Application: 20-07-002
U-39M
Exhibit No.: PGE-1
Date: July 1, 2020
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

PREPARED TESTIMONY

2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION

PUBLIC VERSION

PACIFIC GAS AND ELECTRIC COMPANY
2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION
NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST
REVENUE RETURN AND RECONCILIATION

PREPARED TESTIMONY

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TABLE OF ACRONYMS

Acronym	Full Name
A&O	administrative and outreach
A.	Application
AB	Assembly Bill
AET	Annual Electric True-Up
AL	Advice Letter
AMP	Aggregator Managed Portfolio
BART	Bay Area Rapid Transit
BD	billing determinant
BioRAM	Bioenergy Renewable Auction Mechanism
BPP	Bundled Procurement Plan
BTM	Behind-The-Meter
CAISO	California Independent System Operator Corporation
CAM	Cost Allocation Mechanism
CARB	California Air Resources Board
CARE	California Alternate Rates for Energy
CC	Combined Cycle
CCA	Community Choice Aggregator or Community Choice Aggregation
CCC	California Climate Credit
CCSF	City and County of San Francisco
CDWR	California Department of Water Resources
CEC	California Energy Commission
CED	California Energy Demand
CEEE	Clean Energy and Energy Efficiency
CFR	Code of Federal Regulations
CGS	Colusa Generating Station
CH_4	Methane
CHP	Combined Heat and Power
CO_2	carbon dioxide
CO_2e	Carbon dioxide equivalent
CPSF	CleanPower SF
CPUC or Commission	California Public Utilities Commission
CRT	Customer Rick Tolerance

TABLE OF ACRONYMS
(CONTINUED)

Acronym	Full Name
CSE	Center for Sustainable Energy
CS-GT	Community Solar Green Tariff
CT	Combustion Turbine
CTC	Competition Transition Charge
D.	Decision
DA	Direct Access
DAC-GT	Disadvantaged Community Green Tariff
DAC-SASH	Disadvantaged Community-Single-Family Affordable Solar Housing
DCPP	Diablo Canyon Power Plant
DG	Distributed Generation
DL	Departing Load
DR	Demand Response
E&O	Education and Outreach
E3	Energy and Environmental Economics, Inc.
EBCE	East Bay Community Energy
ED	Energy Division
EE	Energy Efficiency
EITE	Emissions-Intensive and Trade-Exposed
EOY	end-of-year
EPS	Electric Power Sector
ERRA	Energy Resource Recovery Account
ESA	Electric Supply Administration
ESP	Energy Supply Provider
EV	Electric Vehicle
FERA	Family Electric Rate Assistance
FR&R	Forecast Revenue and Reconciliation
FTE	Full-Time Equivalent
GGS	Gateway Generating Station
GHG	Greenhouse Gas
GHGRBA	Greenhouse Gas Revenue Balancing Account
GMC	grid management charges

TABLE OF ACRONYMS
(CONTINUED)

Acronym	Full Name
GRC	General Rate Case
GRR	Generation Rate Ratio
GT&S	Gas Transmission and Storage
GTSR	Green Tariff Shared Renewables
GTSRBA	Green Tariff Shared Renewables Balancing Account
GWh	gigawatt-hour
HBGS	Humboldt Bay Generating Station
HHZ	high-hazard zone
HLBA	Hydro Licensing Balancing Account
ICE	Intercontinental Exchange
IDWA	Irrigation District and Water Agencies
IEPR	Integrated Energy Policy Report
IOU	Investor-Owned Utility or Investor-Owned Utilities
IRP	Integrated Resource Planning
IT	Information Technology
KCCP	King City Community Power
kWh	kilowatt-hour
MtM	mark-to-market
MBCP	Monterey Bay Community Power
MCE	Marin Clean Energy
MDS	Market Data System
MMBtu	Millions of British Thermal Units
ModCAM	Modified Cost Allocation Mechanism
MPB	Market Price Benchmark
MT	metric ton
MTCBA	Modified Transition Cost Balancing Account
$mtCO_2e$	metric tons of carbon dioxide equivalent
MtM	market-to-market
Multifamily Program	Multifamily Affordable Housing Solar Roofs Program
MW	megawatt
MWD	Metropolitan Water District
MWh	megawatt-hour

TABLE OF ACRONYMS
(CONTINUED)

Acronym	Full Name
N_2O	nitrous oxide
NaS	Sodium Sulfur
NBC	non-bypassable charge
NG	natural gas
NP-15	North of Path-15
NRCRBA	Nuclear Regulatory Commission Rulemaking Balancing Account
NSGBA	New System Generation Balancing Account
NSGC	New System Generation Charge
NYMEX	New York Mercantile Exchange
O&M	operations and maintenance
OIR	Order Instituting Rulemaking
OP	Ordering Paragraph
P^3	Procurement Portfolio Planner
PABA	Portfolio Allocation Balancing Account
PCE	Peninsula Clean Energy
PCIA	Power Charge Indifference Adjustment
Pioneer	Pioneer Community Energy
PPA	Power Purchase Agreement
PPP	Public Purpose Program
PSPL	Puget Sound Power & Light Company
Pub. Util. Code	Public Utilities Code
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
QF	Qualifying Facility
QF/CHP Settlement	Qualifying Facility and Combined Heat and Power Settlement
R.	Rulemaking
RA	Resource Adequacy
RAM	Renewable Auction Mechanism
RCEA	Redwood Coast Energy Authority
REC	Renewable Energy Credit
Res.	Resolution

TABLE OF ACRONYMS
(CONTINUED)

Acronym	Full Name
RFO	Request for Offers
RF&U	Revenue Fees and Uncollectibles
RIC	Renewable Integration Charges
RPS	Renewables Portfolio Standard
SB	Senate Bill
SCE	Southern California Edison Company
SCP	Sonoma Clean Power
SDG&E	San Diego Gas & Electric Company
SID	Solano Irrigation District
SiP	Shelter in Place
SJCE	San Jose Community Energy
SJVPA	San Joaquin Valley Power Authority
SOMAH	Solar on Multi-Family Affordable Housing
SRAC	Short-Run Avoided Cost
ST	Steam Turbine
SVCE	Silicon Valley Clean Energy
T&D	Transmission and Distribution
TCR	The Climate Registry
TID	Turlock Irrigation District
TMNBC	Tree Mortality Non-Bypassable Charge
TMNBCBA	Tree Mortality Non-Bypassable Charge Balancing Account
UFE	Unaccounted for Energy
TY	Test Year
UGBA	Utility Generation Balancing Account
UOG	Utility-Owned Generation
VCEA	Valley Clean Energy Authority
WAC	weighted-average cost
WAPA	Western Area Power Administration
WEMA	Wildfire Expense Memorandum Account
WREGIS	Western Renewable Energy Generation Information System

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

INTRODUCTION AND POLICY

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
INTRODUCTION AND POLICY

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
INTRODUCTION AND POLICY

A. Introduction

1. Summary of PG&E's Requests

This testimony supports Pacific Gas and Electric Company's (PG&E) 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges (NBC) Forecast and Greenhouse Gas (GHG) Forecast Revenue and Reconciliation Application (Application). This application presented to the California Public Utilities Commission (CPUC or Commission) has been developed while a state of emergency has been in place to combat the spread of the novel coronavirus (COVID-19), a highly contagious and potentially fatal respiratory illness that is spread person-to-person.[1]

Under the most extraordinary circumstances of a global pandemic, PG&E's testimony herein includes observations concerning the condition of the state economy in 2021 in the midst of rising unemployment and a swift decline in electricity usage due to the COVID-19 pandemic. However, PG&E's forecast does not incorporate load impacts of the COVID-19 pandemic at this time due to a lack of sufficient data on the relationship between the pace of the state's anticipated economic growth and total electricity usage in 2021. State officials predict that a return to the productivity levels that California's economy enjoyed prior to the pandemic will not likely occur until a vaccine becomes available. For these reasons, PG&E anticipates that its sales forecast will be updated as additional economic data and information become available during the course of the proceeding.

In addition, PG&E discovered an error in the electric load forecast during final quality assurance of this Prepared Testimony. Due to the timing of this

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[1] The March 4, 2020 Emergency Proclamation by Governor Newsom is available at hyperlink: https://www.gov.ca.gov/wp-content/uploads/2020/03/3.4.20-Coronavirus-SOE-Proclamation.pdf.

late discovery, PG&E could not correct the error prior to the July 1, 2020 filing date.[2] PG&E's Prepared Testimony identifies information that will likely be subject to correction. PG&E intends to submit supplemental testimony regarding Community Choice Aggregation (CCA) load and bundled load as described in Section A 3 below.

In this Application, PG&E is requesting that the Commission adopt PG&E's 2021 ERRA Forecast Application total revenue requirement of $2,806.1 million, with a revenue requirement for rate setting purposes of $5,328.6 million due to the inclusion of $2,522.5 million of costs associated with Utility-Owned Generation ((UOG)-Related costs).[3]

PG&E requests approval of the Cost Allocation Mechanism (CAM) forecast revenue requirement of $266.3 million, Power Charge Indifference Adjustment (PCIA) forecast revenue requirement of $2,802.6 million, Ongoing Competition Transition Charge (CTC) forecast revenue requirement of $19.9 million, Tree Mortality Non-Bypassable Charge (TMNBC) forecast revenue requirement of $72.6 million, ERRA forecast revenue requirement of $1,889.9 million, and PCIA Undercollection Balancing Account (PUBA) forecast revenue requirement of $277.4 million. These forecast revenue requirements are shown in Table 1-1 below.

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2 On April 21, 2020, CPUC Executive Director Alice Stebbins granted PG&E's request to extend the filing date of the Application from June 1, 2020 to July 1, 2020.

3 The revenue requirement reflected in this chapter reflects the forecast year-end balancing account balances without consideration of the disposition of the ERRA and PUBA Trigger applications that PG&E anticipates the need to file pursuant to D.02-10-062 and D.18-10-019, respectively.

TABLE 1-1
SUMMARY OF 2021 FORECAST ENERGY PROCUREMENT REVENUE REQUIREMENTS
(THOUSANDS OF DOLLARS)

Line No.	Description	2021 Cost with Revenue Fees and Uncollectibles[b]	Year End Balance[c]	Total 2021 Revenue Requirement[c]
		(A)	(B)	(C) = (A) + (B)
1	CAM[a] (Chapter 8)	$181,410	$84,934	$266,344
2	PCIA (Chapter 9)	2,742,186	60,367	2,802,552
3	Ongoing CTC (Chapter 10)	45,955	(26,092)	19,863
4	TMNBC (Chapter 11)	37,354	35,265	72,619
5	ERRA (Chapter 12)	2,177,227	(287,352)[d]	1,889,875
6	PUBA	–	277,364	277,364
7	Revenue Requirement for Rate Setting	$5,184,130	$144,487	$5,328,617
8	Less: UOG-Related Costs[e]	(2,522,491)	–	(2,522,491)
9	2021 ERRA Application Revenue Requirement Request	$2,661,640	$144,487	$2,806,127

(a) The CAM revenue requirement presented in Chapter 8 is recovered through the New System Generation Charge (NSGC).

(b) Costs exclude Green Tariff Shared Renewables (GTSR) Program Costs.

(c) The year-end balancing account balances recovered in rates through the Annual Electric True-Up (AET), and or subsequent rate change Advice Letter.

(d) The ERRA overcollection is the deferred revenue collected in generation rates because of capped departed PCIA rates. The offsetting amount is reflected in PUBA (line 6).

(e) UOG-Related Costs in the revenue requirement components included in PCIA, ERRA, and CAM are solely for rate-setting purposes; PG&E does not request approval of these costs in this Application.

Note: Totals may not add due to rounding.

The total revenue requirement for rate setting of $5,328.6 million set forth in Table 1-1 above includes $2,522.5 million of UOG-Related costs that are either approved or under consideration in other regulatory proceedings, including PG&E's 2020 General Rate Case (GRC), Application (A.) 18-12-009.[4] Inclusion of such UOG-Related costs in the 2021 ERRA revenue requirement is necessary to adopt a forecast of PG&E's electric procurement costs revenue requirement for rate-setting purposes. As described in Section A 3 below, PG&E will submit supplemental testimony in

[4] GRC generation revenue requirements are identified in Exhibit (PG&E-10) (hyperlink at: http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=545394); see discussion in Chapter 9, Section F ("Utility Owned Generation Base Revenue Requirement and Other Generation-Related Costs Authorized by the Commission").

July updating the total revenue requirement to reflect the correction to the electric load forecast.

PG&E requests that the rate changes associated with this Application become effective on January 1, 2021, when consolidated with other approved electric rate changes through the AET advice letter process. In addition to the 2021 revenue requirement request for forecast procurement costs, this Application also requests approval of PG&E's proposal to return GHG allowance revenue to customers. In Decision (D.) 14-10-033, Ordering Paragraph (OP) 10, the Commission directed PG&E and the other Investor-Owned Utilities (IOU) to provide a GHG forecast revenue and reconciliation request in annual ERRA forecast applications.

PG&E has included in this Prepared Testimony the GHG-related information identified by the Commission, and specifically requests Commission approval of the following GHG-related forecasts for 2021: (1) administrative and outreach (A&O) expenses of $847,000 pertaining to implementation of GHG revenue return; (2) customer generation programs funded by GHG-revenues of $67.8 million; (3) net forecast revenue return amount of $195.8 million and PG&E's proposal to return the revenue to customers in rates in 2021; and (4) 2021 semi-annual residential California Climate Credit amount of $18.77 per household. PG&E also requests that A&O set asides be updated to reflect forecast and recorded costs. PG&E will update these GHG related forecasts, costs, and funding allocations in its Update to Prepared Testimony, to be served on November 9, 2020 (November Update).

PG&E also requests that the Commission find the 2019 recorded A&O expenses of $426,000 related to the GHG revenue return were reasonable.

Finally, PG&E requests that the Commission approve the 2021 retail sales forecast.

2. Testimony Overview

Chapter 1 summarizes PG&E's revenue request, which is based on procurement, revenue, and rates analyses presented in subsequent chapters. This chapter also presents an overview of the regulation underlying the CAM, PCIA, Ongoing CTC, TMNBC, ERRA and PUBA

revenue requirements, and addresses consistency with PG&E's approved Bundled Procurement Plan (BPP). In addition, Chapter 1 provides an overview of the GHG forecast revenue and reconciliation information required by D.14-10-033 and other Commission orders that is included in this application.

Chapter 2 presents PG&E's sales and peak demand forecast, discusses the economic and regulatory conditions underlying that forecast, and describes the methodologies to create that forecast, including load adjustments.

Next, PG&E details components of its portfolio and associated costs prior to presenting specific revenue requirements. Specifically, Chapters 3 through 7 introduce and present PG&E's energy procurement costs associated with the following: (1) fuel expenses associated with PG&E's UOG; (2) pre-2002 contracted resources, including water district and Qualifying Facility (QF) agreements; (3) post-2002 contracted resources, including Renewables Portfolio Standard (RPS)-eligible generation and fossil contracts; (4) purchased power costs; and (5) other electric procurement costs, such as hedging and short-term financing. GHG compliance costs required under the California Air Resources Board's (CARB) Cap-and-Trade Program associated with generation resources are reflected in the chapter applicable to the underlying energy procurement costs and summarized in Chapter 15.

Chapters 8 through 14 demonstrate how PG&E uses Commission-approved methodologies to calculate the revenue requirements associated with ERRA, NBCs, and community solar programs. Chapter 9 presents costs associated with PCIA-eligible resources in the CPUC-mandated Common IOU Template, which is the requisite format for the Total Portfolio Indifference calculation.[5]

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5 See D.06-07-030 (as modified by D.17-08-026 and affirmed in D.18-10-019). In response to D.20-03-019, Conclusion of Law (COL) 3, PG&E anticipates to file a Petition for Modification of D.17-08-026 and D.18-10-019 to resolve errors raised in the PCIA Order Instituting Rulemaking (OIR) (R.17-06-026) concerning the application of line losses in the Common IOU Template. A disposition of this petition, if any prior to October 2020, will be incorporated in PG&E's November Update.

Chapter 10 presents costs associated with CPUC-mandated system reliability procurement from the Integrated Resource Planning (IRP) proceeding (Rulemaking (R.) 16-02-007/R.20-05-003) for resources expected to be online by August 2021.[6]

Chapter 11 covers costs associated with a biomass generation procurement channel developed in response to California's tree mortality crisis, pursuant to the Governor's emergency proclamation and the Commission's implementation of Senate Bill 859 (as codified in Public Utilities Code (Pub. Util. Code) Section 399.20.3(f)).

Chapter 12 presents the bundled load cost forecast for the ERRA revenue requirement.

Chapter 13 presents PG&E's 2021 rate proposal for bill charges and credits associated with PG&E's GTSR Program, which includes the green tariff electric rate schedule (E-GT) for PG&E's Solar Choice Program and the enhanced communities renewable electric rate schedule (E-ECR) for PG&E's Regional Renewable Choice Program.

Chapter 14 presents recorded ERRA and Portfolio Allocation Balancing Account (PABA) balances from January to April 2020, including a forecast by vintage for PABA; a forecast of the balancing account balances for May through December 2020; and a detailed explanation of the trigger thresholds for ERRA and PUBA.

Chapters 15 through 17 address GHG-related matters. Specifically, Chapter 15 explains the 2021 GHG cost forecast calculations, including direct and indirect GHG costs, for the purposes of determining volumetric GHG revenue return only, as well as the reconciliation of 2019 GHG costs. Chapter 16 presents both the 2021 forecast and 2019 recorded GHG A&O expenses. Chapter 17 presents the forecast GHG allowance revenue return to customers and the proposed forecast California Climate Credit amount. The chapter also includes a request to update the A&O set aside to reflect recorded and forecast A&O costs, and includes the customer programs

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6 See D.19-11-016, OP 3 (ordering renewable integration procurement to load serving entities (LSE) pursuant to Pub. Util. Code § 454.51), and OP 5 (delegating procurement to IOUs should a CCA or Energy Service Provider (ESP) opt for the utility to procure system reliability resources on their behalf, and establishing a cost allocation framework for opt-out procurement).

funded through GHG allowance proceeds and shows the methodology for returning revenue to eligible customers.

Chapter 18 presents the revenue requirement forecasts for the CAM, PCIA, Ongoing CTC, Tree Mortality, and ERRA capturing the procurement cost forecasts shown in Chapters 3 through 7 and the NBC revenue requirements shown in Chapters 8 through 13. It also presents the forecast revenue requirement for PUBA, which records the shortfall in revenues accruing from departing load (DL) customers when the cap in the PCIA rate is reached.

Chapter 19 presents PG&E's preliminary proposal for collecting or distributing the procurement revenue requirements in rates (including 2020 end-of-year balances). The chapter describes PG&E's proposed revenue allocation and rate design for each of the procurement revenue requirements in Chapter 18. The chapter also includes detailed illustrative rate tables consolidating all the proposed revenue changes in this application, including the ERRA revenue requirement and NBCs, as well as the GHG revenue return presented in Chapter 17. While final 2021 rates are subject to the AET process, Chapter 19 shows the illustrative effect of the procurement revenue requirements and revenue return proposal presented in this application on rates. Chapter 19 further discusses PG&E's return of the 2019 ERRA over-collected balance and the appropriate customers who were entitled to receive the credit as part of their 2020 rates.[7] Customers who departed bundled service during the last half of 2019 that henceforth count among the 2019 PCIA vintage will be made whole by receiving an adder in the 2021 rates. PG&E also presents a proposal to transfer certain year-end ERRA balances to the PABA going forward.

Appendix A presents a GHG emissions intensity value according to the methodology prescribed by the Commission.

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7 See D.20-02-047, p. 12 (determining that the 2021 ERRA Forecast Application proceeding is the appropriate forum for PG&E to address a method for properly crediting customers who departed bundled service during the last half of 2019 and who would be included in the 2019 and 2020 PCIA vintage).

Appendix B includes the statements of qualification for PG&E witnesses sponsoring PG&E's Prepared Testimony.

Appendix C includes the declarations of PG&E witnesses attesting that portions of their testimony meet the Commission's confidentiality requirements, in accordance with D.06-06-066, D.08-04-023, and D.14-10-033. A matrix identifying the data and information for which these witnesses are seeking confidential treatment is also provided.

3. Supplemental Testimony

During the course of the proceeding, PG&E expects to append its Prepared Testimony for various reasons, including but not limited to PG&E complying with Rule 1 of the CPUC's Rules of Practice and Procedure, CPUC directives, and the availability of more recent economic data and information under COVID-19. PG&E discovered an error in the electric load forecast during final quality assurance of this Prepared Testimony. The forecasted 2021 CCA load is understated by approximately 1,000 gigawatt-hours (GWh), and the bundled load is overstated by the same amount.[8]

While this error does not impact the total retail sales forecast, it does impact the division of this forecast into bundled and DL. Due to the timing of this late discovery, PG&E is unable to correct the errors in the Prepared Testimony and will submit s testimony. The error impacts the cost calculation chapters (Chapters 2, 3, and 7), the revenue requirement chapters (Chapters 12 and 18), the GHG cost calculation chapter (Chapter 15) and the rate calculation chapter (Chapter 19). Table 1-2 indicates the location of PG&E's Prepared Testimony impacted by this error.

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8 For the sake of comparison, the total 2021 forecast of electric system load is 78,278 GWh.

TABLE 1-2
TABLES IMPACTED BY UNDERSTATED CCA LOAD DISCOVERED IN PREPARED TESTIMONY

Line No.	Description
1	Table 1-1: Summary of 2021 Forecast Energy Procurement Revenue Requirements
2	Table 2-2: Departed Load Sales Estimated by Category
3	Table 2-3: Energy and Peak Demand Requirements
4	Table 3-1: Capacity Balance
5	Table 3-2: Energy Requirements
6	Table 3-3: Procurement Costs
7	Table 7-3: Procurement Costs
8	Table 12-1: ERRA Revenue Requirement
9	Table 15-1: Annual GHG Emissions and Associated Costs (Template D-2)
10	Table 15-2: Illustrative Annual GHG Emissions and Associated Costs (Template D-2)
11	Table 18-1: Forecast Energy Procurement Revenue Requirements
12	All Chapter 19 tables

PG&E will submit Supplemental Testimony and supporting workpapers for Chapters 1, 2, 3, 7, 12, 15, and 18 by July 17, 2020.[9] PG&E will submit supplemental testimony and supporting workpapers for Chapter 19 by August 14, 2020 because additional modeling is required to develop the customer rates presented in Chapter 19.

The impact of this error to the rates presented in this Application will vary by rate component. Preliminary estimates show that certain ERRA rate components that correlate directly with bundled or DL sales may change by as much as 3 percent, while other rate components may not be sensitive to this change.

Further, on June 11, 2020, the Commission adopted a central procurement framework for multi-year Local Resource Adequacy (RA) beginning with the 2023 RA compliance year and identified Southern California Edison Company (SCE) and PG&E as the central procurement entities for their respective distribution service areas. The multi-year Local RA requirements would require the procurement of sufficient resources in 2021 for the 2022-2024 RA compliance years. Accordingly, these enhancements to the RA Program in D.20-06-002 necessitated that the Commission order the SCE and PG&E to update their respective CAM

[9] Tables 1-1 and 18-1 present identical revenue requirements and will need correcting in the July Supplement.

revenue requirement forecasts for 2021 to include administrative costs related to central procurement of Local RA.[10]

PG&E also reserves the right to present supplemental testimony with regard to a 2021 electric sales forecast updated with more recent economic data and information by no later than PG&E's November Update.

B. The Energy Resource Recovery Account

1. Annual ERRA Forecast Revenue Requirement Proceeding

The purpose of the annual ERRA forecast proceeding is to assure timely recovery of the utilities' actual electric procurement costs, as required by Pub. Util. Code Section 454.5(d)(3). That provision, passed by the legislature in 2002, mandates that the CPUC:

> [e]nsure timely recovery of prospective procurements costs incurred pursuant to an approved procurement plan. The Commission shall establish rates based on forecasts of procurement costs adopted by the commission, actual procurement costs incurred, or combination thereof as determined by the commission…. The commission shall establish power procurement balancing accounts to track the differences between recorded revenues and costs incurred pursuant to an approved procurement plan….

In October 2002, the Commission issued D.02-10-062, which adopted a regulatory framework under which PG&E and the other IOUs would resume full procurement activities as of January 1, 2003. In D.02-10-062, the Commission established the ERRA as the balancing account for the IOUs to track and recover energy procurement costs incurred under Commission-authorized procurement plans, in accordance with Section 454.5(d)(3). PG&E's ERRA balancing account is used to record PG&E's procurement-related costs and revenues, and any difference flows back to or is collected from customers.

D.02-10-062, as modified by D.04-01-050, also directed PG&E to file its annual ERRA forecast application on June 1, to allow the Commission to issue a decision by the end of the calendar year and ensure timely cost

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10 D.20-06-002, OP 18 (ordering the central procurement entity to submit supplemental testimony within 75 days of the issuance of the decision impacting the 2021 ERRA application forecast). PG&E's supplemental testimony is due August 31, 2020.

recovery in rates.[11] However, due to the city of San Francisco's response to the COVID-19 pandemic, employees at PG&E's corporate office began working under the shelter-in-place requirements as of March 13, 2020. On April 16, PG&E petitioned the CPUC's executive director for additional time to develop this Application and Testimony given the logistical challenges associated with multidisciplinary teams working in remote locations. On April 21, PG&E's request was granted and PG&E informed parties to the A.19-06-001 service list that its 2021 ERRA Forecast Application would be filed on July 1, 2020. Consistent with these directives, this Application and Testimony present PG&E's forecast of its electricity sales and procurement cost revenue requirement for the coming year, and PG&E's proposal to collect these costs in rates.

2. ERRA Trigger Mechanism

Section 454.5(d)(3) of the Public Utilities Code directs the Commission to ensure that any overcollection or undercollection in the ERRA balancing account does not exceed 5 percent of a utility's recorded generation revenues (excluding the California Department of Water Resources (CDWR) revenues) for the prior year.

The Commission implemented this statutory provision by adopting the ERRA "trigger" mechanism in D.02-10-062.[12] Each IOU is required to submit an advice letter on or before April 1 to establish their respective trigger amount and threshold amount for that calendar year, based on their prior year's recorded generation revenues, excluding CDWR revenues.[13] If the ERRA balance reaches or exceeds 4 percent of the prior year recorded generation revenues, excluding CDWR revenues, the IOUs must file an expedited application.[14] This trigger application would include a projected account balance in 60 days or more from the date of filing to illustrate when the balance would reach the 5 percent threshold. The trigger application

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11 See D.02-10-062, pp. 59-64; D.04-01-050, p. 177.

12 See D.02-10-062, pp. 64-66; see also, D.15-05-008 (extending ERRA trigger mechanism).

13 See D.04-01-050, pp. 176-177 and OP 5.

14 D.02-10-062, p. 65 and OP 14.

would also propose an amortization period of not less than 90 days to ensure timely recovery of the projected ERRA balance, as well as allocation of overcollection or undercollection among customers for rate adjustment, based on the existing allocation methodology recognized by the Commission.[15]

PG&E's 2020 ERRA trigger amount—4 percent of the actual recorded generation revenues for the prior calendar year excluding revenues collected for the CDWR—is $202 million (4 percent ERRA Trigger). PG&E's 2019 ERRA threshold amount—5 percent of the actual recorded generation revenues for the prior calendar year excluding revenues collected for the CDWR—is $253 million (5 percent ERRA Threshold). These amounts are reflected in PG&E's Advice Letter 5798-E, effective as of April,1, 2020.[16] PG&E monitors the ERRA balance relative to the annual trigger amount on a monthly basis.

Based on the forecast prepared in this testimony, PG&E anticipates filing an expedited application by July 31, 2020 to inform the Commission that the ERRA accumulated over-collection has reached the 4 percent ERRA Trigger as of April 30, 2020, and that the accumulated overcollection will exceed the 5 percent ERRA Threshold. The over-collected ERRA balance is primarily due to: (1) the deferred revenue resulting from the implementation of capped vintage PCIA rates applicable to non-exempt DL (Revenue Deferral); (2) the delay in implementing 2020 rates to May 1, 2020, which were authorized in D.20-02-047; and (3) lower recorded bundled load and net cost, due to weather and the shelter-in-place order attributable to the COVID-19 pandemic. Except for the Revenue Deferral, PG&E proposes to transfer the ERRA overcollection to PABA for recovery in the Vintaged 2020 PCIA rates. Subject to Commission's authorization of the proposed transfer, only the Revenue Deferral, plus balancing account interest is forecast to remain in PG&E's year-end 2020 ERRA balance.

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15 *Ibid.*

16 PG&E's Advice Letter (AL) 5798-E was submitted on April 1, 2020 (hyperlink at: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5798-E.pdf).

C. The Portfolio Allocation Balancing Account

The PCIA OIR was established to respond to concerns that the PCIA cost allocation failed to prevent cost shifting between bundled and DL customers, as required by law.[17] In D.18-10-019, the Commission adopted significant reforms to the PCIA, among other things, including: (1) revised inputs to the Market Price Benchmarks (MPB) used to set the PCIA rates that more closely tracks with actual market transactions; and (2) an annual true-up mechanism to ensure that bundled and DL customers pay equally for the above-market costs of PCIA-eligible resources. Previously, the PCIA rate was set on a forecast basis and not trued-up.

