC™ Program. The proposed modifications are intended to address participation levels (i.e., increasing enrollment and reducing attrition), along with increasing availability and performance of PG&E's existing DR programs. Separately, PG&E addresses its recently filed PSRP, which was originally a carry-over proposal from Phase 1 of the Rulemaking.

An important aspect, which the SCP touches on, pertains to leveraging technology to engage a broader set of Distributed Energy Resources (DER), including but not limited to, Electric Vehicles, battery storage, Smart Thermostats and Energy Efficiency. To this end, PG&E requests that its DR Emerging Technology funding be appropriately sized in order to optimize DR and the deployment of DERs. As a plug-in to boosting the role of DERs, PG&E provides an assessment of ideas advanced by the SCP in order to address policy issues in a true Integrated Demand Side Management manner.

PG&E observes that the role of third-party DR is crucial in supporting California's grid needs. To this end, PG&E seeks funding to enable scaling of its Share-My-Data platform to meet the rapid and significant increase in customer

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1 PG&E believes that the certain programmatic modifications should be informed by an analysis of activities and performance after the first ELRP season concludes at the end of October 2021. Consequently, the option to make enhancements through a year-end Tier 2 joint Investor-Owned Utility filing should be utilized as called for by the Phase 1 D.21-03-056. This is discussed in further detail in Chapter 2 of PG&E's testimony.

enrollments projected by third-party party DRPs under Rule 24. Separately, PG&E shares its perspective on the SCP's proposal for the DR Auction Mechanism.

Lastly, PG&E provides its perspective on how to address tracking of and recovery of costs associated with Phase 2, which would leverage the mechanisms developed in Phase 1 of this proceeding.

C. Supply Side

PG&E appreciates the SCP and solutions-oriented approach to proposals that will address the reliability needs for the summers of 2022 and 2023 during the net peak window. In Chapter 7, PG&E provides comments on the various items proposed in the SCP and opposes the proposed modifications to the penalty structure for both the IRP and RA programs and bundled procurement plan rules for hydroelectric generation. PG&E instead builds upon some of the ideas in the SCP to propose: (1) interim modifications to the centralized procurement framework for local RA; and (2) continued use of the procurement approval process adopted in Phase 1 of this proceeding.

D. Gas

PG&E proposes a change to its Gas Rules and Tariffs that would support the California Independent System Operator (CAISO) grid when faced with emergency situations that would also support the needs of our electric customers for 24/7/365 electric reliability on their premises via clean-burning gas-fired backup generation. PG&E proposes a rebalancing of our Gas Rules and Tariffs that would: 1) allow larger generators to request Core Transportation Service for Generators, 2) require that they would pay for any necessary transportation system reliability upgrades, and 3) continue to prohibit these generators from receiving Core Procurement service from either PG&E as bundled service or via a third party Core Transport Agent.

Gas-fired generation allowed under this proposal would allow customers to choose to install clean-burning generation in place of installing diesel[2]. These customers would also have procurement options from the gas marketplace for

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2 Joe Lyou and Fran Pavley, "Wildfires Create Need for Clean Backup Power Generation," Mercury News – Opinion: https://www.mercurynews.com/2021/09/01/opinion-california-needs-to-invest-in-clean-backup-power-generation/.

Renewable Natural Gas, etc. Diesel generation is limited in operation by air pollution requirements to situations when on-premise electric service is interrupted. However, if these generators cannot receive Core Transportation reliability under PG&E's core G-NR2 (Large Commercial) tariff and instead face the risk of curtailments under PG&E's noncore G-EG (Electric Generation) tariff they will instead choose diesel generation due to their essential use needs for electricity 24/7/365.

PG&E's proposed change provides a rebalancing of our rules and tariffs to meet today's needs in support of CAISO stability, our customer's needs, and California and PG&E's shared goal for emission reduction.

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CHAPTER 2

EMERGENCY LOAD REDUCTION PROGRAM

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EMERGENCY LOAD REDUCTION PROGRAM

A. Introduction

This chapter addresses the existing Emergency Load Reduction Program (ELRP) for the current non-residential offering along with a proposed residential offering based on the Staff Concept Paper (SCP).[1] The current non-residential offering is addressed in Section B of this chapter while Section C addresses the residential offering proposed in the SCP.

B. Modifications to Existing Non-Residential ELRP

1. Energy Division Staff Proposal

The SCP identifies several proposed modifications to the non-residential offering, which Pacific Gas and Electric Company (PG&E) addresses herein.

a. Increased Compensation

Section A.1.a. of the SCP proposes an increase in compensation rates from $1/kilowatt-hour (kWh) to $2/kWh. It is not clear to PG&E if doubling of incentives at this point in time is justified. PG&E believes the issue of increasing the incentive level should be addressed after the first season has ended in order to assess the need for higher incentives based on overall enrollment levels and performance. Without prejudging the outcome of a higher incentive level, PG&E questions why higher incentives would be limited to A.1 and A.2 participants.[2] It would seem if incentives are raised then they would apply across the ELRP offerings, which would presumably include Sub-groups A.3 and A.4 along with Group B participants, and any other sub-groups being contemplated as part of SCP.

Separately, the SCP qualifies higher incentives as being "limited to customers who commit to providing a certain load reduction performance level." PG&E understands the "certain load reduction

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[1] Energy Division SCP covering Proposals for Summer 2022 and 2023 Reliability Enhancements dated August 16, 2021.

[2] SCP at p.4.

performance level" to be measured as the difference between the nominated amount and the measured load drop. The challenge with this proposal is that ELRP is a voluntary, no penalty program developed to promote participation. Therefore, imposing a performance requirement seemingly goes against the framework advanced in the original design of ELRP per Decision (D.) 21-03-056 in Rulemaking 20-11-003.

In lieu of having an explicit performance requirement, which could discourage participation, PG&E recommends the California Public Utilities Commission (CPUC or Commission) consider an adder (i.e., bonus) for performance that meets a specific criterion. For instance, an Incremental Load Reduction (ILR) that exceeds a certain percent of the nominated quantity could be eligible for an adder. Such an adder could increase with higher levels of performance based on bands (e.g., 50-74 percent, 75-100 percent, etc.). While, PG&E does not propose a specific adder amount or band level, as it believes the CPUC should make that determination, the following table provides an illustrative example of an adder mechanism.

TABLE 2-1
ILLUSTRATIVE ELRP COMPENSATION BAND

Line No.	Band	Base Compensation	Adder (Bonus)	Total Compensation
1	<50%	$0	$0	$0
2	50%–74%	$1.00	$0.50	$1.50
3	75%–100%	$1.00	$1.00	$2.00

All told, if the CPUC determines that a higher incentive is warranted, then PG&E requests that the Commission raise the annual incentives cap of $28.6 million adopted in the Phase 1 decision (D.21-03-056), commensurate with the increased incentive level for the current non-residential ELRP.[3] See additional details in Section D of this chapter pertaining to funding of the current ELRP.

3 If the CPUC doubles the current incentive of $1/kWh to $2/kWh, then the current $28.6 million spending cap should be doubled to $57.2 million. This increase doesn't necessarily mean that actual incentive payments will reach the cap, but rather there is authority to do so.

b. Group A Enhancements

The SCP proposes to reduce the “Minimum Size Threshold,” which varies by investor-owned utilities (IOU). The SCP also suggests removal of the 50 percent to 200 percent compensation band.

Because PG&E’s minimum participation level is only 1 kilowatt (kW),[4] it does not believe this threshold should be modified because it is low enough to accommodate participation by both large (CIA)[5] and mid-sized (SMB)[6] participants.

PG&E believes a compensation band for large participants is appropriate with the exception of those dually enrolled with the Base Interruptible Program (BIP) and ELRP.[7] Separately, PG&E supports removal of the compensation band for mid-sizes customers in order to encourage and facilitate participation by this customer class.

On a related matter, if the CPUC eliminates the compensation band for SMB and exempts BIP participants who can drop below their FSL, it may be reasonable to adjust the lower end of the collar to be less than 50 percent. This would still allow for compensation for customers who are below the 50 percent performance level. However, PG&E believes it would make sense to wait until the ELRP season concludes at the end of October in order to make an informed assessment about performance and the appropriate adjustment to the collar, if any. PG&E notes the Phase 1 Decision allows the IOUs to “modify various aspects of ELRP design” through a joint Tier 2 filing by December 31 of each program year.[8]

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4 D.21-03-056, Attachment 1 at p.5, Southern California Edison Company’s (SCE) participation requirement is that a customer must have a peak demand equal to or greater than 200 kW; San Diego Gas & Electric Company’s (SDG&E) participation threshold is that the customer must agree to drop at least 100 kW during an event.

5 CIA = Commercial, Industrial and Agricultural.

6 SMB = Small-Medium Business.

7 D.21-03-056, Attachment 1, pg. 10 stipulates that “…only the incremental reduction below the customer’s pre-committed firm service level (FSL) is counted in ILR.” Therefore, the FSLs serves as an implied ceiling from where a load reduction begins.

8 D.21-03-056, Attachment 1 at p. 15.

c. Group B Enhancements

The SCP proposes adding a DO of trigger for ELRP. In response, PG&E believes having parity between Groups A and B would be beneficial and therefore supports this proposed modification.

The SCP proposes to add a Day-Of (DO) trigger for Group B participants and proposes to cap bids at $900/megawatt-hour (MWh) by Real-Time (RT) Proxy Demand Response (PDR) resources participating in the California Independent System Operator's (CAISO) energy market. PG&E questions why the BIP trigger price of $950/MWh, which is an emergency DR program leveraging the CAISO's Reliability Demand Response Resource would be tied to the economic PDR product. Moreover, it is not clear to PG&E to what extent RT PDR is utilized in the CAISO market today.[9] Relatedly, even if a RT PDR participates in ELRP, the IOUs have no visibility into bids made by third-party DR Providers. Lastly, PG&E's understanding is that the CAISO's market price bid cap has increased from $1,000/MWh to $2,000/MWh for certain resources,[10] which merits an evaluation of how PDR should be assessed relative to other resources, especially during emergencies. Consequently, PG&E cautions against adopting this proposal at this time.

2. PG&E's Proposal for ELRP Enhancements

a. Removal of the "Special Consideration" Provision.

PG&E recommends that the CPUC reconsider and remove parts (a) and (b) of the "Special Considerations" provision in D.21-03-056.[11]

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9 PG&E's Capacity Bidding Program (CBP) is Day-Ahead. While both SCE And SDG&E offer DO CBP options, it's not clear to PG&E if these DO options are true RT offerings. Separately, PG&E does not have visibility into the bidding options utilized by third-party demand response (DR) providers who are either participating in the Demand Response Auction Mechanism (DRAM) or outside of DRAM.

10 FERC Order 831 called for CAISO's $1,000/MWh bid cap to increase to $2,000/MWh for certain resources. An April 2021 presentation by the CAISO, indicates that Non-Generating Resources (NGR) would remain at $1,000/MWh. However, it's not clear if DR resources would fall under the NGR classification.

11 Attachment 1 of D.21-03-056 at p. 10 states:

> In the case of overlapping BIP and ELRP events, only the incremental reduction below the customer's pre-committed FSL is counted in ILR.

Parts (a) and (b) of the provision diminishes the ability for dual enrolled BIP and ELRP participants to be compensated for ELRP during *non*-overlapping events. PG&E has observed that less than 1 percent of all Group A enrolled service agreements were from BIP customers as of mid-August 2021. PG&E believes the limited enrollment by BIP participants in ELRP may be a result of Special Considerations Parts (a) and (b). Removing these limitations could create additional participation by large customers who are enrolled in BIP.

C. Addition of a Residential ELRP Option (A.5)

PG&E agrees with Energy Division Staff that there is significant potential to leverage the voluntary load reduction of residential customers, as the majority of residential customers do not participate in load-modifying (LMR) or supply-side (SSR) DR programs. The SCP introduced the concept of expanding ELRP to include a residential participation option (A.5) providing performance compensation to all individual customers who decrease their energy use during Flex Alerts or day-ahead CAISO Alert based on CAISO's Alerts, Warning, and Emergency notices (AWE). By way of comparison, PG&E notes that it had included a very similar participation option (Option A) for residential customers as part of the Power Saver Rewards Pilot (PSRP) proposal, which PG&E filed in Phase 1 of this proceeding.[12] PG&E's PSRP Option A proposal is a behavioral DR program which would auto-enroll 1,600,000 customers who receive Home Energy Reports to motivate and encourage load reducing efforts on event days. The proposal provides the flexibility to experiment with a smaller group of customers.

1. General Program Design

A DR program such as A.5, where the utility or a third-party provider is not dispatching technologies to achieve load reduction or invoking program or rate-based penalties, is considered to be an entry-level approach into DR

(a) Load reduction by dual-enrolled BIP customers during an ELRP event outside of a BIP event is excluded from ILR (and not eligible for ELRP compensation).

(b) Load reduction by dual-enrolled BIP customers during an ELRP event on a day with no BIP event is excluded from ILR (and not eligible for ELRP compensation).

12 PG&E filed the PSRP Supplemental Testimony on July 7, 2021.

for residential customers. It leverages the known widespread Flex Alert campaign as a trigger to call events. PG&E A.5 offers personal notifications versus the broadcast messaging of Flex Alerts as personal notifications typically results in greater participation. Additionally, personal, targeted notifications will result in less confusion given some customers are already participating in a DR program or may have recently received notifications to transition to a Time-of-Use (TOU) rate. Customer confusion and fatigue is an important consideration given the number of communications regarding TOU and Flex Alerts that have occurred over the last year. These personal notifications can be received by customer via a range of options including, but not limited to, emails, text messages, or mobile application. These notification options can send event day information and thank you emails with corresponding performance report after event day. Education on ways to save energy on event days and every day is an important element in program materials. The program will regularly review customer education and outreach materials in order to increase customer awareness and event performance.

Customers do not need to take action to enroll in this program because the operational implementation revolves around auto-enrollment of customers and implementer system checks that ensure event notifications and program communications are only sent to customers who are not on other DR programs, whether with PG&E, a third-party Aggregator or another Demand Response Provider (DRP).

a. Program Trigger

This subgroup of ELRP follows suit in the objective to help prevent power interruptions by offering advance notification to residential customers that the CAISO has initiated via Flex Alert or Alert as part of CAISO’s AWE for the following day.

TABLE 2-2
ELRP A.5 TRIGGERS

Line No.	Type	Description	Timeframe
1	Flex Alert	Call for conservation	Generally Day-Ahead
2	CAISO Alert	Anticipated operational reserve deficiency	Called by 3 p.m. Day-Ahead

b. Demonstration The Program Will Deliver Benefits During Net Peak

This type of DR program was studied by PG&E in 2015 and 2016 under PG&E's Transmission and Distribution pilot and was implemented by Opower (Oracle), which also administers the PG&E Home Energy Reports (HER).[13] Both HER recipients and non-HER customers were subjected to events. The program leveraged randomized control trials. In all, 110,000 customers were included in the treatment group that received personalized messaging over the course of the two-year pilot. The load impact results were based on whole home meter data and were compiled by Nexant, an independent evaluator. The final report is available on California Measurement Advisory Council (CALMAC).[14] On page 22 of the report, Nexant identified that the change in behavior on DR events days was 0.06 kW per customer averaged across event hours. The range fluctuated between 0.04 and 0.07 kW per customer and PG&E leverages these results in forecasting A.5 per customer load impacts. PG&E believes that offering incentives would increase performance.

c. Program performance requirements

Customers are not penalized for lack of performance but rather are encouraged to reduce their energy use through continuous individualized messaging, which includes educational tips and tools. Further, the incentive being proposed in this program would motivate customers to participate and take action on event days.

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13 The HER program is a behavioral intervention that delivers personalized usage information to customers by mail or email. As in BDR, a key feature of the information feedback is a comparison of each customer's usage to that of their neighbors.

14 CALMAC: "Behavioral Demand Response Study – Load Impact Evaluation Report," CALMAC ID PGE0464

d. Compensation structure

Customers who do respond to notifications to reduce their energy use during alert days would be compensated based on their actual performance as measured with their whole home's meter data. PG&E participants would receive compensation through electronic gift cards or other efficient methods as opposed to a utility bill credit. PG&E would work with a third-party to explore a point system which would allow customers to accumulate points based on their load reduction performance for each event. Table 2-3 is an illustrative example of how much a customer could earn based on their performance. Examples capture an assumption of 60 event hours per year, which is the maximum number of hours in the current ELRP:

TABLE 2-3
ELRP A.5 INCENTIVE ESTIMATIONS

Line No.	Estimated kW reduction per hour	Est. # of Hours / Year	$/kWh	Est. Annual Incentive
1	.04			$2.40
2	.08			$4.80
3	.12	60	$1 per kWh	$7.20
4	.20			$12.00
5	.40			$24.00

e. Program Eligibility, Enrollment and Dual Participation

ELRP A.5 will generally apply to all PG&E residential bundled electric service account customers who are not participating in other DR supply-side programs with PG&E or another DRP and a PG&E load-modifying program, such as SmartRate. PG&E requests guidance on whether the program should automatically default Community Choice Aggregation (CCA) customers in this program. If the CPUC thinks that the IOUs should auto-enroll CCA customers, PG&E requests that it specify the procedure for PG&E to work with all the CCAs in PG&E's territory to resolve outstanding actions, such as disqualifying CCA customers that are part of an existing CCA Load Modifying Program or dynamic rates. In addition, PG&E strongly recommends that any auto-enrollment of CCAs should be "all or nothing" (i.e., all CCA providers participate or no CCA providers) in order to streamline the enrollment process and ensure availability by June of 2022.

While PG&E has approximately 4.8 million residential electricity customers, not all can easily participate in this program due to a variety of reasons. For example, the property where a customer resides must have a Smart Meter. There are rental properties where the occupant is not on the account record so the landlord would only receive the notifications and the notifications would not reach the actual occupant. Customers without email addresses or cell phone numbers cannot be included because they cannot receive the notifications in time to act for a next-day event. If all CCA customers are included with bundled, the total customer count is estimated at 3,000,000. If bundled only it is approximately 1,600,000 currently.

With regard to handling dual participation, customers under ELRP A.5 would not be registered by PG&E in the CAISO Demand Response Registration System (DRRS). Additionally, PG&E's daily system process checks for event eligibility would omit any customers who are registered in DRRS and/or participating in a non-market integrated program.

Customers do not have to "unenroll" in order to join other DR programs or dynamic rates because they are not registered with PG&E as with traditional DR programs.

PG&E notes that from a process standpoint that within seven business days of being registered in DRRS with another DRP, PG&E sets a flag in the PG&E billing system indicating a customer is registered with a third-party. These customers would simply no longer be eligible to receive ELRP A.5 communications because PG&E's daily process would identify them as affiliated. Daily updates of customer records ensure that only "new customers"[15] receive the alerts which assures growth of DR versus creating competition with any other DRPs or Load Serving Entities.

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15 CEDMC Reply Testimony to PG&E and California Environmental Justice Alliance's Supplemental Testimony, p. 6, line 1

f. Measurement and Verification, if Needed

Measurement and evaluation of this subgroup would be conducted as a component of the overall annual ELRP measurement and evaluation process.

2. Program Administration (including who would administer the program)

PG&E would partner with a third-party who would primarily be responsible for implementation including providing customer facing materials, system checks for executing the notifications, performance measurement, and incentive payment. PG&E would partner with an experienced third-party to implement this large-scale participation option in order to launch by the end of May 2022.

3. Program marketing, outreach, and education

Marketing efforts of this subgroup are largely associated with the creation and updating of educational communications and components of the program.

The A.5 participation option of ELRP would not include recruitment activities because eligible residential customers would be automatically enrolled. Because "ELRP A.5" is not a residential customer friendly name, PG&E would identify a branded name for the program on all customer facing materials.

Notifications before event days would incorporate education on effective ways to reduce energy use during event hours. After-event communications would thank customers for participating and would continue with education to encourage customers to reduce energy use through suggested efforts.

If Flex Alert marketing changes to promote customer participation in the residential ELRP A.5 on Flex Alert days, PG&E recommends this be explored by the Flex Alert working group before adjusting messaging. Several items to avoid customer confusion should be considered prior to a shift in messaging, including determining the appropriate time to transition messaging (i.e., when all customers have been defaulted to the ELRP program) and avoiding the duplication of related notifications by the ELRP program and the statewide Flex Alert campaign through the same channels.

Any change in the messaging direction may necessitate a change in the scope that was developed by the Energy Division staff and SCE, who holds the statewide contract for 2021 and 2022.

4. Program Budget, Including Breakouts for Administrative Costs, Marketing, Evaluation, and Breakouts for Startup Costs, Incentive Payments (if applicable), and Ongoing Program Administration

Incentive payments to customers would be in the range of 48-57 percent of the overall budget for this ELRP subgroup. Marketing costs are largely associated with the creation and updating of educational communications and components of the program. Administration consists primarily for the costs of the implementation by the third-party vendor.

TABLE 2-4
ELRP A.5 TWO-YEAR BUDGET

WITH CCA ~ 3,000,000 Customers	Start-Up	2022	2023	Total	% of Budget
Administration	$750,000	$8,400,000	$8,500,000	$17,650,000	40%
Marketing, Education & Outreach	–	500,000	500,000	1,000,000	2%
Measurement & Evaluation	20,000	200,000	200,000	420,000	1%
Incentive	–	12,744,000	12,744,000	25,488,000	57%
Total	$770,000	$21,844,000	$ 21,944,000	$44,558,000	

WITHOUT CCA ~ 1,600,000 Customers	Start-Up	2022	2023	Total	% of Budget
Administration	$750,000	$6,600,000	$6,700,000	$14,050,000	48%
Marketing, Education & Outreach	–	500,000	500,000	1,000,000	3%
Measurement & Evaluation	$20,000	200,000	200,000	420,000	1%
Incentive	–	6,796,800	6,796,800	13,593,600	48%
Total	$770,000	$14,096,800	$14,196,800	$29,063,600	

5. Implementation Timeline

PG&E would launch ELRP A.5 by end of May of 2022 which would render it available for dispatch in June of 2022.

6. Program Duration

While the Scoping Memo is requesting proposals for 2022 and 2023, ELRP A.5 could be extended beyond the next two years, depending on the success of the program and whether grid challenges continue to exist.

7. Estimated Megawatt Contribution/Load Impact (including whether load impact will reduce the demand at net peak hours, and whether and how much the load impact may reduce the impact of any existing programs)

The program could provide up to 212 megawatt (MW) of load reduction per event if offered to all bundled and unbundled customers and 113 MW if CCA customers are not included.

8. Potential Interaction With Other Existing Programs (i.e., dual participation issues)

Participants who are already enrolled in a PG&E or third-party DR supply-side or load-modifying program, including PG&E's SmartRate, would not be eligible to participate and would not receive alerts and communications associated with this program.

9. Prior Similar Program Experience in California or Elsewhere

See details provided under Section C.1.b.

10. Program funding and cost recovery mechanisms

See Table 2-4 for the proposed budget for this program. The funding and cost recovery would be similar to how the other subgroups of ELRP are handled from Phase 1 of the Rulemaking. See Section D of this chapter for additional details on cost recovery and pro-forma estimates for ELRP A.5 using both the existing the current $1/kWh incentive level along with a higher $2/kWh incentive level.

11. Potential Risks of Proposal (e.g., delay, lack of participation, low megawatt contribution, etc.) with discussion of each potential risk

While PG&E presents scenarios to include bundled and unbundled ELRP A.5 to all customers, not including CCA customers (subject to Section 1.e above) may limit the value of this program. PG&E has presented budget and load impact scenarios with and without CCA and requests guidance on this matter.

PG&E notes that certain communications to customers who are auto-enrolled into ELRP A.5 could be subject to the Telecommunications Consumer Protection Act, which may require prior customer consent for telephonic communications. Obtaining such consent could be a significant challenge based on the large number of potential participants.

D. Funding

PG&E appreciates the ability for PG&E to shares its perspective on the existing ELRP and ideas on the implementation of a residential A.5 offering. PG&E believes that the existing mechanism for tracking and recovering costs for ELRP could be leveraged for A.5 with CPUC authorization. Specifically, funding could be authorized to be tracked and recovered in the current ELRP sub-account of the DREBA balancing account. This sub-account would require that the CPUC set a new spending cap based on whether the CPUC raises the current incentive structure and whether it approves the residential A.5 offering. While further details are found in Chapter 10 of this testimony pertaining to cost recovery, the following table provides an illustration of the funding levels that would be required at different incentive levels ($1/kWh vs. $2/kWh) for both the existing ELRP (non-residential) and ELRP A.5.