In compliance with D.18-10-019, the Commission required the IOUs to establish PABA, a two-way balancing account that trues up the forecast of PCIA-eligible resource costs with actual recorded costs and revenues, and to modify associated generation-related regulatory accounts consistent with the approved PABA structure. Costs recorded to PABA are recovered by bundled customers through the generation rate, and by DL customers through the PCIA rate approved in this proceeding.

The PABA is comprised of subaccounts for each year's vintage portfolio that records the costs, market revenues, and imputed revenues of all generation resources executed or approved by the Commission for cost recovery that year. The costs recorded to PABA are those related to contracts executed with third parties and UOG. Also recorded to PABA are various indirect costs, such as credit and collateral interest, Western Renewable Energy Generation Information System fees, independent evaluator costs, and GRC administration costs. The PCIA revenue requirement presented in this ERRA Forecast includes costs recorded to PABA recovered by bundled customers through generation rates, and by departed load customers through PCIA rates.

D. The PCIA Undercollection Balancing Account

In OP 9 of D.18-10-019, the Commission established a half-cent per kilowatt hour cap to the prior years' PCIA rate to mitigate against rate volatility (capped departed PCIA rates) for non-exempt departed load (DL) customers. Additionally, the Commission ordered the IOUs to establish an interest-bearing

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[17] D.18-10-019, p. 1.

balancing account to track the under-collected revenues resulted from the implementation of the capped departed PCIA rates. The purpose of this balancing account is to reflect the amount of under-collected PCIA obligation owed by the DL customers. On December 4, 2019, the Commission approved PG&E's Advice Letter 5624-E to establish the PUBA, which tracks the PCIA obligation that accrues by DL customer vintage if the PCIA rate increase is capped at 0.5 cents per kWh.[18] The accrued PCIA obligation is a revenue shortfall, derived by taking the difference between the uncapped PCIA rate by customer class for that vintage and the capped PCIA rate by customer class and vintage multiplied by the DL usage, by class and vintage. The resulting PCIA obligations or revenue shortfalls will be recorded to PUBA.

OP 10 of D.18-10-019 further established the trigger mechanism for the recovery of the balance tracked in PUBA. Specifically, it sets the trigger threshold at 10 percent of the forecast PCIA revenues. If the PUBA undercollection reaches 7 percent, and PG&E forecasts that the balance will reach 10 percent, PG&E is required to file an expedited application to change the PCIA rates to bring the PUBA undercollection back down to below 7 percent.

Based on PG&E's forecast as part of this filing, PG&E expects to file an expedited PUBA trigger application later this year to address the recovery of the PUBA balance.

E. Generation Non-Bypassable Charges

PG&E's ERRA revenue requirement is recovered through bundled customer generation rates. The remaining revenue requirements are recovered through four NBCs. Two of the NBCs—the Ongoing CTC and the NSGC for recovering CAM costs—are recovered from bundled and non-exempt DL customers. The PCIA is recovered from bundled load and non-exempt DL customers and varies based on the timing of the non-exempt customer's departure. The TMNBC is to be recovered from retail customers. Based on the cost forecast pertaining to each of these NBCs, PG&E determines annual revenue requirements and proposed rates to recover these forecast costs.

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[18] PG&E's AL 5624-E, submitted on August 30, 2019, introduces Electric Preliminary Statement Part HZ for PUBA in PG&E's tariffs and discusses how PG&E calculates the trigger mechanism (hyperlink at: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5624-E.pdf).

Besides the generation rate applicable to ERRA, the revenue requirements associated with other generation-related NBCs are included in this testimony, which are allocated to different recovery methods: (1) the PCIA rate for costs and revenues recorded to the PABA associated with PCIA-eligible resources, (2) the NSGC, (3) the Ongoing CTC, and (4) the TMNBC for costs associated with tree mortality biomass energy procurement.[19]

1. Power Charge Indifference Adjustment

The PCIA revenue requirement represents the above-market costs associated with post-2002-eligible generation resources that are recoverable from bundled customers under the revised PABA structure, and certain non-exempt DL customers based on the vintage of the generation resource commitment and the timing of the customers' departure. The Direct Access Reopening proceeding, R.07-05-025, determined the methodology, which was revised in D.11-12-018, for the Total Portfolio Indifference calculation used for the PCIA. In R.17-06-026 (PCIA OIR), the Commission considered revisions to the PCIA methodology. In October 2018, the Commission issued D.18-10-019 partially revising the PCIA methodology by modifying administratively determined MPBs with transaction data to more closely resemble market prices and ordered the IOUs to establish a new balancing account (i.e., PABA). Among other things, the Commission deferred consideration of the true-up of the RA and RPS adders included as part of the PCIA methodology to a later phase of the proceeding.[20] Subsequently, in October 2019, the Commission issued D.19-10-001 establishing a true-up methodology for benchmarks applied to the RPS Adder and RA Adder to be implemented as part of the ERRA Forecast proceeding.[21] D.19-10-001 also revised the process and data sources used to calculate forecast and final

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19 The GTSR Program costs are not included in the revenue requirement calculation.

20 D.18-10-019, OP 1 and 2, and Appendix 1, define the values and calculation methodology for the MPB, which is composed of: (1) Brown Power Index; (2) RPS Adder; and (3) RA Adder. See COL 16 and OP 6, which adopts a true-up mechanism for the Brown Power Index to ensure that bundled and DL customers pay equitably for brown power associated with PCIA-eligible resources.

21 See D.19-10-001, COL 21 (establishing that the true-up will occur as part of the ERRA Forecast proceeding) and OP 4 (providing direction on the price and quantity calculations associated with such true-ups).

RA and RPS Adders to reflect closer approximation to the true market value.[22] In addition, the 2019 decision authorized the IOUs to transition from using system-level to vintage-level billing determinants in their PCIA rate design.

The PCIA OIR is currently open, as the Commission anticipates resolving Phase 2 issues related to revising bill and tariff presentation of the PCIA; offering DL customers a prepayment option for the PCIA obligation; and portfolio optimization/cost reduction, allocation, and auction.

2. New System Generation Charge and Cost Allocation Mechanism

The CAM allocates certain costs and benefits, including RA benefits, among all load-serving entities in each IOU's service territory under three policy driven procurement channels: (1) resources needed for ensuring system reliability, (2) resources procured within the established megawatt (MW) and GHG targets derived from the Qualifying Facility/Combined Heat and Power (QF/CHP) Settlement, and (3) resources procured for renewable integration. D.06-07-029 initially authorized the NSGC and D.07-09-044 determined the CAM calculation methodology, with specific guidelines to develop the NSGC revenue requirement and resulting rate and provide for a true-up of this rate to actual costs. Subsequently, a CAM approach was adopted for certain QF and CHP contracts arising from the QF/CHP Settlement approved in D.10-12-035 so that all benefiting customers share in these costs, as well as in the benefits.

In November 2019, the Commission further expanded its application of CAM as the cost recovery approach for renewable integration procurement pursuant to Pub. Util. Code § 454.51, with at least 50 percent delivered by August 1, 2021, 75 percent by August 1, 2022, and 100 percent by August 1, 2023.[23] The Commission determined in the IRP proceeding that should a CCA or ESP elect not to procure the system reliability resources assigned to it in D.19-11-016, then the IOU in its service territory would procure the resources on their behalf.

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22 See D.19-10-001, OP 1 and OP 3 (ordering the Energy Division to calculate forecast and final benchmarks using reported market transactions).

23 D.19-11-016, OP 3.

On May 18, 2020, PG&E requested approval of 423 MW of energy storage resources in compliance with the decision for bundled customer and opt-out LSE procurement.[24] In its request, PG&E proposed to recover costs associated with bundled customer procurement through the generation rate beginning in 2021, and to continue to recover costs through the generation rate until the Commission determines permanent cost recovery in R.20-05-003. PG&E also proposed that in the interim the Commission establish a memorandum account to record the 2021 costs and revenues associated with opt-out and deficient procurement until the Commission authorizes the IOUs to create new tariffs for a modified CAM charge and a two-way balancing account.

3. Ongoing CTC Cost Recovery

PG&E's Ongoing CTC forecast revenue requirement represents the above-market costs associated with eligible contract arrangements entered into prior to December 20, 1995, QF contract restructuring costs which are recoverable from bundled and certain non-exempt DL customers, and other Commission-authorized costs. These costs are recorded in the Modified Transition Cost Balancing Account (MTCBA).

The above-market costs are determined by calculating the difference between the cost of the portfolio of resources and the market value of an equivalent portfolio. The methodology for calculating the proxy of the market price or MPB was approved by the Commission in D.06-07-030, as modified by D.11-12-018 and D.18-10-019. The Energy Division will calculate the MPB for the November Update on the first business day of November.[25] PG&E's Ongoing CTC calculation presented in this testimony includes an estimate for the MPB based on the revised methodology adopted in D.18-10-019.

4. Tree Mortality Non-Bypassable Charge

The Commission issued D.18-12-003 on December 21, 2018 establishing an NBC for costs associated with tree mortality biomass energy procurement. As stated in D.18-12-003, the TMNBC will recover the net

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[24] See PG&E's AL 5826-E.

[25] D.19-10-001, Finding of Fact (FOF) 11 and COL 7.

costs of the TM related biomass energy procurement and will exclude revenue received by the IOUs through sales of energy and ancillary services; the value of Renewable Energy Credits, as determined by the sale of these credits in the marketplace (or a benchmark value if such sales are impossible); and the value of the RA capacity, as determined through utility sales of the capacity (or a benchmark value if such sales are impossible).

F. Bundled Procurement Plan

1. Currently Effective BPP

PG&E's BPP, approved in D.15-10-031, addresses the procurement activities that will occur through December 31, 2024, unless subsequently amended or superseded. Under the BPP, PG&E has authority to enter into short-, medium- and long-term procurement contracts. In addition, PG&E has authority to procure natural gas supplies and related services for electric production, to procure nuclear fuel for nuclear generation, and to engage in gas and electric hedging activities, among other things. PG&E's BPP includes procurement processes and rules as a means of ensuring cost-effective procurement for customers and is designed to help meet California's energy and environmental policies, while providing reliable and affordable service to PG&E's customers.[26]

2. BPP Authority for Recovery of Forecast GHG Costs

PG&E's BPP includes the authority to purchase GHG products, as approved in D.12-04-046. Specifically, in D.12-04-046, the Commission authorized the IOUs to procure compliance instruments, including allowances, allowance futures and forwards, and offset and offset forwards, within limits, as described in that decision. In addition, D.12-04-046, OP 10, authorizes PG&E to seek cost recovery for GHG costs through its ERRA Forecast Application. Chapters 15, 16, and 17 discuss PG&E's 2020 GHG-related forecasts in more detail.

G. GHG Revenue Return and Reconciliation

CARB adopted the regulations to implement a Cap-and-Trade Program under Assembly Bill 32, the "Global Warming Solutions Act of 2006," on

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[26] PG&E's BPP, Sheet Nos. 1 through 4.

December 13, 2011. Pursuant to the Commission's GHG OIR 11-03-012, issued March 24, 2011, the IOUs began incurring costs to comply with the Cap-and-Trade Program in January 2013.

CARB acknowledged that the electricity sector incurs costs associated with the Cap-and-Trade Program. In order to mitigate the effect of a sudden increase in the electricity bills associated with the Cap-and-Trade regulations, CARB allocates allowances to the IOUs on behalf of their electric customers. CARB further determined that the IOUs will sell these allocated allowances in quarterly auctions and distribute the proceeds to their customers through electric rates.[27]

PG&E filed its first GHG revenue and reconciliation application in 2014. In D.14-10-033, OP 10, the CPUC directed the IOUs to file the GHG forecast revenue and reconciliation request as an additional chapter or section within the annual ERRA or Energy Cost Adjustment Clause forecast applications.

Chapters 15, 16, and 17 present the derivation of GHG allowance revenue return amounts to be provided to customers. Chapter 17 also contains details about customer programs funded by GHG allowance revenue proceeds and requests a set-aside of GHG revenues to fund these customer program, as well as incurred and forecast A&O expenditures.

H. November Update

Consistent with the previous ERRA and GHG forecast proceedings, PG&E proposes to update its 2021 forecasts of ERRA, NBCs, and revenue requirements, as well as its GHG cost and revenue forecasts and reconciliation amounts, on November 9, 2020 to reflect market conditions closer to the time when 2021 rates go into effect.[28] At that time, PG&E will update certain NBC calculations using a MPB that the Commission provides, as well as balancing account balances.

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[27] R.11-03-012, pp. 4, 8 and 11.

[28] D.06-12-018, OP 5 adopted a process by which gas and electric forward prices are updated 45 days prior to the November Update, consistent with the informal agreement PG&E reached with an intervening party to alleviate concerns regarding the timeliness of the forward price estimates in relation to the test year forecast. See D.06-12-018, p. 12; FOF 5; and COL 4. D.14-10-033 also requires a November Update for the GHG forecast and reconciliation portion of this application. See D.14-10-033, pp. 31-32.

In D.16-12-038, OP 3, the Commission adopted PG&E's proposal for the exchange of load forecast information between PG&E and CCAs for both this Prepared Testimony and the November Update. PG&E will be providing in its November Update more current load forecast information based on the timing and process in the proposal adopted by the Commission in D.16-12-038 and reflecting a final decision in R.19-03-009 concerning direct access expansion. PG&E expects the electric sales forecast will also be updated with more recent available economic data and will be served to parties no later than the November Update.

I. Amortization of Year-End Balances

Consistent with the treatment of year-end balances in previous years' ERRA forecast proceedings, PG&E proposes to amortize its forecasted year-end 2020 CAM,[29] PABA, MTCBA, TMNBC, and ERRA balances in rates over the following calendar year, through the AET process. Additionally, PG&E anticipates filing an expedited application when the total accumulated PUBA reached the level discussed in Section D above. If the Commission does not approve full recovery of the accumulated balance set forth in PG&E's separately-filed trigger application by the end of the year, PG&E will request that any residual balance be included as part of the PCIA revenue requirement in this application, and be included in rates through the AET. To accomplish this, PG&E will update the forecast year end 2020 New System Generation Balancing Account (NSGBA), PABA, MTCBA, TMNBC, ERRA, and PUBA balances in its November Update.

J. Conclusion

The purpose of this testimony is to present PG&E's total 2021 forecast revenue requirement of $2,806.1 million. PG&E requests approval of $5,328.6 million for 2021 rate setting purposes, which includes $2,522.5 million of UOG-related costs not subject to approval in this Application. The component revenue requirements for rate setting purposes comprise of a CAM forecast of

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29 PG&E records all CAM-related costs to ERRA. The net cost of CAM-eligible contracts is transferred to the NSGBA through a credit to the ERRA and a debit to NSGBA. Electric Preliminary Statement Part FS ("New System Generation Balancing Account ") is available at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_FS.pdf.

$266.3 million, PCIA forecast of $2,802.6 million, Ongoing CTC forecast of $19.9 million, TMNBC forecast of $72.6 million, ERRA forecast of $1,889.9 million, and PUBA forecast of $277.4 million. As part of this forecast, PG&E requests that the Commission approve the transfer of the 2020 ERRA balance to PABA vintage 2020 subaccount, excluding the Revenue Deferral, for recovery in the PCIA rates.

In addition, PG&E requests the Commission approve the following elements of PG&E's proposal to return GHG allowance revenue to customers: (1) 2021 forecast A&O expenses of $847,000; (2) customer generation programs funded by GHG revenues of $67.8 million ; (3) 2021 net forecast revenue return amount of $195.8 million; (4) 2021 semi-annual residential California Climate Credit amount of $18.77; (5) $190,000 to true-up A&O set-asides and recorded and forecast A&O expenses through 2021; and (6) the reasonableness of PG&E's 2019 recorded utility A&O expenses for GHG revenue return of $426,000.

PG&E requests that the Commission approve PG&E's rate proposals associated with its proposed electric procurement-related revenue requirements to be effective in rates on January 1, 2021. Finally, PG&E requests that the Commission approve PG&E's 2021 retail sales forecast, as updated, pursuant to its November Update.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

SALES AND PEAK DEMAND FORECAST

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
SALES AND PEAK DEMAND FORECAST

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
SALES AND PEAK DEMAND FORECAST

A. Introduction

The purpose of this chapter is to describe Pacific Gas and Electric Company's (PG&E) 2021 sales and peak demand forecasts and the methodology used to develop these forecasts. The timing of this Energy Resource Recovery Account (ERRA) Forecast filing does not allow for incorporation of the load impacts of the novel coronavirus (COVID-19) pandemic and the concomitant public policy responses, so the forecast and discussion below do not include an adjustment for these impacts. However, PG&E anticipates its electric sales forecast will need updating with more recent available economic data and will provide supplemental testimony to parties by no later than the November update. PG&E anticipates that update will include recalculation of most of the numerical contents of this chapter. The impacts from the COVID-19 pandemic and some very preliminary high-level numerical impacts are discussed in the "Economic Backdrop" subsection below. Summaries of PG&E's forecasted energy (sales) and capacity (peak demand) loads are shown in Table 2-3.

The bundled electricity sales forecast for 2021 is expected to be 10 percent lower than the forecast adopted in Decision (D.) 20-02-047, which approved PG&E's 2020 ERRA Forecast Application (A.) 19-06-001. The primary driver of the decrease in bundled electricity sales is due to continued load departures to Community Choice Aggregation (CCA) and the limited reopening of Direct Access (DA) mandated by Senate Bill (SB) 237 and implemented by D.19-05-043. There are 12 CCAs currently serving load in PG&E's service territory in 2020.[1] One additional CCA is expected to begin service in PG&E's

[1] CCAs currently serving in PG&E's service territory include: Marin Clean Energy (MCE), Sonoma Clean Power (SCP), CleanPowerSF (CPSF), Peninsula Clean Energy (PCE), Silicon Valley Clean Energy (SVCE), Redwood Coast Energy Authority (RCEA), Pioneer Community Energy (Pioneer), Monterey Bay Community Power (MBCP), Valley Clean Energy Alliance (VCEA), East Bay Community Energy (EBCE), King City Community Power (KCCP), and the City of San José, Administrator of San José Clean Energy.

territory in 2021. In total, PG&E expects CCA and DA providers to serve over 59 percent of PG&E's total system sales in 2021. In addition, continued growth of Energy Efficiency (EE) and behind the meter (BTM) Distributed Generation (DG) are contributing to relatively flat systemwide electricity sales growth despite economic growth.

Economic and population growth continue to drive the system peak usage upward, but this increase is approximately offset by other factors. Additional EE mitigates a portion of the increase. BTM DG has a limited impact to the annual system peak as customer owned solar photovoltaic (PV) generation is minimal during the peak hour of 7 p.m., but storage (with or without solar PV) is beginning to have an impact that is expected to grow over time.

B. PG&E's Load Requirements

This section describes the development of the sales and peak demand forecasts for PG&E's service area. The electric sales forecast for PG&E's bundled electric customers is a key input to the procurement cost modeling described in subsequent chapters and used in the calculation of the rates discussed in Chapter 19. The bundled sales forecast is derived by first forecasting total electric sales at the "retail system" level, meaning the energy requirements of all customers who receive electricity over PG&E's distribution system. Bundled sales are then determined by subtracting the energy requirements of those customers who buy their electricity from entities other than PG&E, which includes DA customers, CCA customers, and the Bay Area Rapid Transit District (BART).

1. Sales and Peak Demand Forecast

a. Economic Backdrop

In the first part of 2020, PG&E service territory's economy continued to expand, with wage growth outpacing national averages and fueling consumption. The tech-centric Bay Area continues to be the economic engine of the service territory, with startup investment and continued growth of well-established firms like Facebook, Google, and Apple. With a concentrated need for highly skilled workers in a tight labor market, wage growth continues to rise. This growth has in recent years driven increased construction and consumer spending despite rising costs. In

the long run the economic expansion in PG&E's service territory faces headwinds. Potential downside risks include rising house prices and business costs, both of which exceed national and California averages. China-United States trade disputes have slowed agricultural growth in the Central Valley, lowering demand and thus reducing exports. Although population growth rates are lower than the historic average, the population in PG&E's service territory continues to grow, despite an increase of residents migrating out of the service territory due to high living costs. Much of this growth is moving to less expensive metro areas away from the more concentrated and developed job centers.

However, in the near and perhaps medium term, these economic drivers are overshadowed by another issue. Since the year began, the service area, along with the rest of the world, has been confronted by the COVID-19 pandemic. By changing patterns of work and transportation, the pandemic alters electrical usage directly; by reducing economic growth, it alters electrical usage indirectly.

It is well known that energy usage is driven by economic activity. This relationship is so strong that energy usage can be diagnostic of the onset of economic recessions. Accordingly, economic inputs are a major driver of sales forecasts. In the past, these economic inputs have changed slowly enough that PG&E could incorporate them into a year-ahead forecast with the understanding that the changes in these drivers between forecasts would be mild and understandable. However, the economic effects of COVID-19 and control measures for suppressing the virus' spread have been severe and sudden. The economic picture we face now is substantially different from the one of just a few months ago. For this reason, there is a desire to update forecasts with the latest breaking revised economic data from Moody's, IHS, or other standard sources.

However, along with the undeniable severity of the direct and indirect economic impacts of the COVID-19 pandemic comes extreme unpredictability and a very limited dataset from which to extrapolate. For a numerical forecast update to be meaningful, the updated inputs must be stable enough to be actionable. The changes in the economic

picture due to COVID-19 depend on the future evolution of the pandemic, as well as the response to that evolution.

In PG&E's opinion, there is not sufficient data, or epidemiological or political certainty, to take a future scenario and meaningfully say that scenario is, say, 25 percent more probable than before, or that a forecast that depends on COVID-19 measures next year should be taken as a realistic point estimate. PG&E monitors customer usage in response to COVID-19, and continues to watch for updates from our economic data sources. For the time being, PG&E intends to use this limited data to point out general directions and magnitudes of effects.

With this in mind, PG&E's most recent analysis of current COVID-19 impacts and preliminary updated economic forecasts indicate that over the past few months the pandemic and responses including Shelter in Place (SiP) measures have directly reduced commercial and industrial loads substantially while increasing residential loads somewhat, as well as increasing the relative quantity of energy consumed by residential customers in the middle of the day. The net decrease in total energy consumption observed by the California Independent System Operator (CAISO) in a recent report covering March 23 to June 7 was about 3.7 percent on weekdays and about 1.4 percent on weekends[2] for the CAISO system. The indirect effect of the pandemic and SiP through economic growth is driven by recently revised forecasted 2020 real Gross Domestic Product declines from Moody's with continued softness through 2021. These are initial estimates of the COVID-19 impacts and at this time the effect in 2021 is highly uncertain. For this reason, PG&E provides the following preliminary indicators here. PG&E anticipates it will provide forecast revisions including quantitative effects of COVID-19 impacts by no later than its Update to Prepared Testimony, to be served on November 9, 2020 (November Update).

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2 http://www.caiso.com/Documents/COVID-19-Impacts-ISOLoadForecast-Presentation.pdf.

The table below shows various economic indicators driving the present load forecast for the PG&E service territory as forecasted by Moody's Analytics in July 2019.

TABLE 2-1
SERVICE AREA ECONOMIC INDICATORS

Line No.		2017	2018	2019	2020	2021	2022
1	Real Gross Product ($ billions)						
2	% Change						
3	Total Employment (Thou.)						
4	% Change						
5	Real Personal Income ($ billions)						
6	% Change						

b. Sales Forecast

PG&E uses econometric models to forecast electric retail sales to all customers in PG&E's total service territory, excluding DA customers, with individual regression equations specific to each major customer class—residential, commercial, industrial, and agricultural. The models predict sales or sales by customer using various PG&E service area economic measures, price variables, and weather variables. The forecast models incorporate recorded data through December 2019, with historic and forecast values for the models' economic drivers from the Moody's Analytics July 2019 update of PG&E's service territory economic forecast outlook. The models also include autoregressive terms to remove any serial correlation that remain in residuals, which ensures the robustness of the parameter estimates in the models. The details of the models and underlying data can be found in the workpapers for this exhibit. The final forecast also accounts for the expected future effects of EE, DG, Electric Vehicles (EV), and additional end-use Electrification. Details of these forecasts are described in Section B.2.

On a recorded basis, residential sector sales to all retail customers (including PG&E bundled, CCA, and DA) decreased 4.9 percent between 2017 and 2018, and decreased 0.8 percent between 2018 and 2019. The decrease in 2018 sales followed above normal summer

temperatures throughout the service territory in 2017. This decrease stabilized in 2019. On a weather-normalized basis, residential sales declined 2.4 percent between 2017 and 2018, and declined an additional 0.4 percent between 2018 and 2019. Over the last five years, residential sector sales have declined by 7.7 percent on a recorded basis, and 7.4 percent on a weather-normalized basis.

PG&E primarily attributes the drop in residential sales to increases in growth in EE and BTM DG, primarily via customer owned PV systems. The effect of EE and BTM DG are discussed in Section B.2. below.

The continued growth of BTM DG and EE displaces the load growth from economic expansion and population growth in 2021. PG&E's 2021 residential sales forecast is projected to be 3.3 percent lower than PG&E's forecasted residential sales approved in D.20-02-047 for forecast year 2020.

On a recorded basis, commercial sector sales to all retail customers (including PG&E bundled, CCA, and DA) declined 3.5 percent from 2017-2018, and declined an additional 1.0 percent between 2018 and 2019. On a weather adjusted basis, commercial sales declined 2.6 percent between 2017 and 2018, and declined an additional 1.1 percent from 2018-2019. Over the last five years, commercial sector sales have declined by 8.0 percent on a recorded basis, and 7.4 percent on a weather-normalized basis. Similar to the residential sector, the commercial sector has also become more efficient and has adopted increasing amounts of BTM DG, including rooftop solar and fuel cells. As this trend continues, PG&E's 2021 commercial sales forecast is projected to be 0.9 percent lower than PG&E's forecasted commercial sales filed for forecast year 2020.

Industrial class sales to all retail customers (including PG&E bundled, CCA and DA) declined by 0.2 percent between 2017 and 2018, and declined an additional 2.2 percent in 2019, driven primarily by customer migration out of the service territory. PG&E's 2021 industrial sales forecast is projected to be 5.0 percent lower than PG&E's forecasted industrial sales for 2020.

Agricultural class sales to all retail customers (including PG&E bundled, CCA, and DA) are closely tied to available water in the service territory, since farmers pump groundwater for irrigation needs. With the extreme and prolonged drought from 2012 through 2016, PG&E saw agricultural sales increase by more than 50 percent from 2012 through 2014. Sales plateaued in 2015, increasing a modest 1.1 percent over 2014, even though California was still in the depths of the drought. With the above average precipitation observed since early 2016, sales declined by 12.2 percent between 2015 and 2016. The 2017 water year was one of the wettest years on record across many measures (including precipitation, snow pack and statewide runoff) according to the California Department of Water Resources (CDWR).[3] Correspondingly, electricity sales to the agricultural sector declined 22.5 percent in 2017. PG&E does not anticipate this trend to continue indefinitely. The 2018 water year began well below average; however, a series of spring storms lifted precipitation in the latter half of the water year. This resulted in agricultural sales increasing by 19.4 percent from 2017-2018. The increase in rainfall throughout early 2019 leading to a strong water year in 2019 resulted in a decline in sales of 18.1 percent during 2019. Due to the limited availability of weather data at the time the 2021 sales forecast is created, PG&E assumes a normal weather year throughout the forecast horizon. As a result, PG&E's 2021 agricultural sales forecast is projected to be 1.6 percent higher than PG&E's forecasted 2020 agricultural sales.

In D.18-08-013 (Phase 2 of PG&E's 2017 General Rate Case), the California Public Utilities Commission (CPUC or Commission) ordered PG&E to propose an improved sales forecasting mechanism for the agricultural class in its next ERRA proceeding and involve agricultural parties in the development of that improved mechanism.[4] Prior to the

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3 "Water Year 2017: What a Difference a Year Makes." California Department of Water Resources, September 2017: https://www.water.ca.gov/LegacyFiles/waterconditions/docs/2017/Water%20Year%202017.pdf.

4 D.18-08-013 at Ordering Paragraph (OP) 41.

issuance of D.18-08-013, and in response to the variability in agricultural sales, PG&E had already re-evaluated and altered its agricultural sales forecasting mechanism. PG&E used this forecasting model in the 2019 and 2020 ERRA Forecast proceedings, and relies on the same forecast methodology for this proceeding. Key methodological changes compared to previous agricultural sales forecast include replacing the monthly average cumulative rainfall independent variable with a rolling cumulative water-year rainfall independent variable and removing independent variables related to agricultural energy price, Cooling Degree Days, and lagged sales. These changes were made to better capture the rolling impact that rainfall, which is correlated with water allocation, has on agricultural class sales.

As ordered by D.18-08-013, PG&E previously consulted with the agricultural parties on the proposed agricultural sales forecast mechanism submitted in this application. The agricultural parties provided comments around specific independent variables included in the forecast and alternate variables that should be considered. Although PG&E continues to evaluate these comments to seek further modeling improvements, both parties acknowledge the difficulty of accurately forecasting the highly variable electric sales for the agricultural customer class, given that a primary driver of this variability is near-term water availability not available at the time of the ERRA forecast. Water availability cannot be known until shortly before the growing season, which is after the forecast is developed and adopted into rates. PG&E is exploring solutions that can realistically address these issues.

c. Peak Demand Forecast

PG&E also develops a retail peak demand forecast for the PG&E service area, using a regression methodology where the main model drivers are heating and cooling degree days and household growth as forecast by Moody's Analytics. Preliminary estimates of load modifiers as described in the next part of this chapter are also included. For 2021, PG&E projects a retail peak demand shown in Table 2-3, Line 40. Determining PG&E's bundled procurement need requires that the

demand associated with DA and CCA customers, along with their associated losses, be removed from the system retail peak demand. Table 2-3, Line 46 shows PG&E's forecasted bundled procurement requirement for 2021.

2. Post-Regression Forecast Adjustments

Although the model-based forecast described in Section B.1 above remains at the core of PG&E's sales and peak demand forecast process, the regression forecast alone cannot incorporate all of the impacts of new technologies and policies. For this reason, PG&E takes an additional step to adjust its regression forecast before arriving at final sales and peak demand forecasts. In general, the adjustments described in this section are designed to incorporate the latest BTM DG, Conservation and EE, EV, Building Electrification, BTM Energy Storage, Demand Response (DR), DA, and CCA expectations. Additionally, PG&E's forecasts account for Transmission and Distribution (T&D) losses and Unaccounted for Energy (UFE). Table 2-3 presents the cumulative impact for each of these post-regression adjustments, incremental to 2019.

a. BTM Distributed Generation

The PG&E service territory continues to lead the nation in rooftop solar installations, with over 480,000 installations and over 4,600 megawatts (MW) as of March 2020. PG&E expects steady growth of rooftop solar as the economics continue to be favorable, and California policies, including net energy metering and Zero Net Energy mandates, continue to drive the PV market.

In order to forecast load impacts from rooftop solar, PG&E has developed an internal model which forecasts customer solar PV adoption and installed capacity, and estimates generation associated with that capacity. Forecasts of BTM PV adoption were developed using a Bass technology diffusion modeling approach considering the economics of customer adoption. Generation estimates for BTM PV were developed internally using customer PV system configuration and weather information at a Distribution Planning Area level, which was then translated into generation using the National Renewable Energy

Laboratory's PV Watts modeling framework. Modeled estimates were then calibrated to metered customer PV generation data available through the California Solar Initiative Program. Representative BTM PV generation profiles were developed for residential and non-residential customers.

Table 2-3, Lines 5 and 35, show BTM PV cumulative energy and peak demand forecasts incremental to 2019.

For Non-PV DG resources, a simple Bass technology diffusion model informed the fuel cell adoption forecast. Market, policy, and trend analysis informed the wind and combustion technologies (including combustion turbines, microturbines, internal combustion engines) adoption forecasts. For non-PV BTM technologies, generation estimates were based on annual capacity factors from the 2014-2015 Self-Generation Incentive Program Impact Evaluation (Itron, November 2016) distributed evenly throughout the year.

The non-PV BTM cumulative energy and peak demand forecasts incremental to the 2019 are shown on Table 2-3, Lines 6-7, and Lines 36.

b. Conservation and Energy Efficiency

PG&E incorporates the effects of conservation and EE into its sales and peak demand forecast using savings totals based off the 2019 Navigant Potential and Goals model results utilized by the Commission and California Energy Commission (CEC). PG&E analyzes individual key drivers of potential EE savings to develop a probabilistic estimate of EE savings based on a sensitivity analysis of these key drivers. Table 2-3, Lines 3 and 33, show EE cumulative energy and peak demand forecasts incremental to 2019.

c. Electric Vehicles

PG&E's forecast is adjusted for expected load increases due to plug-in EV adoption. In order to consider the impact of EVs on PG&E's annual load, PG&E built a probabilistic model based on policies and market drivers to forecast the EV population, energy demand, and capacity. The forecast is informed by: (1) aggregated EV registration

data available through August 2019; (2) state policy goals; (3) market drivers such as rideshare growth and direct current fast charging availability; and (4) data-based load profiles which describe the typical EV electricity consumption and charging behavior. Table 2-3, Lines 8 and 37, show EV cumulative energy and peak demand forecasts incremental to 2019.

d. Building Electrification

In addition to EVs, PG&E includes in its forecast additional electricity sales due to an increase in the rate of building electrification. This includes residential and commercial customers who may respond to policy or market incentives to retrofit some appliances in their buildings, particularly space and water heating. Additional building electrification has a relatively minor impact on system sales in the near term. Table 2-3, Lines 9 and 38, show building electrification cumulative energy and peak demand forecasts incremental to 2019.

e. BTM Energy Storage

As the market for BTM Energy Storage is projected to grow in California, PG&E includes demand impacts due to the growth of storage technologies, particularly BTM battery technologies. PG&E assumes storage at this scale will have little impact on annual energy given the expected round-trip efficiencies, but some impact on peak demand, as customers use batteries to (a) reduce their energy purchases during peak hours or (b) offset their peak loads and demand charges. Table 2-3, Line 39, shows the expected cumulative decrease in peak demand due to BTM Energy Storage incremental to 2019.

f. T&D Losses and Unaccounted for Energy

T&D losses and UFE are estimated as a percentage of PG&E's total retail sales, net of DA, CCA, and BART. Pursuant to D.05-10-042, UFE and transmission losses are set at 3 percent of metered load, plus distribution losses.[5] Distribution losses are estimated to average 6 percent based on hourly-load levels.

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5 D.05-10-042, p. 42.

3. PG&E's Versus CEC's Forecast Methodology

The CEC develops the California Energy Demand (CED) forecast every two years as part of the Integrated Energy Policy Report (IEPR). The CEC also updates the electricity forecast in the interim years, but on a more limited basis. This off-year update typically involves updating economic and demographic projections, adding another year of historical peak and consumption data, and making any needed corrections. The most recent CED, adopted in March 2020, contains a forecast of energy deliveries to PG&E bundled and DA/CCA customers from 2019 through 2030. While PG&E does submit its most recent forecast to the CEC to inform the CED, the CEC generates its forecast independently and develops its forecast in a fundamentally different way than PG&E does.

The CEC primarily uses an "end-use" approach,[6] which calculates energy consumption based on appliance saturation, efficiency, and usage data, as well as household growth and other demographic data. As described above, PG&E calculates the sales forecast for all of its customer classes using econometric modeling, which is an approach that uses time-series regression techniques to model the response of the dependent variable, either aggregate sales or sales per account, as a function of a series of predictor variables. These predictors are typically: economic variables; price variables; time variables, and weather variables. That said, there are reasonably expected changes that are likely to occur, based on policy and market conditions that will not be picked up in historical data. This is why both PG&E and the CEC adjust sales forecasts to account for "Additional Achievable Energy Efficiency"—EE savings reasonably expected to occur, as well as DG, and EVs. Of note is that PG&E's forecast includes a building electrification forecast, which the CEC does not currently produce. Both approaches, the end-use bottom-up approach and the econometric

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6 An exception should be noted for the industrial sector, which is a hybrid approach using both end use and econometric analyses. The forecasts of agricultural and water pumping energy consumption are made using econometric methods for individual subsectors (for example, dairy and livestock). See the Final CED for details on methodology. (http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207439_20160115T152221_California_Energy_Demand_20162026_Revised_Electricity_Forecast.pdf).

top-down approach, are valid techniques to predict energy consumption based on underlying trends in historical data. Both approaches typically result in similar long-term forecasts.

For applications requiring forecasted retail electric sales, PG&E uses its internal forecast for two reasons. First, PG&E performs a full sales forecast update at least once a year in order to take advantage of the most recent data available. For example, this 2021 ERRA forecast relies on data through December 2019, while the CED forecast is based on data through 2018. This distinction is important as the energy landscape is changing quickly. Second, PG&E has its own view on the effects of the policy drivers. Again, due to the timing of the forecasts or due to differences in opinion, the effect of these policy drivers can differ between PG&E's forecast and the CEC's. PG&E believes that, with the exception noted for COVID-19 impacts, the forecast presented in this application utilizes the most recent and up-to-date available data on sales, weather, economics, and policy drivers and therefore is the best available estimate of 2021 sales.

C. Departing Load

1. Departing Load Sales Methodology

In this filing, PG&E reflects seven Departing Load (DL) types,[7] including DA and CCA. Consistent with the CPUC-approved methodology used in past forecast proceedings, for Transferred Municipal, New Municipal, Split-Wheeling, Customer Generation and New WAPA, PG&E uses the most recent available recorded DL sales as a proxy for 2021 projected DL. Treatment of DL due to DA and CCA departures are addressed in their specific sub-sections, below.

Some of these DL customers are exempt from paying one or more of the Non-Bypassable Charges (NBC) approved by the Commission. There are seven NBCs:

1) Power Charge Indifference Adjustment;
2) CDWR Bond;

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[7] The first five categories are Transferred Municipal, New Municipal, Split-Wheeling, Customer Generation and New Western Area Power Administration (WAPA), as established in D.03-04-030, D.03-09-052, D.06-05-018, D.03-07-028, and D.04-11-014, respectively.

3) Ongoing Competition Transition Charge;
4) Energy Cost Recovery Amount;
5) Nuclear Decommissioning Charge;
6) Public Purpose Program Charge; and
7) New System Generation Charge (also known as the Cost Allocation Methodology Charge).

For each DL category, PG&E calculates those sales responsible for each specific NBC. PG&E sums the results of the DL categories to produce aggregate estimates of NBC-eligible sales by rate schedule. These sales are presented in Table 2-2 disaggregated by type. PG&E uses this DL sales estimate to design all applicable NBC rates that will take effect in 2021.

TABLE 2-2
2021 DEPARTED LOAD SALES ESTIMATED BY CATEGORY (MWh)

Line No.	Departing Load Category	Total DL	Ongoing CTC	PCIA	NSGC	Vintaged NSGC
1	Pre-2012 Transferred Municipal DL[(a)]	522,217	399,457	Exempt	Exempt	Exempt
2	2012 - 2019 Incremental TMDL[(a)]	122,847	122,847	Exempt	Exempt	122,847
3	Pre-2012 New Municipal DL[(a)]	219,622	0	Exempt	Exempt	Exempt
4	2012 - 2019 Incremental NMDL[(a)]	0	0	Exempt	Exempt	Exempt
5	Customer Generation DL[(a)]	9,403,920	696,048	Exempt	Exempt	N/A
6	New WAPA DL[(a)]	45,686	2,493	0	2,493	N/A
7	Split Wheeling DL[(a)]	6,527	6,527	0	6,527	N/A
8	Direct Access less Continuous D.12-04-012	10,811,759	10,811,759	5,524,307	10,811,759	N/A
9	Continuous DA D.12-04-012(a)	233,458	233,458	Exempt	233,458	N/A
10	Total Direct Access	11,045,217	11,045,217	5,524,307	11,045,217	N/A
11	CCA[(b)]	35,209,960	35,209,960	35,209,960	35,209,960	N/A
12	**Total Departing Load**	**56,575,997**	**47,482,550**	**40,734,267**	**46,264,198**	**122,847**

(a) This item will be updated in PG&E's November Update.
(b) This item is understated and PG&E will correct this value on July 17, 2020.

2. Departing Load Settlements

PG&E entered into four Settlement Agreements regarding the collection of DL charges. The Settlement Agreements with: (1) the Power and Water Resources Pooling Authority;[8] (2) the Modesto Irrigation District and the Merced Irrigation District;[9] (3) the Turlock Irrigation District;[10] and (4) the Center for Accessible Technology, Marin Clean Energy (MCE), the Public Advocates Office, The Utility Reform Network, and Brightline Defense[11] have been completed. While these settlements specify the DL charges to be collected from the responsible parties, they do not affect the calculation of historical annual sales.

3. Departing Load Due to Direct Access

PG&E develops its sales forecast from billed customer data, which includes sales for bundled, CCA, and DA customers. In order for PG&E to develop a forecast of its procurement needs, sales attributable to DA and CCA customers must be removed.

DA, which was created by Assembly Bill (AB) 1890 in 1996, allows electric retail customers to elect to receive service from an alternate electric commodity provider. In 2001, during the energy crisis, DA was suspended to new customer enrollments, pursuant to D.01-09-060. In D.02-03-055, the Commission confirmed that the right to switch to DA was suspended as of September 20, 2001, pursuant to AB 1X. This suspension was amended in accordance with the provisions of SB 695, which required the CPUC to allow increases in the amount of usage eligible for DA. In D.10-03-022, the CPUC implemented a 4-year phase-in of DA, subject to annual caps, and established processes by which eligible customers may enroll in DA. Under the re-opening rules, DA enrollment was subject to a maximum allowable limit over the 4-year timeframe (2010-2013). PG&E's DA load was

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8 A.09-05-017 and D.09-08-015.

9 A.09-06-023 and D.10-11-011, the Merced-Modesto Agreement. This is a single agreement among Merced, Modesto, and PG&E.

10 A.02-01-012 and D.03-04-032.

11 D.18-09-013.

permitted to increase over this period from 5,574 gigawatt-hours (GWh) to a new total cap of 9,520 GWh. In 2013, PG&E's cap was met.

4. Direct Access Expansion

In September 2018, SB 237[12] was enacted requiring the Commission to increase the DA cap by 4,000 GWh statewide. The Commission implemented the expansion with D.19-05-043. The portion of the cap increase allocated to PG&E's service area was 1,873 GWh. The 2021 DA load forecast includes existing DA authorized under SB 695 and new DA authorized under SB 237. PG&E relied on the DA waitlists to estimate the amount of new DA departed from bundled and CCA service.

5. Departing Load Due to Community Choice Aggregation

CCA refers to governmental entities enabled by AB 117 to form entities that assume responsibility for supplying the electric load of all customers within their boundaries. As of the time this testimony and forecast was prepared, 12 CCAs have formed and are providing service in PG&E's service territory:

1) Marin Clean Energy (MCE);
2) Sonoma Clean Power (SCP);
3) Clean Power SF (CPSF);
4) Peninsula Clean Energy (PCE);
5) Silicon Valley Clean Energy (SVCE);
6) Redwood Coast Energy Authority (RCEA);
7) Pioneer Community Energy (Pioneer);
8) Monterey Bay Community Power (MBCP);
9) East Bay Community Energy (EBCE);
10) Valley Clean Energy Alliance (VCEA)
11) King City Community Power (KCCP); and
12) City of San José, Administrator of San José Clean Energy.

A new CCA, Butte Choice Energy, is the only known community forming and will serve load in PG&E's territory in 2021.

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12 SB 237 (Stats. 2018, Ch. 800).

This testimony and forecast reflect the 13 CCAs listed above that are expected to serve load in 2021. See Table 2-3, Lines 14-26 for PG&E's forecast of energy requirements for each CCA.

6. CCA Load Forecast Methodology

In order to forecast year-ahead DL due to CCA growth, PG&E follows a meet-and-confer process[13] to communicate with CCAs that plan to serve load in 2021. In January 2020, PG&E submitted e-mail requests for load, peak demand and customer forecasts from all 13 CCAs planning to provide service in PG&E's territory. PG&E received the requested forecasts from all 13 CCAs. After reviewing the CCAs' forecast methodologies and comparing against PG&E's internal forecast for CCA DL for reasonableness, PG&E accepted 12 of the 13 CCAs' 2021 monthly sales forecasts provided to PG&E and is including those forecasts in this Application. PG&E is using its internally-generated forecast for CPSF due to a discrepancy in forecasts believed to be caused by inclusion of the DA cap expansion. PG&E informed each CCA of its decision by April 2020.

This year, PG&E also discussed peak demand and compared monthly non-coincident peak demand forecasts with CCA parties. PG&E used its internal forecast for coincident peak demand.

The load forecast presented in this chapter was developed in March 2020 and used the best available information at that time. PG&E will provide its most up-to-date CCA forecast in the November Update following the fall 2020 meet-and-confer process.

D. Conclusion

In this chapter, PG&E describes retail electric sales and peak demand forecasts that reasonably reflect the underlying economic fundamentals, projected impacts of new technologies and policies, and recent information regarding customer departures. Therefore, PG&E requests that the Commission adopt the forecasts presented in Table 2-3 pending the update PG&E expects to provide with its November Update.

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[13] D.16-12-038, OP 3. See also D.20-03-019, OP 1 (requiring reporting of meet-and-confer activities and information exchange as part of ERRA Forecast Testimony).

TABLE 2-3
2021 ENERGY (GWh) AND PEAK DEMAND (MW) REQUIREMENTS

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	**Energy Load (GWh)**													
2	Unmitigated Retail Sales													83,949
3	Conservation and Energy Efficiency													
4	Distributed Generation													
5	Solar													
6	CHP													
7	Fuel Cell & Other													
8	Electric Vehicles													
9	Electrification													
10	Retail Sales													78,278
11	Direct Access													
12	Direct Access	(890)	(850)	(873)	(904)	(914)	(935)	(1,003)	(1,039)	(984)	(920)	(878)	(855)	(11,045)
13	Community Choice Aggregation													
14	Marin Clean Energy													
15	Sonoma Clean Power													
16	Clean Power San Francisco													
17	Peninsula Clean Energy													
18	Silicon Valley Clean Energy													
19	Redwood Coast Energy Authority													
20	Pioneer Community Energy													
21	Monterey Bay Community Power													
22	East Bay Community Energy													
23	San Jose Clean Energy													
24	Valley Clean Energy													
25	King City Community Power													
26	Butte Choice Energy													
27	Community Choice Aggregation Total	(2,928)	(2,645)	(2,716)	(2,627)	(2,771)	(2,982)	(3,226)	(3,289)	(3,050)	(2,920)	(2,922)	(3,135)	(35,210)
28	UFE, Transmission & Distribution Losses													2,897
29	Total Requirement													34,919
30	Retail Sales excludes BART energy requirements.													

TABLE 2-3
2021 ENERGY REQUIREMENTS (GWh)
(CONTINUED)

Line No.	Description	2021 PEAK REQUIREMENTS (MW) Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
31	**Peak Load (MW)**												
32	Unmitigated Retail Peak												
33	Conservation and Energy Efficiency												
34	Distributed Generation												
35	Solar												
36	Non-PV DG												
37	Electric Vehicles												
38	Electrification												
39	Battery Energy Storage												
40	Retail Peak with distribution losses												
41	Direct Access with distribution losses	(1,358)	(1,449)	(1,458)	(1,624)	(1,556)	(1,641)	(1,671)	(1,716)	(1,765)	(1,523)	(1,559)	(1,297)
42	Community Choice Aggregation with distrib losses	(5,935)	(5,593)	(5,539)	(5,578)	(6,043)	(7,106)	(7,222)	(7,140)	(7,116)	(6,383)	(6,053)	(6,383)
43	UFE & Transmission Losses												
44	Demand Response	(169)	(171)	(177)	(191)	(240)	(272)	(279)	(270)	(255)	(221)	(182)	(182)
45	Puget Sound Power & Light (Return)												
46	Total Requirement												
47	Retail Peak excludes BART demand requirements.												

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

GENERATION RESOURCE AND SUPPLY COST SUMMARY

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
GENERATION RESOURCE AND SUPPLY COST SUMMARY

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
GENERATION RESOURCE AND SUPPLY COST SUMMARY

A. Introduction

Pacific Gas and Electric Company (PG&E) forecasts the gross 2021 portfolio generation and energy procurement costs to be $4,364 million.[1] This amount reflects PG&E's assessment of projected bundled customer load, energy market conditions, and generation resources in PG&E's electric supply portfolio. The procurement costs described herein are presented in the tables by cost recovery mechanism, with the forecasted revenue requirements presented and discussed in Chapters 8 through 12.

This chapter provides a broad overview of the key portfolio and market drivers that, when combined, result in the forecasted 2021 procurement costs. Detailed assessments of the different cost components that make up the forecast are contained in subsequent chapters.

The remainder of this chapter is organized as follows:

- Section B – Capacity and Energy Resources
- Section C – Energy Procurement Costs
- Section D – Market Prices and Economic Dispatch Modeling
- Section E – Conclusion

B. Capacity and Energy Resources

PG&E typically groups its generation resource portfolio into three broad categories: (1) utility-owned generation (UOG); (2) resources that were contracted prior to 2003—typically legacy Irrigation District and Water Agency (IDWA) and Qualifying Facility (QF) contracts; and (3) resources contracted after 2002. Resources included in these three broad categories are described in

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[1] The gross 2021 portfolio generation and procurement costs reflect the fixed and variable costs of generation for contracted resources, the variable costs of generation for utility owned resources, and the costs of procuring energy from the California Independent System Operator (CAISO) to meet bundled load. The gross costs do not include general rate case costs, forecasted energy revenues from the CAISO, or revenue fees and uncollectibles. The 2021 revenue requirement for rate setting presented in Chapter 18 is equal to the sum of all the items listed above.

detail below. Expected capacity and energy from each of the resource categories is shown in Tables 3-1 and 3-2.

1. Utility Owned Generation

a. Diablo Canyon Power Plant

PG&E owns and operates two nuclear power units at Diablo Canyon Power Plant (DCPP). The plant is expected to have an availability of over 98 percent annually, excluding refueling outages.

b. Hydroelectric Generation

PG&E owns and operates numerous hydroelectric facilities, some run-of-river and others dispatchable, and one pumped storage facility expected to operate in 2021. The hydro generation forecast for 2021 is based on PG&E's 2020 hydro generation forecast and reflects PG&E's current outlook for 2021 hydro generation. The 2021 hydro generation forecast will be updated to reflect PG&E's hydro generation forecast based on more current hydro conditions in PG&E's Update to Prepared Testimony, to be served in November 2020 (November Update).

c. Fossil Generation

PG&E's fossil generation forecast for 2021 includes the Gateway Generating Station, a Combined Cycle (CC) power plant that started commercial operation in January 2009; the Colusa Generating Station, a CC power plant that started commercial operation in December 2010; and the Humboldt Bay Generating Station, which consists of 10 gas-fired reciprocating engines and started commercial operation in September 2010.

d. Solar Resources

On April 22, 2010, the California Public Utilities Commission (CPUC or Commission) adopted Decision (D.) 10-04-052 which authorized PG&E's Photovoltaic (PV) Program. Under this program, PG&E has developed 152 megawatt (MW) of dispersed, midsized (typically 1 to 20 MW) installations within PG&E's service territory. In addition to the PV Program, PG&E owns three small PV facilities in San Francisco that entered commercial operations in 2007.

e. Fuel Cell Project

On April 8, 2010, the Commission adopted D.10-04-028, which approved PG&E's fuel cell project to develop, own, and operate three fuel cell electric generating facilities totaling 3 MW of capacity on two state of California properties: California State University, East Bay; and San Francisco State University.

f. Energy Storage

PG&E began operational testing of the Vaca-Dixon Battery Storage Pilot Project, a 2 MW/7-hour storage Sodium Sulfur (NaS) battery system, in November 2012, and the unit was declared commercial by the CAISO in August 2014. The system is currently operational as a participant in the CAISO Non-Generator Resource market model.

PG&E declared the Yerba Buena Battery Storage Pilot Project, a 4 MW/7-hour NaS system, operational in May 2013. This facility has successfully demonstrated that it can provide an islanding function to an adjacent customer load in the event of a utility disturbance or outage. The facility was declared commercial by CAISO in January 2016 and is a participant in the CAISO Non-Generator Resource market model.

PG&E submitted Advice 5322-E on June 29, 2018 requesting authorization for four new storage projects of which one, PG&E Moss Landing, would be owned and operated by the utility. The Commission authorized the project through Resolution (Res.) E-4949. PG&E Moss Landing is a 182.5 MW/4hr lithium-ion battery that is expected to become operational by April 2021.

2. Pre-2003 Contracted Resources

a. IDWA Contracts

PG&E has one remaining legacy contract with Solano Irrigation District for energy and capacity from their facilities. This includes the Monticello Powerhouse, a Renewables Portfolio Standard (RPS)-eligible hydroelectric facility located in northern California.

b. Metropolitan Water District Contract

PG&E has a Power Purchase Agreement (PPA) with the Metropolitan Water District (MWD) for 24 MW of power from the

Etiwanda Power Plant, an RPS-eligible hydroelectric facility located in southern California. PG&E uses the latest generation forecast provided by MWD to estimate the energy deliveries.

c. Qualifying Facilities

Chapter 5 details PG&E's PPAs with QFs and the associated costs.

d. Puget Sound Power & Light Company Exchange Contract

Under the Puget Sound Power & Light Company (PSPL) contract, PG&E receives capacity and energy (subject to transmission constraints) between June and September. PG&E is obligated to return a similar amount of energy to PSPL between November and February.

3. Post-2002 Contracted Resources

a. RPS-Eligible Resources

Pursuant to Senate Bill 100, which was adopted by the Legislature and signed by Governor Brown in 2018, PG&E is obligated to meet 60 percent of its bundled customer demand with RPS-eligible resources by 2030. Starting in 2003, PG&E initiated a series of solicitations for the purposes of securing, as well as selling, RPS generation. PG&E's RPS-procurement also includes bilaterally-contracted resources and resources procured through Commission-approved programs, such as the feed-in tariff programs, including the Renewable Market Adjusting Tariff and Bioenergy Market Adjusting Tariff programs, PG&E's PV Program, and the Renewable Auction Mechanism (RAM) Program. The RAM Program also includes resource procurement to meet certain of the State's bioenergy requirements. PG&E's contracted RPS-eligible generation includes procurement for customers participating in the Green Tariff Shared Renewables (GTSR) Program and tree mortality-related procurement directed by Res.E-4770 and Res.E-4805.[2]

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[2] In D.15-01-051, the Commission approved with modifications PG&E's GTSR Program and ordered the investor-owned utilities (IOU) to summarize and true-up costs and revenues against charges and credits applied to GTSR customers on an annual basis, either through the annual Energy Resource Recovery Account (ERRA) process or in a separate application. See D.15-01-051, Conclusion of Law 59. Subsequently, to implement the GTSR Program, PG&E submitted Advice 4639-E and Advice 4639-E-A, which were approved by the Commission on November 13, 2015.

b. Non-Combined Heat and Power Fossil Contracts

PG&E has entered into several natural gas tolling agreements that will provide power in 2021. The non-Combined Heat and Power (CHP) fossil generation technology mix includes CC generation and Combustion Turbine (CT).

c. CHP Contracts

PG&E has several CHP PPAs that will provide power in 2021. Most of these contracts convert former must-take CHP QFs to utility pre-scheduled facilities, pursuant to the Qualifying Facility and Combined Heat and Power Settlement. The CHP PPAs include Assembly Bill (AB) 1613 PPAs.

d. Large Hydro

Since 2002, PG&E has entered into new PPAs with various irrigation districts. Typically, these contracts include both large and small-hydro resources. The associated small-hydro energy and capacity positions are grouped with the Post-2002 RPS resources.

e. Energy Storage

Pursuant to AB 2514 became law in 2010, and in D.13-10-040 the Commission established energy storage MW procurement targets for IOUs from 2014-2020. Under D.13-10-040, PG&E is obligated to procure 580 MW of energy storage by 2020. PG&E issued its first energy storage RFO in December 2014 and its second energy storage RFO in December 2016. In 2018, PG&E issued a Local Sub-Area Energy Storage RFO to meet local sub area reliability needs as required by CPUC Res.E-4909. As a result of these various solicitations, PG&E has signed five storage contracts, three of which are expected to begin operating in 2021

The Integrated Resource Plan (IRP) procurement authorized in D.19-11-016 mandates that PG&E acquire 716.9 MW of system RA by 2023 for the bundled portfolio, with a minimum of 50 percent of the mandated amount (358 MW) be installed by August 2021. For purposes of this forecast, PG&E has assumed that it would procure up to the minimum amount (358 MW) and that all of the capacity would come

from battery storage. Under the same program, PG&E is required to procure capacity for LSEs who have chosen to optout of procuring for themselves. To that end, PG&E has included an additional 24 MW of battery storage to the forecast.[3]

f. Market Energy

In 2021, PG&E will incur costs from procuring CAISO market energy products, including energy and ancillary services, needed to serve its bundled customer load.

g. Residual Capacity Transactions

In 2021, PG&E anticipates making purchases of capacity when needed in addition to that provided by the current resource mix to fill short-term gaps between capacity supply and demand. PG&E also anticipates making sales of capacity to manage excess supply.

C. Energy Procurement Costs

The forecasted gross electric procurement costs are summarized in Table 3-3. For PG&E UOG resources, fuel costs (natural gas, nuclear fuel, distillate, and water-for-power), interstate gas transportation costs, and direct greenhouse gas allowance costs are included in the procurement cost forecast. For contracted resources, the costs included are determined by the specific contractual arrangements and expected grid management charge costs from the CAISO where applicable.

Forecasting portfolio costs typically involves pairing forecasted energy and capacity amounts with contractual and/or market prices. In the case of dispatchable resources, the level of generation itself depends on anticipated market conditions. A description of the analytical approach PG&E uses to forecast dispatchable generation is in Section D below.