TABLE 2-5
PROJECTED ELRP FUNDING LEVELS BASED ON INCENTIVES

Line No.	Description	2022	2023
1	ELRP: Non-Residential		
2	$1/kWh	Phase 1 Authorization exists (no action needed)	To be requested in the 2023-2027 DR Application
3	$2/kWh	$28.6M of incremental authorization required for 2022	Conditional request in 2023-2027 DR Application if Phase 2 authorizes increase
4	ELRP: Residential (A.5) *[bundled and unbundled]* (*)		
5	$1/kWh	$22.6 million of incremental authorization per year	$21.9 million of incremental authorization per year
6	$2/kWh	$35.4 million of incremental authorization per year	$34.7 million of incremental authorization per year

Note: (*) Start-up costs are included in 2022.

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CHAPTER 3

POWER SAVER REWARDS PILOT

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CHAPTER 3
POWER SAVER REWARDS PILOT

On June 14, 2021, PG&E was invited to submit supplemental testimony in Rulemaking (R.) 20-11-003 on a new residential rewards pilot which was submitted under Phase 1. On July 7, PG&E submitted an extensive refreshed proposal under the name Power Saver Rewards Pilot (PSRP or Pilot). The Pilot prioritizes the recruiting of Demand Response (DR) megawatts (MW) to be used for emergency purposes while also seeking significant shift and load reduction during peak and net peak periods beginning in 2022 with the response to Time-of-Use (TOU) rates.

The primary program design of PSRP consists of three core components as participation options for customers:

1. **Behavioral DR (Option A)** – An auto-enroll approach to a communication-based program alerting 1,600,000 customers who receive PG&E's Home Energy Reports to event days to motivate and encourage load reducing efforts during event hours.
2. **Smart Technologies DR (Option B)** – A technology-based program for customers with qualifying technology such as smart thermostats, electric vehicle chargers, and heat pump water heaters for dispatch during DR events.
3. **TOU Technology-Assisted Response (Option C)** – For customers with smart technologies who have transitioned to TOU rates and have capable technology, PG&E would dispatch the technology according to the customer's TOU rate schedule to help them save.

The request for supplemental testimony indicated a date of July 21 for reply testimony and parties offered a range or questions and concerns. A schedule was not provided for rebuttal testimony.

In an August 16, 2021 email ruling, Administrative Law Judge Brian Stevens shared the Energy Division Staff Concept Paper for the next phase of R.20-11-003. Among the many concepts presented, Section A.1.d. offered details on a new subgroup of Emergency Load Reduction Program (ELRP), presumably A.5, that would involve defaulting all eligible residential customers to this subgroup. As it reads, this is essentially Pacific Gas and Electric Company's (PG&E) Option A of PSRP but with a larger population of participants, including both Home Energy

Reports (HER) as well as non-HERs, and the addition of incentives for all participants, not just lower-income and disadvantaged community (DAC) customers.

In light of the representation of Staff's preference for an expanded version of Option A to fall under the ELRP, PG&E has considered possibilities for what to do with the remaining components of the PSRP proposal that pertain to smart technologies dispatch.

PG&E presents an approach in Chapters 2 and 4 of this opening testimony to proceed with the expanded PSRP Option A as ELRP A.5 and to incorporate elements of Option B and Option C within the SmartAC™ proposal. Although PG&E makes this current proposal, it defers to the California Public Utilities Commission (CPUC) for guidance on the most appropriate approach. If the CPUC does not approve ELRP A.5 and the expansion of SmartAC to include smart communicating thermostats, PG&E is prepared to proceed with PSRP.

The advantages of proceeding with PSRP are:

- PSRP provides a real-world environment to learn about leveraging Distributed Energy Resources (DER) into DR programs and provides a unique annual stakeholder interface process to ensure the latest strategies and technologies are considered.
- PSRP provides a path to expand to other DERs. With smart thermostats DR falling under SmartAC, there is a gap to work with other DERs in the DR portfolio. However, this gap could be filled through additional funding of PG&E's Demand Response Emerging Technology Program.
- PSRP Option A targets enrollment and communications to a smaller active group of customers and provides incentives for all lower-income and DAC customers, not just those that perform.
- PSRP provides flexibility to experiment with the right incentive levels, triggers and baselines.

Regardless of how the components of PSRP are implemented, all parties agree there is considerable opportunity to bring valuable load reduction from the residential population. Furthermore, as Staff points out in their concept proposal, there are issues of equity associated with fewer DR programs developed by the CPUC with incentive opportunities for residential customers. PG&E is prepared to help fill the gap by implementing some or all of PSRP or components within SmartAC and ELRP as we propose in this testimony.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

EXISTING DEMAND RESPONSE PROGRAMS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
EXISTING DEMAND RESPONSE PROGRAMS

A. Introduction

Pacific Gas and Electric Company (PG&E) proposes several enhancements to its existing Demand Response (DR) programs to enable further grid support and reintroduces a proposal from Phase 1 of the proceeding, consistent with the guidance provided by the Scoping Memo.[1] Specifically, enhancements are being proposed for the Capacity Bidding Program (CBP), the Base Interruptible Program (BIP) and the SmartAC program.

B. Capacity Bidding Program

1. Price Bid Cap

PG&E is reintroducing a proposal from Phase 1 of Rulemaking (R.) 20-11-003 that would institute a price bid cap of $650/megawatt-hour (MWh) for its CBP Elect and Elect+.[2] While the original proposal was for years 2021 and 2022, PG&E now requests implementation of the bid cap for at least the years 2022 and 2023, with potential update beyond 2023. As PG&E indicated in its Opening Testimony to Phase 1, during the August 2020 heatwave a number of CBP Aggregators elected to bid their resources at, or close to, the California Independent System Operator's (CAISO) maximum bid price of $1,000/MWh, which resulted in about 45 percent of CBP resources not being dispatched. Had a bid cap of $650/MWh been in place, all nominated CBP resources would have been dispatched at least once during the August 2020 heatwave. Therefore, PG&E recommends implementation of the bid cap to facilitate dispatch of CBP resources.

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1 Assigned Commissioner's Amended Scoping Memo and Ruling for Phase 2 dated August 10, 2021 at p. 6 states: All proposals submitted by parties, but not addressed in the Phase 1 decision, may be considered in this Phase. If a party recommends such a proposal, it shall refer to the proposal in its Opening Testimony or Opening Brief.

2 PG&E's Opening Testimony, January 11, 2021, page 4-8 titled "Bid Cap."

2. Mandatory Weekend Participation

PG&E proposes to make the current weekend CBP participation option mandatory for at least 2022 and 2023. This expansion provides for additional grid support and leverages the existing weekend *option* that was approved in Phase 1 of this proceeding.[3] Moreover, the Resource Adequacy (RA) requirement for DR resources has been expanded to also include Saturdays as of RA compliance year 2022.[4] Therefore, PG&E would have been required to expand CBP availability to Saturdays to meet the new RA requirement. Recognizing the differential between weekdays and weekends, PG&E would continue with the current 25 percent adder for Saturdays and Sundays.

Making the optional adder mandatory is not expected to vary significantly in cost from the incremental cost projection assumed in Phase 1 of R.20-11-003. Consistent with Phase 1, PG&E plans to utilize the underspend currently authorized for CBP incentives in PG&E's current five-year (2018-2022) funding cycle for at least 2022.[5] However, if the current funding is insufficient then PG&E would request recovery of the shortfall as discussed in Chapter 10 of this testimony.

C. Base Interruptible Program

1. Enhanced Seasonal BIP Incentive

PG&E proposes to increase the current BIP compensation level by $1.00/kilowatt (kW) for *only* May-October for at least years 2022 and 2023. The shoulder months would remain at the current incentive level authorized in Phase 1 by Decision (D.) 21-03-056. The reason for the proposed increase is driven by a desire to encourage enrollment, recognize greater opportunity costs during the peak season (May-October), and to help "minimize loss of DR enrollment." PG&E acknowledges that the Phase 1 (D.) 21-03-056 made several modifications to the BIP tariff to encourage additional participation. However, based on experience to date in 2021,

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[3] D.21-03-056, Attachment 1 at p. 19.

[4] D.21-06-029 at p. 27.

[5] Year 2023 would normally be part of the next DR funding cycle covering 2023-2027.

PG&E has not seen the level of enrollments it had anticipated. The current and proposed incentive structure is summarized below in Table 4-1.

TABLE 4-1
SEASONAL INCENTIVE FOR BIP

Line No.	Potential Load Reduction	Current Incentive (Year-Round)	Proposed Incentive (May – October)
1	1 kW to 500 kW	$9.50/kW	$10.50/kW
2	501 kW to 1,000 kW	$10.00/kW	$11.00/kW
3	1,001 kW and greater	$10.50/kW	$11.50/kW

The projected incremental cost of raising incentives as proposed would range from $1 million to $3 million per year based on the level of BIP enrollment. PG&E forecasts that the additional funding needed for the higher incentives could be fully paid for by existing underspend in the authorized BIP incentives sub-category in PG&E's current five-year (2018-2022) funding cycle for at least 2022.[6] However, if the current funding is insufficient, then PG&E would request authority to recover the shortfall in the Electric Reliability Memo Account established in Phase 1 of R.20-11-003.[7] Therefore, PG&E requests the California Public Utilities Commission (CPUC) to allow PG&E to update its tariff to capture incremental activities associated with Phase 2 of R.20-11-003.

2. Waiver for Prohibited Resources

Consistent with the allowance for the use of backup generation for supporting ELRP and the waiver provided for BIP resources through the Governor's Executive Order issued July 30, 2021,[8] PG&E believes the CPUC should permit the use of backup generation to support BIP events in 2022 and 2023.[9]

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6 2022 is the last year of the current 2018 – 2022 funding cycle. 2023 at this point would be covered by the next DR funding cycle for 2023-2027.

7 D.21-03-056, Ordering Paragraph 18, enabled the establishment of a memorandum account to track budgetary shortfall. PG&E filed Advice Letter (AL)-6143-E and AL-6143-E-A to implement the cost tracking and recovery from D.21-03-056.

8 Section 4(c).

9 This request for waiver is limited to the CPUC's requirements established under Resolution E-4906. It does not pertain to permitting limits that may be imposed by the California Air Resources Board or local Air Quality Management Districts.

D. SmartAC

In order to further increase the peak and net peak value of PG&E's SmartAC program, PG&E proposes modifications and enhancements that can be adopted in entirety or incrementally.

1. Modifications to Existing Direct Load Control (DLC)

The SmartAC program is comprised of approximately 86,000 residential customers who have enrolled in the program since inception in 2007. 74,775 customers have legacy 1-Way commercial paging communicating technology and 11,225 customers have 2-Way communicating load control switches (LCS). PG&E offers the following modification opportunities that could result in net benefits to the resource.

a. Exchange 1-Way Technology for More Reliable 2-Way

Year over year, PG&E has consistently downgraded the value of the SmartAC program due to failing technology and the eroding paging network. Legacy 1-Way LCS and programmable communicating thermostats (PCT) are less effectively dispatched for CAISO market award events. Steady and modest annual campaigns consisting of approximately 1,500 exchanges of 1-Way LCS and PCT for a 2-Way LCS have proven beneficial. PG&E proposes a more aggressive campaign to be undertaken in 2022 and 2023, which would render the program to be more reliable and would provide increased value for years to come. The following is a comparison of the values of the SmartAC devices.[10]

TABLE 4-2
SMARTAC LOAD IMPACT (KW)

Line No.	SmartAC Device	Load Impact (kW)
1	1-Way LCS	0.38
2	1-Way PCT	0.20
3	2-Way LCS	0.57

10 2020 SmartAC Load Impact Evaluation Report, Table 3-8 and Table 3-9.

A lesson that has been gleaned from the annual campaigns is that when customers are reminded they are on the program, a high percentage no longer wish to remain on the program because SmartAC currently only provides a one-time incentive after device installation. To this end, PG&E proposes to add a $25 retention incentive for customers agreeing to a device exchange. While the retention incentive may interest many customers, there will be those that will still leave the program with this campaign. However, the net result will provide greater reliability and value. If PG&E can retain fewer customers that provide greater value, the SmartAC LCS program will be more cost-effective. The cost to complete the exchanges are a one-time cost, and upon completion of all the exchanges, the program will have lower operating expenses while providing greater load value.

TABLE 4-3
SMARTAC DEVICE EXCHANGE VALUES

Line No.			Values at Year End		
			2021	2022	2023
1	Customer Counts	1-Way Customers	70,959	30,253	0
2		2-Way Customers	11,100	39,273	59,139
3		# of Exchanges Completed		29,172	23,400
4		Customers Attrition		12,500	11,000
5	Capacity	1-Way Customer MWs	19.2	8.2	0
6		2-Way customer MWs	6.3	22.4	33.7
7		Gross MWs	25.5[a]	30.6	33.7
8		Incremental MWs	0	5.1	3.2

(a) Monthly Report on Interruptible Load and DR for June 2021.

b. Offer a Retention Incentive for Customers Who Request to Leave

Because retaining customers is more cost-effective than recruiting new customers, PG&E proposes to offer a one-time $25 retention incentive to customers who express a desire to leave the SmartAC program for reasons other than to join a third-party DR program. As stated in PG&E's Opening Comments of Phase 1, the SmartAC program typically experiences 9 percent annual attrition, primarily when customers move and there are upticks in attrition during heatwaves. The retention bonus could help to offset the uptick of customers leaving the program during heatwaves based on dissatisfaction with the experience and the fact that there is no ongoing incentives for them to remain in the program. Under PG&E's proposal, customers who would have already received a retention incentive as part of the 1-way to 2-way device exchange would *not* be eligible for an additional $25 retention incentive.

2. Expansion to Include Customer Installed Smart Controllable Thermostats (SCT)

PG&E had proposed a participation option for customers who have installed smart thermostats on their own in its Power Saver Rewards Pilot (PSRP) proposal in Phase I of this proceeding.[11] However, in this testimony, PG&E is proposing to develop this technology offering within the SmartAC tariff in lieu of implementing Options B and C within the proposed PSRP. This approach follows the path of Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) who have both DLC programs with switches and smart thermostat within their residential air conditioning DR programs. PG&E could implement this segment of the modifications as a two-year pilot to assess the overall potential impact to the SmartAC program's cost effectiveness.

a. SCT Option Design

As a pilot, this proposed segment of the SmartAC program would not be market integrated. Rather, PG&E would partner with a third-party to implement so as to leverage existing system integrations between the third-party and the thermostat manufacturers.

There are two primary components to this option:

- Recruiting customers who have already adopted qualified smart thermostats; and

[11] PG&E's PSRP Testimony was filed July 7, 2021.

- Providing an online store for customers who haven't adopted a smart thermostat yet to obtain one heavily discounted or for free—as long as they enroll in SmartAC.

This expansion would result in the enrollment of approximately 91,500 new customers into the SmartAC program[12] over the course of this two-year pilot and will provide 45 MW of incremental new load reduction.

PG&E would dispatch the smart thermostats during DR events and the devices will curtail energy based on pre-cooling and temperature set-back strategies. Customers will be motivated to join the program through the offer of an enrollment incentive and the commitment of an annual incentive.

Further, as identified in the PSRP proposal as Option C,[13] PG&E would dispatch a subset of the SCT according to the customer's time of use rate schedule and within parameters dictated by the manufacturers to help them save.

b. Enrollment, Eligibility and Dual Participation

The SmartAC program provides a direct-enrolled participation option for residential bundled customers. Community Choice Aggregation customers are also eligible. By leveraging existing workflows that automatically check for customer participation in other load-modifying or supply-side DR programs and with other DR providers, the SmartAC program avoids dual participation.

c. Dispatch Triggers

Unlike the DLC segment of the program, the SCT would not be dispatched based on CAISO wholesale market prices. The most effective triggers for this population would be based on CAISO Flex Alert and CAISO Alert as part of the Alert Warning Emergency Notices, local and system emergencies, and when demand increases due to higher temperatures.

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[12] Enrollment estimates provided by vendor currently implementing PG&E's PSRP.

[13] PG&E's PSRP Testimony filed July 7, 2021 at p. 6.

d. Compensation

Customers will receive an enrollment incentive of $75 and an end-of-year incentive, which could be a flat amount or based on performance calculations averaging $25 annually. Payment will be made in the form of an electronic gift card.

e. Marketing, Education and Outreach

As detailed in the PSRP proposal, PG&E has identified extensive marketing and outreach tactics to recruit customers with smart thermostats.

PG&E would leverage multiple channels and existing PG&E programs to promote the new SmartAC participation option to all residential customers, with intensified focus on low-income customers and those in Disadvantaged Communities. Recruitment efforts will consist of but not be limited to:

- Targeted campaign to convert existing SmartAC PCT participants to adopt a SCT and remain a SmartAC program participant;
- Outreach by smart devices' manufacturers through e-mails and technology platforms applications;
- Co-branded invitational and educational e-mails from the Pilot's implementers;
- Cross-promotional, invitational, and educational e-mails from PG&E to all applicable recipients of PG&E's technology rebates (e.g., energy efficiency, Self-Generation Incentive Program, Automated DR);
- Cross-promotion with other PG&E programs, such as low-income and energy efficiency programs;
- Integration of complementary messages with outreach in newsletters and other collateral;
- Embedded promotion in existing web-based tools in MyAccount and any other appropriate sites; and
- Coordination with the Energy Savings Assistance Program to train technicians to educate and recruit customers.

f. Estimated MW Contribution/Load Impact

Assuming enrollment estimates materialize, this expansion would yield approximately 91,500 new customers into the SmartAC program over the course of this two-year pilot and will provide 45 MW of incremental new load reduction.

g. Prior Similar Program Experience in California or Elsewhere

This expansion follows the path of SCE and SDG&E who have both DLC programs with switches and smart thermostat within their residential air conditioning DR programs.

Additionally, smart thermostat load impact values were substantiated by Nexant via a T&D Pilot that, among other things, studied "bring-your-own thermostat."[14] The pilot included Nest, ecobee, Honeywell, and Emerson thermostats, and concluded that PG&E could anticipate per-customer impacts in the range of 0.43 and 0.44 kW across all event hours. For the SCT pilot under SmartAC, PG&E will work with an implementation vendor whose dispatch platform can leverage sophisticated algorithms and effective pre-cooling strategies, and indicates 0.75 kW per customer is attainable. Subsequently, PG&E has conservatively forecasted an average of 0.50 kW per customer across event hours.

h. Measurement and Evaluation

This segment of the program would be evaluated in the annual Load Impact Evaluation conducted for the SmartAC program, which leverages load impact protocols and standard measurement methodologies.

3. Costs of Modifications and Expansion

Table 4-4 provides an overview of the incremental costs and benefits associated with the modifications described above. SmartAC will be utilizing existing underspend from the 2018-2022 funding cycle to cover a portion of the costs in 2022. As there is no authorized funding for SmartAC for program year 2023, PG&E requests the full costs of the proposed modifications. Table 4-4 represents the total costs for the modifications to

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14 "T&D Third-Party Bring Your Own Thermostat Demand Response Pilot Evaluation" CALMAC study ID PGE0465.

SmartAC and the funding requirements as it relates to administrative, incentive, and marketing categories.

TABLE 4-4
2022-2023 SMARTAC MODIFICATIONS – COST AND FUNDING REQUIREMENTS

Line No.		Program Modification Costs		Existing Funding	Funding Needed	
		2022	2023	2022	2022	2023
1	Admin					
2	1.a. Device Exchange	$2,944,884	$2,529,333	$2,760,127	$184,757	$2,529,333
3	1.b. Retention Incentive	–	–	–	–	–
4	2. SCT Expansion	2,819,930	4,118,451	2,760,126	59,804	4,118,451
5	**Admin Total**	**$5,764,814**	**$6,647,784**	**$5,520,253**	**$244,561**	**$6,647,784**
6	Incentive					
7	1.a. Device Exchange	$729,300	$585,011	$729,300	–	$585,011
8	1.b. Retention Incentive	10,257	3,782	10,257	–	3,782
9	2. SCT Expansion	4,475,817	5,474,678	2,030,143	$2,445,674	5,474,678
10	**Incentive Total**	**$5,215,374**	**$6,063,471**	**2,769,700**	**$2,445,674**	**$6,063,471**
11	Total Admin & Incentive	$10,980,188	$12,711,255	$8,289,953	$2,690,235	$12,711,255
12	Marketing					
13	1.a. Device Exchange	$100,000	$100,000	$4,495,916	–	$100,000
14	1.b. Retention Incentive	–	–	–	–	–
15	2. SCT Expansion	300,000	300,000	300,000	–	300,000
16	**Total Marketing**	**$400,000**	**$400,000**	**$4,795,916**	**–**	**$400,000**
17	**Total Admin, Incentive, and Marketing**	**$11,380,188**	**$13,111,255**	**$13,085,869**	**$2,690,235**	**$13,111,255**

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

THIRD-PARTY DEMAND RESPONSE PROGRAM

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A. Introduction

Pacific Gas and Electric Company (PG&E) appreciates the recognition in the California Public Utilities Commission (CPUC or Commission) Staff Concept Paper of the role of third-party Demand Response (DR) in supporting grid needs. In this chapter, PG&E elaborates on its comments filed with the Commission on August 6th in response to the *Email Ruling Seeking Responses Regarding a Proposed Amended Scope and Schedule to Address Reliability Issues in 2022 and 2023* pertaining to Information Technology (IT) enhancements needed in 2022 to PG&E's Share My Data (SMD) system to meet the customer enrollment growth projections of third-party DR Providers (DRP) in PG&E's Electric Rule 24 (Rule 24) program.[1] The SMD platform is essential for DRPs to be able to deliver resource adequacy from DR for PG&E and other Load-Serving Entities in PG&E's service territory, as well as to participate in Group B of the Emergency Load Reduction Program pilot.[2]

In Section B below, PG&E seeks cost recovery approval in the amount of $1.2 million for a set of targeted IT system enhancements to bolster the SMD platform so that it can meet the projected rapid and significant increase in third party DR enrollments and data access needs of third-party DRPs. In Section C, PG&E also recommends the Commission issue a timely decision on PG&E's proposal improvements described in PG&E's Improvements to Click Through Customer Data Access Application ("Click-Through Application"), Application (A.) 18-11-015.

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1 PG&E, Comments of Pacific Gas And Electric Company (U 39 E) On Administrative Law Judge Ruling To Notice A Pending Amended Scoping Ruling, August 6, 2021, page 9-10.

2 DRPs use SMD to seek customer authorization for the release of their data and to retrieve interval usage data and other customer data authorized under Rule 24 to enable DRPs to use the retail customer in the California Independent System Operator's (CAISO) wholesale market as Proxy DR.

B. Identify Any New Program or Modification to an Existing Program That Could Reduce Demand or Increase Supply at Net Peak?

PG&E notes that 2021 marks the start of mass market participation levels by third-party DRPs participating under PG&E's Rule 24 program.[3] As of August 31, 2021, there are approximately 120,900 customers registered in the CAISO's DR Registration System under PG&E's Rule 24 program. Based on growth projection figures provided recently to PG&E's Rule 24 team by several DRPs, participation in Rule 24 program could increase by hundreds of thousands of customers during the 2021-2023 timeframe.[4] PG&E has determined that significant risks now exist for the SMD service to successfully support the expected rapid loading on the SMD platform in advance of PG&E being able commence work on the IT projects included in PG&E's Click-Through Application. These risks, which are discussed below, are in addition to the issues addressed in PG&E's Click-Through Application scope. PG&E emphasizes that it needs the Click-Through Application approved to fundamentally meet the requirements from the expected growth. However, reducing the new risks identified in this testimony requires a decision in Rulemaking (R.) 20-11-003 this year in order to enable the SMD platform to support third party DRPs' reliability services in 2022 and 2023.

There are two categories of risk impacting the SMD platform that require immediate attention: (1) scalability; and (2) performance. Note that when PG&E filed its Improvements to Click-Through Application and Update, in November 2018 and 2020 respectively, the feature enhancements addressed in

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[3] In PG&E Advice Letter 6165-E, PG&E indicated that it regards the beginning of mass market levels after the number of CAISO DR Registration System registration/locations for third party DRPs exceeds 200,000. PG&E also asked for a Commission forum for third parties to provide their estimates about their expected demands for Rule 24 registrations to inform future increases in scale for Rule 24 and SMD systems. (Page 8.)