D. Market Prices and Economic Dispatch Modeling

To forecast certain generation costs as well as the CAISO market energy supply cost for bundled customer load, PG&E uses forecasted spot prices for

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[3] The 358 MW and 24 MW assumptions were developed prior to PG&E's submission of Advice 5826-E on May 18, 2020 requesting approval of five new storage contracts, totaling 423 MW of new storage capacity. PG&E will update the IRP procurement quantities to reflect the recent commercial activity in the November Update.

energy, adjusted for Locational Marginal Price differences at different locations, and natural gas prices to simulate the economic dispatch of dispatchable resources using the PG&E-developed Procurement Portfolio Planner (P^3) model. P^3 is a Monte Carlo simulation model developed specifically to provide an accurate representation of the bundled electric portfolio at PG&E. Quantities such as prices and generation are calculated using a stochastic model on an hourly time-scale. The use of such a simulation, with a large number of trials, allows one to investigate probabilistic distributions in addition to average values. All of the generation resources and loads in the bundled electric portfolio are modeled. The P^3 model also allows for comparisons and calibrations with historical data and can easily accommodate changes in the PG&E portfolio.

For this forecast, PG&E is using April 14, 2020 forward electricity and natural gas prices, which are summarized by month in Table 3-4.[4]

Other inputs needed to simulate the economic dispatch of resources include various unit characteristics, such as heat rates, minimum up and down times, variable operations and maintenance costs, and fuel transportation charges.[5] Since each resource has its own specific characteristics, each unit is uniquely modeled. These characteristics come from a variety of sources. In the case of contracted resources, sources include the contract operating conditions and pricing terms. Different models are used for different technologies. For example, a CT is modeled differently than a CC unit. The generation and fuel use of each unit has been compared to historical behavior, where possible, to ensure accurate modeling.

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4 The quote date for the natural gas and electricity forward prices is typically selected 45 days prior to filing PG&E's ERRA Forecast Application, which is based on a process adopted by the Commission in D.06-12-018, Ordering Paragraph 5. However, the single price quote used in 2021 ERRA Forecast was selected based on an earlier date due to the logistical challenges associated assembling this filing while COVID-19 safety measures were in place. On April 21, 2020, the CPUC's executive director granted PG&E's request for (1) additional time to file the ERRA Forecast Application, from June 1 to July 1; and (2) keeping the single day price quote tied to the original June 1, 2020 filing date.

5 For 2021, PG&E used gas transportation rates reflecting proposed rates filed in its 2020 General Rate Case (GRC) (Application 18-12-009). PG&E is currently awaiting a Proposed Decision in the 2020 GRC and expects that its 2020 GRC rates will be implemented before the end of 2020. PG&E expects to update forecasted gas transportation rates in the November Update.

The DCPP units are modeled consistent with their maintenance and refueling schedules and their historical outage and curtailment behavior.

The stochastic behavior of the hydroelectric system has also been modeled. The expected generation and pumping profiles for Helms are based on simulated economic dispatch based on the stochastically modeled hourly power prices described above. Both wind and solar generation are constrained to be consistent with the generation profiles provided in their contracts, adjusted based on recent actual average generation.

E. Conclusion

In this chapter, PG&E presents the expected energy and capacity from generation resources in PG&E's electric supply portfolio. PG&E also presents the expected gross cost of procurement that is addressed in this chapter.

TABLE 3-1
2021 CAPACITY BALANCE (MW)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Peak ERRA Load (MW)												
1	PG&E Bundled Peak load Forecast												
2	CPUC 2021 RA Compliance Requirement Adjustment												
3	Peak Coincidence												
4	Reserve Requirement												
5	CAM, DR and other Adjustments												
6	**Total ERRA Capacity Requirement**												
7	Capacity Supply (MW)												
8	Cost Allocation Mechanism (CAM)												
9	Utility-Owned Generation												
10	UOG Energy Storage												
11	Post-2002 Contracted Resources												
12	Other Bilateral Contracts												
13	Non-CHP Fossil												
14	CHP Fossil												
15	QF												
16	Energy Storage												
17	Power Charge Indifference Adjustment (PCIA)												
18	Utility-Owned Generation												
19	Nuclear												
20	Hydro												
21	Fossil												
22	Solar	6	5	27	23	24	47	59	41	21	3	3	0
23	Fuel Cell												

TABLE 3-1
2021 CAPACITY BALANCE (MW)
(CONTINUED)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
24	Pre-2002 Contracted Resources												
25	QF												
26	Post-2002 Contracted Resources												
27	RPS Eligible												
28	Post-2002 RPS Eligible	827	771	1,477	1,324	1,350	1,988	2,155	1,711	1,176	642	695	621
29	Future RPS Eligible												
30	Other Bilateral Contracts												
31	CHP Fossil												
32	Non-CHP Fossil												
33	Large Hydro												
34	Energy Storage												
35	Contracted RA Sales												
		0	0	0	0	0	0	0	0	0	0	0	0
36	Ongoing Competition Transition Charge (CTC)												
37	Pre-2002 Contracted Resources												
38	Irrigation Districts & Water Agencies												
39	MWD Etiwanda												
40	QF												
41	Puget Sound Power & Light (Receive)												
42	Modified Cost Allocation Mechanism (MCAM)												
43	Post-2002 Contracted Resources												
44	Other Bilateral Contracts												
45	Energy Storage	0	0	0	0	0	0	0	0	0	359	359	359

TABLE 3-1
2021 CAPACITY BALANCE (MW)
(CONTINUED)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
46	Energy Resource Recovery Account (ERRA)												
47	Utility-Owned Generation												
48	UOG Energy Storage												
49	UOG Solar	0	0	0	0	0	0	0	0	0	0	0	0
50	Post-2002 Contracted Resources												
51	Contracted RA Purchases												
52	GTSR	2	1	9	7	8	15	18	13	7	1	1	0
53	Outages												
54	Total Net Supply												
55	**Net Long / (Short)**												

Note: Totals may not add due to rounding.

TABLE 3-2
2021 ENERGY REQUIREMENTS
(GWh)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	ERRA Energy Load (GWh)													
2	Retail Sales													
3	Direct Access and CCA	3,818	3,495	3,589	3,531	3,685	3,917	4,229	4,328	4,033	3,840	3,800	3,989	46,255
4	UFE, Transmission & Distribution Losses													(2,897)
5	**Total ERRA Load Requirement**													**(34,919)**
6	Energy Supply (GWh)													
7	Cost Allocation Mechanism (CAM)													
8	Utility-Owned Generation													
9	Energy Storage													
10	Post-2002 Contracted Resources													
11	Other Bilateral Contracts													
12	Fossil Contracts - Non-CHP													
13	Fossil Contracts - CHP													
14	Energy Storage													
15	QF													
16	Power Charge Indifference Adjustment (PCIA)													
17	Utility-Owned Generation													
18	Nuclear													
19	Hydro													
20	Fossil													
21	Solar	12	20	29	32	36	35	35	33	29	26	18	16	321
22	Fuel Cell	2	2	2	2	2	2	2	2	2	2	2	2	21
23	Energy Storage													
24	Pre-2003 Contracted Resources													
25	QF													
26	Post-2002 Contracted Resources													
27	RPS Eligible													
28	RPS-Eligible Contracts	972	1,108	1,439	1,560	1,802	1,851	1,819	1,737	1,519	1,321	1,050	983	17,162
29	RPS-Eligible Contracts - Sales	0	0	0	(300)	0	0	0	0	0	0	0	0	(300)
30	RPS-Eligible Future Contracts	2	2	4	5	5	6	6	6	5	4	4	6	55
31	RPS-Eligible Future Sales	(526)	(503)	(696)	(763)	(879)	(910)	(926)	(868)	(714)	(612)	(522)	(478)	(8,395)

TABLE 3-2
2021 ENERGY REQUIREMENTS
(GWh)
(CONTINUED)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
32	Other Bilateral Contracts													
33	Fossil Contracts - Non-CHP													
34	Fossil Contracts - CHP													
35	Large Hydro													
36	Non-RPS-Eligible Hydro Sales													
37	Energy Storage													
38	Ongoing Competition Transition Charge (CTC)													
39	Pre-2002 Contracted Resources													
40	Irrigation District & Water Agency													
41	MWD Etiwanda	4	3	2	2	2	3	6	6	5	4	6	5	49
42	Puget Sound Power & Light Contract (Net)													
43	QF													
44	Tree Mortality Non-Bypassable Charge (TMNBC)													
45	Post-2002 Contracted Resources													
46	RPS Eligible													
47	RPS-Eligible Contracts	47	47	44	45	40	39	50	52	51	52	42	49	556
48	RPS-Eligible Contracts - Sales	(27)	(30)	(33)	(26)	(21)	(20)	(30)	(32)	(32)	(32)	(28)	(29)	(339)
49	RPS-Eligible Future Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0
50	RPS-Eligible Future Sales	(19)	(18)	(11)	(19)	(20)	(19)	(20)	(20)	(19)	(20)	(14)	(20)	(217)
51	Modified Cost Allocation Mechanism (MCAM)													
52	Post-2002 Contracted Resources													
53	Other Bilateral Contracts													
54	Energy Storage Future Contracts													
55	Energy Resource Recovery Account (ERRA)													
56	Post-2002 Contracted Resources													
57	Other Bilateral Contracts													
58	QF													
59	Energy Storage													
60	Utility-Owned Generation													
61	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0
62	Energy Storage													
63	**Total Supply**													

Note: Totals may not add due to rounding.

TABLE 3-3
2021 PROCUREMENT COSTS
(THOUSANDS OF DOLLARS)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	Energy Supply / Demand Procurement Costs													
2	Cost Allocation Mechanism (CAM)													
3	Utility-Owned Generation													
4	Energy Storage													
5	Post-2002 Contracted Resources													
6	Other Bilateral Contracts													
7	Fossil Contracts - Non-CHP													
8	Fossil Contracts - CHP													
9	Energy Storage													
10	QF													
11	Power Charge Indifference Adjustment (PCIA)													
12	Utility-Owned Generation													
13	Nuclear													
14	Hydro													
15	Fossil													
16	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Fuel Cell													
18	Energy Storage													
19	Pre-2003 Contracted Resources													
20	QF													
21	Post-2002 Contracted Resources													
22	RPS Eligible													
23	RPS-Eligible Contracts													
24	RPS-Eligible Contracts - Sales													
25	RPS-Eligible Future Contracts													
26	RPS-Eligible Future Sales													
27	Other Bilateral Contracts													
28	Fossil Contracts - Non-CHP													
29	Fossil Contracts - CHP													
30	Large Hydro													
31	Energy Storage													
32	RA Contracts													
33	RA Contracts - Sales													
34	Non-RPS-Eligible Hydro Sale													
35	Residual Capacity Sales													
36	CAISO Costs (GMCs)													

TABLE 3-3
2021 PROCUREMENT COSTS
(THOUSANDS OF DOLLARS)
(CONTINUED)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
37	Ongoing Competition Transition Charge (CTC)													
38	Pre-2002 Contracted Resources													
39	Irrigation District & Water Agency													
40	MWD Etiwanda													
41	Puget Sound Power & Light Contract (Net)													
42	QF													
43	CAISO Costs (GMCs)													
44	Tree Mortality Non-Bypassable Charge (TMNBC)													
45	Post-2002 Contracted Resources													
46	RPS Eligible													
47	RPS-Eligible Contracts													
48	RPS-Eligible Contracts - Sales													
49	RPS-Eligible Future Contracts													
50	RPS-Eligible Future Sales													
51	RA Contracts - Sales													
52	CAISO Costs (GMCs)													
53	Modified Cost Allocation Mechanism (MCAM)													
54	Post-2002 Contracted Resources													
55	Other Bilateral Contracts													
56	Energy Storage Future Contracts													
57	Energy Resource Recovery Account (ERRA)													
58	Bundled Load Requirement													
59	Utility-Owned Generation													
60	Energy Storage													
61	Collateral Interest Expense	906	905	886	905	906	885	907	936	885	908	907	886	10,822
62	Hedging - Gas and Electric													
63	RA Contracts													
64	Residual Capacity Purchases													
65	CAISO Costs (Other Load + GMCs)													
66	**Total Supply**	**298,507**	**278,405**	**266,173**	**249,370**	**295,876**	**422,989**	**551,661**	**559,429**	**489,211**	**332,503**	**281,777**	**338,217**	**4,364,118**

Note: Totals may not add due to rounding.

TABLE 3-4
2021 FORWARD ELECTRIC PRICES ($/MWh) AND NATURAL GAS PRICES ($/MMBTU)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave.
1	Energy ($/MWh)													
2	On Peak	[redacted]												
3	Off Peak													
4	Natural Gas ($/MMBtu)													
5	Citygate	[redacted]												

Note: Forward Energy and Natural Gas Prices were derived from April 14, 2020 broker quotes.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

FUEL COSTS FOR UTILITY-OWNED GENERATION ASSETS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
FUEL COSTS FOR UTILITY-OWNED GENERATION ASSETS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
FUEL COSTS FOR UTILITY-OWNED GENERATION ASSETS

A. Introduction

The purpose of this chapter is to present Pacific Gas and Electric Company's (PG&E) 2021 forecast of fuel costs for its Utility-Owned Generation (UOG) assets, which include: fossil fuel, nuclear, hydroelectric, fuel cell, and battery storage facilities. The fuel costs, which reflect generation fuel, transportation and inventory costs, as well as fees, taxes and other expenses, including direct greenhouse gas (GHG) compliance costs, are described in more detail in the remainder of this chapter, and are summarized in Table 4-3.

B. Fuel Costs for PG&E's Fossil Fuel Facilities

In this section, PG&E describes its fuel cost forecast for its Utility-Owned Fossil Generation Program for January 1 through December 31, 2021.

1. Humboldt Bay Generating Station

The Humboldt Bay Generating Station (HBGS) started operation in September 2010. It consists of 10 reciprocating engines, using natural gas (NG) as their primary fuel source, with a small amount of distillate oil as a pilot fuel. The reciprocating engines are dual-fuel capable—meaning they can operate on either NG or distillate. PG&E maintains an adequate inventory of distillate onsite in case of NG delivery limitations to the Humboldt area.

2. Gateway Generating Station

The Gateway Generating Station (GGS) is a NG-fueled Combined Cycle (CC) power plant located east of the city of Antioch in Contra Costa County. The plant started commercial operation in January 2009. The plant is comprised of two Combustion Turbines (CT) whose exhaust heat is used to produce steam for a Steam Turbine (ST). The plant uses a dry cooling system for condensing the ST exhaust.

3. Colusa Generating Station

The Colusa Generating Station (CGS) is a NG-fueled, dry-cooled CC power plant in Colusa County, California. The plant started commercial

operations in December 2010. The plant is comprised of two CTs whose exhaust heat is used to produce steam for a ST. The plant uses a dry cooling system for condensing the ST exhaust.

4. 2021 Fossil Fuel Cost Forecast

Table 4-1 shows PG&E's 2021 forecast for fossil fuel expenditures, which are based on forecast generation, heat rates, and fuel costs. The forecasted generation quantities in megawatt-hours for HBGS are modeled considering regional reliability requirements. The plant may also generate above the minimum reliability requirements, if warranted by economics. Forecasted generation for GGS and CGS is based on economic dispatch of these resources.

The resulting forecasted fossil fuel generation is presented in Chapter 3, Table 3-2.

The cost of NG for HBGS, CGS, and GGS is based on the forecasted generation, plant heat rates and burner-tip price of NG. The burner-tip NG fuel price forecast is based on the PG&E Citygate price presented in Chapter 3, Table 3-4, plus a fixed transportation cost.

PG&E has a direct GHG compliance obligation to the California Air Resources Board for GHG emissions from burning NG at facilities in its portfolio. PG&E forecasts direct GHG emissions costs of its UOG facilities based on multiplying: (1) the forecast of Millions of British Thermal Units (MMBtu) of NG expected to be consumed by UOG facilities during 2021 multiplied by the emission factor of 0.05307 metric tons of carbon dioxide equivalents per MMBtu to forecast GHG emissions; and (2) PG&E's GHG allowance price forecast.[1]

The generation and price assumptions in Chapter 3 yield the following fuel costs forecast for utility-owned fossil generation, presented in Table 4-1.

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[1] For the purpose of forecasting PG&E's direct GHG compliance costs, PG&E's considers the weighted-average cost (WAC) of GHG compliance instruments held in its inventory. The WAC of GHG compliance instruments is discussed in detail in Chapter 15.

TABLE 4-1
SUMMARY OF 2021 FOSSIL FUEL EXPENSE FORECAST
(THOUSANDS OF DOLLARS)

Line No.	Description	2021
1	Natural Gas	[redacted]
2	Distillate	
3	Interstate Transport Costs	
4	GHG Costs	
5	Total Requirement	

Note: Totals may not add due to rounding.

C. Fuel Costs for PG&E's Nuclear Facility

In this section, PG&E describes its nuclear fuel cost forecast for Diablo Canyon Power Plant (DCPP) for January 1 through December 31, 2021.

1. Diablo Canyon Nuclear Facility

DCPP consists of two pressurized water reactors, Units 1 and 2, which began operation in 1984 and 1985, respectively.

2. Nuclear Fuel Generation Forecast for 2021

The nuclear fuel cost forecast includes the amortization of the in-core fuel inventory and fuel engineering expenses associated with the analysis of in-core fuel. These costs are based on contracted purchases of nuclear materials consistent with the strategy approved by the California Public Utilities Commission in PG&E's 2014 Bundled Procurement Plan, Appendix F. The forecast of these nuclear fuel costs is included in Table 4-2.

The forecast fuel amortization is based on the costs of the in-core fuel and the projected cycle burn-up for each reload. Each fuel reload includes the costs of uranium, conversion services, enrichment services, fabrication, and state use taxes, with the total costs dependent on the specific core design. The amortization rate is based on projected fuel energy usage for each cycle, divided by the lifetime design output expected from each reload region over a 2-cycle period. The cycle amortization is allocated to the months based on the planned monthly generation.

The expense item labelled, "Miscellaneous Engineering Expenses and Fuelco," includes the 2021 engineering expense associated with analysis of in-core fuel. Fuelco LLC is a limited liability company under the laws of the state of Delaware. The purpose of Fuelco LLC is to assist its utility members with purchasing nuclear fuel and related services in an efficient and cost-effective manner. The members agreed to share out-of-pocket administrative expenses equally. PG&E and Ameren Missouri are the two member utilities in Fuelco LLC.

The carrying cost is calculated based on the average monthly nuclear fuel inventory balance for in-reactor and out-of-reactor in-process fuel, multiplied by the 3-month commercial paper rate. The total 2021 nuclear fuel inventory carrying cost forecast is included in Table 4-2.

TABLE 4-2
2021 NUCLEAR FUEL EXPENSE FORECAST
(THOUSANDS OF DOLLARS)

Line No.	Description	2021
1	Amortization (Burn-Up) Expense	[redacted]
2	Department of Energy Spent Fuel Fee	
3	Miscellaneous Engineering Expenses and Fuelco	
4	Nuclear Fuel Inventory Carrying Costs	
5	Total Requirement	

Note: Totals may not add due to rounding.

D. Water Costs for PG&E's Hydroelectric Facilities

This section summarizes the water costs for PG&E's hydroelectric facilities for January 1 through December 31, 2021.

The forecast generation by PG&E-owned hydroelectric facilities is discussed in Chapter 3, Section B. PG&E makes payments to various entities for water used in these hydroelectric plants, headwater improvements by others, and water rights fees to the State Water Resources Control Board. The water rights fees are based on acre-feet of storage or the theoretical annual maximum acre-feet that can be diverted depending on the type of license or permit.

Water for power costs are estimated by using historical costs and new or emerging developments for 2021. PG&E's 2021 water costs forecast is shown in Table 4-3 below.

E. Fuel Costs for PG&E's Fuel Cell Project

The fuel cell project comprises three fuel cell electric generating facilities with a combined 3.0 megawatts (MW) of capacity, described in Chapter 3, Section B. The forecast of the NG fuel for the fuel cell project is based on an 80 percent capacity factor operation. The fuel cell project's fuel cost forecast is shown in Table 4-3 below.

F. Net Charging Costs for PG&E's Energy Storage Pilot Projects

Table 4-3 includes the net cost forecast for energy from the Vaca-Dixon and Yerba Buena Battery Storage Projects, described in Chapter 3, Section B.

G. Charging Costs for PG&E's Moss Landing Energy Storage Project

Table 4-3 also includes the energy storage charging cost forecast for PG&E's 182.5 MW Moss Landing Energy Storage project, described in Chapter 3, Section 1f.

H. Conclusion

This chapter presents PG&E's forecasted 2021 UOG fuel costs, as summarized by cost recovery mechanism in Table 4-3 below. These costs are reflected in their respective revenue requirements presented in Chapters 9, 12, and 8.

TABLE 4-3
SUMMARY OF 2021 UOG FUEL COST FORECAST
(THOUSANDS OF DOLLARS)

Line No.	Description	2021
1	PCIA	[redacted]
2	Fossil Fuel	
3	Nuclear Fuel	
4	Water Costs	
5	Fuel Cell Fuel	
6	ERRA	
7	Energy Storage Charging	
8	CAM	
9	Energy Storage Charging	
10	Total Requirement	

Note: Totals may not add due to rounding.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

QUALIFYING FACILITY AND

OTHER LEGACY PURCHASED POWER AGREEMENT COSTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
QUALIFYING FACILITY AND
OTHER LEGACY PURCHASED POWER AGREEMENT COSTS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
QUALIFYING FACILITY AND
OTHER LEGACY PURCHASED POWER AGREEMENT COSTS

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E) 2021 forecast costs of power procured under Qualifying Facility (QF) and other legacy Power Purchase Agreements (PPA) in effect as of December 20, 1995. Other legacy PPAs include those with Irrigation Districts and Water Agencies (IDWA), and with the Metropolitan Water District (MWD). This chapter also includes forecast QF costs under certain *pro forma* PPAs, established under the Qualifying Facility and Combined Heat and Power Program Settlement (QF/CHP Settlement), which became effective on November 23, 2011.[1]

The forecasts of QF and other legacy PPA costs set forth in this chapter are included in the 2021 Cost Allocation Mechanism (CAM), Ongoing Competition Transition Charge (Ongoing CTC), Power Charge Indifference Adjustment (PCIA), and the Energy Resource Recovery Account (ERRA) forecast revenue requirements described in Chapters 8, 9, and 12. These forecast costs are summarized in Table 5-1 below.

B. Qualifying Facilities

PG&E's QF forecast reflects the QF/CHP Settlement, approved by the California Public Utilities Commission (Commission) in Decision (D.) 10-12-035.[2] The QF/CHP Settlement modified Short-Run Avoided Cost (SRAC) energy pricing for QFs. The QF/CHP Settlement also included *pro forma* PPAs to be executed by eligible QFs whose PPAs expire, and permitted optional one-time changes to PPA energy pricing under *pro forma* amendments for legacy QFs. Below, PG&E describes its QF generation and cost forecasting assumptions.

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1 Other bilaterally-negotiated CHP PPAs associated with the QF/CHP Settlement are included in Chapter 6, "Procurement Costs: Post-2002 Contracted Resources."

2 PG&E's Chapter 5 forecast excludes any new QF standard offer contracts authorized under D.20-05-006, issued May 15, 2020, in the Public Utility Regulatory Policies Act (PURPA) Rulemaking 18-07-017. Any such new QF PPAs may be included in Chapter 6 if executed in time to be included in the November Update.

PG&E expects to update its QF generation and cost forecast in its November Update to reflect newly effective PPAs or other portfolio changes.

1. QF Generation Forecast

PG&E has PPAs with approximately 45 operating QFs. PG&E develops its QF generation forecast using historical, project-specific generation from each QF. PG&E generally uses actual energy deliveries from the three most recent calendar years to develop its generation forecast. Only QFs currently in operation are included in the forecast. QFs with terminated or expired contracts are excluded from the generation forecast, as are those QFs which have not operated for the past year. For hydroelectric generation (hydro) QFs, PG&E bases its projections on historical production, normalized for average water year conditions.

PG&E's 2021 QF forecast is based on the Procurement Portfolio Planner (P^3) model described in Section D of Chapter 3, "Generation Resource and Supply Cost Summary." Generation for QFs with contractual dispatch features is estimated using the P^3 economic dispatch model. PG&E expects to purchase the 2021 QF megawatt-hours (MWh) shown in Table 5-1.

2. QF/CHP Settlement PPAs

As mentioned above, the QF/CHP Settlement includes form PPAs for eligible Combined Heat and Power (CHP) and non-CHP QFs. A PURPA PPA for up to a 7-year term for existing QFs is available for QFs 20 megawatts (MW) or smaller.[3] An "As-Available" PPA for up to a 7-year term is available for certain eligible CHP QFs delivering less than 131,400 MWh annually.

As of April 2020, PG&E had eight executed PURPA and As-Available PPAs included in its 2021 forecast.[4]

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[3] The PURPA QF PPA is available for up to a 12-year term for new QFs 20 MW or smaller. PG&E has not executed any PURPA PPAs with new QFs as of April 2020.

[4] These include the non-standard bilaterally-negotiated Chevron Richmond As-Available PPA, approved June 27, 2014 in Resolution (Res.) E-4648. Two PPAs were recently approved by the Commission on May 28, 2020 in Res.E-5037. PG&E expects to submit an Advice Letter (AL) seeking Commission approval for three PURPA PPAs prior to the November Update.

3. Expiring QF Contracts

PG&E assumes continued deliveries at 100 percent of historical levels for expiring non-renewable QFs, under new PURPA contracts available from the QF/CHP Settlement. One such QF is included in the 2021 forecast.

4. Non-CTC-Eligible QF Contracts

QF contracts may be ineligible for Ongoing CTC recovery because, either the contract originated after December 20, 1995—making it ineligible under Public Utilities Code Section 367—or the contract was re-negotiated in a manner that makes it ineligible for Ongoing CTC recovery under Section 367(a)(2).

PG&E no longer has any legacy QF contracts ineligible for Ongoing CTC recovery in its forecast portfolio.

PG&E excludes costs for all QF/CHP Settlement contracts from its Ongoing CTC calculation. Costs for QF/CHP contracts with non-renewable QFs are included under the CAM calculation, as discussed in detail in Chapter 8. Costs for PURPA contracts with renewable QFs are not CAM-eligible, but are included in the PCIA calculation described in Chapter 9.

5. QF Payment Forecast

After completing its QF generation forecast, PG&E prepares its QF payment forecast using contract-specific pricing information. PG&E develops both energy and capacity payment forecasts. These PPA-related payments exclude any gas-hedging-related costs associated with QF energy price variability. Gas-hedging-related costs are discussed in Chapter 7.

a. QF Energy Payments

PG&E calculates QF energy payments by applying hourly energy prices to projected QF generation using the P[3] model. The energy payment forecast categorizes QF projects by energy pricing terms.

Approximately 80 percent of the QFs selling to PG&E, including new *pro forma* QF/CHP PPAs, receive SRAC energy payments under terms of the QF/CHP Settlement.[5] SRAC energy pricing applies to over

[5] QFs receiving SRAC energy payments include the QFs signing *pro forma* "Legacy QF amendments" under the QF/CHP Settlement.

95 percent of PG&E's forecasted 2021 QF energy deliveries. PG&E uses its stochastic forecast of California border natural gas prices derived from April 14, 2020 broker quotes to forecast SRAC energy pricing, consistent with the market prices described in Chapter 3, Section D.

During 2006, PG&E entered into Settlement Agreements and amendments with 123 QFs.[6] Approximately five of these amendments continue in effect during 2021. Under these amendments, QFs receive variable energy prices, derived using a heat rate and burnertip gas price and a variable operations and maintenance (O&M) adder. To forecast these variable energy prices, PG&E uses a stochastic forecast of natural gas burnertip prices, derived from April 14, 2020 broker quotes, consistent with the market prices described in Chapter 3, Section D.

b. QF Capacity Payments

PG&E forecasts QF capacity payments using PPA-specific capacity price terms and contract capacity amounts. QF as-available capacity payments are projected using applicable as-available capacity prices and the forecast QF energy deliveries described above. QF firm capacity payments are based on current PPA-specific parameters.

QF/CHP Settlement PPAs include capacity values originally adopted in D.07-09-040.

c. Total QF Payment Forecast

Based on these assumptions, PG&E's total 2021 forecast payments to QFs for energy and capacity costs are shown in Table 5-1. Table 5-1 also indicates the QF payments eligible for Ongoing CTC and CAM recovery.

This forecast is subject to uncertainty for several reasons. First, QF production levels vary from month-to-month, as well as from year-to-year. These variations are tied to specific operational or economic decisions made by QFs. Production variations may also depend on scheduled maintenance and forced outages that vary each

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6 These amendments were approved in Commission D.06-07-032, and via approval of PG&E's AL 2987-E.

year. Moreover, QF technologies, such as wind and hydro, have delivery patterns which vary based on weather conditions. Finally, a majority of QFs receive SRAC, or other approved energy prices, tied to monthly California natural gas price indices, which are subject to gas market price variability.