[4] Based on growth projection figures provided by several DRPs recently, PG&E believes that the volume of Rule 24 data sharing authorizations to support DRP's resource adequacy portfolios could reach approximately 217,000 at the end of 2021, increasing to 508,000 by the end of 2022 and 800,000 by the end of 2023. For comparison, the number of CAISO DR Registration System locations currently approved in CPUC Resolution E-4983 is 200,000.

that Application focused on performance with respect to Quick Response.[5] The Application, while touching on scalability, identified features and proposed a project budget based on linear growth of data access volumes for DRPs observed at that time. Given the rapid and significant growth in third party DR activity under Rule 24 at levels far exceeding participation levels assumed in the Click-Through Application, IT enhancements are needed immediately to mitigate the two new risks. Enhancements for scalability and general performance are not specifically in scope of PG&E's Click-Through Application and therefore the funding requested in this testimony are in addition to and not duplicative of the funding requested in the Click-Through Application. The new and current scalability and performance risks are described below in further detail.

1) Scalability: PG&E's current on-premise SMD infrastructure limitations mean that constraints hinder the SMD platform's capacity for handling forecasted volumes of data sharing authorizations and associated Application Programming Interface (API) calls for interval meter data and other Rule 24 data elements. This risk of system issues will increase as long as SMD infrastructure remains on-premise and is not cloud-based as proposed in PG&E's Click-Through Application.[6] Hence, gap measures are required to better manage scale on SMD's current on-premise infrastructure as a bridge until the eventual cloud infrastructure upgrade proposed in PG&E's Click-Through Application is developed and implemented. These specific bridge enhancements are described in more detail in Section 4 along with request for cost recovery for work to be completed by the end of 2022.

2) Performance: As a result of current on-premise SMD infrastructure limitations, PG&E has experienced several instances of system overloads, which hampered the SMD platform's ability to quickly respond to incoming data requests. There is increased risk of system latency, longer response times, or no responses to API requests as long as SMD infrastructure remains on-premise and coupled strongly to other backend systems. Here, a timely decision approving PG&Es proposed Click-Through Application will

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5 "PG&E Improvements to Click Through Customer Data Access Application Updated Testimony," A.18-11-015 U 39 E, November 13, 2020, Chapter 2. C Section 3.

6 Ibid.

facilitate better performance sooner rather than later, as touched upon further in Section C.

1. General Program Design

PG&E is not proposing any revisions to the Rule 24 program design.

a. Program Trigger

N/A

b. Demonstration That Program Will Deliver Benefits During Net Peak

N/A

c. Program Performance Requirements

N/A

d. Compensation Structure

N/A

e. Program Eligibility and Enrollment

N/A

f. Measurement and Verification, if Needed

N/A

2. Program Administration (including who would administer the program)

PG&E is not proposing any changes related to Rule 24 program administration.

3. Program Marketing, Outreach and Education

PG&E's testimony in this chapter does not include proposals for marketing, outreach, and education.

4. Program Budget, Including Breakouts for Administrative Costs, Marketing, Evaluation, and Breakouts for Startup Costs, Incentive Payments (if applicable), and Ongoing Program Administration

PG&E requests authority to recover $1.2 million to fund a set of targeted bridge enhancements for scalability of data access via SMD, all to be completed by the end of 2022, prior to the time when PG&E is able to begin and complete the scope of work proposed in PG&E's Click-Through

Application.[7] Importantly, PG&E's currently authorized 2021 and 2022 budgets for Rule 24 and the SMD funding levels are insufficient to meet these immediate bridge enhancements. For instance, pending budget requests for particularly relevant SMD enhancements as detailed in A.18-11-015,[8] for which IT systems work was originally forecast to begin in 2021, is still awaiting Commission decision.

In the Click-Through Application proceeding,[9] PG&E comprehensively described the characteristics of its on-premise SMD service and the meter data access it provides to DRPs and other external third parties for their energy service needs. DRPs have been particularly vocal to associate PG&E's data access service for daily interval meter data to the success of their market-integrated DR programs.[10] The added urgency of this proceeding together with the funding gap that exists until the Commission approves PG&E's Click-Through Application means that PG&E requires very specific IT bridge work to reinforce existing SMD services. Specifically,

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7 PG&E proposes to initiate a portion of the bridge enhancement work in 2021 in order to be able to better support third party DRP services in 2022.

8 "PG&E improvements to Click Through Customer Data Access Application Updated Testimony," A.18-11-015 U 39 E, November 13, 2020 Chapter 2.

9 "PG&E improvements to Click Through Customer Data Access Application Updated Testimony," A.18-11-015 U 39 E, November 13, 2020 Chapter 2, "PG&E improvements to Click Through Customer Data Access Application Rebuttal Testimony," A.18-11-015 U 3 E January 22, 2021, and "PG&E improvements to Click Through Customer Data Access Application Surrebuttal Testimony," A.18-11-015 U 39 E March 2, 2021.

10 "Improvements to the Click Through Authorization Process Prepared Testimony of OhmConnect, Inc.," A.18-11-015 et al. OHM-01, December 18, 2020, OhmConnect states as follows: "Data sharing processes, by definition, are IT systems processes made possible by the linking of multiple entities to facilitate the transmission of data. Specific to this proceeding, the click-through authorization process and the subsequent data sharing process require integration between the third-party DR provider systems and the Meter Data Management Agents (MDMA, i.e., the IOUs). The very nature of this relationship is that the entity receiving the data (the DRP) is completely reliant on the entity sharing the data (the MDMA) to have the opportunity to collect the data. Put simply, the MDMA is providing a data sharing service to the DRP(s). Furthermore, in California, access to customer smart meter data is available solely through the provision of this data by the MDMA. No other entity has immediate access to this information. Therefore, not only does the MDMA provide a service to the DRPs authorized to receive customer data, it is the only option, as the MDMA collects the data directly from its customers' meters and then chooses how to distribute it. Critically, this paradigm means that even if DRPs are unsatisfied with the level of service the MDMA is providing, there is at this time no alternative option."

PG&E proposes the following work to bridge this potential capability shortcoming forecast for 2022.

- Scalability Bridge and Stress Testing Remediation Work: PG&E requests cost recovery authorization in the amount of $1.2 million to fund IT bridge work to enhance SMD scalability to support the projected rapid increase in volume for Rule 24 customer enrollments and data access on the current on-premise infrastructure. The scope of work includes: caching pre-processed data warehouse tables used to support data queries by third party DRPs, performance tuning of those data queries, optimizing database connections, enabling more granular configurations and flexible responses from the API gateway, optimizing scheduled data extraction jobs for more efficient data access request handling, and adding physical data servers. In addition, PG&E initiated a stress testing program in April 2021 of existing SMD and Rule 24 systems and processes for purposes of identifying constraints due to supporting simulated mass market volumes for Rule 24 participation. The testing work is expected to be completed during the last week of August, followed by the identification in mid-September of IT system enhancements to resolve constraints identified from the testing.[11]

  PG&E's cost estimates for scalability bridge and stress testing remediation are summarized in Table 5-1 below.

TABLE 5-1
COST OF SCALABILITY BRIDGE AND STRESS TESTING REMEDIATION WORK
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Cost	2022
1	Expense: Scalability Bridge Work	$624
2	Expense: Remediation of Stress Testing Findings	576
3	Total	$1,200

[11] Given that this testimony is due several weeks prior to the time when PG&E is expected to have key remediation findings available from the stress testing, PG&E has developed a cost estimate totaling $576,000 based on similar IT work conducted earlier in 2021 to represent the possible costs for the remediation work. PG&E estimates that to address improvements from stress testing results, a development team with typical monthly cost of $96,000 will need to operate for six months.

As discussed in Chapter 10 on Cost Recovery, PG&E requests flexibility to shift funds between 2021 and 2022, as well as authority to shift funds across the various categories of bridge enhancement work described in this chapter to avoid any delays in work completion once the IT work has begun.

5. Implementation Timeline (must demonstrate program can be designed and fully implemented such that it can deliver demand reduction or increase supply at net peak for June 2022, and if not on this timeline, why the proposed timeline still provides benefit in addressing the summer net peak reliability need)

Ideally, PG&E would execute on a significant portion of the bridge enhancement scope of work in 2021. However, recognizing that there will likely only be a brief period of time between the date when the Commission is expected to issue a final decision on PG&E's proposals in this proceeding and the end of 2021, PG&E is designating the IT work to be conducted in 2022. If the opportunity exists, PG&E will attempt to commence work in 2021. PG&E underscores the importance of a timely decision by the Commission on this proposal to help ensure that PG&E can plan and stage resources to execute on the work deemed necessary for completion in 2022.

6. Program Duration

The IT enhancements described in this section are needed as a bridge given that PG&E's Click-Through Application is still awaiting Commission approval and recognizing it will take over 24 months for PG&E to complete the IT work described in Chapter 2 of the Click-Through Application. While PG&E cannot warrant that all work will be durable, the bridge features are nevertheless expected to be durable in that they enhance SMD in light of the current proceeding and the recent DRP growth forecasts.

7. Estimated Megawatt Contribution/Load Impact (including whether load impact will reduce the demand at net peak hours, and whether and how much the load impact may reduce the impact of any existing programs)

N/A

8. Potential Interaction With Other Existing Programs (i.e., dual participation issues)

N/A

9. Prior Similar Program Experience in California or Elsewhere

N/A

10. Program Funding and Cost Recovery Mechanisms

Please refer to Chapter 10, Cost Recovery.

11. Potential Risks of Proposal (e.g., delay, lack of participation, low megawatt contribution, etc.) With Discussion of Each Potential Risk

N/A

C. Identify Any New Policy or Modification to an Existing Policy That Could Reduce Demand or Increase Supply at Net Peak (for example a rule, regulation, incentive, penalty)?

PG&E highlights the importance for the Commission to issue a timely decision on PG&E's improvements described in its testimony for its Click-Through Application (A.18-11-015), which includes a wide range of IT systems and infrastructure enhancements to support performance on quick data response at mass market levels, as well as flexibility to handle a wider range of use cases related to the scope of the various proposals in the current proceeding, R.20-11-003. For example, features related to Role-Based data access and Quick Response are presented in Chapter 2 of PG&E's Click-Through Application in A.18-11-015 and are particularly relevant.[12] These enhancements are designed to resolve existing SMD feature and infrastructure limitations for the long term and are not duplicative of the bridge IT enhancements described in this chapter.

1. Duration – Temporary or Permanent

PG&E notes that the scalability bridge features are not to be interim in duration, but rather they are durable features that will persist and be utilized

[12] Refer to footnote 5.

even after the Click-Through scope of work is eventually completed. Therefore, most of the $1.2 million are durable expenses.[13]

2. Justification or Demonstration That Policy Will Support the Delivery of Reliability Benefits During Net Peak

N/A

3. Estimate of Policy's Impact (megawatts)

N/A

4. Implementation Requirements, Including Whether Other State Agencies or CAISO Must Approve

N/A

5. Potential Risk of Proposal

N/A

6. Statutory and/or Regulatory Justification and History (especially if recommendation is to change an existing policy)

N/A

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13 In the Scalability proposed budget, note that $120,000 out of $624,000 is allocated for new data servers, to help offset cost of physical server additions to the current SMD on-premise system. This is justified in order to support the expected volume by 2022, where SMD will still be on-premise based service owing to the fact that Click-Through Application decision is still pending. The physical server assets to be funded may be interim expense when the Click-Through Application funding is finally approved and SMD migrates to cloud-based infrastructure.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

DEMAND RESPONSE AUCTION MECHANISM

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DEMAND RESPONSE AUCTION MECHANISM

A. Introduction

The August 16, 2021, Energy Division Staff Concept Paper with Proposals for Summer 2022 and 2023 Reliability Enhancements (Energy Division Staff Paper) proposes (a) to expand the 2022 Demand Response Auction Mechanism (DRAM) pilot with a supplemental auction for demand response (DR) capacity delivered between June and December 2022, (b) to expand the budget of the 2023 DRAM pilot auction for DR capacity delivered between January and December 2023, and (c) additional requirements for these two auctions. As Pacific Gas and Electric Company (PG&E) stated in its rebuttal testimony in Phase I of this proceeding, PG&E strongly disagrees with expansion of the DRAM pilot beyond its existing scope.[1] While PG&E generally supports additional penalties for capacity shortfalls, PG&E's experience suggests that the additional requirements proposed will not sufficiently improve the performance and reliability of the DRAM resource.

B. PG&E Does Not Support an Additional 2022 DRAM Auction

PG&E's position has remained that it seeks the results of the DRAM evaluation ordered in Decision (D.) 19-07-009,[2] the stakeholder process to review the results, and the California Public Utilities Commission's (CPUC or Commission) final determination in the 2023-2027 DR application before any expansion of DRAM should be considered.[3] It is PG&E's experience that significant performance and reliability issues remain in the DRAM pilot, and that incremental modifications implemented since the last DRAM evaluation have not sufficiently resolved the deficiencies. It would be premature to consider

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1 PG&E Emergency Reliability OIR Rebuttal on DRAM Testimony, pp. 9-2, lines 12-18.

2 D.19-07-009, OP 16. p. 15 and p. 32. D.19-07-009 specifies that the draft evaluation report is to be issued no later than September 1, 2021, and a final evaluation report is to be issued no later than December 1, 2021; however, PG&E understands that this schedule may fall behind.

3 D.19-07-009 states on p. 27, "Because the Auction Mechanism has not successfully met all six criteria, we should not expand its role nor adopt it as a permanent mechanism at this time."

piecemeal modifications to the DRAM contract before obtaining the results of the DRAM evaluation and understanding the extent of the issues at play. At this time, the record does not support expansion of the DRAM pilot, and PG&E strongly believes it would be inconsistent with the type of reliability necessary for addressing the needs of this proceeding.

Simply comparing the amounts of capacity contracted in the DRAM pilot against delivered capacity suggests that capacity contracted for in the DRAM pilot is often not delivered. For instance, only 83 percent of the contracted capacity in the 2020 DRAM was committed on supply plans, and only 65 percent was delivered through a combination of the California Independent System Operator (CAISO) market dispatches, capacity tests, and, in the majority of months, CAISO market bids.[4] Evaluating solely the August 2020 performance, in which DRAM Sellers were required to conduct a two-consecutive-hour CAISO market dispatch or capacity test of all of their resources, only 60 percent of the contracted capacity and 69 percent of the capacity committed on supply plans was delivered to PG&E. Thus far, for the 2021 DRAM deliveries, the percent of capacity committed on supply plans compared to the contracted capacity falls to 74 percent for January through October 2021.

In addition, the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) filed a motion on June 16, 2021 requesting that the Commission evaluate the invoicing practices of third-party Demand Response Providers (DRP) in the DRAM pilot, stating that certain DRPs have invoiced demonstrated capacity that are greatly overstated compared to the reported performance reflected in CAISO settlement data. Cal Advocates stated that such "overstated performance results in ratepayers paying for services not received."[5] Such troublesome findings have not yet been fully investigated and it is not clear to PG&E what the magnitude of overstated performance results has been, what steps must be taken to address such issues, and whether the

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4 In fact, a number of resources committed on supply plans were not ultimately bid in the CAISO wholesale market as required for DR resources.

5 Motion of the Public Advocates Office for Evaluation of Third-Party DRP Invoicing Practices (Public Version), filed June 16, 2021, in A.17-01-012 et al, pp. 1-2. While the Commission ultimately rejected this motion, it reveals concerning information that PG&E was not previously aware of and is currently working with the Energy Division to investigate further.

DRAM contract fundamentally allows sufficient oversight and transparency to the investor-owned utilities (IOU) contracting for such capacity.

Further, PG&E notes that the DRAM market is consolidating and losing its competitiveness due to fewer bidders and offers. The independent evaluator for the DRAM request for offers (RFO) concurred, noting that “the response of the market was not robust” and “disappointing.”[6] The independent evaluator recommended a review and assessment of the factors leading to the decline in interest before proceeding with the next DRAM auction.[7] PG&E wholeheartedly agrees that further review is necessary before any expansion of DRAM is permitted, as such consolidation limits the competitiveness of the auction process and subsequent awards.

PG&E believes that these issues, among PG&E’s other experiences outlined in its previous testimony and experience to date,[8] are demonstrating a troubling trend that requires that the DRAM pilot be fully and formally evaluated before any expansion. PG&E believes that there are a wide range of other opportunities for third parties to contribute to reliability needs through other pilots, programs, solicitations, etc. that do not have the types of issues identified thus far in the DRAM pilot.[9]

C. If the Commission Orders Additional DRAM Auctions, PG&E Recommends a Stakeholder Process to Review Initial Evaluation Results and Propose Improvements

Although PG&E does not support an additional DRAM auction, if ordered, PG&E would support the institution of penalties for capacity shortfall based on

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6 PG&E Advice 6206-E, Appendix D (Public Version), p. 55. The independent evaluator, Merrimack Energy, has held this role through every DRAM RFO since 2016 for PG&E, Southern California Edison Company, and San Diego Gas & Electric Company (collectively, the joint IOUs, or IOUs).

7 PG&E Advice 6206-E, Appendix D (Public Version), p. 58.

8 This includes the reliability of DRAM resources identified in the Final Root Cause Analysis Report, insufficient penalties for underperformance, and weaknesses in the qualifying capacity assessment process. Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave Report, prepared by the CAISO, CPUC, and California Energy Commission, issued January 13, 2021, p. 56.

9 PG&E’s Capacity Bidding Program, Base Interruptible Program, and Emergency Load Reduction Program are open for enrollment. PG&E is also conducting several DR Emerging Technology pilots and conducting ongoing solicitations for resource adequacy capacity.

the capacity shown on the monthly supply plan relative to the contracted capacity.[10] The Energy Division's other proposed modifications to implement bid caps may be helpful, but it is not clear to PG&E that such recommendations would have any impact on or sufficiently address the troubling trends identified in the DRAM pilot thus far.[11] Further, one recommendation to require a Proxy Demand Resource to be maintained on a supply plan in each month since it is introduced suggests stricter requirements on DRAM participants than seem reasonable in managing a portfolio of customers with weather-sensitive DR capabilities.[12]

Should the Commission ultimately decide to order additional DRAM auctions and expand the budgets for the 2022 and 2023 DRAM pilots, PG&E recommends a stakeholder process that starts with a workshop to discuss the issues identified in PG&E's testimony and recommend more substantive modifications to the solicitation process and the contract. The IOUs should then follow similar processes as the existing refinements for each pilot year to submit a Tier 2 advice letter to seek Commission approval of such modifications before launching any supplemental auctions.[13] While PG&E acknowledges that this will delay the intended schedule beyond the ability to contract for 2022 deliveries, PG&E believes such steps are imperative before any additional ratepayer funds are allocated for DRAM auctions.

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10 Energy Division Staff Paper, section A.2.b.iv. PG&E supported penalties for capacity shortfalls in PG&E's Emergency Reliability OIR Rebuttal on DRAM Testimony, pp. 9-3, lines 25-28.

11 Energy Division Staff Paper, Section A.2.b.i-ii.

12 Energy Division Staff Paper, Section A.2.b.iii.

13 See D.19-12-040, OP 29.

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CHAPTER 7

DISTRIBUTED ENERGY RESOURCES

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DISTRIBUTED ENERGY RESOURCES

A. Introduction

This chapter addresses a number of issues raised in the Staff Concept Paper (SCP) pertaining to Distributed Energy Resources (DER). In order to facilitate piloting of ideas, Pacific Gas and Electric Company (PG&E) proposes to expand its Demand Response Emerging Technology (DRET) funding to accelerate a number of studies and pilots as described in Section B of this chapter. Section C, in response to the SCP, addresses Electric Vehicle Grid Integration (VGI) participation in the Emergency Load Reduction Program (ELRP). Section D addresses Energy Efficiency (EE) issues primarily focused on the utilization of smart controllable thermostats (SCT). Section E addresses SCT in the context of the Energy Savings Assistance (ESA) Program. In Section F, PG&E provides perspective on optimizing Integrated Demand Side Management (IDSM) Program.

B. Demand Response Emerging Technology Program

PG&E's DRET Program enables the assessments and studies of new technologies and applications, such as "smart" devices behind customers' meters, new Supply side and load modified demand response (DR) programs design, tools, channels, features to enhance customers' ability to perform in DR and dynamic rates. DRET assessments are designed to explore potential enhancements to the existing DR portfolio and inform the ongoing development of PG&E's DR pilots for future DR programs and dynamic rates. The results and lesson learned of these studies may help facilitate and scale DR integration into the California Independent System Operator (CAISO) markets in order to provide different grid services. PG&E provides semi-annual reports regarding its Emerging Technology projects to the California Public Utilities Commission (CPUC). These reports summarize each project, the potential benefits of the technology or technique, the activities undertaken as part of the project, and any available data and results. All of the DRET reports are published in the

Emerging Technologies Coordinating Council website[1] and DRET Program website.[2]

In 2018-2021, the DRET Program examined the following topics:

- Developing an Automated Demand Response (ADR) incentive for residential electric vehicle (EV) service equipment;
- Exploring using smart speaker, voice automation and mobile app for DR and dynamic rate notification;
- Providing residential rate in a digital format to third parties;
- Assessing a new DR Program design for Agricultural customers;
- Evaluating battery system load reduction shifting capability for DR, time-of-use (TOU) and hourly price signals;
- Evaluating SCT for DR and TOU optimization;
- Using Heat Pump Water Heater (HPWH) for Load Shifting; and
- Increasing adoption of HPWH through the mid-stream channel.

In 2019, PG&E's DRET Program worked with the internal EE team to study program implementation approaches and collect HPWH load shifting data that could be used for future "Watter Saver" program implementation. The DRET study was separated into two Phases. Phase One was a lab test and Phase Two was a field test. The study confirmed that the technology enabled electric water heaters to control water heater operations and recorded granular information about water heater energy use, temperature setting, operation modes. The process for dispatching and monitoring water heaters was fully automated and allowed testing of multiple algorithms. The algorithms clearly reduced peak demand over all five hours in the 4-9 p.m. window while avoiding increases in total daily energy use. The result of this study was used for program design for the "Watter Saver" Pilot and Self-Generation Incentive Program (SGIP) HPWH incentive.

In 2021, PG&E worked with a battery manufacturer to develop a Virtual Power Plant (VPP) DRET pilot which focuses on creating residential customer value and potential energy for the investor-owned utility (IOU) and the grid, through controlled behind-the-meter battery storage serving a single-family

1 https://www.etcc-ca.com/.

2 https://www.dret-ca.com/.

residential premise. Customers are compensated for export (to home and/or grid) from their battery during event-based dispatches by controlling the customer's enrolled battery in the manufacturer's platform.

The DRET Program is the most flexible and nimble program in the DR portfolio, which allows IOUs to evaluate, study and expand new DR and DER Technologies adoption for grid needs. As of August 2021, PG&E has fully committed its DRET Program funding for the balance of the current funding cycle ending in 2022. Therefore, PG&E is requesting authority to increase the DRET funding by $10 million in 2022 and up to $10 million in 2023 ($20 million total), thereby allowing PG&E to carry on with some of these new technologies that would be crucial in addressing the capacity shortage in summer of 2022 and 2023.[3] Chapter 10 of the testimony describes the cost tracking and recovery mechanism for DRET. If approved, the new budget may be used for the development or expansion of the following ideas and concepts:

- Increase adoption of residential and non-residential batteries for DR in coordination with SGIP, other customer programs and new offerings.
- Increase the number of customer and battery storage manufacturers in the VPP Pilot started in summer 2021.
- Explore and evaluate nascent technologies such as "Smart Electrical Panels" for use in DR and dynamic rates.
- New ways to streamline and simplify the DR program enrollment process.

C. Electric Vehicles and Vehicle-Grid Integration Related Modifications to Emergency Load Reduction Program

PG&E generally supports the SCP contemplating modifications to ELRP that integrate VGI use cases. VGI is a set of solutions covering unidirectional (V1G) and bidirectional charging (V2G) of EVs and can provide benefits to the customer and to the grid.[4] V2G use cases provide several options to support grid reliability and grid resiliency by either reducing demand or increasing supply

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3 The year 2023 would be covered in PG&E's next DR Funding Application, which at this time is due November 1, 2021. Accordingly, PG&E plans to also request $10 million in DRET funding for program year 2023 in its DR funding Application covering 2023-2027 due to the timing of the Phase 2 final decision targeted for November 18, 2021.

4 VGI Working Group Report: https://gridworks.org/wp-content/uploads/2020/07/VGI-Working-Group-Final-Report-6.30.20.pdf.

of energy from EV batteries. In Advice Letter 6259-E pursuant to VGI Decision 20-12-029, PG&E is proposing V2G pilot programs that intend to demonstrate deployment of V2G solutions at scale. *PG&E recommends accelerated approval of these pilot programs and funding to meet the need more rapidly for increased demand response.*

In the SCP, Energy Division's recommendations to modify ELRP specifically identify the following:

- Allow aggregators to utilize networks of unidirectional (V1G) or bi-directionally capable (V2G) charging stations (EVSEs) to be eligible to participate in ELRP, providing the aggregation can contribute incremental load reduction (ILR) exceeding the Minimum VGI Aggregation Size Threshold of 25 kilowatt (kW) within an IOU service territory.
  - PG&E supports this option. Based on internal analysis, the 25-kW threshold is a realistic target. However, PG&E points out that in its existing design, ELRP does not allow for an aggregator to participate unless their customer currently is dual participating with BIP (ELRP options A1 and A2), has a VPP resource made of net energy metering (NEM), energy storage, and photovoltaic (ELRP option A4), or is CAISO market integrated as a Proxy Demand Resource (ELRP option B1 and B2). *In order to support this change, a new option for aggregators will be needed to facilitate participation.*
- The IOUs shall dispatch the VGI aggregators for at least 30 hours per season including ELRP events and compensate the aggregators for the ILR delivered during the dispatched hours.
  - PG&E does not support this carve-out, which deviates from the current design of ELRP. ELRP is a voluntary program and is triggered based on CAISO's Alert, Warning, and Emergency. If the grid is in a dire situation and requires load reduction or additional supply via export, this would be the time to execute an ELRP event and call on aggregators for dispatch. Mandating IOUs to force dispatch for at least 30 hours without an emergency does not seem to align with how and why ELRP was

developed.[5] *Therefore, PG&E does not agree with this additional requirement for VGI aggregators.*

V1G use cases have been successfully demonstrated and scaled in PG&E's service territory. Additionally, there exist today Underwriters Laboratories (UL) certified and PG&E Rule 21 compliant bidirectional direct current (DC) chargers and commercially-available bidirectional vehicles to participate in V2G use cases. However, scaling of market-ready V2G assets face existing barriers, not similarly faced by V1G assets. See Table 7-1 below.

TABLE 7-1
STATUS OF BIDIRECTIONAL CHARGER TECHNOLOGY

Line No.	Charger Type	Rule 21 Interconnection Regulation[a]	Participation in DR-Program: ELRP	Notes
1	Bidirectional Direct Current (DC) Charger	Yes[b]	Proposed by ED Concept Paper	The majority of commercially available V2G bidirectional chargers are Direct Current (DC).
2	Bidirectional Alternating Current (AC) Charger	Pending[c]	Proposed by ED Concept Paper	The V2G alternating current (AC) interconnection proceeding is open.

(a) Any DER source that plans to export to the grid will need to go through an interconnection process with the utility. During this process interconnection experts will conduct a study to determine whether the applicant is able to safely inject energy to the grid or not.

(b) Rule 21 Decision_223V2GDC: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M347/K953/347953769.PDF.

(c) Currently, there is no Rule 21 interconnection regulation for AC bidirectional chargers (where the inverters are on-board the vehicles) and for that reason the table above lists "pending" for bidirectional AC chargers.

Known existing barriers for V2G technologies to participate at scale are described below:

- Rule 21 has regulations in place for the interconnection of V2G DC chargers (i.e., the DC bidirectional charging approach). However, there remains a need to evaluate the extension of existing regulations to include vehicles with on-board inverters (i.e., the AC

5 While ELRP has a seasonal 60-hour operating cap, participation is completely voluntary as there are no penalties for non-participation.

bidirectional charging approach). *PG&E encourages the CPUC to continue efforts in the Rule 21 proceeding to address and evaluate the V2G AC bidirectional regulation.*

- Limited availability and production capacity of DC bidirectional chargers will likely constrain deployment of V2G functionality for capable vehicles to support reliability use cases at scale. Creating predictable, increased demand for these bidirectional chargers will allow Original Equipment Manufacturers (OEM) to scale up production at rates that would support participation in ELRP. Moreover, current pricing of DC bidirectional single-phase chargers shows there is a premium over the cost of unidirectional AC Level 2 chargers and this cost differential is a potential barrier to the adoption of DC bidirectional single-phase chargers for residential customers, particularly those residing in social justice and environmental communities. *An accelerated review and approval of PG&E's VGI pilots*[6] *may support increased participation of bidirectional vehicles in ELRP.*
- Currently, bidirectional vehicles are not allowed to export to the grid under the NEM tariff because the NEM tariff requires all exports to be 100 percent renewable energy. We cannot guarantee that these bidirectional vehicles have charged from 100 percent renewable energy. Therefore, any bidirectional EV that is co-located with solar participating in a NEM tariff cannot also participate in the ELRP program. Also, bidirectional vehicles are not eligible to receive incentives under the Self-Generation Incentive Program (SGIP) because the SGIP program requires that all incentivized DERs be stationary assets and available for customer or grid services 24 hours a day. These two barriers limit the number of bidirectional EVs available to support load reduction or supply increase through vehicle-to-grid energy export and therefore, limit the potential effectiveness of ELRP. Both of these barriers will be explored in PG&E's VGI pilots pursuant to VGI decision D.20-12-029.

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[6] PG&E Advice Letter 6259-E.

Therefore, PG&E recommends accelerating approval of these pilot programs to begin addressing market barriers, such as these, ahead of the 2022 Summer Reliability season.

D. Smart Controllable Thermostat-Related Modifications to Energy Efficiency Programs

Staff offers that several changes could be made to EE program rules to better target new installations of SCT in 2021 and 2022 to the regions of the state and to the specific customers that will lead to greatest load reductions at net peak.

PG&E offers a $50 EE rebate when an eligible customer purchases a qualified SCT regardless of where they reside, even though SCTs provide different energy savings in different climate zones. PG&E's EE savings are guided by the statewide workpaper (i.e., SWHC039) which dictates savings by climate zone. As such, PG&E does not claim any EE savings from SCTs installed in climate zones CZ5 and CZ14.

1. *Require enrollment in a DR program with any Smart Thermostat Incentive*

   PG&E already encourages customers to enroll in a DR program when purchasing an eligible SCT by providing an additional $50 ADR incentive in addition to the EE incentive. In order to require that all customers receiving an EE incentive enroll in a DR program, modifications would be required to the existing EE rebate processes. Such modification may cost significantly and take six to eight months to implement. Moreover, PG&E plans to discontinue the downstream $50 EE rebate program on March 31, 2022 to make way for the Statewide Plug Load and Appliances (PLA) Program that is planned to launch in early 2022 by a third-party implementer. Given this transition period, it would not make financial sense to make this change in the EE rebate program.

2. *Consider either a new statewide program to encompass these changes or direct the IOUs and other EE program administrators to, at a minimum, maintain the budgets for their current programs.*

   As stated above, PG&E plans to discontinue the EE rebate program on March 31, 2022. The reason for discontinuation is that the Statewide EE PLA Program will launch in early 2022 and is intended to replace PG&E's local EE rebate program. The lead IOU on the Statewide EE PLA program is San Diego Gas and Electric Company (SDG&E) and PG&E will work with SDG&E and its third-party implementer to explore the possibility of including SCT as a measure in the Statewide EE PLA Program.

3. Combine EE-DR Cost Effectiveness Tests to increase the Cost Effectiveness of Smart thermostats for EE Programs.

Due to the complexity of the EE and DR cost effectiveness calculation methodology and limited time in this proceeding, PG&E does not recommend modifications or enhancements to the existing EE-DR Cost Effectiveness Tests. Any changes should be made in the appropriate EE regulatory process and as part of the next DR funding cycle.

E. SCT Modifications to Energy Savings Assistance Programs

The SCP shares a couple of points related to the ESA Programs, which PG&E addresses herein.

1. Continue to allow smart thermostats in all climate zones with potential voluntary participation in the DR program.

PG&E supports continuing to offer SCT rebates to all eligible customers across all climate zones for PG&E customers in the ESA Program. In order to encourage ESA customers who have received a SCT to enroll in a DR program, PG&E leaves behind an informational flyer after the SCT is installed which offers DR basic information and leads to PG&E's web page[7] with a list of the current residential PG&E programs and third-party DR providers.

2. For hotter climate zones that currently allow central AC measures (and potentially paired with insulation measures) as well as smart thermostats, include voluntary participation in the DR program.

ESA delineates certain hot climate zones that can receive central Air Conditioning measures in order to increase cost-effectiveness and minimize use of ratepayer funds. These climate zones overlap with the five top climate zones identified in the "EE proposal" as stated in the SCP.

Energy Division submitted a program concept for customers who have SCT installed in these climate zones, either in conjunction with central Air

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7 https://www.pge.com/en_US/residential/save-energy-money/savings-solutions-and-rebates/demand-response/demand-response.page.

Conditioning measures or separately, be set up to automatically participate in the ELRP program.

As described above in Section D-1, PG&E already provides information to encourage ESA customers who receive a SCT to enroll in a DR program.

F. Update Integrated Demand Side Management Program Rules for Better Integration

In 2018, the Commission adopted general requirements and a budget allocation to begin integrating EE and DR capabilities to customers. The use of those funds, called “integrated demand-side management” (IDSM) funds, are subject to a number of requirements and policy principles.

PG&E believes that these requirements and guidelines were intended to take a measured and conservative step towards integrating EE and DR activities. However, times have changed and current grid reliability challenges may warrant a more aggressive approach. Modifying or eliminating some of these requirements, even on a temporary basis, could encourage EE program implementers to add activities into their programs that benefit grid reliability. PG&E is currently weighing which requirements could be changed, what the implications of those changes might be, and how best to bring those recommendations before the Commission. PG&E requests that the Commission delegate the reform of IDSM rules to Commission staff, who could more expeditiously review and approve PG&E’s recommendations. PG&E requests that recommendations be proposed via an Advice Letter. These potential rule changes could encourage the market to propose innovative load management solutions that historically have not been supported by customer programs. In addition, PG&E requests that Commission staff provide comments on the IOUs’ IDSM Program Guidance Document that was shared in June 2021.[8] This document would help clarify IDSM program policies and could be used in the near future.

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[8] Document titled “Limited EE+DR Integrated Demand Side Management (IDSM)” jointly shared by the IOUs’ IDSM teams with the CPUC staff via email on June 9, 2021.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

GAS CORE SERVICES

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A. Introduction

At present, some classes of customers experience electric service outages, often for prolonged periods due to Public Safety Power Shutoff (PSPS) events or other electric grid interruptions due to emergency circumstances, requiring the use of back-up generation. Some of these customers would prefer to use core gas transportation service to access natural gas, rather than diesel, and Pacific Gas and Electric Company (PG&E) would like to support the customers' preference for gas. Therefore, this testimony proposes changes to PG&E's Gas Rule 1, Gas Rule 12, G-electric generation (EG) and G-NR2 gas tariffs to enable the customers to elect core transportation service for gas delivery. PG&E believes that under the conditions applicable to its proposed change to Gas Rule 1, Gas Rule 12, G-EG, and G-NR2 tariffs, neither core transportation nor core procurement customers would be harmed in service reliability or applicable rates.

This proposal is responsive to the needs in Phase 2 of this proceeding by allowing customers to secure higher priority gas transportation service to serve back-up generation that could be used when the grid is under stress, and as may be permitted in programs like Emergency Load Reduction Program and the California State Emergency Program. When the grid is facing emergencies, such as rotating outages, customers with back-up generation may be able to use diesel fuel. However, some customers would prefer to use cleaner-burning natural gas[1] instead of diesel, but they need gas transportation service that is secure. This proposal aligns with the goals of Phase 2 of this proceeding by facilitating the installation of gas-fired back-up generation by customers that would be able to run under local air pollution rules when an emergency grid

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1 As defined by PG&E's Gas Rule 1, the use of the term "natural gas" out of tradition is already evolving: "GAS: Any mixture of combustible and non-combustible gases used to produce heat by burning that can be accepted into a Utility pipeline without any compromise to operational safety or integrity. It shall include, but not be limited to, natural gas, renewable gas, biomethane, manufactured gas, or a mixture of any or all of the above."

situation was declared, compared to diesel that may not be able to be used other than when the customer itself experiences electric outages and/or for a limited number of run hours for testing only.

B. Identify Any New Policy or Modification to an Existing Policy That Could Reduce Demand or Increase Supply at Net Peak (For Example a Rule, Regulation, Incentive, Penalty)?

This testimony discusses proposed revisions to Gas Rule 1 customer classification definitions and parallel references in Gas Rule 12 and Gas Schedules G-EG and G-NR2 to specifically allow EG and cogeneration customers (customers qualifying under Gas Schedule G-EG) with historical or potential annual use exceeding 250,000 therms per year or capacity greater than 500 kilowatt (kW) to request Core Transportation Service under certain criteria and conditions. Approving these rule and tariff changes would support California's electric grid under emergency situations. It would do so by allowing core transportation reliability required by customers to consider installing gas-fired generation instead of installing diesel. Installed gas-fired backup generation would then have the ability to be engaged when called upon to support the grid under various emergency situations compared with the more limited ability to run diesel. Once gas-fired generation is installed, it also offers the medium and long-term option for customers to arrange for Renewable Natural Gas and other pipeline quality options with further reduction in emissions.

Based on customer interest in PG&E's proposal for this tariff option, PG&E estimates that 200 megawatts (MW) of additional gas-fired backup generation could potentially be in place for summer 2022 with additional capacity in place by summer 2023. Over a dozen customers have expressed their interest in PG&E's proposal. PG&E believes its proposed changes provide a thoughtful path, consistent with California's environmental goals, while also meeting the needs of all of our gas and electric customers, including those desiring an option to use reliable core natural gas transportation service to access gas, instead of diesel, for their backup generation.

As is the case for noncore customers currently permitted to request transfer to core service under Gas Rule 12, to be considered for such categorization, customers must agree to pay for reinforcement and/or special facility requirements necessary to provide such service and remain on core service for a minimum of five years. As part of its approval review process before approving such a request by a generator with annual or potential usage exceeding 250,000 therms per year for Core Transportation Service or capacity greater than 500 kW, PG&E will consider whether serving or enabling the transportation system in the manner necessary for the customer to elect Core Transportation Service would detrimentally impact system safety or reliability to existing core customers. Any detrimental safety or reliability impacts will be included in the assessment and any costs related to the required reinforcement and/or special facility requirement will be fully borne by the Electric Generation (EG) customer requesting for Core Transportation Service, per Gas Rule 2.

The EG customers that are approved for Core Transportation Service shall not be eligible for commodity service from a core procurement group. EG and cogeneration customers qualifying for Gas Schedule G-NR2 Core Transportation Service will continue their exemption from Gas Schedule G-PPPS and Gas Schedule G-SUR, as specified in the tariff, but not other applicable tariff charges pursuant to the core rate. Upon California Public Utilities Commission (Commission) approval, PG&E would file a Tier 1 Advice Letter to implement the approved changes within 30 days of a decision approving PG&E's request.

1. Duration – Temporary or Permanent

The changes are proposed as a permanent change to PG&E's gas rules and tariffs as customers are required to make investment decisions to install gas or diesel backup systems and, if gas, pay for any necessary system upgrades to provide core reliability on PG&E's transportation system.

2. Justification or Demonstration That Policy Will Support the Delivery of Reliability Benefits During Net Peak

Prior to PG&E Application 02-11-028 and resulting Decision 03-12-008, the issue of core versus noncore service focused on qualifications to be allowed to take service under noncore tariffs. Customers qualifying to be noncore could also choose to be core. The energy crisis of 2000-2001 resulted in a wave of noncore customers electing core service primarily to avail themselves of core procurement service.

This migration of large numbers of customers with substantial annual gas usage negatively impacted long-standing core customers both in terms of allocated end-user transportation revenue requirements for the distribution or local transmission systems, and for G-CP's core procurement service which is subject to the Total Core's 1-cold-day-in-10-year reliability requirement.

Additionally, if noncore customers who obtained the option to switch to core then switched back to noncore transportation service within a short period of time, PG&E would have made enhancements to the system under its Abnormal Peak Day planning criteria that would no longer be needed. At that time, to forestall such impacts from occurring in the future, PG&E proposed the two adopted changes to its tariff language which (1) prohibited Gas Schedule G-EG customers with capacity of over 500 kW or annual gas usage of over 250,000 therms from electing core service and (2) required noncore customers who remained eligible to switch to core to sign five year agreements to remain core and pay core transportation rates.

a. 20-Years Since the 2000-2001 Energy Crisis and New Challenges and New Goals Support Rebalancing of Gas Rules

Twenty years later the needs and goals of California and PG&E's service territory particularly have changed. Given PSPS events, continued impacts of Climate Change in PG&E's service territory, requests from our EG customers, and the need for new programs to protect reliability for the California Independent System Operator (CAISO) electric grid during extreme events impacting demand and/or supply, has prompted PG&E to propose a solution. PG&E has in the solution proposed by this filing considered how to better balance supporting the needs of all of its gas and electric customers, the electric grid, and the Commission environmental goals. Customers requesting Core Transportation Service explain to PG&E that curtailable noncore service would not be sufficient as they require 24/7/365 backup capability and cannot afford to have any electricity outages at their facilities;[2] they are willing to pay for Core Transportation Service, and absent this choice they would instead consider relying on diesel or, in the case of a new business or new business premise, locating their business elsewhere.

i. Supporting Customer Needs and CAISO Electric Grid

PG&E's noncore gas customers are typically large commercial or industrial customers who are subject to curtailment. Other customers in need of this option would be predominantly or even solely electric customers but which now need reliable gas transportation service to choose gas to power their needed backup generation facility. By installing gas-fired instead of diesel back-up, in addition to having a reduced emissions impact, these gas-fired facilities would have greater ability to run in support of CAISO electric grid emergency situations compared to if the customer that has installed diesel back-up generation. Many of these customers provide a critical service to the community and must have reliable service and therefore are utilizing back-up diesel generation or other alternative fuels with higher carbon dioxide and other emissions than evolving pipeline-quality gas.

ii. Supporting California Emission Goals

California has a 2045 zero carbon initiative. PG&E supports this initiative and recognizes that natural gas plays a vital role as an interim fuel solution. Carbon dioxide emissions from pure natural gas are significantly lower than from diesel resources (an approximate reduction of 44.3 Pounds of carbon dioxide emitted per million British thermal units of energy). As an example, one facility that experiences electric service interruption of a total of 14 days per year could result in a carbon dioxide reduction of close to 11,000 metric tons, if it used natural gas instead of diesel. For this reason, PG&E proposes that these companies be allowed to

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2 Examples include but are not limited to entities which provide essential services to the economy and society such as data centers, hospitals/medical and long term care facilities, governmental command centers, and manufacturing sites where random loss of electricity is costly for their process.

request Core Transportation Service with the requirement of paying all applicable rates and charges as well as reinforcement costs.

iii. Protecting Core Customers

This proposal will have no reliability or cost impacts on existing core customers. This proposal will not increase costs or reduce reliability for existing Core customers because all incremental costs to interconnect and upgrade assets for the EG customer will be fully borne by the EG customer.

With regard to gas supply, PG&E's Core Gas Supply is required to procure intrastate transportation and storage assets to meet the 1 cold day-in-10-year reliability requirement, as well as interstate pipeline capacity to meet the Interstate Capacity Planning Range for <u>all</u> core procurement volumes served by PG&E <u>and</u> third-party Core Transport Agent's (CTA). Since EG particularly backup generation, customers' <u>daily</u> loads are potentially significant, unpredictable and misaligned with core customer loads, PG&E's proposal would protect current core customers by continuing to exclude these volumes from eligibility to receive Core Procurement Service from any Core Procurement Group whether PG&E's G-CP service or via a CTA. To effectuate this protection PG&E proposes to establish a new and separate class of Core Transportation Service for Generation as defined in Gas Rule 1 for generation over 500 kW (or 250,000 therms per year potential use given the customers' capacity) under its G-NR2 Core Large Commercial transportation tariff.

iv. Rebalanced Gas Rules and Tariffs to Support the Grid, the Environment, and the Jobs Customers Create in California

PG&E believes these combinations of proposed requirements and constraints would reduce pollution emissions by encouraging use of gas-fired back-up generation instead of diesel (compared to not approving these changes), and support the ability of electric customers to site or maintain their facilities in California, thus providing jobs and other benefits, including making generation capacity available to support the CAISO grid when it is stressed by extreme situations involving demand, supply or both.

3. Estimate of Policy's Impacts (MWs)

Based on known customer interest in PG&E's proposal for this tariff option, PG&E estimates that 200 MW of additional gas-fired backup generation could potentially be in place for summer 2022 with additional capacity in place by summer 2023. Over a dozen customers have expressed their interest in PG&E's proposal to date.

4. Implementation Requirements, Including Whether Other State Agencies or CAISO Must Approve

Tariff Revisions Below summarize the Gas Tariffs that would be revised in an Advice Letter to enable EG and cogeneration customers to request Core Transportation Service under certain criteria and conditions. The affected tariff sheets are listed on the enclosed Attachment 1 with red-line versions.

- Gas Schedule G-EG – Gas Transportation Service to EG Proposed Gas Schedule G-EG tariff revision reflects the proposed Gas Rule 1 Change allowing for Large Gas Schedule G-EG customers to request Core Transportation Service under Gas Schedule G-NR2 ("Large Commercial") subject to PG&E approval.
- Gas Schedule G-NR2 – Gas Service to Large Commercial Customers Proposed Gas Schedule G-NR2 tariff revision reflects the proposed Gas Rule 1 and Gas Rule 12 Changes allowing for Large Gas Schedule G-EG customers to request Core Transportation Service under Gas Schedule G-NR2 ("Large Commercial") subject to PG&E approval.
- Gas Schedule G-PPPS – Gas Public Purpose Program Surcharge Proposed Gas Schedule G-PPPS tariff revision identifies gas qualifying for consumption under Gas Schedule G-EG but electing Core Transportation Service and separately metered under G-NR2 remains exempt from Gas Schedule G-PPPS. Advice 4409-G-4 – March 26, 2021
- Gas Schedule G-SUR – Customer-Procured Gas Franchise Fee Surcharge Proposed Gas Schedule G-SUR tariff revision identifies gas

qualifying for consumption under Gas Schedule G-EG but electing Core Transportation Service and separately metered under Gas Schedule G-NR2 continues to remain as an applicable exception from Gas Schedule G-SUR.

- Gas Rule 1 – Definitions Proposing a new definition identified as:
  - CORE TRANSPORTATION SERVICE FOR GENERATORS. This definition applies to customers who would otherwise qualify for and typically would be required to take noncore service under PG&E's Gas Schedule G-EG and Gas Schedule G-EG-BB tariffs. The definition allows for medium-large Generation customers to seek and upon approval receive core transportation service excluding core procurement service.
  - NONCORE END-USE CUSTOMER. This modification allows for EG and Cogeneration Customers with historic or potential annual use exceeding 250,000 therms per year or rated generation capacity equal to or greater than 500 kW, typically classified as Noncore End Use Customers, to request consideration of Core Transportation Service under the Gas Schedule G-NR2 (aka "Large Core Commercial") tariff as described in Core Transportation Service definition and proposed Gas Rule 12.
- Gas Rule 12 – Rates and Optional Rates Proposed Gas Rule 12 Tariff change incorporates proposed Gas Rule 1 changes into the Noncore to Core Service transfer Section Ea. For convenience of the reader, where text has been revised in the tariff sheets, PG&E has included the redline revisions in Attachment 2.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

ATTACHMENT 1

PROPOSED GAS RULE AND TARIFF CHANGES

GAS SCHEDULE G-EG

GAS TRANSPORTATION SERVICE TO ELECTRIC GENERATION

APPLICABILITY: This rate schedule[1] applies to the transportation of natural gas used in: (a) electric generation plants served directly from PG&E gas facilities that have a maximum operation pressure greater than sixty pounds per square inch (60 psi); (b) all Cogeneration facilities that meet the efficiency requirements specified in the California Public Utilities Code Section 216.6[2] and other electric generation facilities that meet an overall electric efficiency of at least 45%; (c) solar electric generation plants, defined herein and (d) Advanced Electrical Distributed Generation technology that meets all of the conditions specified in Public Utilities Code Section 379.8, as defined in Rule 1, and are first operational at a site prior to January 1, 2016. This schedule does not apply to gas transported to non-electric generation loads. (T) (T)

Customers on Schedule G-EG ~~permanently~~ with usage of 250,000 therms per year or installed capacity of 500kW or larger are typically required to be classified as Noncore End-Use Customers, per Rule 1 must procure gas supply from a third-party gas supplier, not from a Core Procurement Group, as defined in Rule 1. Per Rule 1 Core Transportation Service and Noncore End-Use Customer definitions, such customers may request Core Transportation Service under G-NR2 ("Large Commercial") subject to PG&E approval. (T)

~~Certain noncore customers served under this rate schedule may be restricted from converting to a core rate schedule.~~ See Rule 12 for details on core and noncore reclassification. (T)

Per D. 15-10-032 and D. 18-03-017, transportation rates include GHG Compliance Cost for non-covered entities. Customers who are directly billed by the Air Resources Board (ARB), i.e., covered entities, are exempt from paying AB 32 GHG Compliance Costs through PG&E's rates.[3] A "Cap-and-Trade Cost Exemption" credit for these costs will be shown as a line item on exempt customers' bills.[4,5]

TERRITORY: Schedule G-EG applies everywhere within PG&E's natural gas Service Territory.