C. Other Legacy PPAs in Effect as of December 20, 1995

1. IDWA (Ongoing CTC-Eligible)

PG&E has one remaining long-term hydro partnership contract with Solano Irrigation District (SID). Table 5-1 presents PG&E's projected 2021 costs for this hydro partnership contract. PG&E forecasts irrigation district contract costs based on existing contract provisions. Beginning in 2020, SID receives energy payments in lieu of bond or debt service payments. O&M payments are based on historic expenditures and projected budgets, which consider scheduled maintenance, overhauls, etc. Miscellaneous payments are based on fixed payment schedules or unit prices established in the contracts and contract amendments, and consider historic expenditures, energy production, and water-year conditions.

2. Other PPAs (Ongoing CTC-Eligible)

PG&E also has an Ongoing CTC-eligible PPA with the MWD. Table 5-1 presents PG&E's forecast 2021 costs for the MWD contract. This forecast is based on contract provisions, projected monthly generation provided by the MWD, and natural gas price forecasts derived from April 14, 2020 broker quotes.

D. Conclusion

This chapter presents PG&E's forecasts of QF and other legacy PPA costs, as summarized in Table 5-1 below. These costs are reflected in the 2021 CAM, Ongoing CTC, PCIA and ERRA forecast revenue requirements presented in Chapters 8, 9, and 12.

TABLE 5-1
SUMMARY OF 2021 MONTHLY PURCHASED POWER COST FORECAST FOR QF AND OTHER LEGACY PPAS

Line No.	Purchased Power Cost Element	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total-21
1	Qualifying Facilities													
2	Ongoing CTC-Eligible													
3	Generation, MWh													
4	Energy & Capacity, ($000s)													
5	CHP CAM-Eligible													
6	Generation, MWh													
7	Energy & Capacity, ($000s)													
8	Other													
9	Generation, MWh													
10	Energy & Capacity, ($000s)													
11	Total													
12	Generation, MWh													
13	Energy & Capacity, ($000s)													
14	Irrigation Districts and Water Agencies													
15	Ongoing CTC-Eligible													
16	Generation, MWh													
17	Total Payments, ($000s)													
18	Metropolitan Water District													
19	Ongoing CTC-Eligible													
20	Generation, MWh	3,691	3,343	2,417	1,955	1,888	3,336	5,991	6,356	5,277	4,451	5,572	5,185	49,462
21	Total Payments, ($000s)													
22	TOTAL QF and Legacy PPAs													
23	Total Generation, MWh													
24	Total Payments, ($000s)													
25	Ongoing CTC-Eligible (a)													
26	Total Generation, MWh													
27	Total Payments, ($000s)													

Notes:
(a) Line 26 MWh sums lines 3, 16 and 20. Line 27 $000 sums lines 4, 17 and 21.
Totals may not add due to rounding.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

PROCUREMENT COSTS: POST-2002 CONTRACTED RESOURCES

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
PROCUREMENT COSTS: POST-2002 CONTRACTED RESOURCES

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
PROCUREMENT COSTS: POST-2002 CONTRACTED RESOURCES

A. Introduction

This chapter discusses Pacific Gas and Electric Company's (PG&E) 2021 procurement cost forecast for resources contracted after 2002. Table 6-1 summarizes procurement costs discussed in this chapter.

B. Post-2002 Contracted Resources

1. Renewables Portfolio Standard-Eligible Contracts

a. RPS Procurement Mechanisms

Starting in 2003, PG&E initiated a series of solicitations for the purpose of securing, as well as selling, Renewables Portfolio Standard (RPS) generation. In addition, PG&E has executed RPS-eligible contracts through various California Public Utilities Commission (CPUC)-approved programs and bilateral negotiations. As discussed in Chapter 3, PG&E's contracted RPS generation includes procurement for customers participating in the Green Tariff Shared Renewables Program. RPS procurement costs discussed in this section are attributable to contracts executed pursuant to the following procurement mechanisms:

- RPS Request for Offers (RFO) solicitations from 2003-2019;
- RFO solicitations for the Power Purchase Agreement (PPA) portion of PG&E's Photovoltaic Program;
- The Renewable Auction Mechanism Program including bioenergy procurement, pursuant to CPUC Resolution (Res.) E-4770;
- Standard tariffs offered pursuant to Assembly Bill 1969;
- Standard tariffs offered pursuant to Senate Bill (SB) 32;
- Standard tariffs offered pursuant to SB 1122; and
- Bilateral negotiations.

PG&E has executed numerous contracts that are expected to provide RPS-eligible energy in 2021. Table 6-1 shows the procurement costs forecast for RPS contracts.

b. RPS Contract Sales

Starting in PG&E's 2016 RPS Plan, PG&E established annual RPS sale solicitation protocols and held at least one RPS sale solicitation in each year beginning in 2017. PG&E has executed an RPS sale contract for deliveries in 2021 and anticipates additional contracts with 2021 deliveries to be executed during 2020 through PG&E's 2020 RPS sale solicitation(s). Executed contracts are forecasted using their respective contract prices while expected sales are based on the Power Charge Indifference Adjustment (PCIA) RPS adder. Table 6-1 shows the procurement costs (revenues) forecast for RPS sale contracts.

2. Conventional Resources

a. Non-Combined Heat and Power Fossil Contracts

The Non-Combined Heat and Power (CHP) fossil facilities that are expected to provide energy and capacity to PG&E in 2021 are as follows:

Combined Cycle Facilities

1. Calpine Los Esteros (repower)
2. MRP San Joaquin Tracy
3. Calpine Russell City

Combustion Turbines

1. Starwood Power-Midway
2. Panoche Energy Center
3. Calpine 3_Creed
4. Calpine 3_Gilroy12
5. Calpine 3_Gilroy3
6. Calpine 3_GooseHaven
7. Calpine 3_Lambie
8. Calpine 3_Riverview
9. Mariposa
10. Marsh Landing
11. MRP San Joaquin Hanford Facility
12. MRP San Joaquin Henrietta

Table 6-1 shows the total procurement costs forecast for the non-CHP fossil PPAs described above.

b. CHP Fossil Contracts

PG&E has executed PPAs for capacity and/or energy with CHP fossil generators pursuant to various RFO solicitations and bilateral negotiations. In most instances, these PPAs convert former must-take CHP Qualifying Facilities to utility pre-scheduled facilities. The CHP facilities expected to provide generation and/or capacity to PG&E in 2021 are as follows:

1. O.L.S. Energy-Agnews
2 Bear Mountain Limited
3 Badger Creek Limited
4 Live Oak Limited
5. McKittrick Limited
6. Chalk Cliff Limited
7. Tesoro Refining & Marketing Company, LLC
8 Chevron McKittrick CHP Plant

Table 6-1 shows the total procurement costs forecast for the fossil CHP PPAs described above

c. Large Hydro

In recent years, PG&E has signed PPAs with several Irrigation Districts and Water Agencies. Typically, these contracts cover generation units that were previously dedicated to PG&E under pre-2003 legacy agreements. The PPAs include generation from both small- and large-hydro facilities. The costs associated with the small-hydro generation facilities are accounted for in RPS-eligible procurement costs in Table 6-1. Also included is revenue from a single non-RPS-eligible hydro sale contract. The procurement costs and revenue forecast for capacity and energy from large hydro facilities are shown in Table 6-1, in the large hydro category.

d. Energy Storage

PG&E issued its first energy storage RFO in December 2014 and its second energy storage RFO in December 2016. In 2018, PG&E

issued a Local Sub-Area Energy Storage RFO to meet local sub area reliability needs as required by Res. E-4909.

Pursuant to Decision 19-11-016, PG&E anticipates meeting a portion of its Resource Adequacy (RA) requirement with energy storage resources as mandated in the Integrated Resource Planning proceeding, R.16-02-007/R.20-05-003. PG&E has included two positions, reflecting 50 percent of its bundled and opt-out (or backstop) procurement requirements consistent with required 2021 on-line dates and procurement requirements

The forecasted procurement costs associated with energy storage resources expected to be operational in 2021 are shown in Table 6-1, in the energy storage category.

e. Resource Adequacy Capacity Contracts – Executed

Pursuant to various procurement processes set forth in PG&E's Bundled Procurement Plan, PG&E executes contracts to purchase or sell capacity for months when the capacity supply is forecast to be less than or greater than the requirement. Given PG&E's forecasted excess supply position, the 2021 forecast includes a significant number of capacity sale contracts. There is no energy associated with these contracts. The procurement costs and revenues forecast for executed RA capacity contracts are based on the respective contract prices and shown in Table 6-1.

f. Residual Peaking Capacity Transactions

The capacity ratings for the various utility-owned and contracted resources are consistent with California Independent System Operator and RA capacity counting rules. The total supply is based on these ratings less reductions for planned outages. For those months where the supply is greater than the requirement (i.e., a physical long position), PG&E forecasts selling capacity. For those months when the supply is less than the requirement (i.e., a physical short position), PG&E forecasts purchasing additional capacity. The estimated net purchase costs and sales revenues associated with these residual capacity transactions are based on the PCIA RA adder and shown in Table 6-1.

C. Conclusion

In this chapter, PG&E presents the 2021 cost forecasts associated with post-2002 contracted resources. The costs, summarized in Table 6-1 by cost recovery mechanism, are reflected in the revenue requirements forecast presented in Chapter 18.

TABLE 6-1
PROCUREMENT COSTS: 2021 POST-2002 CONTRACTED RESOURCES
(THOUSANDS OF DOLLARS)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	Energy Supply / Demand Procurement Costs ($)													
2	Cost Allocation Mechanism (CAM)													
3	Post-2002 Contracted Resources													
4	Other Bilateral Contracts													
5	Fossil Contracts - Non-CHP													
6	Fossil Contracts - CHP													
7	Energy Storage													
8	**Subtotal (CAM)**													
9	Power Charge Indifference Adjustment (PCIA)													
10	Post-2002 Contracted Resources													
11	RPS Eligible													
12	RPS-Eligible Contracts													
13	RPS-Eligible Contracts - Sales													
14	RPS-Eligible Future Contracts													
15	RPS-Eligible Future Sales													
16	Other Bilateral Contracts													
17	Fossil Contracts - Non-CHP													
18	Fossil Contracts - CHP													
19	Large Hydro													
20	Non-RPS-Eligible Hydro Sales													
21	Energy Storage													
22	RA Contracts													
23	RA Contracts - Sales													
24	Residual Capacity Sales													
25	**Subtotal (PCIA)**													
26	Tree Mortality Non-Bypassable Charge (TMNBC)													
27	Post-2002 Contracted Resources													
28	RPS Eligible													
29	RPS-Eligible Contracts													
30	RPS-Eligible Contracts - Sales													
31	RPS-Eligible Future Contracts													
32	RPS-Eligible Future Sales													
33	RA Contracts - Sales													
34	**Subtotal (TMNBC)**													
35	Modified Cost Allocation Mechanism (MCAM)													
36	Post-2002 Contracted Resources													
37	Other Bilateral Contracts													
38	Energy Storage Future Contracts													
39	**Subtotal (MCAM)**													
40	Energy Resource Recovery Account (ERRA)													
41	RA Contracts													
42	Residual Capacity Purchases													
43	**Subtotal (ERRA)**													
44	**Total Supply**													

Note: Totals may not add due to rounding.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

HEDGING, COLLATERAL, CAISO AND OTHER COSTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
HEDGING, COLLATERAL, CAISO AND
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
HEDGING, COLLATERAL, CAISO AND OTHER COSTS

A. Introduction

The purpose of this chapter is to present Pacific Gas and Electric Company's (PG&E) 2021 forecast costs of electric portfolio hedge transactions, collateral costs, California Independent System Operator's (CAISO) costs, and other procurement costs.

B. Electric Portfolio Hedge Transactions Costs

This section presents the cost forecast associated with hedging the electric and gas price exposure in PG&E's electric portfolio. This includes the cost of hedging the residual bundled electric open position, the gas price exposure from Combined Heat and Power (CHP) contracts, Qualifying Facilities receiving short-run avoided cost or variable energy pricing from the Independent Energy Producers settlement,[1] the costs of greenhouse gas compliance, as well as the natural gas cost of PG&E's utility-owned and contracted generation resources.

Consistent with PG&E's implementation filing for the Power Charge Indifference Adjustment Order Instituting Rulemaking Phase 1 Decision,[2] any utility hedging costs and benefits are recorded in the Energy Resource Recovery Account balancing account for allocation only to bundled electric customers. Community Choice Aggregators and other departed load customers will not share in any costs or benefits of any future hedging transactions.

1. PG&E's Electric Portfolio Hedging Program

PG&E's Electric Portfolio Hedging Program is guided by Public Utilities Code Section 454.5, which requires the Investor-Owned Utilities (IOU) to develop procurement plans that address, among other things, measurement and management of commodity price risk. In addition, the California Public Utilities Commission (Commission) expressly approved such procurement plans in its generation procurement decisions—specifically,

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1 D.06-07-032.

2 PG&E's Advice Letter (AL) 5440-E.

Decision (D.) 02-10-062, D.02-12-074, D.03-12-062, D.04-01-050, D.04-12-048, D.12-01-033 and D.15-10-031.[3] In these decisions, the Commission has provided PG&E with the tools to manage the exposure of its portfolio to changes in gas and electricity prices. These tools include approved physical and financial products, approved procurement/trading processes, and approved markets.

In addition, in D.12-01-033, the Commission established a Customer Risk Tolerance (CRT) of 10 percent of each utility's system average rate as a benchmark to guide the utilities in managing the exposure of their portfolios to commodity price risk, and re-affirmed To-Expiration Value-at-Risk as the IOUs' portfolio risk measure for comparison with the CRT.[4]

PG&E's Electric Portfolio Hedging Plan (Hedging Plan) is a part of its Bundled Procurement Plan (BPP). The Commission approved PG&E's BPP, with modification, in D.15-10-031. On December 10, 2015, PG&E submitted its conformed BPP, in compliance with D.15-10-031.[5] PG&E provided several updates on implementation of its Hedging Plan: Advice Letter 5282-E on May 1, 2018; Advice Letter 5469-E on January 16, 2019; Advice Letter 5507-E on March 27, 2019; and Advice Letter 5704-E on December 2, 2019. PG&E's forecasted 2021 hedging transactions are consistent with its Hedging Plan and the temporary management described by PG&E in these advice letter updates.

PG&E's hedging forecast includes both electric and gas hedging costs. These estimates are based on market conditions as of April 14, 2020. The forecast assumes that hedge transactions executed after this date will be settled at the price executed. In other words, PG&E assumes the

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3 PG&E's current electric portfolio Hedging Plan is contained in its BPP, Appendix E, which was approved in D.15-10-031.

4 D.12-01-033 at p. 27.

5 PG&E's AL 4750-E was approved June 15, 2016.

mark-to-market (MtM)[6] of future hedging transactions to be zero.[7] The estimated costs, described in more detail below, are divided into two parts: (1) costs incurred at trade execution, and (2) costs incurred at trade settlement.

PG&E's projection of the net cost associated with the forecasted 2021 hedging transactions is presented in Table 7-1. The itemized forecast of these costs, as described in the following sections, is presented in Table 7-1. [redacted] PG&E's actual costs in 2021 will depend on its Hedging Plan implementation.

2. Costs Incurred at Trade Execution

The costs incurred at hedge trade execution are broken into two categories: New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE) clearing and broker fees, and option premiums.

PG&E executes a significant percentage of its hedging transactions through the NYMEX and ICE exchanges and clearing markets. Transactions cleared on either exchange incur small transaction fees. PG&E's projection of the fees that it will incur in 2021 is listed in Table 7-1, Line 2. [redacted] PG&E's actual costs for in 2021 will depend on its Hedging Plan implementation.

PG&E pays option premiums to its counterparties within several days following execution of an option transaction.[8] PG&E's use of options as

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6 MtM is a comparison of the market value of a transaction on a specified date with the market value of that transaction when it was executed.

7 The assumption that the MtM of a transaction at its execution is zero is a no arbitrage assumption. That is, if the MtM at execution were anything other than zero, it would represent an arbitrage opportunity for market participants, who would exploit that opportunity until the MtM reached equilibrium at zero.

8 Such a payment schedule for options is standard in financial and energy markets. Typically, the option seller provides a written confirmation within one day of the transaction. The option buyer then has two business days to pay the premium.

hedging instruments is discussed in detail in its Hedging Plan. [redacted] PG&E's actual cost for in 2021 will depend on its Hedging Plan implementation.

3. Costs Incurred at Trade Settlement

The costs (and benefits) anticipated from executed hedges at settlement are broken into two categories: (1) the current MtM of executed futures; and (2) the current market value of executed options. PG&E estimates their settlement value based on market conditions on April 14, 2020. Because [redacted], as shown in Table 7-1, Line 8. PG&E's actual cost for in 2021 will depend on its Hedging Plan implementation.

The estimated settlement value of futures contracts with future delivery periods is best represented by their MtM value. MtM is calculated by subtracting the current forward price for the contract from the transacted price for the contract and multiplying it by the transaction volume. This value is not discounted for time value. A positive MtM represents a cost and a negative MtM represents a benefit. PG&E's estimate of the MtM of all the futures from the hedging program with delivery periods in 2021 in PG&E's portfolio as of April 14, 2020, is listed on Line 6 in Table 7-1. The MtM value of the futures contracts with delivery periods in 2021 that have not been executed, but will be executed between April 14, 2020, and December 31, 2021, is zero.

The estimated settlement value of options with delivery periods in 2021 is best represented by the current market value of the options, which is the options' premium value on April 14, 2020. PG&E calculates option premiums using the Black 76[9] formula with current forward prices and

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9 Similar to the Black-Scholes option pricing formula, Black 1976 is a pricing formula for options on futures contracts and is appropriate for valuing options on futures and swaps. For a discussion of Black-Scholes, see Options, Futures and Other Derivatives, Sixth Edition, John C. Hull, Pearson Education, 2006, Chapter 13. For a discussion of Black 1976, see Energy and Power Risk Management, Alexander Eydeland and Kryzysztof Wolyniec, Wiley Finance, 2003, pp. 43-47.

volatilities. PG&E's estimate of the market value of executed options with delivery periods in 2021 is listed in Table 7-1, Line 7.

TABLE 7-1
2021 FORECAST OF NATURAL GAS AND ELECTRIC HEDGE TRANSACTION COSTS
(THOUSANDS OF DOLLARS)

Line No.			Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
1	**Costs Incurred at Trade Execution**														
2	Exchange and Broker Fees														
3	Option Premiums														
4	Total Costs Incurred at Trade Execution														
5	**Costs Incurred at Trade Settlement**														
6	Mark-to-market of Futures and Swaps on	April 14, 2020													
7	Market Value of Call Options/Swaptions on	April 14, 2020													
8	Total Costs Incurred at Trade Settlement														
9	**Net Gas and Electric Hedging Costs**														

C. Collateral Costs

PG&E separates its 2021 collateral and prepayment cost estimates into two parts: (1) costs incurred for posting letters of credit and cash, and (2) net interest (if any) paid to counterparties who post collateral with PG&E. This section does not cover financial planning and strategy, but rather describes the collateral costs based upon resources available to PG&E.

1. Collateral for Physical and Financial Transactions

Counterparties require PG&E to post collateral to cover market movements associated with fixed price forward gas and power transactions, accrued payable amounts for physical deliveries, and certain tolling agreements. Thus, PG&E would provide collateral to counterparties for the exposure amounts beyond the credit limit granted by individual counterparties.[10]

PG&E meets its transaction collateral requirements by using a combination of letters of credit and cash postings. In addition to annual fixed costs PG&E also pays the marginal cost for letters of credit. Upon emergence from bankruptcy, PG&E will have a new credit facility against which the aforementioned letters of credit will be posted. The forecasted annual cost for posting cash ranges from approximately 214 to 237 basis points. PG&E's estimate of the fees is shown in Table 7-2.

2. Net Interest Paid on Collateral Posted to PG&E by Its Counterparties

Similarly, PG&E requires its counterparties to post collateral to cover market movements associated with fixed price forward gas and power transactions, any accrued receivable amounts for physical deliveries, and certain other energy-related agreements. Thus, the counterparties would provide collateral for the exposure amounts beyond the credit limit granted by PG&E. In general, PG&E is required under its contracts to pay interest

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[10] The credit limit (also referred to as the collateral threshold) is extended to PG&E by the counterparty. Credit limits represent the amount of credit exposure (the amount of loss a counterparty would incur if PG&E failed to perform its contractual obligations) that a counterparty is willing to allow. Credit exposure includes the MtM calculations, payables and receivables balance, and any accruals, though actual loss will depend on how much a counterparty recovers in a bankruptcy proceeding. If the amount of the credit exposure exceeds the limit, then the counterparty may request that PG&E submit an acceptable form of collateral to cover the amount of exposure in excess of the limit.

on cash posted by its counterparties. PG&E uses cash collateral (if any) which it receives from counterparties as part of its operating funds to avoid borrowing on revolving credit facilities. The net cost (or benefit) equals the difference between the interest paid to counterparties and the revolving credit facilities interest rate. PG&E's estimate of the annual interest on collateral is shown in Table 7-2.

TABLE 7-2
SUMMARY OF 2021 FORECAST COLLATERAL COSTS
(THOUSANDS OF DOLLARS)

Line No.	Collateral Costs	Amount
1	Collateral on Physical and Financial Transactions	$11,008
2	Net Interest Paid on Collateral Posted to PG&E	(186)
3	Total	$10,822

D. CAISO and Other Costs

1. CAISO Generator and Load Costs

PG&E's forecast of costs and revenues from the CAISO in 2021 are based on a combination of volumetrically driven costs and costs that are extrapolated from historical remittances over the previous three years. Volumetrically driven costs include: (a) power purchases for PG&E's gross bundled load; (b) grid management charges for load and generators; (c) load ancillary service charges; and (d) load uplift charges. Extrapolated costs include: (a) Federal Energy Regulatory Commission fees; (b) unaccounted for energy; and (c) net real-time market costs. PG&E's forecast of net CAISO costs for load and generation for 2021 is shown in Table 7-3.

2. Interstate Gas Transportation Costs

Under several of the tolling agreements discussed in Chapter 6 and Utility-Owned Generation (UOG) generators discussed in Chapter 4, PG&E supplies natural gas fuel to the generator. Interstate gas transportation costs are incurred for delivery of the fuel to the generator's facility. Forecast fuel transportation costs for those contracts are included in the Non-CHP Fossil and CHP Fossil procurement costs shown in Table 6-1 and

UOG generators in Table 4-1. PG&E's forecast of interstate gas transportation costs for 2021 is shown in Table 7-3.

TABLE 7-3
2021 PROCUREMENT COSTS
(THOUSANDS OF DOLLARS)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	CAISO Costs													
2	Grid Management Charges													
3	CTC													
4	ERRA													
5	PCIA													
6	TMNBC													
7	Bundled Load Requirement (ERRA)													
8	Other Load (ERRA)													
9	Interstate Gas Transportation Costs													
10	Cost Allocation Mechanism (CAM)													
11	Post-2002 Contracted Resources													
12	Other Bilateral Contracts													
13	Fossil Contracts - Non-CHP													
14	Fossil Contracts - CHP													
15	Power Charge Indifference Adjustment (PCIA)													
16	Utility-Owned Generation													
17	Fossil													
	Fuel Cell													
18	Post-2002 Contracted Resources													
19	Other Bilateral Contracts													
20	Fossil Contracts - Non-CHP													
21	**Total Costs**													

Note: Totals may not add due to rounding.

E. Conclusion

In this chapter, PG&E forecasts electric and natural gas hedging transaction and collateral costs CAISO and other costs. These forecast costs are reflected in the forecast revenue requirements presented in Chapter 18.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

COST ALLOCATION MECHANISM

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
COST ALLOCATION MECHANISM

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
COST ALLOCATION MECHANISM

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E) 2021 procurement-related revenue requirements for the Cost Allocation Mechanism (CAM). The methods and calculations used in this chapter have been authorized by the California Public Utilities Commission and reflect similar methods and calculations to those used in PG&E's prior Energy Resource Recovery Account (ERRA) Forecast applications.

B. Cost Allocation Mechanism

The purpose of the CAM is to allocate certain costs and benefits, including Resource Adequacy (RA) benefits, among all load serving entities (LSE) in the Investor-Owned Utility's service territory. The LSE's customers receiving the RA benefit pay the net cost of this capacity, determined as a net of the total cost of the contract minus the energy and ancillary service revenues associated with dispatch of the contract.

The CAM charge was initially authorized in Decision (D.) 06-07-029. The method by which it was to be calculated was determined in D.07-09-044, which approved specific guidelines to be used to develop the CAM revenue requirement and resulting rate, and to provide for a true-up of this rate to actual costs. Subsequently, a CAM approach was adopted in D.10-12-035 for certain contracts arising from the Qualifying Facility and Combined Heat and Power Settlement (QF/CHP Settlement) approved in that decision and was first included in forecast year 2012. CAM treatment was also approved for the Marsh Landing Power Purchase Agreement (PPA) approved in D.10-07-045. Resolution (Res.) E-4949, issued November 9, 2018, approved CAM treatment for certain energy storage projects, including PG&E's Utility-Owned Generation (UOG) Moss Landing Energy Storage facility, finding that "Ongoing and future local reliability concerns warrant CAM treatment of this storage procurement."[1]

[1] Res.E-4949, Finding 16.

For the 2021 ERRA Forecast, the CAM includes CHP generation authorized under the QF/CHP Settlement,[2] the Marsh Landing PPA,[3] and energy storage PPAs approved pursuant to Res.E-4949, as well as the Moss Landing UOG facility approved therein.[4] Forecast costs related to the Marsh Landing and energy storage PPAs are presented in Chapter 6. Forecast costs related to actual and expected CHP contracts eligible for CAM recovery under the terms of the QF/CHP Settlement are presented in Chapters 5 and 6. Forecast energy charging costs for PG&E's Moss Landing Energy Storage facility are presented in Chapter 4, while the UOG revenue requirement for Moss Landing derives from that approved in Res.E-4949.

The CAM revenue requirement presented in this chapter adheres to the guidelines approved in D.07-09-044, which were included as Appendix A of that decision. Specifically, Appendix A included a "Joint Parties' Proposal" that articulated a calculation method to determine the market value of the resource.[5] The basic idea is that the cost of the resource minus the value of the energy and ancillary services results in a net capacity cost that is then allocated to all benefiting customers.

Generally, the method provides for developing a forecast of relevant contract costs, then determining the value that the contract resource's generation would have in the California Independent System Operator's (CAISO) day-ahead market. The differences between the cost and market value of the individual contracts are summed, and the total determines the net capacity costs that would be allocated to bundled and departed load customers.

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2 D.10-12-035.

3 D.10-07-045.

4 Res.E-4949 approved both the 182.5 megawatt (MW) Moss Landing UOG facility and a 300 MW energy storage PPA at Moss Landing.

5 D.14-02-040, Ordering Paragraph (OP) 3 eliminated the energy auction originally approved in D.07-09-044 as the primary mechanism to determine market revenues associated with reliability resources. OP 3 states:

> Energy auctions shall no longer be used to net capacity costs for facilities subject to the CAM. Instead PG&E, Southern California Edison Company and San Diego Gas & Electric Company shall use the mechanism adopted in D.07-09-044, known as the "Joint Parties' Proposal," to set the residual capacity costs that would be allocated to benefitting customers.

This forecast of the net capacity costs is then used to set the CAM rate, as discussed in Chapter 19. The forecast will be trued-up to actual costs by recording actual contract costs and the value of the generation based on the CAISO hourly day-ahead nodal price for the PPA's "injection point."

PG&E's calculation of the forecasted 2021 CAM revenue requirement of $181.4 million is detailed in Table 8-1.

TABLE 8-1
2021 CAM FORECAST REVENUE REQUIREMENT
(THOUSANDS OF DOLLARS

Line No.	Description	Cost
1	CAM-eligible Contract Costs – Table 5-1, Line 7	[redacted]
2	CAM-eligible Contract Costs – Table 6-1, Line 8	
3	CAM-eligible UOG Costs	
4	Total CAM-eligible Contract and UOG Costs	$237,539
5	CAISO Market Revenues	(58,165)
6	Net Capacity Costs	$179,374
7	Revenue Fees and Uncollectibles (RF&U) @ 0.011349[(a)]	2,036
8	CAM Revenue Requirement	$181,410

(a) The RF&U factor of 0.011349 is from Advice Letter 4020-G/5389-E, effective January 1, 2019. This factor will be updated in the November Update if available.

Note: Totals may not add due to rounding.

C. Conclusion

PG&E's forecasted 2021 CAM revenue requirement is $181.4 million. PG&E will update the 2021 CAM revenue requirement in the November Update.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

POWER CHARGE INDIFFERENCE ADJUSTMENT AND ONGOING COMPETITION TRANSITION CHARGE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
POWER CHARGE INDIFFERENCE ADJUSTMENT AND ONGOING COMPETITION TRANSITION CHARGE

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
POWER CHARGE INDIFFERENCE ADJUSTMENT AND ONGOING COMPETITION TRANSITION CHARGE

A. Introduction

This chapter addresses Pacific Gas and Electric Company's (PG&E) 2021 revenue requirement forecast for the vintaged Power Charge Indifference Adjustment (PCIA) and Ongoing Competition Transition Charge (Ongoing CTC).