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1 PG&E's gas tariffs are available on-line at www.pge.com.

2 Efficiency Standard: In accordance with PU Code Section 216.6, at least 5 percent of the facility's total output must be in the form of useful thermal energy. Where useful thermal energy follows power production, the useful annual power output plus one-half the useful annual thermal energy output must equal no less than 42.5 percent of any natural gas and oil energy input.

3 Covered entities are not exempt from paying costs associated with LUAF Gas and Gas used by Company Facilities.

4 The exemption credit will be equal to the effective non-exempt AB 32 GHG Compliance Cost Rate ($ per therm) included in Preliminary Statement – Part B, multiplied by the customer's billed volumes (therms) for each billing period.

5 PG&E will update its billing system annually to reflect newly exempt or newly excluded customers to conform with lists of Directly Billed Customers provided annually by the ARB.

Note: Customers who are directly billed by Air Resources Board (ARB) for ARB AB32 Administration Fees are exempt from PG&E's ARB AB32 Cost of Implementation (COI) rate component. Customers on the Directly Billed list, as provided annually by the ARB, may change from year to year. The exemption credit will be equal to PG&E's currently-effective ARB AB32 COI per-therm rate component (as shown in PG&E's Preliminary Statement, Part B – "Default Tariff Rate Components"), times the customer's billed volumes (therms) for each billing period.

GAS SCHEDULE G-NR2 Sheet 1
GAS SERVICE TO LARGE COMMERCIAL CUSTOMERS

APPLICABILITY: This rate schedule[1] applies to natural gas service to non-residential Core End-Use Customers on PG&E's Transmission and/or Distribution Systems. To qualify, a Customer's average monthly use must have exceeded 20,800 therms during those months in the last twelve (12) months in which gas use exceeded 200 therms, except as specified below in the Energy Efficiency Adjustment Provision. Each March, service to all Customers under this schedule will be reviewed to determine continued applicability. Such determination will be based on natural gas use in the twelve (12) billing months ending in the most recent calendar year. This schedule may be taken in conjunction with Schedule G-EG; however, electric generators ~~permanently~~ typically classified as Noncore End-Use Customers, per gas Rule 1 or electing and being approved for Core Transportation Service under G-NR2 per gas Rules 1 and 12~~,~~ must procure gas from a third-party supplier, not from a Core Procurement Group, as defined in gas Rule 1. This rate schedule is also available as an option for service in separately metered common areas in a multifamily complex. Common area accounts are those accounts that provide separately metered gas service to Common Use Areas as defined in Rule 1. (T) (N)

Per D. 15-10-032 and D. 18-03-017, transportation rates include GHG Compliance Cost for non-covered entities. Customers who are directly billed by the Air Resources Board (ARB), i.e., covered entities, are exempt from paying AB 32 GHG Compliance Costs through PG&E's rates.[2] A "Cap-and-Trade Cost Exemption" credit for these costs will be shown as a line item on exempt customers' bills.[3,4] (N)

TERRITORY: Schedule G-NR2 applies everywhere PG&E provides natural gas service.

RATES: Customers on this schedule pay a Customer Charge, a Procurement Charge and a Transportation Charge, per meter, as specified below. Customers that have executed a Request for Reclassification from Noncore Service to Core Service (Form 79-983) will pay the Customer Charge and Transportation Charge shown below. Such Customers will pay the Procurement Charge specified in Schedule G-CPX for any of the first twelve (12) regular monthly billing periods that they are taking core procurement service from PG&E. After the twelfth regular monthly billing period, such Customers will pay the Procurement Charge specified on this schedule.

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1 PG&E's gas tariffs are available online at www.pge.com.
2 Covered entities are not exempt from paying costs associated with LUAF Gas and Gas used by Company Facilities.
3 The exemption credit will be equal to the effective non-exempt AB 32 GHG Compliance Cost Rate ($ per therm) included in Preliminary Statement – Part B, multiplied by the customer's billed volumes (therms) for each billing period.
4 PG&E will update its billing system annually to reflect newly exempt or newly excluded customers to conform with lists of Directly Billed Customers provided annually by the ARB.

(Continued)

RATES (CON'T):

Customer Charge: Per Day $4.95518

	Per Therm			
	Summer		Winter	
	First 4,000 Therms	Excess	First 4,000 Therms	Excess
Procurement Charge:	$0.16251 (R)	$0.16251 (R)	$0.16251 (R)	$0.16251 (R)
Transportation Charge:	$0.81023	$0.47735	$0.95768	$0.56422
Total:	$0.97274 (R)	$0.63986 (R)	$1.12019 (R)	$0.72673 (R)

Cap-and-Trade Cost Exemption (per therm): $0.07366

The Cap-and-Trade Cost Exemption is applicable to customers who are identified by the California Air Resources Board (CARB) as being Covered Entities for their Greenhouse Gas (GHG) emissions as part of the Cap-and-Trade program. Applicable Cap-and-Trade Cost Exemptions may be provided from the date CARB identifies a customer as being a Covered Entity, or provided based upon documentation satisfactory to the Utility for the time period for which the customer was a Covered Entity, whichever is earlier.

Public Purpose Program Surcharge:

Customers served under this schedule are subject to a gas Public Purpose Program (PPP) Surcharge unless exempt under Schedule G-PPPS. (T)

See Preliminary Statement, Part B for the Default Tariff Rate Components.

The Procurement Charge on this schedule is equivalent to the rate shown on informational Schedule G-CP—Gas Procurement Service to Core End-Use Customers but not available to customers served under G-NR2 per Core (T) Transportation Service as defined in Rule 1. (T)

SEASONS: The Summer Season begins April 1 and ends on October 31. The Winter Season begins November 1 and ends on March 31.

CARE DISCOUNT FOR QUALIFIED FACILITIES: Facilities which meet the eligibility criteria in Rules 19.2 or 19.3 are eligible for a California Alternate Rates for Energy (CARE) Discount under Schedule G-CARE.

(Continued)

GAS SCHEDULE G-NR2 Sheet 3
GAS SERVICE TO LARGE COMMERCIAL CUSTOMERS

ENERGY EFFICIENCY ADJUSTMENT: A Customer who implements measures to improve energy efficiency on or after January 1, 1992, may be eligible to receive an energy efficiency adjustment. The following qualifications must be met by the Customer: (1) the Customer's service was established prior to January 1, 1992; and (2) the efficiency measures reduce the Customer's natural gas usage and/or demand to the point that the Customer would no longer be eligible for service under this schedule. Qualifying Customers must execute an Agreement for Adjustment for Natural Gas Energy Efficiency Measures (Form 79-788) with PG&E in order to receive an energy efficiency adjustment.

SURCHARGES: Customers served under this schedule in conjunction with Schedule G-CT, or in conjunction with noncore service, are subject to a franchise fee surcharge unless exempt under Schedule G-SUR for gas volumes purchased from parties other than PG&E and transported by PG&E. (T) (T)

Customers served under this schedule are subject to a gas Public Purpose Program (PPP) Surcharge unless exempt under Schedule G-PPPS. (T)

ALTERNATIVE PROCUREMENT OPTIONS: Customers may procure gas supply from a party other than PG&E by taking service on this schedule in conjunction with Schedule G-CT—Core Gas Aggregation Service. Customers who procure their own gas supply will not pay the Procurement Charge component of this rate schedule, and will be subject to the applicable rates specified in Schedule G-CT.

Service under this schedule may also be taken in conjunction with procurement service from a party other than PG&E if the Customer executes a Natural Gas Service Agreement (Form No. 79-756) with PG&E. Service will be provided in increments of one (1) year. If there is a difference between actual deliveries and actual usage, such differences will be subject to the terms and conditions of Schedule G-BAL. Customers who procure their own gas supply will not pay the Procurement Charge component of this schedule.

Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21.

NONCORE ELIGIBILITY OPTION: Customers taking service under this schedule are eligible to be reclassified to noncore status as provided in Rule 12. Customers eligible for noncore service must execute a Natural Gas Service Agreement (Form 79-756).

CURTAILMENT OF SERVICE: Service under this schedule may be curtailed. Details are provided in Rule 14.

GAS SCHEDULE G-PPPS
GAS PUBLIC PURPOSE PROGRAM SURCHARGE

APPLICABILITY: Pursuant to Public Utility (PU) Code Sections 890-900, this schedule applies a gas Public Purpose Program (PPP) surcharge to gas transportation volumes under the rate schedules* specified below. The gas PPP surcharge is collected to fund gas energy efficiency and low-income energy efficiency programs, the California Alternate Rates for Energy (CARE) low-income assistant program, and public interest research and development. Under PU Code Section 896, certain customers are exempt from the gas PPP surcharge as described in the Exempt Customer section, below.

TERRITORY: This rate applies everywhere within PG&E's natural gas Service Territory.

RATES: The following surcharges apply to natural gas service for eligible Core and Noncore End-Use Customers.

Customer Class (Rate Schedule)	Per Therm Non-CARE		Per Therm CARE	
Residential: (G-1, G1-NGV, GM, GS, GT, GL-1, GL1-NGV, GML, GSL, GTL)	$0.07021	(I)	$0.02959	(I)
Small Commercial (G-NR1)	$0.07647	(I)	$0.03585	(I)
Large Commercial (G-NR2)	$0.06539	(I)	$0.02477	(I)
Industrial: (G-NT—Distribution)	$0.07656	(I)	N/A	
Industrial: (G-NT—Transmission/ Backbone)	$0.05305	(I)	N/A	
Natural Gas Vehicle (G-NGV1, G-NGV2, G-NGV4)	$0.04308	(I)	N/A	
Liquid Natural Gas (G-LNG)	0.04308	(I)	N/A	

EXEMPT CUSTOMERS: In accordance with PU Code Section 896, certain customers are exempt from Schedule G-PPPS. These include:

a. All gas consumed by customer's served under Schedules G-EG, gas qualifying for consumption under G-EG but electing Core Transportation Service and separately metered under G-NR2, and gas consumed by customers served under ~~and~~ G-WSL; (T)

b. All gas consumed by Enhanced Oil Recovery (EOR) facilities;

c. All gas consumed by customers in which the State of California is prohibited from taxing under the United States Constitution or the California Constitution, consistent with California Energy Resources Surcharge Regulations 2315 and 2316, as described in Publication No. 11 issued by the California State Board of Equalization (BOE), which include:

1. The United States, its unincorporated agencies and instrumentalities;

2. Any incorporated agency of instrumentality of the United States wholly owned by either the United States or by a corporation wholly owned by the United States;

3. The American National Red Cross, its chapters and branches;

4. Insurance companies, including title insurance companies, subject to taxation under California Constitution, Article XIII, Section 28, or it successor;

GAS SCHEDULE G-SUR

CUSTOMER-PROCURED GAS FRANCHISE FEE SURCHARGE

APPLICABILITY: Pursuant to California State Senate Bill No. 278 (1993) and pursuant to PU Code sections 6350-6354, this schedule applies to all gas volumes procured by Customers from third-party entities and transported by PG&E ("Customer-procured gas") with the following exceptions:

a. The state of California or a political subdivision thereof;

b. One gas utility transporting gas for end use in its Commission-designated service area through another utility's service area;

c. A utility transporting its own gas through its own gas transmission and distribution system for purposes of generating electricity or for use in its own operations;

d. Cogeneration Customers and other electrical generation facilities that meet an overall electric efficiency of at least 45%, for that quantity of natural gas billed under either Schedule G-EG or separately metered under G-NR2; and (T)

e. Advanced Electrical Distributed Generation Technology that meets all of the conditions specified in Public Utilities Code Section 379.8 that is first operational at a site prior to January 1, 2016.

TERRITORY: Schedule G-SUR applies everywhere PG&E provides natural gas service.

RATES: The Customer-procured gas Franchise Fee Surcharge is comprised of the following components:

	Per Therm
a. The monthly core Weighted Average Cost of Gas (WACOG), exclusive of storage costs and Revenue Fees and Uncollectible (RF&U) accounts expense, which is multiplied by:	$0.25169 (R)
b. The Franchise Fee factor* adopted in PG&E's most recent General Rate Case, which is	0.009772
The G-SUR Franchise Fee Surcharge is....................................	$0.00246 (I)

SURCHARGE RECOVERY: The surcharge will be shown on the Customer's monthly bill based on volumes procured by the Customer from a third party and transported by PG&E (metered usage).

DELINQUENT SURCHARGES: In the event that payment on a transportation Customer's closed account becomes more than 90 days delinquent or a transportation Customer notifies the utility that they refuse to pay the surcharge, PG&E shall, within 30 days, notify the municipality of the delinquency and provide information on the name and address of the delinquent transportation Customer and the surcharge amount owed. PG&E shall not be liable for delinquent surcharges.

* Does not include Uncollectibles factor of 0.003050

GAS RULE NO. 1
DEFINITIONS

COMMON USE AREAS: Those areas that may be shared or used by occupants within a multifamily accommodation, including, but not limited to, laundry room, recreation room, swimming pool, tennis courts, gardens, hall/outdoor lighting.

COMPANY: Pacific Gas and Electric Company (PG&E).

COMPANY'S OPERATING CONVENIENCE: The use, under certain circumstances, of facilities or practices not ordinarily employed which contribute to the overall efficiency of PG&E's operations; the term does not refer to customer convenience nor to the use of facilities or adoption of practices required to comply with applicable laws, ordinances, rules, regulations, or similar requirements of public authorities.

CONSUMER PRICE INDEX: The Index, as published monthly by the Bureau of Labor Statistics in its "Consumer Price Index Detailed Report"; specifically therein referred to as the "San Francisco-Oakland Consumer Price Index."

CORE END-USE CUSTOMER: A Core End-Use Customer is a Customer physically connected to the local distribution system. Core End-Use Customers normally lack alternatives to gas service. Core End-Use Customers include all residential Customers, and non-residential Customers whose gas use does not meet the minimum usage requirements specified in the noncore rate schedules, or whose gas use meets the minimum usage requirements, but do not elect to be classified as a Noncore End-Use Customer.

CORE PROCUREMENT GROUP: Core Transport Groups and PG&E's Core Gas Supply Department.

CORE TRANSPORT AGENT: An individual or company that contracts with PG&E and participating core gas transportation service Customers as the responsible agent to manage gas deliveries to PG&E on behalf of a Core Transport Group.

CORE TRANSPORT GROUP: Any combination of core Customers (individual commercial and/or residential customers) whose total gas use is greater than or equal to 120,000 therms on an annual basis. The aggregation of gas accounts into a Core Transport Group is needed for core Customers to qualify for core gas transportation service.

(L)
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CORE TRANSPORTATION SERVICE FOR GENERATORS: Core Transportation Service for Generators applies to customers who would otherwise qualify for and typically would be required to take noncore service under PG&E's G-EG and G-EG-BB tariffs and Noncore End-Use Customer definition but which have elected to request consideration for Core Transportation Service under G-NR2 (aka "Large Commercial"). As is the case for other noncore customers requesting transfer to core service under Rule 12, to be considered for such categorization customers must agree to pay for reinforcement and/or special facility requirements necessary to provide such Core Transportation Service and remain on core service for a minimum of five years. During the review process PG&E will consider whether serving or enabling the transportation system in the manner necessary for the customer to elect Core Transportation Service would detrimentally impact system safety or service to existing core customers and will include this assessment in any reinforcement and/or special facility requirement per Gas Rule 2. Generators with annual gas usage of over 250,000 therms or installed capacity of over 500 kW which are approved for Core Transportation Service would receive core transportation reliability from PG&E's Citygate to the burner tip. Electric generation and cogeneration customers electing and approved for Core Transportation service will continue qualified exemption per G-SUR and G-PPPS tariffs but would not be exempt from other applicable tariff charges pursuant to the applicable core rate and must obtain their procurement service from noncore -portfolio and not from a Core Procurement Group as defined in Rule 1. (N)

COST OF OWNERSHIP (COO): A monthly charge applied to special facilities to recover the cost to PG&E of operating the special facility. When applicant-financed the charge includes the cost components for operations and maintenance (O&M), administration and general expenses (A&G), property taxes, and Revenue Fees and Uncollectible (RF&U) accounts expense, and the cost of replacement facilities at no additional cost for sixty (60) years The applicant-financed percentage is also used to calculate COO charges on unsupported distribution line extension costs. See Rule 15.E.6 (L)

(Continued)

When PG&E-financed the monthly cost components include all of those listed above for applicant-financed special facilities plus components to cover the costs of income taxes, return on investment, and depreciation. The PG&E-financed COO is also used to calculate line extension allowances. (See Rule 15. C. 2 & C.3.) (L)

CPUC (CALIFORNIA PUBLIC UTILITIES COMMISSION): The Public Utilities Commission of the State of California.

CUBIC FOOT OF GAS: The quantity of gas that, at a temperature of sixty (60) degrees Fahrenheit and a pressure of 14.73 pounds per square inch absolute, occupies one cubic foot.

CUSTOMER: The person, group of persons, firm, corporation, institution, municipality, or other civic body, in whose name service is rendered, as evidenced by the signature on the application, contract, or agreement for that service or, in the absence of a signed instrument, by the receipt and payment of bills regularly issued in that name, regardless of the identity of the actual user of the service.

CUSTOMER-OWNED GAS: Gas procured by the Customer which is not part of PG&E's procured supplies.

DAILY AVAILABLE CAPACITY: The maximum capacity of a pipeline system on a given day. This capacity can vary from day to day depending on the operating conditions, e.g., load pressures and ambient temperatures, and the availability of facilities and equipment, such as compressor units.

DECATHERM (Dth) (Also DEKATHERM): A unit of energy equal to ten therms, or one million Btu.

DECORATIVE GAS APPLIANCES: Decorative gas appliances include, but are not limited to, artificial fireplace logs or decorative gas lighting, and do not provide space or water heating.

DELIVERY POINT(S): The point(s) on PG&E's pipeline system where PG&E delivers gas that it has transported to the Customer.

DISPLACEMENT RECEIPT POINT CAPACITY: Utility pipeline system improvements which increase the takeaway capacity from a Receipt Point but do not increase the overall downstream capacity of the Utility's pipeline system. The addition of Displacement Receipt Point Capacity increases the ability of the Utility to receive gas from a particular Receipt Point or zone in competition with other gas supplies diverted into the Utility's pipeline system.

DISTRIBUTION SYSTEM: Generally, mains, service connections, and equipment that carry or control the supply of gas from point of local supply to and including the meter. (L)

ELECTRIC-UTILITY START-UP AND IGNITOR FUEL: Electric utility gas use where no alternative-fuel capability exists for: (a) heating the boiler system adequately during start-up to enable efficient oil burning to meet pollution standards; and (b) insuring continuous ignition and flame stabilization within the boiler. (L)

EMERGENCY CONSUMER PROTECTION PLAN: Pursuant to CPUC directives and advice letters listed below, residential and non-residential customers in areas where a state of emergency proclamation is issued by the California Governor's Office or the President of the United States due to a disaster that affects utility services are eligible for applicable measures under PG&E's Emergency Consumer Protection Plan.

The Emergency Consumer Protection Plan includes:

Measure for Impacted[1] Customers.

- Stop estimated usage for billing attributed to the period account was unoccupied due to disaster* (Gas Rule 9).
- Offer favorable payment plan as needed to impacted customers, including customers with employment impacted by a disaster† (Gas Rule 11).
- Offer Low income support measures† (Gas Rule 19.1, 19.2 and 19.3).

Additional Emergency Measure for Red-Tagged[2] Customers.

- Discontinue billing and prorate the minimum delivery charges* (Gas Rule 9).
- Suspend disconnections for non-payment† (Gas Rule 11).
- Waive reconnection fees and return check fees† (Gas Rule 11).
- Waive security deposit for reestablishment of service† (Gas Rule 6).
- Expedite move-in and move-out service requests.‡
- Ability to reestablish service under a prior rate schedule as long as the rate schedule is still available and has not been retired‡ (Gas Rule 12).

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[1] Impacted customers live within 2 miles of the fire-impacted perimeter as designated by CAL FIRE.
[2] Red-tagged customers have homes or businesses that are unserviceable because of the disaster.
* On a one-time per event basis.
† For 12 months from the date the Governor issues state of emergency proclamation.
‡ For 12 months from the date the Governor issues state of emergency proclamation and until services are restored (once permanent electric or gas meter is installed/set). (L)

(Continued)

EMERGENCY CONSUMER PROTECTION PLAN: (Cont'd): (L)

The Emergency Consumer Protection Plan is available for the following events:

October 2017 Northern California Wildfire

Pursuant to CPUC Resolution M-4833 and Advice 3914-G-A/5186-E-A, PG&E adopted the emergency consumer protection to support our customers who were affected by the October 2017 Northern California Wildfires.

Residential and non-residential customers in Butte, Lake, Mendocino, Napa, Nevada, Plumas, Santa Cruz, Solano, Sonoma, and Yuba counties affected by the 2017 Northern California Wildfire are eligible for the Emergency Consumer Protection Plan until December 31, 2018. Measures related to expedited service, rate selection and temporary service for red-tagged customers are available to affected customers until December 31, 2018 and until PG&E service is restored (once permanent electric or gas meter is installed/set).

State of emergency proclamation issued by the Governor of California

Pursuant to Decision 19-07-015, PG&E extends PG&E's Emergency Consumer Protection Plan to include residential and non-residential customers in areas where a state of emergency proclamation is issued by the California Governor's Office or the President of the United States where the disaster has either resulted in the loss or disruption of the delivery or receipt of utility service, and/or resulted in the degradation of the quality of utility service. Eligibility for PG&E's Emergency Consumer Protection Plan is extended to applicable customers in the affected disaster area within the counties listed below.

Date of Proclamation	Disaster Name	Affected County
June 25, 2018	Pawnee Wildfire	Lake
July 26, 2018	Carr Wildfire	Shasta
July 26, 2018	Ferguson Wildfire	Mariposa
July 28, 2018	River, Ranch and Steele Wildfires	Lake, Mendocino and Napa
November 8, 2018	Camp Wildfire	Butte
February 21 & 28, 2019	February 2019 Winter Storms	Amador, Calaveras, El Dorado, Glenn, Humboldt, Lake, Marin, Mendocino, Monterey, San Mateo, Santa Barbara, Santa Clara, Shasta, Sonoma, Tehama, Trinity and Yolo

(L)

(Continued)

GAS RULE NO. 1
DEFINITIONS

EMERGENCY CONSUMER PROTECTION PLAN: (Cont'd) (L)

Date of Proclamation	Disaster Name	Affected County
April 12, 2019	February 2019 Winter Storms	Butte, Colusa, Mariposa, Napa, Santa Cruz, Solano and Tuolumne
July 4 & 5, 2019	July 2019 Ridgecrest Earthquake	Kern and San Bernardino
October 25, 2019	Kincade Wildfire	Sonoma
March 4, 2020	COVID-19 Pandemic[3, 4]	All Counties throughout PG&E territory
August 18, 20220	August 2020 Wildfires	All Counties affected by wildfires throughout PG&E territory
September 6, 2020	Creek Fire	Fresno, Madera and Mariposa Counties
September 25, 2020	Oak Fire	Mendocino County
September 28, 2020	Glass and Zogg Wildfire	Napa, Sonoma and Shasta Counties
January 29, 2021	January 2021 Winter Storms	Monterey and San Luis Obispo Counties

3 Pursuant to CPUC Resolution M-4842 the consumer protections associated with the COVID-19 pandemic are extended through June 30, 2021.

4 Due to the special circumstances of COVID-19 pandemic only applicable measures of the Emergency Consumer Protection Plan were available to impacted customers per Advice 4227-G/ 5784-E and Advice 4244-G-B/5816-E-B. (L)

(Continued)

GAS RULE NO. 1
DEFINITIONS

END-USE CUSTOMER: See CORE END-USE CUSTOMER and NONCORE END-USE CUSTOMER. (L)

ELECTRONIC BILLING: A billing method whereby at the mutual option of the Customer and PG&E, the Customer elects to receive, view, and pay bills electronically and to no longer receive paper bills.

ELECTRONIC PRESENTMENT: When made available or transmitted electronically to the Customer at an agreed upon location.

ENERGY PUBLIC UTILITY: Investor-owned electric and/or natural gas public utility regulated by the California Public Utilities Commission, or a municipal utility.

ENHANCED OIL RECOVERY: Any operation which includes the use of gas as a fuel to pressure, cycle or inject steam or hot water into a well for the purpose of increasing oil production from that well, including gas used for cogeneration to promote these operations.

EXPANSION RECEIPT POINT CAPACITY: Utility pipeline system improvements which increase the takeaway capacity from a Receipt Point and the overall downstream capacity of the Utility's pipeline system.

GAS: Any mixture of combustible and non-combustible gases used to produce heat by burning that can be accepted into a Utility pipeline without any compromise to operational safety or integrity. It shall include, but not be limited to, natural gas, renewable gas, biomethane, manufactured gas, or a mixture of any or all of the above. It shall meet the Utility's quality specifications, tariffs, rules and other applicable regulations.

HEATING VALUE: The term "heating value" as used in these rules shall mean total heating value of the gas normally measured on a dry basis (unless otherwise specified), and is defined as the number of British Thermal Units evolved by the complete combustion, at constant pressure, of one standard cubic foot of gas with air, the temperature of the gas, air and products of combustion being 60 degrees Fahrenheit and all of the water formed by the combustion reaction being condensed to the liquid state.

HOUSING PROJECT: A building or group of buildings located on a single premises and containing residential dwelling units for which master metering of gas service at one location has been requested. (L)

(Continued)

INDIVIDUAL METERING: Where PG&E installs a separate service and meter for each individual residence, apartment dwelling unit, mobilehome space, store, office, etc. (L)

INDUSTRIAL USE: Services to Customers engaged primarily in a process which creates or changes raw unfinished materials into another form or product. Industrial use is further defined as uses in the categories falling under Division B, Mining, Division C, Construction, and Division D, Manufacturing in the Standard Industrial Classification Manual issued by the Executive Office of the President, Office of Management and Budget.

INTERSTATE TRANSPORTATION: Transportation of natural gas on a pipeline system under the regulation of the Federal Energy Regulatory Commission.

INTRASTATE TRANSPORTATION: Transportation of gas on the PG&E system.

LIQUEFIED PETROLEUM GAS (LPG): A gas containing certain specific hydrocarbons (such as butane or propane) which are gaseous under ambient atmospheric conditions, which can be liquefied under moderate pressure at normal temperatures.

LOCAL TRANSMISSION SYSTEM: The term Local Transmission System includes the pipeline used to accept gas from the Backbone Transmission System, and transport it to the Distribution System. For PG&E, the Local Transmission System consists of all numbered (i.e., named) pipelines that are not considered part of the Backbone Transmission System, and Distribution Feeder Mains (DFMs), with a maximum operating pressure of greater than 60 (sixty) pounds per square inch.

MAILED: A communication sent by electronic means or enclosed in a sealed envelope, properly addressed and deposited in any U.S. Post Office box, postage prepaid, or unless otherwise prescribed in California Public Utility Code §779.1 or by the CPUC[4].

MAIN EXTENSION: The length of main and related facilities required to move gas from the existing facilities to the point of connection with the service piping.

[4] Public Utilities Code §779.1 requires PG&E to provide a mailed, prepaid notice to customers of potential disconnection due to nonpayment at least 10 days prior to the proposed termination. In addition, pursuant to D.20-06-003, OP 15, PG&E will provide disconnection notices via email to customers who have opted to receive electronic communications. (L)

(Continued)

GAS RULE NO. 1
DEFINITIONS

MASTER-METERING: Where PG&E installs one service and meter to supply more than one residence, apartment dwelling unit, mobilehome space, store, office, etc. (L)

MAXIMUM DAILY QUANTITY (MDQ): The maximum quantity of gas that can be nominated daily, as specified in the Customer's Natural Gas Service Agreement or Gas Transmission Service Agreement.

MERCHANTABILITY: The ability to purchase, sell, or market Gas. The Gas shall not contain dust, sand, dirt, gums, oils, microbes, bacteria, pathogens and/or other substances at levels that would be injurious to Utility facilities or which would present a health and/or safety hazard to Utility employees, customers, and/or the public or that would cause Gas to be unmarketable.

METER: The instrument owned and maintained by PG&E that is used for measuring the gas delivered to the Customer.

MIXED USE: Existing customers with a mix of residential and non-residential uses (mixed use) will be presumed to be on an applicable rate. However, if the predominate use is demonstrated to be more than 50% of the designated billing classification (residential or non-residential), then the rate may be changed to the billing classification applicable to the predominate use if the billing classification is consistent with the local governmental entity's treatment of the Premise as residential or non-residential (e.g. commercial). For purposes of determining predominate use, all common area usage will be considered residential usage regardless of whether the customer has elected a residential or non-residential billing classification for that common area usage under PG&E's tariffs. To the extent a Residential Dwelling Unit has both gas and electric service, all of the services must be served under the same billing classification. A customer however, has the obligation to notify PG&E if the billing classification is no longer consistent with the predominant use on the meter. PG&E has no obligation to change rates until such notification is received. Rate change obligations shall be prospective only unless PG&E failed to act on a customer notification in a timely fashion. If a notification occurs and there is a failure to act on PG&E's part, then such failure to act will be treated as a billing error under Rule 17.1 1. (L)

(Continued)

MOBILEHOME: A mobilehome is a structure designed for human habitation and for being moved on a street or highway under permit pursuant to the California Vehicle Code. Mobilehome also includes a manufactured home as defined in the California Health and Safety Code, but does not include a recreational vehicle or a commercial coach as defined in the California Health and Safety Code. (L)

MOBILEHOME PARK: A mobilehome park is an area of land where two or more mobilehome sites are rented, or held out for rent, to accommodate mobilehomes used for human habitation. A mobilehome park is not a recreational vehicle park.

MODIFIED FIXED VARIABLE (MFV): A rate design method which allocates all fixed costs, except return on equity and related taxes, to the demand charge. Return on equity and related taxes, and all variable costs, are allocated to the commodity charge.

MULTIFAMILY ACCOMMODATION: An apartment building, duplex, court group, residential hotel, or any other group of residential units located upon a single premises, providing these residential units meet the requirements for a residential dwelling unit. Hotels, guest or resort ranches, tourist camps, motels, auto courts, rest homes, rooming houses, boarding houses, dormitories, and trailer courts, consisting primarily of guest rooms and/or transient accommodations are not classed as multifamily accommodations. (L)

(Continued)

NATURAL GAS: See Gas. (L)

NONCORE END-USE CUSTOMER: Noncore End-Use Customers are typically large commercial, industrial, cogeneration, wholesale or electric generation Customers who meet the usage requirements for service under a noncore rate schedule and who have executed a Natural Gas Service Agreement. ~~Electric Generation,~~ Enhanced Oil Recovery, ~~Cogeneration~~, and Refinery Customers with historical or potential annual use exceeding 250,000 therms per year or rated generation capacity of five hundred kilowatts (500 kW) or larger, are permanently ~~typicallypermanently~~ classified as Noncore End-Use Customers. Electric Generation and Cogeneration Customers with historic or potential annual use exceeding 250,000 therms per year or rated generation capacity of five hundred kilowatts are typically classified as Noncore End-Use Customers but may request consideration of Core Transportation Service for Generators under the G-NR2 (aka “Large Core Commercial”) tariff. In its approval review process ~~and at its sole discretion~~ PG&E will consider system safety and whether serving or enabling the transportation system in the manner necessary for the generation customer to elect Core Transportation Service could detrimentally impact service to existing core customers. As is the case for other noncore customers requesting transfer to core service under Rule 12, to be considered for such categorization customers must agree to pay for reinforcement and/or special facility requirements necessary to provide such Core Transportation Service and remain on core service for a minimum of five years. Electric generation and cogeneration customers electing and approved for Core Transportation service will continue their exemption from G-PPPS and G-SUR but not be exempt from other applicable tariff charges pursuant to the applicable core rate and must obtain their procurement service from noncore balancing aggregation agent and not from a Core Procurement Group as defined in Rule 1. (L)/(T) (N)

NONPROFIT GROUP-LIVING FACILITY: A facility operated by a corporation that has received a letter of determination by the Internal Revenue Service that the corporation is tax-exempt due to its nonprofit status under IRS Code Section 501©(3). The facility must be one of the following: (L)

1. A homeless shelter with 10 or more beds and open at least 180 days per year;

2. Transitional housing, such as a half-way house or drug rehabilitation facility;

3. Short- or long-term care facility, such as a hospice, nursing home, seniors’ home, or children’s home; or

4. A group home for physically or mentally disabled persons.

With the exception of homeless shelters, the nonprofit group-living facility must provide services such as meals or rehabilitation in addition to lodging. All of the residents of the facility must meet the CARE eligibility standard for a single-person household. At least 70 percent of the gas supplied to the facility’s premises must be used for residential purposes, and the facility must be licensed by the appropriate state agency, with the exception of homeless shelters which must have the appropriate municipal or county (L)

(Continued)

conditional use permits.

Facilities such as student housing/dormitories are excluded. For complete eligibility requirements see Rule 19.2.

(Continued)

OFF-SYSTEM DELIVERY POINT(S): Any interconnection for delivery outside of PG&E's service territory. (L)

OFFER EVALUATION: PG&E will contract for service during Open Seasons and on an on-going basis, as Backbone-transmission capacity remains available. PG&E's acceptance of offers to purchase Backbone-transmission capacity will be subject to PG&E's willingness to accept negotiable terms or, if requests exceed Backbone-transmission capacity during an Open Season, by ranking offers based on the highest economic value available to PG&E, for each individual product, during the specific Open Season period. Before each Open Season, PG&E will specifically define the criteria for evaluating offers in its promotional materials.

ON-SYSTEM DELIVERY POINT: An on-system delivery point is defined as any point at which deliveries are made to, or for ultimate delivery to, PG&E's Local Transmission and Distribution system, PG&E's Market Center Citygate location, PG&E's storage facilities, or a third party's storage facilities located in PG&E's service territory.

ON-SYSTEM STORAGE FACILITY: An entity, acknowledged by the CPUC as providing storage services within California, which is physically connected to the PG&E pipeline transmission or distribution system with facilities dedicated to the transmission, injection and withdrawal of gas supply, and which also has an interconnection and a storage operating agreement with PG&E or which is owned by PG&E.

OPEN SEASON: An Open Season is the process used to advertise and take applications for services to the market.

OPTIONAL RATE SCHEDULES: CPUC approved rate schedules for a customer class from which any customer in that class may choose. Optional rate schedules do not include experimental schedules or schedules available at the sole option of PG&E.

PERMANENT SERVICE: Service which, in the opinion of PG&E, is of a permanent and established character. This may be continuous, intermittent, or seasonal in nature.

PERSON: Any individual, partnership, corporation, public agency, or other organization operating as a single entity. (L)

(Continued)

GAS RULE NO. 1
DEFINITIONS

(L)

PRESSURE RECORDING DEVICE: A mechanical or electronic device that automatically records gas pressure on a storage medium.

PUBLIC UTILITIES COMMISSION: The Public Utilities Commission of the State of California.

QUALIFIED CONTRACTOR/SUBCONTRACTOR (QC/S): An applicant's contractor or subcontractor who:

1. Is licensed in California for the appropriate type of work such as, but not limited to, gas and general;
2. Employs workmen properly certified for specific required skills such as, but not limited to, plastic fusion and welding. Workmen shall be properly qualified; and
3. Complies with applicable laws such as, but not limited to, Equal Opportunity Regulations, OSHA, and EPA.

RATE SCHEDULE: One or more tariff sheet(s) setting forth the charges and conditions for a particular class or type of service in a given area or location. A Rate Schedule includes all the wording on the applicable tariff sheet(s), such as schedule number, title, class of service, applicability, territory, rates, conditions, and references to rules.

RAW PRODUCT GAS OR FEEDSTOCK GAS: Gas from biogenic or other renewable sources, such as Biogas, biomass or power to Gas from renewable electricity, before conditioning or upgrading to comply with Gas Rule 29's gas quality specifications.

RECEIPT POINT(S): The place(s) where Customer delivers, or has delivered on its behalf, gas into the PG&E pipeline system.

(L)

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RECREATIONAL VEHICLE: A recreational vehicle (RV), as defined in the California Health and Safety Code, is a motor home, slide-in camper, park trailer, or camping trailer, with or without motive power, designed for human habitation for recreational or emergency occupancy. (L)

RECREATIONAL VEHICLE PARK: A recreational vehicle (RV) park is an area or tract of land or a separate designated section within a mobile home park where one or more lots are occupied by owners or users of recreational vehicles.

REFINERY: (1) Establishments primarily engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, and lubricants, through fractionation or straight distillation of crude oil, redistillation of unfinished petroleum derivatives, cracking or other processes. Establishments of this industry also produce aliphatic and aromatic chemicals as byproducts; and (2) Establishments primarily engaged in hydrogen manufacturing for sale in compressed liquid, and solid forms.

REQUIREMENT: A Customer's requirement for any period is the sum of the Customer's metered gas use and the customer's curtailed deliveries, expressed in therms.

RESIDENTIAL CUSTOMER: Class of customers whose dwellings are single-family units, multi-family units, mobilehomes or other similar living establishments (see "Residential Dwelling Unit" and "Residential Hotel"). A customer who meets the definition of a Residential Customer will be served under a residential rate schedule if 50% or more of the annual energy use on the meter is for residential end-uses. (See "Mixed Use")

RESIDENTIAL DWELLING UNIT: A group of rooms, such as a house, a flat, or an apartment which provides complete family living facilities in which the occupant(s) normally cooks meals, eats, sleeps, and carries on the household operations incidental to domestic life. (L)

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RESIDENTIAL HOTEL: A hotel establishment which provides lodging as a primary or permanent residence and has at least 50 percent of the units or rooms leased for a minimum period of one month and said units are occupied for nine months of the year. Residential hotels do not include establishments such as guest or resort hotels, resort motels or resort ranches, tourist camps, recreational vehicle parks, half-way houses, rooming houses, boarding houses, dormitories, rest homes, military barracks, or a house, apartment, flat or any residential unit which is used as a residence by a single family or group of persons. (L)

REVENUE FEES AND UNCOLLECTIBLE: Revenue Fees and Uncollectible (RF&U) can be used conjunctively or independently of each other. Revenue Fees include authorized expenses for the use of public rights-of-way (franchise fees), and the San Francisco Gross Receipts tax (SFGR) as authorized in the 2017 GRC. Uncollectibles include accounting expenses due to bad debts. Collectively, the RF&U factor will include franchise fees, SFGR, and uncollectibles. Rates for retail customers include a component for RF&U, as adopted in PG&E's General Rate Case. Rates for wholesale customers include a component for the revenue fees only, per Decision 87-12-039.

RULES: Tariff sheets which cover the application of all rates, charges, and services, when such applicability is not set forth in and is a part of the rate schedules.

SCHEDULED METER READING DATE: The date PG&E has scheduled a Customer's meter to be read for the purposes of ending the current billing cycle and beginning a new one. PG&E's meter reading schedule is published annually, but is subject to periodic change.

SERVICE PIPE: All pipe, valves, and fittings from and including the connection at the main, up to and including the stop-cock on the riser.

SERVICE-PIPE EXTENSION: Extension of a Service Pipe as defined above, in accordance with the service-extension rules.

SHRINKAGE: The amount of gas used by PG&E's Gas Department and the lost and unaccounted for supply, both of which are a function of moving gas for a Customer. (L)

(Continued)

GAS RULE NO. 1
DEFINITIONS

SMALL BUSINESS CUSTOMER: A non-residential Customer with annual gas usage of 10,000 therms, or less, per meter during the most recent 12 month period, or who meets the definition of a “micro-business” under California Government Code 14837. This definition does not include non-residential Customers who are on a fixed usage or unmetered usage rate schedule. (L)

SMARTMETER™: Trademark used by PG&E with permission of trademark owner for use in conjunction with PG&E's Advanced Metering Infrastructure (AMI) project (approved by the Commission in D.06-07-027) and in conjunction with the marketing of any or all related goods and services of PG&E associated with AMI.

STANDARD ATMOSPHERIC PRESSURE: A pressure of 14.73 pounds per square inch absolute (psia).

STANDARD CUBIC FOOT OF GAS: The quantity of gas that occupies one cubic foot at standard temperature under standard atmospheric pressure and is free of water vapor (dry), unless otherwise specified.

STANDARD TEMPERATURE: 60 degrees Fahrenheit, based on the international temperature scale.

STORAGE INJECTION: Quantities of gas delivered into storage facilities for later use by Customers.

STORAGE WITHDRAWAL: Quantities of gas delivered from storage facilities for use by Customers.

STRAIGHT FIXED VARIABLE (SFV): A rate design method which allocates all fixed costs to the demand charge and all variable costs to the commodity, or usage, component. (L)

(Continued)

GAS RULE NO. 1
DEFINITIONS

STUB SERVICE: A lateral pipe, including valves and fittings, from and including the connection at the main to a dead end near the curb or property line of the street in which the main is located. (L)

SUBMETERING: Where the master-metered customer installs, owns, maintains, and reads the meters for billing the tenants in accordance with Rule 18.

TARIFF SCHEDULES: The entire body of effective rates, rentals, charges, and rules, collectively, of PG&E, including title page, preliminary statement, rate schedules, rules, sample forms, service area maps, and list of contracts and deviations.

TARIFF SHEET: An individual sheet of PG&E's tariffs.

TEMPORARY SERVICE: Service for enterprises or activities which are temporary in character or where it is known in advance that service will be of limited duration. Service which, in the opinion of PG&E, is for operations of a speculative character of which the permanence has not been established is also considered temporary service.

TRACT OR SUBDIVISION: An area for family dwellings which may be identified by filed subdivision plans or as an area in which a group of dwellings may be constructed about the same time, either by a large scale builder or by several builders working on a coordinated basis.

TRANSMISSION SYSTEM: The Transmission System is PG&E's backbone and local gas transmission lines, including gathering and Stanpac lines.

UTILITY: Pacific Gas and Electric Company (PG&E).

UTILITY USERS TAX: A tax imposed by local governments on PG&E's customers. PG&E is required to bill customers within the city or county for the taxes due, collect the taxes from customers, and then pay the taxes to the city or county. The tax is calculated as a percentage of the charges billed by PG&E for energy use.

WHOLESALE/RESALE CUSTOMER: A Customer who takes service under gas Schedule G-WSL—Gas Transportation Service to Wholesale/Resale Customers, which applies to the transportation of gas for resale.

WOBBE INDEX: HHV/($\sqrt{}$Relative Density$_{real}$) as defined in Section 2.20 in the 2009 American Gas Association (AGA) Report No. 5 Natural Gas Energy Measurement. (L)

E. CHANGES TO CUSTOMER CLASSIFICATION

Noncore to Core Reclassification

a. Transfer from Noncore to Core Service

In accordance with California Public Utilities Commission Decision 03-12-008, dated December 4, 2003, transfers of noncore Customers to core service are prohibited for customers who are defined as Electric Generation (including gas-fired cogeneration), Enhanced Oil Recovery (EOR), and Refinery, with historical or potential annual gas use exceeding 250,000 therms per year. However, as approved in Advice 4409-G, and described below, generators may request Core Transportation Service. Where no historical data is available, potential gas use will be based on the capacity of the gas service facilities serving such load. If the capacity of the gas service facilities is sized to meet a peak load of one-hundred thousand cubic feet per day (100 Mcf/day) this load will be classified as noncore. ~~Electric Generation or Cogeneration Customers with generation capacity of five-hundred kilowatts (500 kW) or larger will be prohibited from core service.~~ (N) | (N) (D) | (D)

All other Noncore End-Use Customers are allowed to request reclassification to core service but will be required to remain on core service for a minimum of five (5) years. Customers otherwise assigned to G-EG tariff with annual gas usage exceeding 250,000 therms or with generating capacity of 500kW or greater must comply with terms provided in Rule 1 and tariffs G-EG and G-NR2 in order to be considered for Core Transportation service. Prior to reclassification to core service, Customers must complete and sign the Request for Reclassification from Noncore Service to Core Service (Form 79-983) (Request). Reclassification will take effect on the first day of the next Billing Cycle after PG&E's acceptance of the Request. (N) | | (N)

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

SUPPLY-SIDE PROCUREMENT FOR SUMMER 2022/2023

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
SUPPLY-SIDE PROCUREMENT FOR SUMMER 2022/2023

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
SUPPLY-SIDE PROCUREMENT FOR SUMMER 2022/2023

A. Introduction

This chapter includes Pacific Gas and Electric Company's (PG&E): (1) comments on the portion of the *Energy Division Staff Concept Paper – Proposals for Summer 2022 and 2023 Reliability Enhancements* (Concept Paper) prepared by the Energy Division Staff of the California Public Utilities Commission (Commission) and circulated by Administrative Law Judge Brian Stevens on August 16, 2021 that offers observations and proposals regarding opportunities to bring new battery and generation resources online by summer 2022 (Section B), and (2) proposals related to increasing supply during the net peak window for summers 2022 and 2023 (Section C).

B. PG&E's Comments on Staff's Concept Paper

PG&E appreciates Energy Division Staff's thoughtful Concept Paper and solutions-oriented approach to proposals that will address the reliability needs for the summers of 2022 and 2023 during the net peak window. In this section, PG&E provides comments on the various items proposed in the Concept Paper and builds from some of these ideas to either elaborate on or formulate its own proposals, as outlined in the subsequent sections.

1. Introduce Penalties for Delays to Decision 19-11-016 Procurement

PG&E opposes the introduction of a penalty framework for delays associated with online deadlines for procurement ordered in Decision (D.) 19-11-016. Load serving entities (LSE) have already completed or may be in the process of completing their procurement to meet the online deadlines for their proportional share of the 3,300 megawatts (MW) ordered in D.19-11-016. The introduction of a penalty framework at this stage in the process could have unintended consequences. For example, contracts already executed may not have sufficient provisions to account for the new penalty framework. This could result in executed contracts requiring amendments or impact current negotiations. If developers of new resources and LSEs cannot come to an agreement, this could effectively risk the ability of these new resources to come online and meet the respective online deadlines established by the Commission.

Further, PG&E notes that Energy Division Staff has recently issued (on August 23, 2021) a *Status Update on Procurement in Compliance with D.19-11-016* in the Integrated Resource Planning (IRP) proceeding. The status update and review indicate that LSEs have completed their incremental procurement of 3,300 MWs ordered in D.19-11-016.[1] In fact, LSEs have exceeded their 2021 obligation by 329 MWs of net qualifying capacity and are on track to meet their 2022 and 2023 obligations. While the ongoing Coronavirus (COVID-19) pandemic has caused delays, most are expected to be less than six months, and all 25 LSEs who did not opt-out of their procurement obligation have demonstrated an effort to meet their procurement targets. Moreover, Energy Division Staff determined there was no need for backstop procurement at this time. Accordingly, PG&E does not support the introduction of a penalty framework at this stage in the process. There is no evidence of under-procurement or a lack of effort by LSEs, and the implementation of penalties at this stage could have unintended consequences for procurement intended to support reliability during the summers of 2022 and 2023.