B. Overview

As required by state law,[1] the purpose of the PCIA and Ongoing CTC is to fairly allocate the above-market costs associated with procurement made by the utility to those customers on whose behalf the procurement was made, including both bundled customers and customers that have departed from PG&E's service to receive service from an alternative supplier (i.e., departing load (DL)). This testimony presents PG&E's calculation of Total Portfolio Indifference used to calculate the PCIA and Ongoing CTC for forecast year 2021.

In Decision (D.) 04-12-048, issued December 16, 2004, the California Public Utilities Commission (CPUC or Commission) approved a Non-Bypassable Charge (NBC) to recover stranded costs when customers: (1) elect Direct Access (DA) service; (2) depart to be served by Community Choice Aggregators (CCA); or (3) elect another DL option.

According to the decision, the amount of the NBC is determined based on the timing of the customers' departure (i.e., customer vintage) and the date of the new generation resource commitment. D.08-09-012 approved a calculation methodology associated with the new generation resource commitments authorized in D.04-12-048 using a vintaged total portfolio indifference calculation.[2]

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1 See D.08-09-012; D.11-12-018; D.18-10-019; Public Utilities Code (Pub. Util. Code) §§ 365.2, 366.1(d)(1), 366.2(a)(4), 366.2(c)(7) and 366.3.

2 The total portfolio indifference calculation, originally defined in D.06-07-030, as modified by D.07-01-025, D.08-09-012 and D.11-12-018, includes the addition of new generation resources to each utility's total portfolio of resources, by vintage.

In D.18-10-019, the Commission revised the PCIA and Ongoing CTC methodology and adopted new accounting mechanisms to recover the above-market costs of the utility's portfolio, including an annual true-up to more accurately allocate costs between bundled and departing load customers. In that decision, the Commission opened a second phase to Rulemaking (R.) 17-06-026 that establishes three working groups to resolve various issues identified in the proceeding. On October 10, 2019, the Commission issued D.19-10-001 that adopts the recommendations by Working Group One, with modifications. Specifically, it sets the procedural and methodological mechanisms to true-up the Market Price Benchmark (MPB) adders, among other things. The recommendations of the other working groups are still under consideration by the Commission, and if resolved in time and relevant to the 2021 PCIA forecasted costs, PG&E will include them in its Update to Prepared Testimony in this proceeding to be served on November 9, 2020 (November Update).[3]

PCIA costs are calculated by vintage, and are applicable to both responsible eligible bundled and departing customers, that are not exempt from the NBC associated with new generation resources, as defined in D.08-09-012.[4] Bundled customers pay their portion of PCIA costs through generation rates, and the DL customers pay through the PCIA rates.

Ongoing CTC are calculated to recover uneconomic costs resulting from California's electric industry restructuring.[5] These are above-market costs associated with eligible Qualifying Facility (QF) contracts and Power Purchase Agreement restructuring costs, and other Commission authorized costs. The Ongoing CTC is to be collected from all existing (as of December 20, 1995) and

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3 See Phase 2 Scoping Memo and Ruling of Assigned Commissioner in R.17-06-026 (February 1, 2020), pp. 2, 4.

4 Includes Direct Access (DA), Community Choice Aggregation Aggregators (CCA), and Departing Load (DL) customers, as defined in D.06-07-030, D.07-01-025, D.08-09-012, D.11-12-018, and Resolution (Res.) E-4475.

5 These costs are calculated based on a statutory method as mandated in Pub. Util. Code Section 367(a)(1)(6).

future consumers in PG&E's service territory,[6] for all power purchase contract costs included in CPUC rates as of that date.[7]

In D.17-08-026, the Commission modified D.06-07-030 by requiring the investor-owned utilities (IOU) to utilize a common template to improve transparency of the calculation underlying the PCIA revenue requirement.[8] The tables presented in this testimony reflects the methodologies shown in that appendix.[9] In D.20-03-019, the Commission considered a proposal supported by PG&E to eliminate errors in the workpaper template related to the mis-application of line losses, suggesting that the IOUs address the issue by petitioning the Commission to modify the relevant decisions.[10] PG&E's November Update will incorporate changes resulting from the Commission's disposition of such a request.

C. Vintaged Total Portfolio Indifference

The vintaged total portfolio indifference calculation, authorized by the Commission, is applied to both the 2021 PCIA and 2021 Ongoing CTC revenue requirements. The calculation for non-exempt DL customers is vintaged, such that new generation resource commitments are included in the total portfolio calculation based on the year the commitment was made. Table 9-1 presents the 2021 forecast total portfolio indifference calculation, including PG&E's forecast of total portfolio generation gigawatt hours and cost of generation, by vintage.

Applicable generation resources include PG&E's Utility-Owned Generation (UOG) resources, legacy QFs and Irrigation District and Water Agency contracts, and post 2002 resource commitments.[11] Costs of these applicable generation resources that are included in the portfolio indifference calculation,

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6 Pub. Util. Code § 369.

7 Pub. Util. Code § 367.

8 D.06-07-030 (as modified by D.17-08-026, Ordering Paragraph (OP) 3); see also, D.18-10-019, OP 3 (requiring the continued use of common PCIA template).

9 For clarity, the tables presented in this testimony includes additional information than that mandated in D.17-08-026, Appendix A.

10 D.20-03-019, Conclusion of Law (COL) 9.

11 These generation resources are authorized in D.04-12-048, D.06-07-030, D.07-01-025, D.08-09-012, D.11-12-018, and D.18-10-019. Cost of generation resources that are recoverable in other balancing accounts are not included in the portfolio.

and presented in Table 9-1, are broadly categorized as energy procurement costs and UOG-Related costs.

1. Energy Procurement Costs

The energy procurement costs are presented in Chapters 3 through 7 and summarized in Table 3-3. Further adjustments were made to these costs in the total portfolio indifference calculation as follows:

- Assigned a zero[12] value to forecasted unsold excess[13] Resource Adequacy (RA) capacity; and
- Assigned the applicable MPB to forecast sales of excess PCIA-eligible products. Existing transactions for the sale of PCIA-eligible products are valued using the terms applicable to the respective executed transaction.[14]

PG&E's November Update will reflect any changes that result from Commission decisions that are applicable to the total portfolio indifference calculation and associated PCIA rates.

2. Utility-Owned Generation Costs

In this testimony, PG&E is requesting the inclusion of $2,441 million of UOG-related costs for rate setting. As described below, this amount includes costs related to UOG approved or under consideration in PG&E's other regulatory proceedings, including the 2020. The inclusion of UOG-Related Costs is solely for rate-setting purposes, and PG&E is not requesting approval of these costs in this application.

The UOG-related costs are those authorized by the Commission to be recovered in PCIA in Advice Letter 5440-E. [15] Additionally, PG&E also includes the insurance cost recorded in the Wildfire Expense Memorandum

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12 D.19-10-001, OP 2, Attachment B.

13 PG&E intends to make capacity in excess of the bundled portfolio's operational and regulatory requirements available for sale. Past experience suggests that some amount of surplus capacity will remain unsold. To account for this likelihood, PG&E forecasts that 10 percent of available surplus capacity will remain unsold.

14 D.19-10-001, OP 2, Attachment B.

15 Pursuant to OP 10, D.18-10-019, PG&E submitted Advice Letter (AL) 5440-E to establish the Portfolio Cost Balancing Account which, among other things, allowed PG&E to recover its UOG cost from the PCIA rates. AL 5440-E was approved by the Commission on May 3, 2019.

Account (WEMA) as presented in PG&E's WEMA Application (A.02-02-004), that is under consideration by the Commission. PG&E's WEMA cost recovery request is pending before the Commission. PG&E's November Update will reflect the status of that application.

Section D below provides more discussion of UOG costs included in the indifference calculation.

D. Utility Owned Generation Base Revenue Requirement and Other Generation-Related Costs Authorized by the Commission

UOG resource costs are recoverable through the PCIA, pursuant to D.18-10-019.[16] Below are descriptions of these costs.

1. 2021 Electric Generation Requested in the General Rate Case

On December 20, 2019, PG&E submitted to the Commission a settlement agreement, with a number of parties, regarding its 2020 General Rate Case (GRC) Application (A.) 18-12-009.[17] The settled 2021 electric generation revenue requirement after adjusting for anticipated hydro sales is included in vintaged total portfolio indifference calculation. The amount allocated to PCIA is $ 2,206 million. PG&E's 2020 GRC (A.18-12-009) is still under consideration by the Commission. In the November Update, PG&E will accordingly update the electric generation revenue requirement, as authorized by the Commission.

2. Other UOG-Related Costs

In addition to the GRC electric generation revenue requirement, PG&E includes the sum of costs authorized and/presented in other proceedings, for recovery:

a) Diablo Canyon Retirement Cost in D.18-11-024 of $53 million;

b) Pension in D.09-09-020 of $48 million;

c) Cost of Capital in D.19-12-056 of $3 million; and

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16 D.18-10-019, see discussion, pp. 51-59, and COL 12 and 13.

17 The settled parties include the Public Advocates Office at the California Public Utilities Commission, The Utility Reform Network, Center for Accessible Technology, National Diversity Coalition, Small Business Utility Advocates, Coalition of California Utility Employees, California City County Street Light Association, the Office of the Safety Advocate of the California Public Utilities Commission, and PG&E.

d) WEMA Insurance Cost in A.20-02-007 of $131 million. PG&E's cost recovery is pending before the Commission. PG&E's November Update will reflect the status of that Application.

The total UOG revenue requirement included in the total portfolio indifference amount calculation totals $2,441 million.[18] These amounts will be updated in the November update, based on Commission's decisions and in accordance with the same procedures as the other revenue requirements presented in this testimony.

E. Market Price Benchmark

1. Background

MPBs are used to calculate the Indifference Amount described in Section D, to derive the Ongoing CTC and the vintaged PCIA revenue requirements. These revenue requirements are derived by taking the difference between the cost of the portfolio of resources, and the market value of an equivalent portfolio to determine the above-market costs associated with the portfolio. The market value for the portfolio is determined by taking the Commission approved MPB and multiplying it by the generation for the portfolio to determine an equivalent market value for the generation portfolio.

The MPB calculation was originally adopted in D.06-07-030[19] and modified in D.07-01-025, D.11-12-018, and Res.E-4475. A revised methodology to calculate two components of the MPB, the Renewables Portfolio Standard (RPS) and RA Adders, was adopted in D.18-10-019 and D.19-10-001. Both decisions stated that the Energy Division shall calculate the components of the MPB and make them available at the beginning of November each year. Therefore, PG&E will include the MPB information provided by Energy Division applicable to the forecast and true-up of the MPBs in its November update of this testimony.

2. Components of the MPB

The MPB consists of the following components:

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[18] Includes Revenue Franchise Fees and Uncollectibles.

[19] See Appendix 1 of D.06-07-030.

a) Brown Power MPB – Represents the energy value of the vintaged portfolio;

b) Green or RPS Adder – Represents the market value, incremental to the energy and capacity value, associated with RPS-compliant resources in the vintaged portfolio; and

c) Capacity or RA Adder – Represents the market value of the RA that is provided by the vintaged portfolio.

a. Brown Power MPB

OP 1(a) of D.18-10-019 [20] stated that the Brown Power Index shall continue to be calculated using the methodology adopted in D.06-07-030, and modified in D.11-12-018, as follows:

- Collect daily forward price quotes from October 1 through October 31 for 12 months of on-peak (6 days × 16 hours/day) and off-peak (6 days × 8 hours/day; 1 day × 24 hours/day) power delivered at North of Path-15 (NP-15), as published in Platts-ICE Forward Curve – Electricity for NP-15;[21] and
- Weight the peak and off-peak factors based on PG&E's historical bundled load profile.[22]

b. Green/RPS Adder

OP 1(b) of D.18-10-019 stated that green/RPS adder is calculated annually by the Commission's Energy Division, based on data submitted by the IOUs, CCA and ESPs during the year two years prior to the forecast year (year n-2) for delivery in the forecast year (year n).

c. Capacity/RA Adder

OP 1(c) of D.18-10-019 [23] stated that the Capacity/RA Adder shall be calculated using reported purchase and sales prices from IOU, CCA,

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20 See also OP 1 of D.19-10-001.

21 D.06-07-030, Appendix 1.

22 D.11-12-018, p. 34, Section 3.4.2 ("We conclude that the MPB should be weighted based on the historical IOU bundled load profile. In order to promote transparency, we shall direct that historical bundled load data be used, as suggested by SCE. The use of historical bundled load data will avoid the need to use confidential data, and will still promote reasonable accuracy.")

23 See also OP 1(d) and 1(e) of D.19-10-001

and ESP transactions made during (year n-1) for deliveries from (year n). Capacity expected to remain unsold is assigned a price of zero.[24] The RA Adder shall be calculated in a manner that reflects the three types of RA capacity: system, local, and flexible.

d. Line Loss Factor

The line loss factor accounts for delivery losses from NP-15 to load centers and is applied to the sum of the forward price cost, the weighted average Green benchmark results, and the capacity adder to arrive at the final MPB value for each vintage portfolio. D.07-01-030 set the line loss factor at 6.0 percent for PG&E which remained unchanged in D.11-12-018, as described in Res.E-4475. PG&E's November Update will reflect the Commission's disposition, if any, of a Petition to address the improper application of the line loss factor.

3. 2021 MPB

The 2021 MPBs used in this testimony, and presented in Table 9-2, are calculated based using data consistent with the methodology described above, except as described below. PG&E will incorporate available updated information in these MPBs in November.

a) Brown Power MPB

The Brown Power MPB relies on the April forward market data, instead of October data.

b) Green/RPS Adder

The Green/RPS Adder use a placeholder value of $17.35/megawatt-hour as authorized by the Commission in D.20-02-047.

c) Capacity/RA Adders

The Capacity/RA Adders use placeholder values as authorized by the Commission in D.20-02-047, as follows:

- System $4.59/kilowatt (kW)-month
- Local $4.11/kW-month
- Flex $4.41/kW-month

[24] See D.19-10-001, COL 22.

F. Indifference Amount Calculation

Table 9-3 present the generation energy and capacity, as well as costs (lines 1 through 7) for the total portfolio, derived from Table 9-1. The market value of the portfolio is derived by multiplying the appropriate MPB, presented in Table 9-2, by the portfolio's generation and capacity. The cost is compared to market value for each vintage[25] to determine the level of the indifference.[26]

The indifference amount calculation includes the line loss factor described in Section E.2(d) above, which was authorized in D.17-08-026 with modifications in subsequent decisions as discussed in this chapter. PG&E's November Update will incorporate any changes resulting from any Commission disposition of a Petition to address the misapplication of line losses.

Line 30 of Table 9-3 reflects the Indifference Amount that shows whether the portfolio costs are above or below market. Below-market costs (i.e., portfolio costs are less than the market value) are negative while above-market costs are positive (i.e., portfolio costs are more than the market value). The cumulative indifference amounts are shown on line 36.

G. Conclusion

The Indifference Amount discussed in Section F includes the above market revenue requirements recoverable in Ongoing CTC and vintage PCIA rates. The 2021 Ongoing CTC and PCIA revenue requirement, payable by PG&E's eligible bundled and DL customers,[27] not exempt from the NBC associated with new generation resources, as defined in D.08-09-012 is $46 million, and $2,742 million, respectively (see Table 9-3, Line 36). PG&E will update these amounts in the November Update of this testimony.

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25 As well as the Ongoing CTC portfolio.

26 The MPB is discussed in more detail in Section D.3. above. The market value will be updated in November to reflect both updated forecast cost, and MPB values, including adoption of any procedural and/or methodological mechanisms changes authorized in R.17-06-026.

27 See footnote 5.

TABLE 9-1
INDIFFERENCE CALCULATION INPUTS AND SOURCES, PURSUANT TO D.17-08-026

Line No.		Ongoing CTC-Eligible	PCIA Vintage Portfolios													IOU Total Portfolio
			UOG Legacy	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	
1.	CRS Eligible Portfolio Costs ($000)	$134,605	$2,057,590	$2,117,956	$384,167	$139,192	$124,335	$56,214	$1,151	$14,618	$10,619	$5,747	$11,814	$12,221	$2,926	$5,073,155
2.	CRS Eligible Non-Renewable Supply at Customer Meter (GWh)	1,648	23,937	9,407	-1,263	73	162	-7	0	17	0	0	0	0	0	33,974
3.	CRS Eligible Renewable Supply at Customer Meter (GWh)	155	401	5,080	2,365	722	790	622	9	170	126	28	35	26	10	10,540
4.	CRS Eligible Total Net Qualifying Capacity (MW)															
5.	CRS Eligible System NQC (System only, No flex or local)	122	1,749	235	64	31	54	30	0	3	0	1	0	0	0	2,289
6.	CRS Eligible Local NQC (System and local, with or without flex	218	2,096	2,564	91	180	98	7	1	4	10	2	0	0	0	5,271
7.	CRS Eligible Flexible NQC (System and flex only, No local)	0	217	491	0	0	0	0	0	7	0	0	0	0	0	715

To comply with D. 18-10-019, OP 3 and subsequent direction from the CPUC's Energy Division, PG&E, in October 2018, submitted revisions to the confidential version of PG&E's uniform common spreadsheet template for calculation of the PCIA rates. The table above reflects one of the worksheets included in the template.

TABLE 9-2
INDIFFERENCE CALCULATION INPUTS AND SOURCES, PURSUANT TO D.17-08-026

Line No.	Description	Source of Data	Value
1.	On Peak NP 15 Price ($/MWh)	Platt	$38.38
2.	Off Peak NP 15 Price ($/MWh)	Platt	$31.22
3.	On Peak Load Weight (%)	2019 Recorded Bundled Load - On Peak Hours	59.2%
4.	Off Peak Load Weight (%)	2019 Recorded Bundled Load - Off Peak Hours	40.8%
5.	Load Weighted Average Price ($/MWh) [1]	Line 1 x Line 3 + Line 2 x Line 4	$35.46
6.	Green/RPS Adder ($/MWh)	2020 authorized Benchmark	$17.35
7.	Green Benchmark ($/MWh)	Line 6 + Line 5	$52.81
8.	System RA Benchmark ($/kW-Year)	2020 authorized Benchamrk ($4.59kW-Month x 12)	$55.08
9.	Local RA Benchmark ($/kW-Year)	2020 authorized Benchamrk ($4.11kW-Month x 12)	$49.32
10.	Flexible RA Benchmark ($/kW-Year)	2020 authorized Benchamrk ($4.41kW-Month x 12)	$52.92
11.	Line Loss Adjustment Factor	Resolution E-4475	6%

To comply with D. 18-10-019, OP 3 and subsequent direction from the CPUC's Energy Division, PG&E, in October 2018, submitted revisions to the confidential version of PG&E's uniform common spreadsheet template for calculation of the PCIA rates. The table above reflects one of the worksheets included in the template.

TABLE 9-3
INDIFFERENCE AMOUNT CALCULATION, PURSUANT TO D.17-08-026

Line No.	Description	Equation	Unit	Ongoing CTC-Eligible	PCIA Vintage Portfolio												
					UOG Legacy	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	Cost of Portfolio																
1.	Total Portfolio Cost	Table 9-1, Line 1	$000	134,605	2,057,590	2,117,956	384,167	139,192	124,335	56,214	1,151	14,618	10,619	5,747	11,814	12,221	2,926
2.	CRS Eligible Non-Renewable Supply at Customer Meter	Table 9-1, Line 2	GWh	1,648	23,937	9,407	(1,263)	73	162	(7)	(0)	17	(0)	0	(0)	(0)	0
3.	CRS Eligible Renewable Supply at Customer Meter	Table 9-1, Line 3	GWh	155	401	5,080	2,365	722	790	622	9	170	126	28	35	26	10
4.	CRS Eligible System NQC	Table 9-1, Line 4	MW	122	1,749	235	64	31	54	30	0	3	0	1	0	0	0
5.	CRS Eligible Local NQC	Table 9-1, Line 5	MW	218	2,096	2,564	91	180	98	7	1	4	10	2	0	0	0
6.	CRS Eligible Flexible NQC	Table 9-1, Line 6	MW	0	217	491	0	0	0	0	0	7	0	0	0	0	0
7.	**Portfolio Unit Cost**	**Line 1 / (Line 2 + Line 3)**	**$/MWh**	**$74.64**	**$84.54**	**$146.20**	**$348.76**	**$175.08**	**$130.57**	**$91.43**	**$123.73**	**$78.14**	**$84.48**	**$207.97**	**$337.36**	**$461.18**	**$298.78**
8.	**Market Value of Portfolio**																
9.	**Market Value of Brown Portfolio**																
10.	Non-Renewable Energy	Line 2	GWh	1,648	23,937	9,407	(1,263)	73	162	(7)	(0)	17	(0)	0	(0)	(0)	0
11.	Platt's Weighted Price (Brown Benchmark)	Table 9-2, Line 5	$/MWh	$35.46	$35.46	$35.46	$35.46	$35.46	$35.46	$35.46	$35.46	$35.46	$35.46	$35.46	$35.46	$35.46	$35.46
12.	**Market Value of Brown Portfolio**	**Line 10 x Line 11**	**$000**	**$58,444**	**$848,795**	**$333,563**	**($44,788)**	**$2,577**	**$5,754**	**($242)**	**($0)**	**$600**	**($11)**	**$0**	**($0)**	**($0)**	**$0**
13.	**Market Value of Green Portfolio**																
14.	Renewable Energy	Line 3	GWh	155	401	5,080	2,365	722	790	622	9	170	126	28	35	26	10
15.	Weighted Average Green Benchmark	Table 9-2, Line 7	$/MWh	$52.81	$52.81	$52.81	$52.81	$52.81	$52.81	$52.81	$52.81	$52.81	$52.81	$52.81	$52.81	$52.81	$52.81
16.	**Market Value of Green Portfolio**	**Line 14 x Line 15**	**$000**	**$8,200**	**$21,188**	**$268,280**	**$124,873**	**$38,147**	**$41,718**	**$32,827**	**$491**	**$8,986**	**$6,655**	**$1,459**	**$1,849**	**$1,399**	**$517**
17.	**Capacity Adder**																
18.	Average Monthly System NQC	Line 4	MW	122	1,749	235	64	31	54	30	0	3	0	1	0	0	0
19.	System RA Benchmark	Table 9-2, Line 8	$/kW-Year	$55.08	$55.08	$55.08	$55.08	$55.08	$55.08	$55.08	$55.08	$55.08	$55.08	$55.08	$55.08	$55.08	$55.08
20.	Average Monthly Local Area NQC	Line 5	MW	218	2,096	2,564	91	180	98	7	1	4	10	2	0	0	0
21.	Local RA Benchmark	Table 9-2, Line 9	$/kW-Year	$49.32	$49.32	$49.32	$49.32	$49.32	$49.32	$49.32	$49.32	$49.32	$49.32	$49.32	$49.32	$49.32	$49.32
22.	Average Monthly Flexible NQC	Line 6	MW	0	217	491	0	0	0	0	0	7	0	0	0	0	0
23.	Flexible RA Benchmark	Table 9-2, Line 10	$/kW-Year	$52.92	$52.92	$52.92	$52.92	$52.92	$52.92	$52.92	$52.92	$52.92	$52.92	$52.92	$52.92	$52.92	$52.92
24.	**Market Value of Capacity**	**Sum (Lines 18 x 19, 20 x 21, 22 x 23)**	**$000**	**$17,474**	**$211,174**	**$165,374**	**$8,031**	**$10,577**	**$7,824**	**$2,018**	**$66**	**$730**	**$487**	**$154**	**$0**	**$0**	**$0**
25.	**Portfolio Market Value**	**Line 12 + Line 16 + Line 24**	$000	**$84,118**	**$1,081,157**	**$767,217**	**$88,115**	**$51,301**	**$55,297**	**$34,603**	**$557**	**$10,316**	**$7,130**	**$1,613**	**$1,849**	**$1,399**	**$517**
26.	**Line Loss Adjusted Portfolio Market value**	**Line 25 * (1 + Table 9-2, Line 11)**	$000	**$89,165**	**$1,146,026**	**$813,250**	**$93,402**	**$54,379**	**$58,614**	**$36,679**	**$591**	**$10,935**	**$7,558**	**$1,710**	**$1,960**	**$1,483**	**$548**
27.	**Indifference Amount**																
28.	**Portfolio Total Cost**	**Line 1**	$000	**$134,605**	**$2,057,590**	**$2,117,956**	**$384,167**	**$139,192**	**$124,335**	**$56,214**	**$1,151**	**$14,618**	**$10,619**	**$5,747**	**$11,814**	**$12,221**	**$2,926**
29.	**Portfolio Unit Value**	**Line 26**	$000	**$89,165**	**$1,146,026**	**$813,250**	**$93,402**	**$54,379**	**$58,614**	**$36,679**	**$591**	**$10,935**	**$7,558**	**$1,710**	**$1,960**	**$1,483**	**$548**
30.	**Total Indifference Amount (Unadjusted)**	**Line 28 - Line 29**	$000	**$45,439**	**$911,564**	**$1,304,706**	**$290,765**	**$84,813**	**$65,720**	**$19,534**	**$560**	**$3,683**	**$3,061**	**$4,037**	**$9,854**	**$10,738**	**$2,378**
31.	**DWR Revenue Requirement**		$000														
32.	**One-Time Adjustments (if applicable)**		$000														
33.	**Adjusted Indifference Amount**	**Sum (Lines 24:27)**	$000	**$45,439**	**$911,564**	**$1,304,706**	**$290,765**	**$84,813**	**$65,720**	**$19,534**	**$560**	**$3,683**	**$3,061**	**$4,037**	**$9,854**	**$10,738**	**$2,378**
34.	**Revenue Franchise Fees & Allowances @ 0.011349**	**Advice 4020-G/4389-E**	$000	**$516**	**$10,345**	**$14,807**	**$3,300**	**$963**	**$746**	**$222**	**$6**	**$42**	**$35**	**$46**	**$112**	**$122**	**$27**
35.	**Adjusted Indifference Amount with RF&U**	**Line 28 + Line 29**	$000	**$45,955**	**$921,909**	**$1,319,513**	**$294,065**	**$85,776**	**$66,466**	**$19,756**	**$567**	**$3,725**	**$3,096**	**$4,083**	**$9,966**	**$10,859**	**$2,405**
36.	**Cummulative Adjusted Indifference Amount with RF&U**		$000	**$45,955**	**$921,909**	**$2,241,422**	**$2,535,487**	**$2,621,262**	**$2,687,729**	**$2,707,485**	**$2,708,052**	**$2,711,777**	**$2,714,872**	**$2,718,956**	**$2,728,921**	**$2,739,781**	**$2,742,186**

To comply with D. 18-10-019, OP 3 and subsequent direction from the CPUC's Energy Division, PG&E, in October 2018, submitted revisions to the confidential version of PG&E's uniform common spreadsheet template for calculation of the PCIA rates. Lines 1 through 35 of the above table reflects thos included in one of the worksheets of
Totals may not add due to rounding

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 10

MODIFIED COST ALLOCATION MECHANISM

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CHAPTER 10
MODIFIED COST ALLOCATION MECHANISM

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 10
MODIFIED COST ALLOCATION MECHANISM

A. Introduction

This chapter addresses costs related to Pacific Gas and Electric Company's (PG&E) 2021 procurement for Resource Adequacy (RA) mandated by Decision (D.) 19-11-016.

It also provides PG&E's proposal to best reflect related 2021 forecasted costs in its 2021 revenue requirements as of this filing.

B. Overview

D.19-11-016 requires PG&E to procure incremental system-level qualifying RA capacity to meet both a bundled customer portion as well as to provide backstop procurement for certain load-serving entities choosing not to voluntarily self-procure or which fail to meet their self-procurement responsibilities. The decision also requires that at least 50 percent of the resources be online by August 1, 2021.

PG&E's forecast assumptions regarding this procurement are described in Chapter 6, Section 2d. For the 2021 forecast, PG&E included two energy storage positions:

- One half of its bundled RA requirement of 716.9 megawatts (MW)
- One half of its opt-out LSE RA requirement of 48.2 MW.

In D.19-11-016, the Commission also adopted the concept of a new Modified Cost Allocation Mechanism (ModCAM), the details of which do not yet exist. The ModCAM will be developed as part of the recently issued Integrated Resource Planning Rulemaking (R.) 20-05-003, with a proposed decision expected in Spring 2021.[1]

Until the Commission adopts the details associated with ModCAM cost recovery for procurement required by D.19-11-016, including an implementation timeline, PG&E proposes 2021 cost recovery consistent with that detailed in its Advice Letter 5826-E, submitted on May 18, 2020. Specifically,

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[1] R.20-05-003, p. 13.

1) Recovery of costs associated with the bundled procurement through its Energy Resource Recovery Account (ERRA) generation rate; and
2) Costs for the opt-out position to be recorded in a memorandum account consistent with that proposed in the advice letter.[2]

As noted in Advice Letter 5826-E footnote 15, "PG&E would only record costs in the memorandum account that are not already being recovered in rates." If the Commission were to approve PG&E's rate proposal and memorandum account proposed in Advice Letter 5826-E, the bundled procurement costs would not be included in the proposed memorandum account. Rather, they would be implemented in ERRA rates until such time as the Commission approves implementation of the ModCAM during 2021.

PG&E believes that the Commission could easily approve Advice Letter 5826-E in advance of the ModCAM decision expected in R.20-05-003 (and perhaps in advance of PG&E's November Update).