2. Increase Resource Adequacy Penalties

The Concept Paper includes a proposal to double the applicable resource adequacy (RA) penalties for LSEs who fail to meet their RA obligations for August 2022 and September 2022. Given the recent enhancements to the RA penalty structure adopted in the Commission's June 24, 2021 decision (D.21-06-029) in Track 3B.1/4 of the RA proceeding (Rulemaking (R.) 19-11-009), it would be premature to make additional changes to the RA penalty structure at this time. In D.21-06-029, the Commission recognized the increasing number of system RA deficiencies and acknowledged the need for a penalty structure that aims to prevent repeated LSE deficiencies. To address this, the Commission adopted a

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[1] See the Commission's Status Update on Procurement in Compliance with D.19-11-016 at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/ed_staff_review_of_feb2021_data_in_compliance_with_d1911016.pdf.

modified penalty structure proposed by PG&E that is intended to discourage an LSE's repeated deficiency through escalating tiers and increased penalty prices over time. D.21-06-029 also established that this penalty structure would take effect for the 2022 RA compliance year.[2]

As a result, the newly adopted modifications to the RA program's penalty structure have not yet taken effect, and there has not been an opportunity to determine their efficacy in preventing RA deficiencies, including the impact of escalating prices associated with non-compliance. Further, in D.21-06-029, the Commission highlights its need to evaluate recently adopted shaped system RA penalties before considering raising the overall penalty price.[3] Considering the need for more time to pass in order to implement this new structure, introducing additional changes to the RA penalty structure in this proceeding would be premature and inconsistent with the Commission's prior determinations. For all these reasons, PG&E recommends that the Commission not adopt any additional changes to the RA penalty structure until the recently adopted enhancements are applied and assessed.

3. Emergency Procurement and Cost Recovery via a New Non-Bypassable Charge

The Concept Paper includes a proposal to establish a new non-bypassable charge (NBC) to recover the costs associated with emergency-based procurement that may not already fit into the existing Cost Allocation Mechanism (CAM) used by the investor-owned utilities (IOU) for procurement done on behalf of all customers within their respective distribution service territories. The Concept Paper also recommends that the new proposed NBC could be used for cost recovery of procurement under contract to an IOU or a non-IOU entity with the IOU submitting the contract to the Commission, presumably on behalf of itself or the non-IOU entity, via an advice letter (AL) process. PG&E has concerns with establishing a new NBC for emergency-based procurement purposes and opposes this proposal from the Concept Paper.

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2 D.21-06-029, pp.59-60.

3 *Id.*, p. 60.

First, PG&E disagrees with the Concept Paper indicating that CAM does not allow for cost recovery for emergency-based procurement that either adds to the planning reserve margin or does not provide capacity attributes. In fact, the Commission found that the procurement directives from D.21-02-028 and D.21-03-056 are eligible for CAM cost recovery and recognized that there may "not be RA capacity benefits to allocate to all LSEs, as is usually the case with resources procured through the [CAM]."[4] With the exception of allowing the new proposed NBC to be eligible to a non-IOU entity, PG&E does not believe this proposal provides any incremental benefit for emergency-based procurement.

Second, should the Commission establish a new proposed NBC, PG&E has significant concerns with allowing a non-IOU entity to use this as a cost recovery mechanism without also establishing clear and upfront standards for approval. PG&E notes that the Commission does not currently have the statutory authority to perform such a reasonableness review for cost recovery for procurement under contract with a non-IOU entity (such as a community choice aggregator (CCA) or energy service provider (ESP)), and the Commission would need to request and receive such authority from the legislature. Further, it is not clear to PG&E that a CCA has the legislative authority to procure for customers outside of its CCA service, which could include procurement for another CCA and their customers; or whether some CCAs' bylaws may need to change to accommodate this procurement. Moreover, the Concept Paper suggests that the contract would be submitted by the IOU on behalf of the non-IOU entity but does not provide any further Commission oversight on prudent management of the contract. Performing such after-the-fact reasonableness reviews would likely be administratively burdensome and highly litigious, and PG&E advises that the Commission consider the challenges associated with such a responsibility.

In addition, PG&E has a significant backlog of billing system changes and estimates that the adoption of the new proposed NBC may not be implemented until 2025. In PG&E's Advice 4302-G/5932-E, submitted on August 31, 2020 in the Power Charge Indifference Adjustment Rulemaking

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[4] D.21-03-056, Finding of Fact (FOF) 73.

(17-06-026), PG&E expressed that upgrades to its main and ancillary billing systems may occur beginning in 2021. Such multi-year upgrades will require freeze and stabilization periods, and these periods may impact PG&E's ability to implement the new proposed NBC and recover the associated costs for emergency-based procurement for the summers of 2022 and 2023. This would likely result in bundled service customers financing the costs, likely through bundled service generation rates, until these multi-year billing system changes can be implemented.[5]

For the reasons discussed above, PG&E believes the existing CAM cost recovery mechanism is appropriate and applicable for emergency-based procurement and urges the Commission to reject the new proposed NBC in the Concept Paper. In lieu of the new proposed NBC, PG&E encourages coordination with the CCAs and ESPs for those entities to sell any supply that may be in excess of their RA obligations (e.g., above the 15 percent planning reserve margin) to the IOUs for use in meeting any incremental procurement targets established by the Commission. This will effectively allow the IOUs to procure cost competitive supply from CCAs and ESPs and provide broad cost recovery to all benefitting customers through the existing CAM cost recovery mechanism.

4. Bundled Procurement Rules Modifications for Hydroelectric Generation

Lastly, the Concept Paper proposes to modify the current least cost dispatch (LCD) practices to allow the IOUs to preserve hydroelectric generation for maximum availability during strained grid conditions. For the reasons outlined below, PG&E does not believe modifications to the current LCD practices are warranted for its hydroelectric resources. Modifications would not result in additional capacity being available for critical peak events nor additional RA value available in August and September as suggested.

PG&E optimizes the dispatch of its hydroelectric fleet on a forecast basis to maximize customer benefit, which includes the ability to generate during critical reliability events. Throughout the year and for each of PG&E's watersheds, water plans are updated weekly, using the latest forecasts of

[5] *See* PG&E's Advice 5826-E, p. 13.

water supply and energy demand as well as safety, physical, operational, and license constraints.

When considering the trade-off between generating in earlier months of the year versus August and September, PG&E's processes already incorporate maximizing generation for the later summer period. While PG&E uses price forwards to indicate when energy is most needed, there is a correlation between prices and high need periods. Additionally, PG&E's operators consider summer reliability needs and August and September RA needs when making dispatch decisions throughout the year. PG&E does not believe that changing the regulatory framework for hydroelectric bidding decisions will result in any incremental benefits given that actual dispatch decisions generally would not change.

Regardless of the RA value (measured in terms of a net qualifying capacity), PG&E makes its dispatchable hydroelectric capacity available during critical reliability events. PG&E does not believe that the capacity that would be available next year during similar critical events would be any less than this year, and it could be greater, if the drought diminishes. Additionally, PG&E does not believe this capacity would be any greater if the LCD rules were changed as proposed in the Concept Paper. Accordingly, PG&E does not believe modifications to the current LCD practices are warranted for its hydroelectric resources and opposes this proposal from the Concept Paper.

C. PG&E's Proposals Related to Increasing Supply During the Net Peak Window for the Summers of 2022 and 2023

1. PG&E Proposes that the Commission Adopt Interim Modifications to the Central Procurement Entity Framework

PG&E proposes that the Commission authorize PG&E as the Central Procurement Entity (CPE) to bilaterally negotiate, in addition to using an all-source solicitation, for contracting with counterparties that can both: (1) provide incremental local RA resources and (2) meet the near-term emergency-based procurement needs for the summers of 2022 and 2023. Should these negotiations prove successful, PG&E proposes that the Commission allow the CPE to file a Tier 1 AL, consistent with D.21-02-028 and D.21-03-056 (collective, the Phase 1 Decisions), for expedited approval of the contract. Further, in accordance with the Phase 1 Decisions and D.20-06-002 (the CPE Decision), the associated costs of these incremental local RA resources would be allocated similarly to other CAM resources procured by the CPE for local area reliability.

In the CPE Decision, the Commission adopted a centralized framework for the procurement of local RA, beginning with the 2023 RA compliance year, in the PG&E and Southern California Edison Company (SCE) distribution service areas and identified PG&E and SCE as the CPEs for their respective distribution service areas. In doing so, the Commission also outlined various implementation details by which the CPE would procure local RA resources, such as the use of an all-source solicitation to procure existing and/or new resources and a Tier 3 AL process for long-term (more than 5 years) agreements. In adopting a centralized framework for local RA, the Commission concluded that it was "…the solution most likely to provide cost efficiency, market certainty, reliability, administrative efficiency, and customer protection."[6] PG&E agrees and has supported the adoption of a centralized framework for local RA. However, some of the current implementation details should be modified to streamline the procurement process for PG&E as the CPE to meet the objectives of this proceeding, specifically the sole use of an all-source solicitation and the use of a Tier 3 AL for procuring long-term agreements that are typically needed for new and incremental resources.

The Phase 1 Decisions appropriately recognized the importance of streamlining the procurement process given the accelerated timelines before the Commission and authorized the IOUs to use offers from new solicitations, bilateral negotiations, or allow counterparties an opportunity to refresh prior IRP procurement bids in responding to the Phase 1 procurement directives.[7] The Commission also authorized the use of a Tier 1 AL process on a continuing basis, except for contracts for incremental gas generation of five years or more and incremental imports. PG&E's

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6 D.18-06-030, p. 32.

7 D.21-03-056, FOF 75.

proposed interim modifications to the CPE framework are consistent with the guidance from the Phase 1 Decisions. To also ensure consistency with the objectives for establishing a centralized framework for local RA resources, PG&E suggests that these procurement parameters are only applicable to the CPE if:

a) The CPE procures preferred and/or energy storage resources that can come online by the summers of 2022 or 2023.

b) The procured local RA resource is located within the CPE's respective distribution service area.

c) The procured local RA resource is located within a CAISO-designated local area (such as Humboldt, North Coast/North Bay, Sierra, Greater Bay Area, Stockton, Fresno, or Kern for PG&E as the CPE).[8]

PG&E believes that this limited scope will meet the Commission's objectives of this proceeding under the accelerated timeframe and provide cost efficiency, market certainty, local area reliability, and administrative efficiency. PG&E urges the Commission to adopt PG&E's proposal for interim modifications to the CPE framework as set forth above.

a. Guidance to Parties for Proposals to Reduce Demand or Increase Supply – Identify Any New Policy or Modification to an Existing Policy That Could Reduce Demand or Increase Supply at Net Peak[9]

1) Duration – Temporary or Permanent

PG&E's proposal is temporary and shall only be applicable to the extent that the CPE has demonstrated it has met all of the following procurement parameters:

- The CPE procures preferred and/or energy storage resources that can come online by the summers of 2022 or 2023.
- The procured local RA resources are located within the CPE's respective distribution service area.

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8 D.20-06-002, Conclusion of Law 15.

9 PG&E's proposal for interim modifications to the CPE framework is a modification to existing policy. As such, PG&E is only responding to Section 2 ("Identify Any New Policy or Modification to an Existing Policy That Could Reduce Demand or Increase Supply at Net Peak") of Energy Division Staff's Guidance on Proposals Submitted in Opening Testimony by Parties to this Proceeding.

- The procured local RA resources are located within a CAISO-designated local area.

2) Justification or Demonstration That Policy Will Support the Delivery of Reliability Benefits During Net Peak

PG&E will demonstrate that the incremental local RA resources are able to deliver during the net peak window through the Tier 1 AL process.

3) Estimate of Policy's Impact (MWs)

PG&E will provide the estimated MWs from the incremental local RA resources through the Tier 1 AL process.

4) Implementation Requirements, Including Whether Other State Agencies or CAISO Must Approve

This element does not apply to PG&E's proposal for interim modifications to the CPE framework.

5) Potential Risk of Proposal

PG&E does not anticipate any additional risks in adopting its proposal for interim modifications to the CPE framework.

6) Statutory and/or Regulatory Justification and History (Especially if Recommendation is to Change an Existing Policy)

The Commission adopted a centralized framework for the procurement of local RA prior to the August 2020 outage events and this subsequent proceeding. During the proceeding adopting the CPE Decision, the Commission did not anticipate the need for an expedited and emergency-based procurement process for incremental local RA resources and, thus, did not consider implementation details to support accelerated procurement. PG&E's proposal is intended to streamline the procurement process for the respective CPEs to both meet the objectives of this proceeding and provide cost efficiency, market certainty, local area reliability, and administrative efficiency.

2. PG&E Proposes that the Commission Continue its Use of the Procurement Approval Process and Clearly Apply Utility-Owned Generation (UOG) Resources to the IRP Procurement Order

PG&E appreciates the expedited procurement approval process adopted in this proceeding and the significant time dedicated by Energy Division Staff to review the contracts that are submitted by the IOUs under this proceeding's procurement directives. Sections C.4.c and d of the Concept Paper presumably contemplate continuing and implementing an expedited procurement approval process for certain categories of procurement, including the installation of new utility-owned storage at utility-owned or controlled properties. The Concept Paper posits that storage may be more rapidly deployed at IOU-owned sites, especially substations, because of innate benefits conferred by IOU ownership to site control, interconnection, deliverability, and permitting. While the process of building and deploying new resources still involves significant uncertainty, especially in light of constraints imposed by the ongoing COVID-19 pandemic, PG&E agrees that new utility-owned storage may have a higher chance of coming on-line by the summers of 2022 and 2023.

Consequently, retaining and enhancing the current procurement approval process for the construction of utility-owned resources that meet certain criteria may allow storage resources, capable of shifting energy to the crucial net peak window, to come on-line more expeditiously than other resources. To that end, PG&E supports the continued use of a Tier 1 AL process for resources that are not IOU-owned and a Tier 2 AL process for utility-owned resources when developed in configurations that enhance the state's reliability, climate, and affordability goals.[10]

The continued use of a Tier 2 AL process for utility-owned resources could be effectively utilized to facilitate a variety of procurement types that are consistent with and facilitate state policy goals, specifically those identified in the IRP proceeding. In D.21-06-035, the Commission directed all LSEs to procure 11,500 MWs of incremental September net qualifying capacity. This order represents an immense volume of incremental capacity

[10] D.21-02-028, p. 11.

procurement being ordered amidst tight market conditions, significant reliability concerns, a global pandemic, and a worsening climate crisis. The Commission elected to adopt a more stringent approval standard for pumped storage and UOG resources, requiring submission of a full application.[11] PG&E recommends that the Commission take prudent steps to ensure this procurement, especially procurement types that effectively serve the net peak window like pumped storage and storage at utility-owned sites, can come online as soon as possible. As discussed above, the Concept Paper correctly points out that these same resource types may be able to come on-line faster than others, and that it may be prudent to expedite their approval process.

Accordingly, PG&E recommends that the Commission continue the use of a Tier 1 AL process for resources that are not IOU-owned and a Tier 2 AL process for utility-owned resources for this proceeding. Additionally, it is important that the Commission clearly indicate that UOG resources approved in this proceeding do not require a corresponding or subsequent application to be submitted to meet the procurement orders from D.21-06-035.

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[11] D.21-06-035, p. 4.

a. Guidance to Parties for Proposals to Reduce Demand or Increase Supply – Identify Any New Policy or Modification to an Existing Policy That Could Reduce Demand or Increase Supply at Net Peak[12]

1) Duration – Temporary or Permanent

PG&E's proposal is temporary and shall only be applicable to the extent that the procured resources can come online by the summers of 2022 or 2023.

2) Justification or Demonstration That Policy Will Support the Delivery of Reliability Benefits During Net Peak

PG&E's proposal will facilitate the construction of new energy storage resources. These resources are capable of meeting reliability needs by charging prior to the net peak window (e.g., during periods of high renewable generation) and discharging during the net peak window.

3) Estimate of Policy's Impact (MWs)

PG&E will provide the estimated MWs from the incremental RA resources through the Tier 1 or Tier 2 AL process.

4) Implementation Requirements, Including Whether Other State Agencies or CAISO Must Approve

This element does not apply to PG&E's proposal for interim modifications to the CPE framework.

5) Potential Risk of Proposal

PG&E does not anticipate any additional risks in adopting its proposal for an expedited procurement process.

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12 PG&E's proposal for an expedited procurement process is a modification to existing policy. As such, PG&E is only responding to Section 2 ("Identify Any New Policy or Modification to an Existing Policy That Could Reduce Demand or Increase Supply at Net Peak") of Energy Division Staff's Guidance on Proposals Submitted in Opening Testimony by Parties to this Proceeding.

6) Statutory and/or Regulatory Justification and History (Especially if Recommendation is to Change an Existing Policy)

PG&E proposes the continued use of a Tier 1 AL process for resources that are not IOU-owned and a Tier 2 AL process for utility-owned resources and does not believe it changes any existing policy. While D.21-06-035 allows an IOU to show procurement "conducted to support the Commission's orders or requirements in the context of [sic] emergency reliability purposes in R.20-11-003, as compliance toward the requirements herein," the decision's language that UOG resources require an application could be interpreted by parties that a corresponding or subsequent application is needed regardless of Commission approval through the Tier 2 AL process.[13] PG&E is requesting that the Commission make it clear that a Tier 2 AL for UOG resources in this proceeding shall also allow an IOU to show the same resource towards compliance in D.21-06-035 and would not require an application.

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13 D.21-06-035, p. 80.

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CHAPTER 10

COST RECOVERY

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COST RECOVERY

A. Introduction

T The purpose of this chapter is to present Pacific Gas and Electric Company's (PG&E or the Utility) ratemaking and cost recovery proposal for the following demand-side programs:

1) Emergency Load Reduction Program (ELRP): All incremental ELRP costs that PG&E incurs for program administration, implementation, and incentives as described in Chapter 2 of PG&E's Opening Testimony, should be authorized to be recorded and tracked in the ELRP Subaccount of Demand Response Expenditures Balancing Account (DREBA) and recovered through the currently adopted cost recovery treatment in electric distribution rates.
2) Existing Demand Response (DR) Portfolio: The additional costs to implement and operate enhancements to PG&E's existing DR Programs, specifically the Base Interruptible Program (BIP), the Capacity Bidding Program (CBP), and SmartAC, as described in Chapter 4 of PG&E's Opening Testimony, should be authorized to be recorded and tracked in the same subaccounts in DREBA as those programs are currently authorized to be recorded and tracked. PG&E proposes to utilize unspent funds from its existing DR budget adopted in Decision (D.) 17-12-003 for BIP, CBP, and SmartAC. If existing unspent funds are exhausted, PG&E proposes to use the additional program funding adopted for SmartAC, as described in Chapter 4.
3) Third Party DR Program: All incremental costs that PG&E incurs for Information Technology (IT) enhancements to the ShareMyData system as described in Chapter 5 of PG&E's Opening Testimony, should be authorized to be recorded and tracked in the Operations Subaccount of DREBA and recovered through the currently adopted cost recovery treatment in electric distribution rates.
4) Distributed Energy Resources (DER) - Demand Response Emerging Technology (DRET): The incremental costs to accelerate a number of

DRET studies and pilots as described in Chapter 7 should be authorized to be recorded in the Operations Subaccount of DREBA and recovered through the currently adopted cost recovery treatment in electric distribution rates.

5) Electric Reliability Memorandum Account (ERMA): All incremental costs for other activities authorized in the Phase 2 decision of this proceeding that are not specifically authorized for recovery should be authorized to be tracked in the ERMA and included in a future application for recovery in rates, subject to the California Public Utilities Commission's (CPUC or Commission) review and approval of reasonableness.

B. Cost Recovery and Ratemaking Proposals

PG&E requests the Commission approve its cost recovery and ratemaking proposals as reasonable and necessary to address Summer 2022 and 2023 reliability needs at net peak as described in the Energy Division Staff Concept Paper and further described in Chapters 2, 3 through 4, and 7 of this testimony.

To the extent possible, PG&E proposes using currently adopted balancing accounts and cost recovery mechanisms in order to be efficient and cost effective. Internal orders may be used to separately track budgets and costs authorized through this phase of the proceeding from those previously authorized by the CPUC. If necessary, PG&E will file a Tier 1 Advice Letter (AL) to modify its preliminary statements after the CPUC issues its final decision. All costs presented in this Application are incremental and were not requested in the General Rate Case (GRC), or other CPUC-approved funding or pending applications, including Application 18-11-015, *Improvements to Click-Through Customer Data Access Application*.

1. Background on Existing Accounts to be Used to Record and Recover Demand-Side Program Costs

The purpose of the revenue adjustment mechanism described below is to ensure the recovery of adopted revenue requirements in PG&E's electric rates, as actual energy sales deviate from forecasted energy sales.

- Distribution Revenue Adjustment Mechanism (DRAM):[1] DRAM is a two-way revenue balancing account that records adopted electric distribution revenue requirements, including adopted DR. PG&E's currently adopted DRAM is defined in Electric Preliminary Statement Part CZ.

Sometimes the Commission adds a second step to the recovery process for adopted revenue requirements/funding associated with programs. Specifically, the Commission adopts expense balancing accounts that require PG&E to true-up its adopted revenue requirements to actual expenses. For one-way balancing accounts, the Commission limits recovery of actual expenses to the adopted revenue requirement and for two-way balancing accounts, PG&E can recover actual spending above the adopted funding. The expense balancing accounts described below track the difference between actual program costs and the adopted funding for relevant demand side programs presented in testimony.

- DREBA: DREBA is defined in Electric Preliminary Statement Part EC and consists of five subaccounts. A description of the subaccounts PG&E proposes to utilize in its testimony below are as follows:
  - The ELRP Subaccount is a one-way balancing account that tracks the difference between PG&E's authorized ELRP budget and the costs incurred, including administrative expenses, incentives, and other costs to implement ELRP. Disposition of the balance in this subaccount is through the Annual Electric True-Up (AET) AL process once all program costs have been recorded.
  - The Incentives Subaccount is a two-way balancing account that records PG&E's adopted event-based participation incentives compared to costs incurred for payment of incentives to participating customers or their aggregators. Disposition of the balance in this subaccount is annually through the AET AL process or other filing as authorized.

1 The use of the acronym DRAM herein only refers to the Distribution Revenue Adjustment Mechanism and not the Demand Response Auction Mechanism.

- The Operations Subaccount is a one-way balancing account that tracks the difference between the annual authorized program budget and the actual program costs incurred to operate, maintain, and administer DR programs. Disposition of the balance in this subaccount is through the AET AL process or other proceeding authorized by the Commission once all authorized budget cycle program costs have been recorded.

Sometimes the Commission defers authorizing cost recovery and instead authorizes a utility to track its costs in a memorandum account. Establishment of a memorandum account does not guarantee recovery of any costs booked to that account. Cost recovery is subject to CPUC review and approval of reasonableness through a future application for recovery in rates.

- ERMA: ERMA is a memorandum account defined in Electric Preliminary Statement IQ. It tracks incremental costs associated with implementing the requirements of Rulemaking 20-11-003 and D.21-03-056. Disposition of the balances may be included in a future application for recovery in rates, subject to CPUC review and approval of reasonableness. Upon approval by the CPUC, PG&E will transfer the costs to the appropriate accounts for recovery.

2. Emergency Load Reduction Program

PG&E proposes to use ELRP's currently adopted cost recovery treatment[2] for the incremental costs described in Chapter 2. Specifically, PG&E proposes recording the incremental ELRP expenses compared to the related additional funding adopted in this application in the ELRP Subaccount of the DREBA. The budget is designed to be spent over the course of the period in which the work is performed. As such, unspent funds at the end of each calendar year may be carried over to the following calendar year and used until the work is completed. The adopted revenue requirements would be recorded in DRAM and incorporated into distribution rates annually as illustrated below in Table 10-1. Any unspent amounts

2 As approved in D.21-03-056, Ordering Paragraph (OP) 9 and further detailed in AL 6143-E-A, which was approved on June 2, 2021 with an April 1, 2021 effective date.

would be returned to customers upon completion of the work by transferring the balance in the DREBA to the DRAM for true-up in rates through the AET AL process.

This proposed one-way balancing account treatment is appropriate in situations like this where (1) the Utility is performing necessary work to better serve its customers in the ordinary course of business, (2) the Utility is able to develop a reasonable forecast for the cost of the work to be performed, and (3) parties have an opportunity to review the proposed scope of the necessary work and the associated forecasted costs before any costs are recorded to the balancing account. Adopting balancing account treatment that caps the adopted budget that the Utility may spend and the authorized revenue that the Utility may collect from customers without further reasonableness review is an appropriate method of controlling costs and allows the Commission and stakeholders to understand the full costs of the program in a comprehensive manner.

3. Existing Demand Response Programs

In order to implement the modifications, operational changes, and payment of incentives as described in Chapter 4 of this testimony for BIP, CBP, and SmartAC, PG&E will incur two types of costs: (1) operational and administrative costs, and (2) incentive payments. PG&E proposes to record and track these costs in the same subaccounts in DREBA as those programs are currently authorized to be recorded and tracked, i.e. the Operations and Incentives subaccounts, respectively.