The forecasted 2021 costs for the two ModCAM positions are shown in Table 10-1 below. At this time, PG&E proposes to recover only the ERRA-related costs shown for Bundled RA in its 2021 bundled customer rates. PG&E's November Update will reflect any changes concerning costs or cost recovery resulting from the Commission's disposition of Advice Letter 5826-E.

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2 Advice Letter 5826-E, pp. 12-13.

C. Conclusion

PG&E's forecasted 2021 costs related to mandated IRP procurement are summarized in Table 10-1 below. PG&E currently proposes recovering $[redacted] million in its 2021 ERRA revenue requirement (Chapter 12). PG&E will update these forecasted costs in the November Update.

TABLE 10-1
2021 MODIFIED CAM PROCUREMENT COSTS
(THOUSANDS OF DOLLARS)

Line No.	Description	2021
1	ERRA	
2	Bundled RA	[redacted]
3	Memo Account	
4	Opt-Out RA	

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CHAPTER 11

TREE MORTALITY REVENUE REQUIREMENTS

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CHAPTER 11
TREE MORTALITY REVENUE REQUIREMENTS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 11
TREE MORTALITY REVENUE REQUIREMENTS

A. Introduction

This chapter discusses Pacific Gas and Electric Company's (PG&E) 2021 procurement cost forecast and revenue requirement for the Tree Mortality Non-Bypassable Charge (TMNBC). The discussion will cover a background of the TMNBC, the procurement cost forecast for TMNBC contracts, and the value of energy, Resource Adequacy (RA) capacity, and Renewable Energy Credits (REC) for TMNBC contracts.

B. Program Background

On October 30, 2015, Governor Edmund G. Brown, Jr. issued a Proclamation of a State of Emergency (Proclamation) to address the tree mortality crisis in California.[1] In response to the Proclamation, on March 17, 2016, the California Public Utilities Commission (CPUC or Commission) issued Resolution (Res.) E-4770 (Bioenergy Renewable Auction Mechanism (BioRAM) 1 Resolution), requiring that each of the Investor-Owned Utilities (IOU) enter into contracts to purchase its share of at least 50 megawatts (MW) of generating capacity collectively from biomass generation facilities that use prescribed levels of high-hazard zone (HHZ) material as feedstock. Additionally, the IOUs were ordered to use the Renewable Auction Mechanism (RAM) solicitation procedures to procure the contracts. This procurement of biomass energy using RAM procedures was also known as BioRAM.

On August 30, 2016, the California Legislature passed Senate Bill (SB) 859 and Governor Brown signed it into law on September 14, 2016.[2] SB 859 required electrical corporations to procure their respective shares of 125 MW from existing biomass facilities using prescribed amounts of dead and dying trees located in HHZ as feedstock, for 5-year contractual commitments. SB 859, as codified in Section 399.20.03(f) of the Public Utilities Code, required that the

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1 http://www.fire.ca.gov/treetaskforce/downloads/library/CPUC_procurement.pdf.

2 http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB859.

procurement costs to satisfy this requirement be recovered from all customers on a non-bypassable basis.

On October 21, 2016, the Commission issued Res.E-4805 (BioRAM 2 Resolution) to implement the requirements of SB 859. The BioRAM 2 Resolution required the IOUs to track electric procurement costs associated with power purchase agreements executed to comply with BioRAM 1 Resolution and the BioRAM 2 Resolution. The BioRAM 2 Resolution also required the Joint IOUs to file applications to establish a TMNBC within 30 days. On November 14, 2016, the Joint IOUs filed Application 16-11-005 setting forth their proposal for a TMNBC. The Commission issued Decision (D.) 18-12-003 on December 21, 2018 establishing a non-bypassable charge (NBC) for costs associated with tree mortality biomass energy procurement for both Res.E-4770 and Res.E-4805 procurement.

As stated in D.18-12-003, the TMNBC will recover the net costs of the tree mortality-related biomass energy procurement and will exclude revenue received by the IOUs through sales of energy and ancillary services, the value of RECs as determined by the sale of these credits in the marketplace, and the value of the RA capacity as determined by the sale of the RA in the marketplace.[3]

C. Contract Procurement Costs and Revenue Requirement

The 2021 procurement cost forecast used for calculating the TMNBC revenue requirement are based on executed supply purchase contracts, executed RA and Renewables Portfolio Standard (RPS) sales, and California Independent System Operator's (CAISO) market energy and ancillary service revenues for unsold RPS-eligible generation. For PG&E, the executed supply contracts that are forecasted to provide deliveries to PG&E in 2021 include the following biomass facilities:

1) Burney Forecast Products; and
2) Wheelabrator Shasta.

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[3] D.18-12-003, p. 22.

The TMNBC cost forecast is calculated using the methodology described below that was authorized in D.18-12-003:

TMNBC Revenue Requirement = (Fixed Costs + Variable Costs) – ((Energy Revenue) + (Ancillary Service Revenue, if any) + (RA Revenue, if any) + (REC Revenue, if any))

In summary, the net cost for the TMNBC is calculated by subtracting the forecasted value of energy, RA sales, and REC sales from the TMNBC contracts' forecasted cost. PG&E will update the cost and attribute forecasts in the November Update.

Table 11-1 shows the 2021 TMNBC net cost revenue requirement forecast for the contract costs and the value of energy, RA sales, and REC sales.

TABLE 11-1
2021 TMNBC REVENUE REQUIREMENT FORECAST
(THOUSANDS OF DOLLARS)

Line No.	Description	2021 Forecast
1	Tree Mortality Non-Bypassable Charge (TMNBC)	
2	Post-2002 Contracted Resources	
3	RPS Eligible	
4	RPS-Eligible Contracts (Table 6-1, Line 29)	[redacted]
5	RPS-Eligible Contracts - Sales (Table 6-1, Line 30)	
6	RPS-Eligible Future Contracts (Table 6-1, Line 31)	
7	RPS-Eligible Future Sales (Table 6-1, Line 32)	
8	Resource Adequacy Sales (Table 6-1, Line 33)	
9	CAISO Costs (GMCs) (Table 7-3, Line 6)	
10	**Net Costs**	**36,935**
11	RF&U @ 0.011349	**419**
12	**Total RRQ**	**37,354**

Notes:

(a) The Revenue Franchise & Uncollectible (RF&U) factor of 0.011349 is extracted from Tier 1 AL 4020-G/5389-E, effective January 1, 2019.

(b) RPS-Eligible sales include expected revenues for the sale of both renewable energy credits and energy.

(c) Resource adequacy sales include expected revenues for the sale of capacity.

Totals may not add due to rounding.

D. Conclusion

In this chapter, PG&E presents its forecast for the TMNBC revenue requirement which based on the forecasted net costs to be incurred in 2021, as presented in Table 11-1. PG&E will update the TMNBC revenue requirement in its November update.

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CHAPTER 12

ENERGY RESOURCE RECOVERY ACCOUNT

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ENERGY RESOURCE RECOVERY ACCOUNT

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 12
ENERGY RESOURCE RECOVERY ACCOUNT

A. Introduction

The purpose of this chapter is to present the 2021 revenue requirement forecast for the Energy Resource Recovery Account (ERRA). The 2021 ERRA revenue requirement for ratesetting will primarily be based on the summation of the Pacific Gas and Electric Company (PG&E) bundled load forecast related costs that were presented in Chapter 7, as well as the imputed market value of any Resource Adequacy (RA) and Renewable Energy Credits (REC) based on RA and Renewables Portfolio Standard (RPS) Adders presented in Chapter 9 that are retained by PG&E for PG&E's bundled load. A portion of Utility-Owned Generation (UOG) costs are included as well.[1]

In Table 7-3 PG&E shows the 2021 procurement cost forecast related to PG&E's bundled customers. These costs were comprised of the following California Independent System Operator (CAISO) market cost categories:

1) Energy purchases based on PG&E's expected 2021 bundled load;
2) Volumetric load charges for ancillary services, uplift charges, and grid management charges; and
3) Other miscellaneous, non-volumetric CAISO costs.

The total cost forecasts for the above items are included in the ERRA revenue requirement forecast shown in Table 12-1.

B. Resource Market Value Forecast

Similar to 2020, and as authorized by the Commission,[2] PG&E's bundled customer ERRA costs include the imputed costs of RA and REC attributable to the bundled portfolio's retention of resources eligible for Power Charge Indifference Adjustment (PCIA) and Ongoing Competition Transition Charge (Ongoing CTC) cost recovery at forecasted RA and RPS Adders. Therefore, the 2021 market value forecast of applicable RA and RECs that is presented in Chapter 9 is included in the ERRA revenue requirement forecast in order to

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1 Details of UOG costs are discussed in Chapter 9 of this testimony.

2 Decision (D.) 18-10-019, D.19-10-001, and D.20-02-047.

recover the costs associated with this imputed market value. These totals are included in the ERRA revenue requirement forecast shown in Table 12-1.

C. Other Costs

The remaining components of the ERRA revenue requirement forecast are comprised of executed short-term purchase and sale transactions, if any, which were presented in Chapter 6. Hedging and collateral interest expense costs that were presented in Chapter 7. The net energy charging costs for the UOG storage presented in Chapter 4. As noted in Chapter 3, PG&E will be acquiring RA resources pursuant to D.19-11-016 in the Integrated Resource Planning (IRP) Proceeding that will be operational in 2021. The aforementioned decision ordered that these costs are to be recovered via a modified Cost Allocation Mechanism (CAM) rate mechanism. However, the decision left open the implementation details of the modified CAM for the stakeholder process in the recently initiated IRP proceeding, Rulemaking (R.) 20-05-002. A proposed decision to resolve this matter is anticipated to issued in Spring 2021.[3] As a result, PG&E has requested that for the purposes of the 2021 forecast, the anticipated costs associated with the bundled customer portion of IRP procurement be assigned to the ERRA revenue requirement. Finally, certain UOG costs that are further detailed in Chapter 9 are included as well, but only for ratemaking purposes. The 2021 forecast of these costs are shown in Table 12-1.

D. Conclusion

Based on the procurement cost components presented above, the forecasted 2021 ERRA revenue requirement for rate setting is $2,177 million (shown in Table 12-1, line 20). PG&E will update the ERRA revenue requirement in the November Update.

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[3] Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes (R.20-05-003), p. 13.

TABLE 12-1
2021 ERRA FORECAST REVENUE REQUIREMENT
(THOUSANDS OF DOLLARS)

Line No.	Description	2021 Forecast
1	ERRA	
2	Bundled Load Energy Requirement (Table 7-3, Line 7)	[redacted]
3	UOG	
4	Energy Storage (Table 4-3, Line 5)	[redacted]
5	Grid Management Charges (Table 7-3, Line 4)	
6	Other Load (Table 7-3, Line 8)	
7	Hedging (Table 7-1, Line 9)	
8	Collateral Interest Expense (Table 7-2, Line 3)	10,822
9	RA Contracts (Table 6-1, Line 41)	[redacted]
10	Residual Capacity Purchases (Table 6-1, Line 42)	
11	IRP Procurement Track - PGE (Table 10-1, Line 2)	
12	ERRA GRC Costs	50,574
13	Resource RA and REC Market Benchmark Value[(a)]	
14	PCIA REC Value (from Table 9-3 calculations)	190,979
15	PCIA RA Value (from Table 9-3 calculations)	430,820
16	CTC REC Value (from Table 9-3 calculations)	2,856
17	CTC RA Value (from Table 9-3 calculations)	18,522
18	Total Costs	$2,152,795
19	Revenue Fees and Uncollectibles (RF&U) @ 0.011349[(b)]	$24,432
20	Total Revenue Requirement	$2,177,227

Note: Totals may not add due to rounding.

(a) RA and REC market benchmark values are calculated based on the Net Qualifying Capacity and Renewable Energy at the meter totals shown on lines 18, 20, 22, and 14, respectively, in Table 9-3. These values are multiplied by 1.06 and then multiplied by the appropriate benchmark adder (RA or RPS).

(b) The RF&U factor of 0.011349 is extracted from Tier 1 Advice Letter 4020-G/5389-E, effective January 1, 2019.

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CHAPTER 13

GREEN TARIFF SHARED RENEWABLES

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GREEN TARIFF SHARED RENEWABLES

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 13
GREEN TARIFF SHARED RENEWABLES

A. Introduction

The purpose of this testimony is to request the California Public Utilities Commission (Commission) approve Pacific Gas and Electric Company's (PG&E) 2021 rate proposal for bill charges and credits associated with PG&E's Green Tariff Shared Renewables (GTSR) Program. This request is consistent with Decision (D.) 15-01-051 directives, which state that the renewable power rate and other components of GTSR rates should be updated annually.[1]

B. Background

PG&E's GTSR Program was required by Senate Bill 43, and implemented by the Commission in D.15-01-051 on February 2, 2015, issued in Application 12-04-020. This program was established to expand access to renewable energy resources, and to create a mechanism by which institutional customers, commercial customers, and individuals can meet their electrical needs with generation from renewable energy resources.

PG&E's 2020 GTSR Forecast was approved in the 2020 Energy Resource Recovery Account (ERRA) Forecast Decision (D.20-02-047), which was submitted to the Commission in PG&E's Advice Letter 5781-E on March 13, 2020 and approved as effective on April 13, 2020. The 2020 rates were then consolidated with other electric rate changes and implemented through the Annual Electric True-Up (AET) process for rates effective May 1, 2020.[2]

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1 D.15-01-051, p. 130 and Conclusion of Law (COL) 53. Previously, PG&E's request to update the GTSR Program rates was submitted through Advice Letters (AL), which was allowed under D.15-01-051, COL 51. However, given the interdependency of the GTSR Program rates on the Power Charge Indifference Adjustment (PCIA) and generation rates set in the ERRA Forecast proceeding, going forward, PG&E plans to consolidate the GTSR rate request with the Annual ERRA Forecast proceeding.

2 PG&E's 2020 AET was implemented through AL 5661-E-A, submitted on April 22, 2020, with three supplemental ALs 5661-E-B, E-C, and E-D, submitted on April 28, April 30, and May 13, 2020, respectively.

C. 2021 Rate Forecast for GTSR Program

PG&E's request is to update the GTSR Program rate components for rates effective January 1, 2021. The GTSR Program bill credit and charges that make-up the E-GT and E-ECR rates are:

1) Solar Rate (E-GT rate schedule only);
2) Power Charge Indifference Adjustment;
3) Program Charge
    a. Resource Adequacy (RA) Charge;
    b. California Independent System Operator (CAISO) Grid Management Charge (GMC);
    c. Western Renewable Energy Generation Information System (WREGIS) Fees;
    d. Renewable Integration Charges (RIC);
    e. Solar Value Adjustment (Time of Day and RA);
    f. Administrative and Marketing Costs; and
4) Class Average Generation Rate.

All the rate components have been reviewed and updated as appropriate in this request for 2021 except for the RIC, which will remain unchanged for 2021.[3]

The GTSR rate component forecast for 2021 starts with the solar rate, which is based on the forecast deliveries and costs for dedicated GTSR Program resources. The PCIA and the RA charge presented in this testimony are consistent with PG&E's 2021 ERRA Forecast values. In Chapter 19, the PCIA rates are presented by customer class, and are an input into the GTSR Program rates presented in this chapter.

The RA charge is calculated using the RA Market Price Benchmarks (MPB) issued by Energy Division in November 2019 for use in PG&E's 2020 ERRA Forecast Proceeding. The forecast MPBs are multiplied by the current portfolio's net qualifying capacity to determine the portfolio value, which is then divided by sales to determine the applicable rate. PG&E will receive a forecast

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[3] D.15-01-051 set the RIC at zero and ordered that within 60 days of a decision setting a RIC charge for ratepayers, the Investor-Owned Utilities should submit a Tier 3 AL setting forth how the RIC will be allocated to customers (both new and existing). The RIC is currently being evaluated in Rulemaking 11-05-005 but as of the date of this filing, no RIC has been approved.

for the 2021 MPB in November 2020 when the Energy Division issues the final 2020 and forecast 2021 MPBs for the 2020-2021 cycle.

The costs for CAISO GMC have been updated and are based on a 3-year rolling average of recorded data as presented in FERC Form 1. Lastly, the WREGIS fee and administrative and marketing expenses have been updated based on PG&E's current forecast of sales and expected administrative and marketing expenditures.

For 2021, PG&E is forecasting an end-of-year balance in the GTSR Balancing Account near zero given excess deliveries from the GTSR dedicated resources are forecast to transferred to ERRA in December through a backstop entry. PG&E will update this forecast in its November Update and anticipates there may be a small residual balance associated with interest expense that has accrued to the account. As required by D.15-01-051, PG&E will present a summary of the true-up of costs and revenues against charges and credits applied to the GTSR customers in its annual ERRA Compliance Review Application,[4] which will be submitted to the Commission in February of 2021, reviewing balancing account activity for the 2020 record period.

Tables 13-1 and 13-2 below summarize the 2021 GTSR Program charges and credits for the and E-GT and E-ECR rate schedules for a 2020 vintage customer and for a 2021 vintage customer. Vintage 2020 customers elect service between July 1, 2020 and June 30, 2021 whereas a vintage 2020 E-GT customer elects service on or after July 1, 2021.

Tables 13-3 through 13-7 summarize the 2021 GTSR Program charges and credits for customers currently being served under the E-GT rate schedule, which includes vintage customers 2015 through 2019.

D. Conclusion

PG&E requests that the Commission approve PG&E's GTSR Program rates for Schedules E-GT and E-ECR.

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4 D.15-01-051, COL 59.

TABLE 13-1
GTSR PROGRAM – VINTAGE 2020 AND VINTAGE 2021
E-GT OPTION

Line No.		E-1 cents/kwh	A1 cents/kwh	A-6 cents/kwh	A-10 cents/kwh	E-19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	E-20 T cents/kwh	E-20 P cents/kwh	E-20 S cents/kwh
	Charges										
1	**Solar Generation Price**	6.703	6.703	6.703	6.703	6.703	6.703	6.703	6.703	6.703	6.703
2	PCIA	3.223	3.219	3.219	3.318	3.058	2.569	2.886	2.626	2.813	2.964
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309
5	Resource Adequacy	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798
6	CAISO Charges	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074
7	WREGIS Fees	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
8	**Sub Total**	**11.108**	**11.104**	**11.104**	**11.204**	**10.944**	**10.454**	**10.771**	**10.512**	**10.698**	**10.849**
9	**Credits**										
10	**Class Average Generation Rate**	11.548	11.168	11.168	11.890	10.956	9.201	10.338	9.407	10.076	10.616
11	Solar Value Adjustment										
12	TOD	-	-	-	-	-	-	-	-	-	-
13	RA	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.262
14	Other	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	11.810	11.430	11.430	12.152	11.219	9.463	10.600	9.669	10.339	10.878
16	**2021 Premium (cents/kwh)**	**(0.702)**	**(0.326)**	**(0.326)**	**(0.949)**	**(0.275)**	**0.991**	**0.171**	**0.843**	**0.359**	**(0.029)**

TABLE 13-2
GTSR PROGRAM – VINTAGE 2020 AND VINTAGE 2021
E-ECR OPTION

Line No.		E-1 cents/kwh	A1 cents/kwh	A-6 cents/kwh	A-10 cents/kwh	E-19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	E-20 T cents/kwh	E-20 P cents/kwh	E-20 S cents/kwh
	Charges										
1											
2	PCIA	3.223	3.219	3.219	3.318	3.058	2.569	2.886	2.626	2.813	2.964
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.336	0.336	0.336	0.336	0.336	0.336	0.336	0.336	0.336	0.336
5	Resource Adequacy	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798
6	CAISO Charges	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074
7	WREGIS Fees	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
8	**Subtotal**	**4.433**	**4.429**	**4.429**	**4.528**	**4.268**	**3.778**	**4.095**	**3.836**	**4.022**	**4.173**
9	**Credits**										
10	**Class Average Generation Rate**	11.548	11.168	11.168	11.890	10.956	9.201	10.338	9.407	10.076	10.616
11	Solar Value Adjustment										
12	TOD	-	-	-	-	-	-	-	-	-	-
13	RA	-	-	-	-	-	-	-	-	-	-
14	Other	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	11.548	11.168	11.168	11.890	10.956	9.201	10.338	9.407	10.076	10.616
16	**2021 Premium (cents/kwh)**	**(7.115)**	**(6.739)**	**(6.739)**	**(7.362)**	**(6.688)**	**(5.423)**	**(6.242)**	**(5.571)**	**(6.054)**	**(6.443)**

TABLE 13-3
GTSR PROGRAM – VINTAGE 2019
E-GT OPTION

Line No.		E-1 cents/kwh	A1 cents/kwh	A-6 cents/kwh	A-10 cents/kwh	E-19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	E-20 T cents/kwh	E-20 P cents/kwh	E-20 S cents/kwh
	Charges										
1	**Solar Generation Price**	6.703	6.703	6.703	6.703	6.703	6.703	6.703	6.703	6.703	6.703
2	PCIA	4.899	4.893	4.893	5.044	4.648	3.904	4.386	3.991	4.275	4.504
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309
5	Resource Adequacy	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798
6	CAISO Charges	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074
7	WREGIS Fees	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
8	**Sub Total**	**12.784**	**12.778**	**12.778**	**12.929**	**12.534**	**11.789**	**12.271**	**11.877**	**12.160**	**12.389**
9	**Credits**										
10	**Class Average Generation Rate**	11.548	11.168	11.168	11.890	10.956	9.201	10.338	9.407	10.076	10.616
11	Solar Value Adjustment										
12	TOD	-	-	-	-	-	-	-	-	-	-
13	RA	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.262
14	Other	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	11.810	11.430	11.430	12.152	11.219	9.463	10.600	9.669	10.339	10.878
16	**2021 Premium (cents/kwh)**	**0.974**	**1.348**	**1.348**	**0.777**	**1.315**	**2.326**	**1.671**	**2.208**	**1.822**	**1.511**

TABLE 13-4
GTSR PROGRAM – VINTAGE 2018
E-GT OPTION

Line No.		E-1 cents/kwh	A1 cents/kwh	A-6 cents/kwh	A-10 cents/kwh	E-19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	E-20 T cents/kwh	E-20 P cents/kwh	E-20 S cents/kwh
	Charges										
1	**Solar Generation Price**	6.703	6.703	6.703	6.703	6.703	6.703	6.703	6.703	6.703	6.703
2	PCIA	4.903	4.896	4.896	5.048	4.652	3.907	4.389	3.994	4.278	4.508
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309
5	Resource Adequacy	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798
6	CAISO Charges	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074
7	WREGIS Fees	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
8	**Sub Total**	**12.788**	**12.782**	**12.782**	**12.933**	**12.537**	**11.792**	**12.275**	**11.880**	**12.164**	**12.393**
9	**Credits**										
10	**Class Average Generation Rate**	11.548	11.168	11.168	11.890	10.956	9.201	10.338	9.407	10.076	10.616
11	Solar Value Adjustment										
12	TOD	-	-	-	-	-	-	-	-	-	-
13	RA	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.262
14	Other	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	11.810	11.430	11.430	12.152	11.219	9.463	10.600	9.669	10.339	10.878
16	**2021 Premium (cents/kwh)**	**0.978**	**1.352**	**1.352**	**0.781**	**1.318**	**2.329**	**1.675**	**2.211**	**1.825**	**1.515**

TABLE 13-5
GTSR PROGRAM – VINTAGE 2017
E-GT OPTION

Line No.		E-1 cents/kwh	A1 cents/kwh	A-6 cents/kwh	A-10 cents/kwh	E-19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	E-20 T cents/kwh	E-20 P cents/kwh	E-20 S cents/kwh
	Charges										
1	**Solar Generation Price**	6.703	6.703	6.703	6.703	6.703	6.703	6.703	6.703	6.703	6.703
2	PCIA	4.873	4.867	4.867	5.018	4.624	3.884	4.363	3.971	4.253	4.481
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309
5	Resource Adequacy	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798
6	CAISO Charges	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074
7	WREGIS Fees	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
8	**Sub Total**	**12.759**	**12.752**	**12.752**	**12.903**	**12.509**	**11.769**	**12.248**	**11.856**	**12.138**	**12.366**
9	**Credits**										
10	**Class Average Generation Rate**	11.548	11.168	11.168	11.890	10.956	9.201	10.338	9.407	10.076	10.616
11	Solar Value Adjustment										
12	TOD	-	-	-	-	-	-	-	-	-	-
13	RA	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.262
14	Other	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	11.810	11.430	11.430	12.152	11.219	9.463	10.600	9.669	10.339	10.878
16	**2021 Premium (cents/kwh)**	**0.948**	**1.323**	**1.323**	**0.750**	**1.291**	**2.306**	**1.648**	**2.187**	**1.799**	**1.488**

TABLE 13-6
GTSR PROGRAM – VINTAGE 2016
E-GT OPTION

Line No.		E-1 cents/kwh	A1 cents/kwh	A-6 cents/kwh	A-10 cents/kwh	E-19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	E-20 T cents/kwh	E-20 P cents/kwh	E-20 S cents/kwh
	Charges										
1	**Solar Generation Price**	6.703	6.703	6.703	6.703	6.703	6.703	6.703	6.703	6.703	6.703
2	PCIA	4.785	4.779	4.779	4.926	4.540	3.813	4.284	3.898	4.176	4.399
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309
5	Resource Adequacy	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798
6	CAISO Charges	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074
7	WREGIS Fees	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
8	**Sub Total**	**12.670**	**12.664**	**12.664**	**12.812**	**12.425**	**11.699**	**12.169**	**11.784**	**12.061**	**12.285**
9	**Credits**										
10	**Class Average Generation Rate**	11.548	11.168	11.168	11.890	10.956	9.201	10.338	9.407	10.076	10.616
11	Solar Value Adjustment										
12	TOD	-	-	-	-	-	-	-	-	-	-
13	RA	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.262
14	Other	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	11.810	11.430	11.430	12.152	11.219	9.463	10.600	9.669	10.339	10.878
16	**2021 Premium (cents/kwh)**	**0.860**	**1.234**	**1.234**	**0.659**	**1.207**	**2.235**	**1.569**	**2.115**	**1.722**	**1.407**

TABLE 13-7
GTSR PROGRAM – VINTAGE 2015
E-GT OPTION

Line No.		E-1 cents/kwh	A1 cents/kwh	A-6 cents/kwh	A-10 cents/kwh	E-19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	E-20 T cents/kwh	E-20 P cents/kwh	E-20 S cents/kwh
	Charges										
1	**Solar Generation Price**	6.703	6.703	6.703	6.703	6.703	6.703	6.703	6.703	6.703	6.703
2	PCIA	4.790	4.784	4.784	4.932	4.545	3.817	4.289	3.903	4.180	4.404
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309	0.309
5	Resource Adequacy	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798	0.798
6	CAISO Charges	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074
7	WREGIS Fees	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
8	**Sub Total**	**12.675**	**12.669**	**12.669**	**12.817**	**12.430**	**11.703**	**12.174**	**11.788**	**12.065**	**12.289**
9	**Credits**										
10	**Class Average Generation Rate**	11.548	11.168	11.168	11.890	10.956	9.201	10.338	9.407	10.076	10.616
11	Solar Value Adjustment										
12	TOD	-	-	-	-	-	-	-	-	-	-
13	RA	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.262	0.262
14	Other	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	11.810	11.430	11.430	12.152	11.219	9.463	10.600	9.669	10.339	10.878
16	**2021 Premium (cents/kwh)**	**0.865**	**1.239**	**1.239**	**0.665**	**1.212**	**2.239**	**1.574**	**2.119**	**1.727**	**1.411**

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 14

BALANCING ACCOUNTS FORECASTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 14
BALANCING ACCOUNTS FORECASTS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 14
BALANCING ACCOUNTS FORECASTS

A. Introduction

The purpose of this chapter is to provide an overview of Pacific Gas and Electric Company's (PG&E) electric procurement balancing accounts and amortization of 2020 year-end balances for inclusion in 2021 electric rates.