In terms of funding sources for these incremental costs, PG&E proposes the following:

- For BIP and CBP incremental operational and administrative costs, PG&E proposes that the Commission authorize the use of existing, unspent funds from PG&E's 2018-2022 DR budget cycle as adopted in D.17-12-003;
- For SmartAC incremental operational and administrative costs, PG&E proposes that the Commission (1) authorize the use of existing, unspent funds from PG&E's 2018-2022 DR budget cycle as adopted in D.17-12-003 to the extent existing funds are available and (2) authorize additional program funding as described in Chapter 4. The existing,

unspent funds would be exhausted before the additional program funding would be utilized for these costs. If any of the additional adopted program funding approved in this application is needed to fund the operational and administrative costs, then PG&E proposes to record the necessary additional funding amount in the Operations Subaccount of DREBA so that it is no longer overspent, or undercollected, and record an equal amount to the DRAM for recovery from customers; and

- For incremental incentive payments, the currently approved operation of the Incentive Subaccount of DREBA already allows for the recovery of overspent funding, or undercollection, that may result from the modifications described in Chapter 4 related to incentives.

4. Third Party Demand Response

PG&E proposes to use Rule 24's currently adopted cost recovery treatment[3] for Third Party DR as described in Chapter 5. PG&E believes this is appropriate and reasonable since the need for IT system enhancements is driven by the growth projections of Rule 24 providers. Specifically, PG&E proposes recording the Third Party DR expenses compared to the related funding adopted in this application in the Operations Subaccount of the DREBA. The budget is designed to be spent over the course of the period in which the work is performed. As such, unspent funds at the end of each calendar year may be carried over to the following calendar year and used until the work is completed. The adopted revenue requirements would be recorded in DRAM and incorporated into distribution rates annually as illustrated below in Table 10-1. Any unspent amounts would be returned to customers upon completion of the work by transferring the balance in the Operations Subaccount to the DRAM for true-up in rates through the AET AL process. This proposed one-way balancing account treatment is appropriate for the reasons described above.

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3 Refer to Resolution E-4983 and AL 5446-E, which was approved with an effective date of October 10, 2019.

5. Distributed Energy Resources - Demand Response Emerging Technology

PG&E proposes to use the currently adopted cost recovery treatment[4] for the incremental costs described in Chapter 7. Specifically, PG&E proposes recording the incremental DRET expenses compared to the related additional funding adopted in this application in the Operations Subaccount of the DREBA. The budget is designed to be spent over the course of the period in which the work is performed. As such, unspent funds at the end of each calendar year may be carried over to the following calendar year and used until the work is completed. The adopted revenue requirements would be recorded in DRAM and incorporated into distribution rates annually as illustrated below in Table 10-1. Any unspent amounts in the Operations Subaccount would be returned to customers upon completion of the work by transferring the balance in the DREBA to the DRAM for true-up in rates through the AET AL process. This proposed one-way balancing account treatment is appropriate for the reasons described above.

C. Summary of Revenue Requirements

The following table shows the proposed revenue requirements for each of the demand-side programs requiring cost recovery discussed in testimony. Although the revenue requirements are stated separately for 2022 and 2023 for information purposes, PG&E requests authority to recover the costs and revenue requirements for the entire 2022/2023 period, since costs could potentially shift between the two years.

The Revenue, Fees and Uncollectibles (RF&U) amount is calculated as a product of the RF&U factor and the proposed budget for that year. The RF&U factor is determined through the GRC and updated on an annual basis through an AL filing. The revenue requirements are calculated as the sum of the RF&U amount and the proposed budget.

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4 Refer to D.17-12-003, OP 31.

TABLE 10-1
PROPOSED REVENUE REQUIREMENTS

Line No.	Program	2022	2023	Total
1	ELRP (with CCA) (Chapter 2)			
2	Budget	$22,614,000	$21,944,000	$44,558,000
3	RF&U[(a)]	245,792	238,509	484,301
4	RRQ	$22,859,792	$22,182,509	$45,042,301
5	Existing DR – SmartAC (Chapter 4)			
6	Budget	$2,690,235	$13,111,255	$15,801,490
7	RF&U[(a)]	29,240	142,506	171,746
8	RRQ	$2,719,475	$13,253,761	$15,973,236
9	Third Party DR Program (Chapter 5)			
10	Budget	$1,200,000	$0	$1,200,000
11	RF&U[(a)]	13,043	0	13,043
12	RRQ	$1,213,043	$0	$1,213,043
13	DER – DRET (Chapter 7)			
14	Budget	$10,000,000	$10,000,000	$20,000,000
15	RF&U[(a)]	108,690	108,690	217,380
16	RRQ	$10,108,690	$10,108,690	$20,217,380

(a) The 2021 RF&U factor of 0.010869 presented in the 2020 GRC (for the period 2020-2022) pursuant to D.20-12-005 and approved in AL 4353-G/6039-E with an effective date of January 1, 2021 is used for illustrative purposes. The actual, adopted RF&U factor to derive the RRQ for 2022 will be adjusted accordingly when the annual RF&U factor is presented and approved in a future AL filing for that year. The actual, adopted RF&U factor to derive the RRQs for 2023 will be adjusted accordingly with the RF&U factor approved in the 2023 GRC (for the period 2023-2026) applicable to that year.

D. Electric Reliability Memorandum Account

In order to implement the Phase 2 decision of this proceeding, PG&E may incur unanticipated, incremental costs. As such, PG&E proposes that costs for activities authorized in the Phase 2 decision that are not specifically authorized for recovery should be tracked in the ERMA. Memorandum accounts are appropriate in situations such as this one when a utility is unable to make a forecast, or when a utility has not made the forecast available for review by parties prior to cost recovery. PG&E believes that this treatment is reasonable and appropriate since the ERMA is currently authorized to track incremental costs for activities authorized in the Phase 1 decision, D.21-03-056, but are not specifically authorized for recovery. Disposition of the ERMA balance will be included in a future application for recovery in rates, subject to the Commission's review and approval of reasonableness. Upon approval by the Commission, PG&E will transfer the costs to the appropriate accounts for recovery.

E. Conclusion

In summary, PG&E requests that the Commission approve the cost recovery and ratemaking proposals presented in this chapter. Specifically, PG&E requests that the Commission approve the following:

- ELRP:
  - Record in the ELRP Subaccount of DREBA the difference between the incremental ELRP program expenses and the additional adopted ELRP program funding;
  - Recover the adopted revenue requirement in DRAM; and
  - Incorporate the adopted revenue requirements into rates annually and any unspent amounts be returned to customers through the AET advice filing.
- Existing DR Programs:
  - Record in the Operations and Incentives Subaccounts of DREBA as appropriate the incremental costs resulting from the proposed modifications to the existing DR programs;
  - Authorize the use of existing, unspent funds from its 2018-2022 DR budget cycle as adopted in D.17-12-003 as the funding source for the incremental operational and administrative costs resulting from the proposed modifications to BIP, CBP, and SmartAC;
  - Authorize additional program funding for SmartAC as requested in Chapter 4. If this additional funding is needed, PG&E proposes to record the necessary additional funding amount in the Operations Subaccount of DREBA and record an equal amount to the DRAM for recovery from customers; and
  - For modifications described in Chapter 4 related to incentives, the currently approved operation of the Incentives Subaccount of DREBA as

a two-way balancing account already allows for the recovery of overspent funding, or undercollection.

- Third Party DR:
  - Record in the Operations Subaccount of DREBA the difference between the Third Party DR expenses and the adopted Third Party DR funding;
  - Recover the adopted revenue requirement in DRAM; and
  - Incorporate the adopted revenue requirements into rates annually and any unspent amounts be returned to customers through the AET advice filing.
- DER – DRET:
  - Record in the Operations Subaccount of DREBA the difference between the incremental DRET program expenses and the additional adopted DRET program funding;
  - Recover the adopted revenue requirement in DRAM; and
  - Incorporate the adopted revenue requirements into rates annually and any unspent amounts be returned to customers through the AET advice filing.
- ERMA:
  - Record in the ERMA all incremental costs for other activities authorized in the Phase 2 decision of this proceeding that are not specifically authorized for recovery; and
  - Allow PG&E to dispose of the balance in the ERMA by filing a future application for recovery in rates, subject to the Commission’s review and approval of reasonableness.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF WENDY BRUMMER

Q 1 Please state your name and business address.

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

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

A 2 I am a Program Manager in the group supporting PG&E's Demand Response Operations and Programs.

Q 3 Please summarize your educational and professional background.

A 3 I studied accounting at Los Rio Community College. My work experience at PG&E has been in demand response program management. Prior to PG&E, I worked for Honeywell Utility Solutions implementing demand side management programs, owned my own café and was a founding Director of two environmental justice non-profits.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Emergency Reliability Order Instituting Rulemaking Proceeding:

- Chapter 2, "Emergency Load Reduction Program":
  - Section C.
- Chapter 3, "Power Saver Rewards Pilot."

Q 5 Was this material prepared by you or under your supervision?

A 5 Yes, it was.

Q 6 Insofar as this material is factual in nature, do you believe it to be correct?

A 6 Yes, I do.

Q 7 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A 7 Yes, it does.

Q 8 Do you adopt this testimony as your sworn testimony in this proceeding?

A 8 Yes, I do.

Q 9 Does this conclude your statement of qualifications?

A 9 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ALBERT CHIU

Q 1 Please state your name and business address.

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

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

A 2 I am an expert product manager of the Energy Storage and Load Management Strategy team within the Integrated Grid Planning and Innovation Department. I manage the Demand Response Emerging Technology Program (DRET) and the Integrated Demand Side Management (DSM) Program. I provide technical advises and support to DSM Programs that focus on technologies and designs such as Demand Response, Dynamic Rate, TOU/RTP, Electric Vehicle, Energy Efficiency, distributed generation, Decarbonation, and Load Management activities.

Q 3 Please summarize your educational and professional background.

A 3 I received my bachelor degree from San Jose State University, major in Environmental Study, focus on Energy Efficiency, Renewable Energy, and Geographical Information System. I joined PG&E in 1999, started in the Energy Efficiency Department. In 2007, I joined the Demand Response (DR) Department, managed the Auto DR Program and eventually responsible for other DR technology programs such as PLS and DRET. I serve on the Board of the OpenADR Alliance as a Treasure and participate in many Technical Advisor Groups on DER and IDSM with DOE, LBNL, SLAC, EPRI, CEE, CEC, etc.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Emergency Reliability Order Instituting Rulemaking Proceeding:

- Chapter 7, "Distributed Energy Resources."

Q 5 Was this material prepared by you or under your supervision?

A 5 Yes, it was.

Q 6 Insofar as this material is factual in nature, do you believe it to be correct?

A 6 Yes, I do.

Q 7 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A 7 Yes, it does.
Q 8 Do you adopt this testimony as your sworn testimony in this proceeding?
A 8 Yes, I do.
Q 9 Does this conclude your statement of qualifications?
A 9 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF GILLIAN CLEGG

Q 1 Please state your name and business address.

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

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

A 2 I am the Senior Director of Energy Portfolio Procurement and Policy. I currently oversee commodity procurement for the Company's long term energy portfolio, as well as the development of policy positions for various regulatory, legislative, and market processes. As part of my role, I manage the requests for offers and negotiations of power purchase agreements related to renewable energy, energy storage, distributed energy resources, and other wholesale market activities.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mathematics from Simon Fraser University in British Columbia, Canada. I also received a Master of Science degree in Mathematical Finance from the University of British Columbia. In 2007, I joined PG&E and have since held various positions of increasing responsibility, including as a Principal of Renewable Transaction, Director of Core Gas Supply and Senior Director of Electric and Gas Acquisition. Prior to joining PG&E in 2007, I held a Quantitative Analyst position at Powerex Corporation.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Emergency Reliability Order Instituting Rulemaking Proceeding:

- Chapter 1, "Summary of Opening Testimony in Phase 2 of the Emergency Reliability Rulemaking":
  - Section C;
- Chapter 9, "Supply Side Procurement For Summer 2022/2023"; and
  - Sections B.1, B.2, B.3 and C.2.

Q 5 Was this material prepared by you or under your supervision?

A 5 Yes, it was.

Q 6 Insofar as this material is factual in nature, do you believe it to be correct?
A 6 Yes, I do.
Q 7 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A 7 Yes, it does.
Q 8 Do you adopt this testimony as your sworn testimony in this proceeding?
A 8 Yes, I do.
Q 9 Does this conclude your statement of qualifications?
A 9 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF SEBASTIEN CSAPO

Q 1 Please state your name and business address.

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

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

A 2 I am a Product Manager in the group supporting PG&E's Demand Response Operations and Programs.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Accountancy and a Bachelor of Art degree in Economics from the University of Illinois at Urbana-Champaign; and a Master's degree in Business Administration from San Jose State University. I also earned my Certified Public Accountant credential from the state of Illinois (inactive). My work experience at PG&E covers a number of functional areas, including accounting, audit, regulatory and program management. Prior to PG&E, I worked for an agency within the United States Department of Treasury handling matters of compliance and enforcement.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Emergency Reliability Order Instituting Rulemaking Proceeding:

- Chapter 1, "Summary of Opening Testimony in Phase 2 of the Emergency Reliability Rulemaking":
  - Section B;
- Chapter 2, "Emergency Load Reduction Program"; and
  - Section B.

Q 5 Was this material prepared by you or under your supervision?

A 5 Yes, it was.

Q 6 Insofar as this material is factual in nature, do you believe it to be correct?

A 6 Yes, I do.

Q 7 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A 7 Yes, it does.
Q 8 Do you adopt this testimony as your sworn testimony in this proceeding?
A 8 Yes, I do.
Q 9 Does this conclude your statement of qualifications?
A 9 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF KATHARINA LAMB

Q 1 Please state your name and business address.

A 1 My name is Katharina Lamb, and my business address is Pacific Gas and Electric Company, 6121 Bollinger Canyon Road, San Ramon, California.

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

A 2 I am an Expert Gas Transmission Interconnection Manager in the Gas Strategy Implementation section in the Wholesale Marketing and Business Development Department. My responsibilities primarily include project management for gas interconnections within PG&E's gas transmission system as well as customer relationship development.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mathematics from Weber State University in 1989 and a Professional Master of Science and Technology from the University of Utah in 2006. In 2020, I joined PG&E as a Senior Gas Transmission Interconnection Manager and was promoted to an Expert Gas Transmission Interconnection Manager shortly after. Prior to joining PG&E, I held project management and leadership positions at Western Area Power Administration Department of Energy, Williams Gas Pipelines, Kern River Gas Pipeline, as well as Sheet Metal Works Incorporated.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Emergency Reliability Order Instituting Rulemaking Proceeding:

- Chapter 1, "Summary of Opening Testimony in Phase 2 of the Emergency Reliability Rulemaking":
  - Section D; and
- Chapter 8, "Gas Core Services."

Q 5 Was this material prepared by you or under your supervision?

A 5 Yes, it was.

Q 6 Insofar as this material is factual in nature, do you believe it to be correct?

A 6 Yes, I do.

Q 7 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A 7 Yes, it does.
Q 8 Do you adopt this testimony as your sworn testimony in this proceeding?
A 8 Yes, I do.
Q 9 Does this conclude your statement of qualifications?
A 9 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JOHN LIN

Q 1 Please state your name and business address.

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

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

A 2 I am an Expert Product Manager for data access products and Share My Data platform within PG&E's Customer Care department, Data and Energy Management Products team. I have been in my current role for four and half years. In my current role I am responsible for overseeing product planning and specifications for data access products that include Share My Data, the system used by PG&E Rule 24 program to deliver meter data to demand response providers. I work in collaboration with the Rule 24 Program team and Information Technology partners for Operations and Maintenance support, along with planning for future feature improvements.

Q 3 Please summarize your educational and professional background.

A 3 I hold PhD in Physics from Osaka University in Japan, a Master of Arts degree in Physics from University of Texas at Austin, and a Bachelor of Arts in Physics from Cornell University. I have been a PG&E employee since 2016. My first position was as a Senior Product Manager in Data Governance and Products within Customer Care. Prior to PG&E, I was founder and officer for a software and hardware development company focused on energy management and data, of Wireless Glue Networks, Inc.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in the Emergency Reliability Order Instituting Rulemaking Proceeding:

- Chapter 5, "Third-Party Demand Response Program."

Q 5 Was this material prepared by you or under your supervision?

A 5 Yes, it was.

Q 6 Insofar as this material is factual in nature, do you believe it to be correct?

A 6 Yes, I do.

Q 7 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A 7 Yes, it does.

Q 8 Do you adopt this testimony as your sworn testimony in this proceeding?

A 8 Yes, I do.

Q 9 Does this conclude your statement of qualifications?

A 9 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF REBECCA MADSEN

Q 1 Please state your name and business address.

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

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

A 2 I am an Expert Regulatory Analysis and Forecasting Analyst in PG&E's Energy Accounting Department within the Controller's organization. In this position, I am responsible for ensuring the recovery of the costs included in cases from customers. I advise on emerging regulatory issues, act as a cost recovery witness for cases, and implement cost recovery requirements in California Public Utilities Commission (CPUC) decisions. I am also responsible for process improvements and documentation of existing processes.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Arts degree in Archaeology from the George Washington University and an Associate in Science degree in Accounting from Skyline College. I have been a registered Certified Public Accountant in California (License 118069) since 2013.

I have been with PG&E for over five years. During that time, I have worked within the Energy Accounting Department of the Controller's organization, where I was responsible for performing month end close activities, including recording journal entries, reconciling accounts, and performing variance analysis, related mainly to Public Purpose Programs. I was also responsible for reading and interpreting decisions and resolutions issued by the CPUC, understanding the accounting impacts, and recording the related journal entries and preparing the supporting documentation.

My current assignment is described in A 2.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Emergency Reliability Order Instituting Rulemaking Proceeding:

- Chapter 10, "Cost Recovery."

Q 5 Was this material prepared by you or under your supervision?
A 5 Yes, it was.
Q 6 Insofar as this material is factual in nature, do you believe it to be correct?
A 6 Yes, I do.
Q 7 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A 7 Yes, it does.
Q 8 Do you adopt this testimony as your sworn testimony in this proceeding?
A 8 Yes, I do.
Q 9 Does this conclude your statement of qualifications?
A 9 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF NEDA OREIZY

Q 1 Please state your name and business address.

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

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

A 2 I am a Principal Product Manager in the Integrated Grid Planning and Innovation Department at PG&E. In this position, my responsibilities include policy and administration of the Demand Response Auction Mechanism pilot, including the Request for Offers, contract administration, and evaluation. I am also responsible for policy development of third-party demand response in various California Public Utilities Commission proceedings and Electric Rule 24 in the Click-Through Application 18-11-015.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in International Studies with concentrations in Political Science and Economics from the University of California – San Diego, La Jolla, California; and a Master of Arts degree in Energy, Resources, and the Environment and International Economics from the Johns Hopkins University Paul H. Nitze School of Advanced International Studies, Washington, District of Columbia.

I joined PG&E in 2015 in the Demand Response Department, before moving to the Integrated Grid Planning and Innovation Department. Prior to joining PG&E, I worked in financial, economic, and strategic consulting, including supporting the World Bank on energy access policy in rural areas.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Emergency Reliability Order Instituting Rulemaking Proceeding:

- Chapter 6, "Demand Response Auction Mechanism."

Q 5 Was this material prepared by you or under your supervision?

A 5 Yes, it was.

Q 6 Insofar as this material is factual in nature, do you believe it to be correct?

A 6 Yes, I do.

Q 7 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A 7 Yes, it does.

Q 8 Do you adopt this testimony as your sworn testimony in this proceeding?

A 8 Yes, I do.

Q 9 Does this conclude your statement of qualifications?

A 9 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JOMO THORNE

Q 1 Please state your name and business address.

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

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

A 2 I am the Manager of Demand Response (DR) Operations & Programs. In this role I lead a team of program managers and support staff responsible for designing, marketing, and operating PG&E's 400 megawatt DR program portfolio.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in History from Harvard University in Cambridge, Massachusetts. I've also received a Master of Business Administration, and a Master of Public Policy from the University of Michigan. I joined PG&E in 2008 and have since held various positions of increasing responsibility, including Renewable Transactor where I negotiating renewable energy power purchase agreements with third-party developers; Manager of Renewable and Clean Energy Strategy in the run up to implementation of California's 33 percent Renewable Portfolio Standard law; Manager of Value Based Reliability via which I conducted a comprehensive review of power plant outage scheduling business processes, and governance, across merchant and operational lines of business and implemented broad change-management strategy; and Manager of Market Initiatives Implementation where I was charged with implementing California Independent System Operator initiatives that impact the design, policy, and operations of California's wholesale energy markets, as well as conducting all market monitoring functions.

Q 4 What is the purpose of your testimony?
A 4 I am sponsoring the following testimony in the Emergency Reliability Order Instituting Rulemaking Proceeding:

- Chapter 4, “Existing Demand Response Programs.”

Q 5 Was this material prepared by you or under your supervision?
A 5 Yes, it was.
Q 6 Insofar as this material is factual in nature, do you believe it to be correct?
A 6 Yes, I do.
Q 7 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A 7 Yes, it does.
Q 8 Do you adopt this testimony as your sworn testimony in this proceeding?
A 8 Yes, I do.
Q 9 Does this conclude your statement of qualifications?
A 9 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF BRAD WETSTONE

Q 1 Please state your name and business address.

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

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

A 2 I am an Expert Program Manager for the Rule 24 Demand Response program within PG&E's Customer Care department. I have been in my current role for three and half years. In my current role I am responsible for overseeing all aspects of Rule 24 program administration including managing the budget, coordinating the work of the Rule 24 team for day-to-day operations, collaborating with Information Technology partners for Operations and Maintenance support, overseeing compliance, onboarding new DRPs and responding to DRP inquiries. Prior to my current role, I was a Senior Account Manager for Rule 24 for two years starting in 2016 when the Rule 24 program initially launched.

Q 3 Please summarize your educational and professional background.

A 3 I hold a Bachelor's degree in Political Science from George Washington University and a Master of Business Administration degree from the University of San Francisco. I have been a PG&E employee since 2012. My first position was as a Senior Regulatory Analyst in the FERC and CAISO Relations group within the Regulatory Affairs department. I also worked as a Generator Outage Coordinator in PG&E's Energy Procurement department.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Emergency Reliability Order Instituting Rulemaking Proceeding:

- Chapter 5, "Third-Party Demand Response Program."

Q 5 Was this material prepared by you or under your supervision?

A 5 Yes, it was.

Q 6 Insofar as this material is factual in nature, do you believe it to be correct?

A 6 Yes, I do.

Q 7 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A 7 Yes, it does.

Q 8 Do you adopt this testimony as your sworn testimony in this proceeding?

A 8 Yes, I do.

Q 9 Does this conclude your statement of qualifications?

A 9 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MARTIN WYSPIANSKI

Q 1 Please state your name and business address.

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

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

A 2 I am the Senior Director of Electric and Gas Acquisition. I currently oversee commodity procurement for the Company's short-term energy portfolio, including natural gas for Core customers and our generation portfolio. As part of my role, I also manage the operations of PG&E's energy portfolio in the California Independent System Operator's energy and capacity markets. In addition, I also oversee PG&E's Central Procurement Entity team.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Chemical Engineering from Brown University in Providence, Rhode Island, in 1999. In addition, I received by Master of Business Administration from the Haas School of Business at the University of California in Berkley, California, in 2006. In 2006, I joined PG&E and have since held various positions of increasing responsibility, including most recently as Senior Director Market and Credit Risk and Senior Director of Energy Portfolio Procurement and Policy. Prior to joining PG&E, I held analyst positions at Towers Willis Watson and Boston Millenia Partners.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in the Emergency Reliability Order Instituting Rulemaking Proceeding:

- Chapter 9, "Supply-Side Procurement for Summer 2022/2023."
  - Sections B.4 and C.1.

Q 5 Was this material prepared by you or under your supervision?

A 5 Yes, it was.

Q 6 Insofar as this material is factual in nature, do you believe it to be correct?

A 6 Yes, I do.

Q 7 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A 7 Yes, it does.
Q 8 Do you adopt this testimony as your sworn testimony in this proceeding?
A 8 Yes, I do.
Q 9 Does this conclude your statement of qualifications?
A 9 Yes, it does.