The remaining sections in this testimony are organized as follows:

- Section B – Overview of PG&E's 2020 forecast year-end balances
- Section C – Description of the balances recorded in the Portfolio Allocation Balancing Account (PABA)
- Section D – Description of the transactions forecast in PABA
- Section E – Explanation of the 2020 forecast year-end balances
- Section F – Conclusion

B. Overview of Balancing Accounts Forecast

1. Summary of Forecast Methodology and Amortization

Similar to previous years and as adopted by the California Public Utilities Commission (CPUC or Commission),[1] the forecast end of 2020 balancing account balances are based on the balances recorded through April 30, 2020, plus forecast transactions from May 1 through December 31, 2020. These balances will be the subject of PG&E's Update to Prepared Testimony served on November 9, 2020 (November Update); and, except as described herein, are amortized for recovery through the 2021 Annual Electric True-Up (AET) advice letter process, or a subsequent electric rate

[1] On page 12 of D.20-02-047, the Commission found that "PG&E's use of recorded data through September 2019, plus a forecast of the remaining three months is appropriate and sufficient for its forecast."

change advice letter.[2] Based on PG&E's forecast presented in this testimony, PG&E anticipates filing two expedited applications to address the balancing account balances that have or will likely exceed the trigger levels set by the Commission. The balance forecasts in this testimony are prepared without consideration of the disposition of these anticipated applications.

a. Energy Resource Recovery Account Trigger Application

Decision (D.) 02-10-062 requires PG&E to file an expedited application when its Energy Resource Recovery Account (ERRA) balance reaches or exceeds 4 percent of the prior year recorded generation revenues, excluding California Department of Water Resources revenues. The 2020 year-end ERRA overcollection is forecast to exceed the $202 million 4 percent trigger level, as well as the $253 million 5 percent threshold, authorized in Advice 5798-E.[3] PG&E anticipates filing an expedited application to address the ERRA overcollection by July 31, 2020.

b. Power Charge Indifference Adjustment Undercollection Balancing Account Trigger Application

D.18-10-019 requires PG&E to file an expedited application to address the Power Charge Indifference Adjustment (PCIA) Undercollection Balancing Account (PUBA) when its recorded balance

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2 Consistent with previous years, and in accordance with PG&E's rate change procedures, the balancing account balances will be updated based on available recorded balances, plus the balance of the year authorized forecast. For example, the recorded balances included in PG&E's 2020 rates, authorized in Advice 5781-E, were based on recorded through December 2019, with the modifications ordered in D.20-02-047. In Finding of Fact 10 of that decision, the Commission stated that "PG&E's use of recorded data through December 2019, is appropriate and sufficient for its forecast."

3 Advice 5798-E was approved by the Commission on May 21, 2020, effective April 1, 2020.

reaches the 7 percent filing level of $112.5 million.[4] Based on the forecast presented in this testimony, PG&E anticipates filing an expedited application to address the PUBA undercollection sometime later this year.

2. Balancing Accounts Included in This Testimony

Below are brief descriptions of the balancing accounts included in this testimony.

a. Portfolio Allocation Balancing Account

As stated in PG&E's Electric Preliminary Statement Part HS, the purpose of the PABA is to recover above-market costs for PCIA-eligible generation resources from both bundled and departing load customers. The PABA is comprised of subaccounts for each year's vintage portfolio that records the costs, market revenues, and imputed revenues of all generation resources executed or approved by the Commission for cost recovery that year. Amounts include costs related to contracts executed with third parties and Utility-Owned Generation (UOG). PCIA-eligible generation resources are assigned based on the year the resource commitment is made (i.e., contract execution date or construction start date in the case of UOG). Customers are assigned cost responsibility for vintages of generation resources based upon when the customer departed bundled service.

b. Energy Resource Recovery Account

As stated in PG&E's Electric Preliminary Statement Part CP, the purpose of the ERRA is to record and recover power costs associated with PG&E's authorized procurement plan and California Public Utilities Code (Pub. Util. Code) Section 454.5(d)(3). Power costs recorded in ERRA are applicable solely to PG&E's bundled customers while power

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[4] On March 13, 2020, PG&E submitted Advice 5781-E to implement the 2020 ERRA Forecast Revenue Requirement in compliance with D. 20-02-047. In this advice letter, PG&E stated that if the PUBA under-collection reaches the 7 percent filing level of $112.5 million, and is further forecast to reach 10 percent trigger threshold of $160.7 million, PG&E will file an expedited application to change the PCIA rates and bring the balance back down below 7 percent. Advice 5781-E was approved by the Commission on April 17, 2020, effective as of April 13, 2020.

costs incurred on behalf of both bundled and departing load customers are recorded and recovered in the PABA.

c. Modified Transition Cost Balancing Account

As stated in PG&E's Electric Preliminary Statement Part CQ, the purpose of the Modified Transition Cost Balancing Account (MTCBA) is to record ongoing transition costs associated with procurement, and other costs as authorized by the Commission as defined by the Pub. Util. Code Section 367(a)(1)-(6).

d. New System Generation Balancing Account

As stated in PG&E's Electric Preliminary Statement Part FS, the purpose of the New System Generation Balancing Account (NSGBA) is to record the benefits and the costs of contracts associated with generation resources for which the Commission has determined that the costs and benefits will be allocated to all benefitting customers, including bundled, Direct Access, and Community Choice Aggregation customers. The net costs of these contracts are recovered through the New System Generation Charge.

e. Tree Mortality Non-Bypassable Charge Balancing Account

As stated in PG&E's Electric Preliminary Statement Part HW, the purpose of the Tree Mortality Non-Bypassable Charge Balancing Account (TMNBCBA) is to record and recover the net costs of tree mortality-related procurement contracts in compliance with Senate Bill 859, and Resolution (Res.) E-4770 and Res. E-4805 as defined in D.18-12-003.

f. PCIA Undercollection Balancing Account

As stated in PG&E's Electric Preliminary Statement Part HZ, the purpose of the PUBA is to record the shortfall in revenues accruing from departing load customers when the cap in the PCIA rate is reached. Starting in 2020, the cap of the PCIA rate is set at 0.5 cents-per kilowatt-hour more than the current cumulative system average rate per vintage.

3. Summary of 2020 Forecast Year End Balancing Account Forecast

Table 14-1 below shows a summary of PG&E's 2020 forecast year-end balancing account forecast, derived by adding the recorded balances as of April 2020, plus the forecast from May through December 2020, including an allowance for revenue franchise fees and uncollectibles (RF&U).[5] Column A shows the balances recorded in PG&E's accounts through April 2020, and Columns B through F reflects the May through December 2020 forecast. Column A and F sum to the "Forecast Year-End Balance" in Column G. Column I is the forecast year-end balances for recovery in rates, that is derived by adding Column G and the RF&U reflected in Column H.

TABLE 14-1
2020 FORECAST YEAR-END BALANCES
(THOUSANDS OF DOLLARS)

Line No.	Description	Recorded Balance	Forecast Cost	Forecast Customer Revenue	One Time Adjustments	Forecast Interest	Forecast Balance	Forecast Year-End Balance	RF&U @ 0.011349	Year-End Balalance with RF&U
		(A)	(B)	(C)	(D)	(E)	(F) = Σ (B..E)	(G) = (A) + (F)	(H)	(I) = (G) + (H)
1	ERRA	($513,208)	$1,550,898	($1,790,158)	$477,432	($9,092)	$229,081	($284,127)	($3,225)	($287,352)
2	MTCBA (i.e. Ongoing CTC)	(21,289)	41,145	(45,341)		(313)	($4,510)	($25,799)	($293)	($26,092)
3	NSGBA (i.e. CAM Charge)	192,338	125,121	(235,344)		1,867	($108,357)	$83,981	$953	$84,934
4	PABA (i.e. PCIA)	793,783	1,796,763	(2,063,325)	(477,432)	9,900	($734,094)	$59,689	$677	$60,367
5	TMNBCBA	75,305	25,292	(66,482)		754	($40,436)	$34,869	$396	$35,265
6	PUBA	0		272,367		1,885	$274,252	$274,252	$3,112	$277,364
7	**Total**	**$526,929**	**$3,539,219**	**($3,928,283)**	**$0**	**$5,000**	**($384,063)**	**$142,865**	**$1,621**	**$144,487**

Totals may not add due to rounding.

In Table 14-2 below, PG&E presents the 2020 Forecast Year-End PABA vintage subaccount balances. Line 1 shows the recorded beginning PABA vintage subaccount balances, brought forward from previous year and as of January 1, 2020. Lines 2 through 10 summarize the recorded PABA vintage subaccount balances through April 2020. Lines 11 through 19 reflects the forecast transactions discussed in Section D. Lines 20 through 31 are summations of preceding recorded and forecast items, plus RF&U.

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5 This forecast does not presuppose the Commission's disposition of the ERRA and PUBA Trigger applications PG&E anticipates filing pursuant to D.02-10-062 and D.18-10-019. The amounts shown in the testimony reflect the balances if no action was taken in regard to these applications.

TABLE 14-2
2020 FORECAST YEAR-END PABA VINTAGE SUBACCOUNT BALANCES
(THOUSANDS OF DOLLARS)

Line No.	Description	Legacy UOG	Vin 2009	Vin 2010	Vin 2011	Vin 2012	Vin 2013	Vin 2014	Vin 2015	Vin 2016	Vin 2017	Vin 2018	Vin 2019	Vin 2020	Total
1	Recorded Beginning Balance as of Jan 2020	($101,809)	$490,854	$203,635	$56,030	$57,149	$27,418	$6,735	$14,668	($4,825)	$2,455	$482	($39,078)	$0	$713,714
2	Recorded transactions from Jan to April 2020														
3	PCIA Customer Revenue	(183,862)	(260,905)	(69,413)	(20,002)	(22,783)	(3,903)	(403)	(1,243)	2,075	(965)	(1,011)	(20,640)	0	(583,053)
4	Portfolio Costs	658,801	576,464	141,368	46,655	51,416	16,135	178	5,791	4,354	1,991	1,233	2,518	(0)	1,506,904
5	Energy Value	(307,459)	(76,109)	(14,211)	(6,022)	(9,807)	(3,547)	(39)	(1,394)	(537)	(297)	(294)	0	0	(419,717)
6	RPS Value	(4,476)	(47,553)	(21,694)	(6,652)	(7,339)	(5,470)	(87)	(1,826)	(955)	(255)	(246)	(62)	(2)	(96,615)
7	RA Value	(63,962)	(55,398)	(2,518)	(3,307)	(2,321)	(459)	(18)	(134)	(742)	(51)	5	(269)	0	(129,175)
8	One Time Adjustments	4,072	(36,212)	(11,216)	(4,860)	(6,597)	(3,940)	(276)	(1,290)	(6,786)	(16,684)	(23,871)	(1,134)	(93,471)	(202,265)
9	Interest	(349)	2,769	1,097	287	296	130	26	74	(29)	27	(41)	(241)	(56)	3,991
10	Recorded Balance as at April 2020 (a) (∑ Line 1 through Line 9)	957	593,909	227,050	62,128	60,014	26,364	6,116	14,647	(7,444)	(13,779)	(23,744)	(58,906)	(93,529)	793,783
11	Forecast Balance from May to Dec 2020														
12	PCIA Customer Revenue	(431,758)	(1,189,507)	(332,240)	(99,187)	(73,299)	(39,429)	606	(5,677)	(8,308)	56,169	22,174	43,682	(6,552)	(2,063,325)
13	Portfolio Costs	1,283,307	1,551,784	297,572	105,787	95,178	44,273	863	9,478	13,070	3,586	5,850	6,192	13	3,416,954
14	Energy Value	(650,054)	(465,528)	(19,418)	(23,597)	(16,330)	(9,512)	(158)	(2,788)	(1,959)	(578)	(659)	(184)	(11)	(1,190,777)
15	RPS Value	(4,560)	(53,441)	(24,812)	(7,274)	(7,634)	(6,003)	(85)	(1,672)	(1,268)	(265)	(252)	(88)	(6)	(107,360)
16	RA Value	(180,180)	(114,795)	(7,620)	(7,689)	(6,652)	(2,015)	(45)	(309)	(364)	(109)	0	(2,275)	0	(322,054)
17	One Time Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	(477,432)	(477,432)
18	Interest	325	6,908	2,760	694	836	324	94	203	(95)	228	(139)	(482)	(1,756)	9,900
19	Forecast transactions from May to Dec 2020 (b) (∑ Line 11 through Line 18)	17,081	(264,579)	(83,758)	(31,266)	(7,901)	(12,363)	1,276	(765)	1,076	59,031	26,974	46,845	(485,744)	(734,094)
20	Year-End 2020 Forecast (c = a + b)														
21	Recorded Beginning Balance as of Jan 2020	(101,809)	490,854	203,635	56,030	57,149	27,418	6,735	14,668	(4,825)	2,455	482	(39,078)	0	713,714
22	PCIA Customer Revenue	(615,620)	(1,450,412)	(401,653)	(119,189)	(96,082)	(43,332)	203	(6,920)	(6,233)	55,204	21,163	23,043	(6,552)	(2,646,378)
23	Portfolio Costs	1,942,109	2,128,247	438,941	152,442	146,594	60,408	1,041	15,269	17,424	5,577	7,083	8,710	13	4,923,858
24	Energy Value	(957,513)	(541,637)	(33,629)	(29,619)	(26,137)	(13,060)	(197)	(4,182)	(2,496)	(875)	(953)	(184)	(11)	(1,610,494)
25	RPS Value	(9,035)	(100,994)	(46,506)	(13,926)	(14,973)	(11,473)	(172)	(3,498)	(2,223)	(520)	(497)	(150)	(9)	(203,975)
26	RA Value	(244,142)	(170,193)	(10,138)	(10,997)	(8,973)	(2,475)	(63)	(443)	(1,106)	(160)	5	(2,544)	0	(451,230)
27	One Time Adjustments	4,072	(36,212)	(11,216)	(4,860)	(6,597)	(3,940)	(276)	(1,290)	(6,786)	(16,684)	(23,871)	(1,134)	(570,903)	(679,697)
28	Interest	(23)	9,677	3,858	981	1,132	453	121	276	(123)	255	(180)	(724)	(1,812)	13,891
29	Year-End 2020 Forecast	18,037	329,330	143,292	30,863	52,113	14,001	7,392	13,882	(6,368)	45,252	3,230	(12,061)	(579,273)	59,689
30	RF&U @ 0.011349	205	3,738	1,626	350	591	159	84	158	(72)	514	37	(137)	(6,574)	677
31	**Year-End Balance Forecast with RF&U**	**$18,242**	**$333,068**	**$144,918**	**$31,213**	**$52,705**	**$14,159**	**$7,476**	**$14,039**	**($6,440)**	**$45,765**	**$3,267**	**($12,198)**	**($585,848)**	**$60,367**

Totals may not add due to rounding.

C. PABA Balances Recorded Through April 2020

The PABA balances recorded through April 2020 include customer revenue, authorized cost, transfers/adjustments and balancing account interest, in accordance with the Generally Accepted Accounting Principles, as well as PG&E's Electric Preliminary Statement Part HS. These transactions will be reviewed by the Commission in PG&E's 2020 ERRA Compliance Review Application to be filed in February 2021 after the recording of actual amounts for all months of 2020.[6]

The components of January through April transactions recorded in PABA are listed in Table 14-2 Lines 2 through 9. Below is a high-level description of these components.

1. Customer Revenue

Customer revenue appearing on Table 14-2, Line 3 includes revenue from both eligible departing load and bundled customers calculated from the PCIA rates effective as of January 1, 2020. It is a combination of the PCIA revenue extracted from customers' bills, as well as that accrued based on customers' usages that occur outside their billing cycles.

2. Portfolio Costs

Portfolio costs recorded in PABA (Table 14-2, Line 4) are as authorized in PG&E's Electric Preliminary Statement Part HS. These include (1) purchase power contracts; (2) adopted UOG revenue requirements;[7] (3) fuel and related transportation costs, and direct greenhouse gas costs; (4) renewable and/or resource adequacy sale transaction revenues allocated to the vintage subaccounts; and (5) miscellaneous costs or credits approved to be recovered in the generation revenue requirement and/or from bundled and departing load customers.

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6 D.20-02-047, page 12-13, the Commission stated that "Furthermore, PG&E is correct that the review of the PABA recorded balance is to occur within the ERRA Compliance Review proceeding and not the ERRA Forecast."

7 The adopted UOG revenue requirement associated with PG&E-owned generation includes capital and related non-fuel operating and maintenance expenses, as well as other non-fuel costs that are authorized in various Commission decisions.

3. Energy Value

The energy value on Table 14-2, Line 5 consists of California Independent System Operator Corporation (CAISO) related revenues and charges from energy and ancillary services market.

4. Retained Renewable Portfolio Standard and Resource Adequacy Values

The retained Renewables Portfolio Standard (RPS) and Resource Adequacy (RA) values (Table 14-2, Lines 6-7) are based on the recorded Retained RPS and RA quantities. These are then multiplied by the D.20-02-047 authorized RPS and RA Adders to calculate the applicable credits in PABA.[8]

5. One-Time Adjustments

Significant one-time adjustment transactions recorded in the period from January through April 30, 2020 that are included in Table 14-2, Line 8 are: (1) Recovery of Diablo Canyon seismic studies (DCSS) costs; (2) 2018 Cost Allocation Method (CAM) misallocation from ERRA to PABA; (3) Unsold RPS adjustment; and (4) Narrows Hydro sale and Manzanita Lake donation.

a. Recovery of DCSS Cost

In February 2020, PG&E recorded an adjustment of $4.6 million related to the recovery of the 2018 DCSS costs in PABA as authorized in D.20-02-009, the 2018 ERRA Compliance Review Decision, D.20-02-009.

b. 2018 CAM Misallocation from ERRA to PABA

In the 2020 ERRA Forecast Decision, D.20-02-047, the CPUC authorized the transfer of misallocated CAM credit amounts from ERRA to PABA for recovery in the PCIA rates from both the bundled and non-exempt departing customers. Accordingly, in April 2020, PG&E recorded a reclassification of 2018 CAM misallocation credit amounts from ERRA to PABA of $141.3 million.

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8 Corresponding debit entries are recorded in ERRA.

c. Unsold RPS Adjustment

In March 2020, PG&E recorded a credit of $69.3 million related to 2019 unsold Renewable Energy Credits (REC). This entry is an adjustment that is consistent with D.20-02-047, which found that 20 percent of starting bank RECs included in PG&E's Advice 5554-E should not be considered as unsold RPS. After removing the portion of the starting REC bank previously included as unsold RPS, PG&E recorded a credit of $69.3 million, with a corresponding debit to ERRA to increase the retained RPS value for the 2019 record year.

d. Narrows Hydro Facility Sale and Manzanita Lake Donation

In March 2020, PG&E recorded an adjustment of $3.7 million related to the recovery of the loss on Narrows Hydro Facility Sale and Manzanita Lake Facility Donation in PABA as authorized in the PG&E Sale of Narrow Hydroelectric Project Decision, D.19-10-010.

6. Balancing Account Interest

The balancing account interest on Table 14-2, Line 9 is calculated based on the three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15.

D. PABA Forecast from May through December 2020

The components of the forecasted PABA transactions from May 1, 2020 through December 31, 2020 and reflected in Table 14-2, are: (1) Customer revenue; (2) Portfolio costs and energy value; (3) Retained RPS and RA values (4) One-time adjustment; and (5) Balancing account interest. These components are calculated based on the same methodologies and assumptions described in the other chapters of PG&E's Prepared Testimony in this Application, as well as in PG&E's rate change advice letters,[9] effective May 1, 2020. Consistent with the forecast methodology described in Section B.1 above, the forecast presented in the Tables 14-1 and 14-2 will be updated with recorded values in the November Update.

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[9] See, PG&E Advice Letters 5781-E, 5661-E, 5661-E-A, 5661-E-B, 5661-E-C and 5661-E-C.

1. Customer Revenue

The forecast billed revenue (Table 14-2, Line 12) is calculated by multiplying the rates which became effective May 1, 2020, with the applicable customer load forecast that was updated for 2020 as part of the load forecast detailed in Chapter 2 of PG&E's Prepared Testimony.

2. Portfolio Costs and Energy Value

a. Energy Procurement Costs and Energy Value

PG&E's forecast generation resource and supply costs for May-December 2020 (Table 14-2, Lines 13-14) are based on the same methodologies described in Chapters 3 through 12 of the Prepared Testimony. The model run to determine dispatch and prices used to forecast 2020 costs and revenues is the same vintage as used to calculate the 2021 forecast amounts (i.e., price curve date of April 14, 2020).[10]

b. UOG Related Cost

The UOG-related cost forecast reflects the UOG revenue requirement as authorized in the Commission's decisions, and recoverable through 2020.

3. Retained RPS and RA Values

The retained RPS and RA value (Table 14-2, Lines 15-16) is based on the forecasted Retained RPS and RA quantities. These are then multiplied by the D.20-02-047 authorized RPS and RA Adders to calculate the applicable credits in PABA.[11]

4. One-Time Adjustment

Except for the deferred revenue collected in generation rates, resulting from the implementation of capped vintage PCIA rates applicable to non-exempt departing load effective May 1, 2020, PG&E proposes to transfer both the ERRA recorded and forecast balances, totaling

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10 On April 21, 2020, the CPUC's executive director granted two specific requests made by PG&E: (1) additional time to file the ERRA Forecast Application, from June 1 to July 1, due to the logistical challenges associated COVID-19 safety measures; and (2) tie the single day price quote to the original June 1, 2020 filing date.

11 Corresponding debit entries are recorded in ERRA.

$477 million, to the PABA Vintage 2020 Subaccount (see Table 14-2, Line 17). The purpose of this transfer is to ensure that the 2020 overcollected ERRA is returned to the Vintage 2020 non-exempt departing load customers and remaining bundled customers, as described in Chapter 19 of this testimony.

5. Balancing Account Interest

The respective preliminary statements of the balancing accounts described in Section B, authorize PG&E to include interest in calculating the balances for recovery in rates. The forecast balancing account interest in Table 14-2, Line 18, is calculated based on a placeholder of 2.07 percent per annum.

Consistent with the previous year applications, the forecast transactions and adjustments will be updated in the November Update.

E. Primary Drivers of the 2020 Forecast Year End Balancing Account Forecast

The primary drivers of the over/under collected balances are due to the delay in the implementation of rates approved in D.20-02-047, as well as variances in the sales load forecast and market prices, among other things. Explanations of the PABA forecast year-end undercollection, ERRA forecast year-end overcollection; and PUBA forecast year-end undercollection, are as follows:

1. PABA Undercollection

In Table 14-1, Line 1 and Table 14-2, Line 31, PG&E presents its PABA forecast year-end undercollection of $60 million. The primary drivers of the 2020 year-end PABA balance forecast are below.

a. Late Implementation of the Authorized PCIA Rates

D.20-02-047 authorized PG&E's 2020 PABA revenue requirements for recovery in rates, with modification. Subsequently, on March 3, 2020, PG&E filed Advice 5781-E, requesting to implement these rates. Advice 5781-E was approved on April 17, 2020, and the new 2020 PCIA rates were effective May 1, 2020 upon PG&E's filing of the Tier 1 2020 AET Advice 5661-E-A, and subsequent supplementals.

As a result of the late implementation of the 2020 PCIA rates recovered in PABA, PG&E was collecting the lower 2019 PCIA rates from January through April 2020. Based on the authorized forecast in rates, the impact of the undercollection is approximately $325 million.[12]

b. Lower PCIA-eligible Customer Demand

Total PG&E sales quantities are approximately 1,550 gigawatt-hour (GWh) less than the authorized 2020 authorized sales forecast, driven by mild weather and shelter-in-place impacts related to COVID-19 (reflects actuals for months January-April 2020). PCIA eligible load is correspondingly reduced, resulting in lower than forecast PCIA revenue of approximately $45 million. The forecasted months (May-December) do not reflect COVID-19 sales impacts.

c. CAISO Energy Revenues Are Lower Than Expected

Generation from PCIA-eligible resources is approximately 3,500 GWh less than the authorized 2020 forecast driven primarily by lower than expected precipitation and snowpack. This reduction in generation represents an approximately $120 million under-collection in energy value.

d. Recorded 2019 Unsold RPS

Pursuant to D.20-02-047, PG&E reduced the 2020 PCIA revenue requirement by $93 million to remove the unsold RPS value entry that had been included in the 2019 year-end PABA balancing account forecast. As presented in PG&E's 2019 ERRA Compliance Review testimony,[13] the correct adjustment for the 2019 unsold RPS entry should have been for $69 million. The net impact from the initial revenue requirement adjustment for 2020 PCIA rates and the correct recorded entry represents a $24 million under-collection.[14]

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12 Calculated based on forecast in rates.

13 2019 ERRA Compliance Review (A.20-02-009) supplemental testimony submitted on April 13, 2020, p. 2-1, Line 12 through p. 2-4, Line 4.

14 The corresponding over-collection impact is in ERRA.

e. Other Miscellaneous Items

Other miscellaneous items include updated higher recorded cost and balancing account interest totaling approximately $20 million.

f. Return of Overcollected ERRA, Less Deferred Revenue, to the PABA Vintage 2020 Subaccount Through a Transfer From the ERRA

PG&E proposes to credit the PABA Vintage 2020 Subaccount the $477 million of the ERRA recorded and forecast balances, excluding the Deferred Revenue, as described in Section D.4 above. The purpose of this transfer is to ensure that the 2020 overcollected ERRA is returned to the Vintage 2020 non-exempt departing load customers and remaining bundled customers, as described in Chapter 19 of this testimony. A corresponding debit for this entry is made in the ERRA.

2. ERRA Overcollection

The forecast year-end ERRA overcollection $287 million (Table 14-1, Line 2) primarily consists of the forecast deferred revenue, resulted from the implementation of capped vintage PCIA rates applicable to non-exempt departing load (Revenue Deferral).[15] This is after accounting for PG&E's proposed transfer of the $477 million recorded/forecast overcollected ERRA balance to the PABA Vintage 2020 Subaccount, as described in Section D.4 above.[16] The primary drivers of the $477 million recorded/forecast overcollected ERRA are explained below.

a. Late Implementation of Authorized 2020 Costs in Generation Rates

D.20-02-047 authorized PG&E's 2020 ERRA revenue requirements for recovery in rates, with modification. Subsequently, on March 3, 2020, PG&E filed Advice 5781-E, requesting to implement these rates. Advice 5781-E was approved on April 17, 2020, and the new 2020 generation rates were effective May 1, 2020.[17]

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15 Include balancing account interest and an allowance for RF&U.

16 The corresponding credit in PABA is described in Section E.1(f) of this chapter.

17 See PG&E's AET advice letter, Advice 5661-E-A and subsequent supplementals.

As a result of the late implementation of the 2020 generation rates recovered in ERRA, PG&E was collecting the higher 2019 generation rates from January through April 2020. Based on authorized forecast in rates, the impact of the overcollection is approximately $170 million.

b. Unamortized 2019 ERRA Balance From Delayed Rate Implementation

PG&E's 2020 generation rates for bundled customers included an approximately $380 million overcollection credit adjustment for the 2019 year-end ERRA balance. As a result of the four months delay in the implementation of the 2020 generation rates, approximately $115 million of the 2019 year-end ERRA overcollection is not amortized in 2020.[18]

c. CAM Adjustment Rate Implementation

As ordered in D.20-02-047 and effective on May 1, 2020 in PG&E's AET, PG&E made a one-time rate adjustment to account for the misallocation of CAM costs.[19] PG&E implemented the revenue requirements approved in D.20-02-047 after updating for the year-end balances as outlined in Table 2 of Advice 5781-E. During the implementation of this adjustment, bundled generation rates were inadvertently set too high. As a result, PG&E forecasts an overcollection in ERRA for bundled customers of approximately $95 million by year end. PCIA rates were correctly implemented. PG&E has not yet sought to address this discrepancy through Commission processes. PG&E's November Update will reflect disposition of this balance.

d. CAISO Energy Unit Costs for Load Are Lower Than Expected

Mild weather and shelter-in-place impacts related to COVID-19 have driven the average CAISO cost per megawatt-hour (MWh) for load down by approximately $4 per MWh. This reduction has lowered the procurement costs for PG&E bundled load by approximately $160 million.

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18 Calculated based on forecast in rates.

19 See PG&E's 2020 ERRA Forecast Application (A.19-06-001), Chapter 14 and Section C.5(b) of this testimony for more discussions.

e. Lower Bundled Customer ERRA Demand

Mild weather and shelter-in-place impacts related to COVID-19 reduced PG&E's bundled customer demand from January through April 2020. The lower than expected demand reduced revenues from bundled customers by approximately $200 million, which were partially offset by approximately $95 million in lower CAISO energy market costs for bundled load. The net impact is an under-collection of $105 million.

f. Recorded 2019 Unsold RPS

Pursuant to D.20-02-047, PG&E reduced the 2020 PCIA revenue requirement by $93 million to remove the unsold RPS value entry that had been included in the 2019 year-end PABA balancing account forecast. As presented in PG&E's 2019 ERRA Compliance Review testimony,[20] the correct adjustment for the 2019 unsold RPS entry should have been for $69 million. The net impact from the initial revenue requirement adjustment for 2020 PCIA rates and the correct recorded entry represents a $24 million over-collection.[21]

3. ERRA Trigger

On May 19, 2020, PG&E sent a letter to the Energy Division informing the Commission that the ERRA balance exceeded the 4 percent trigger point and 5 percent threshold amount established in Advice 5798-E.[22] PG&E forecasts that the ERRA overcollection will not self-correct within 120 days. In this letter, PG&E requested an extension to July 31, 2020, to file its ERRA Trigger Application for 2020 (the 2020 ERRA Trigger Application). The purpose of PG&E's request, among other things, is to improve the accuracy of the 2020 ERRA Trigger Application by incorporating the forecast data developed in Section D above. PG&E's request was granted by the Commission on June 5, 2020.

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20 See also Section E.1(d).

21 The corresponding under-collection impact is in PABA.

22 On April 1, 2020, PG&E's submitted AL 5798-E to establish the trigger point and threshold amounts for calendar year 2020, in the amounts of $202 million and $253 million, respectively. Advice Letter 5798-E was accepted by the Commission effective April 1, 2020.

4. PUBA

Due to the late implementation of the 2020 authorized PCIA rates, there were no accounting entries recorded in PUBA from January through April 2020. The May through December 2020 forecast PUBA amounts were calculated based on the difference between capped vintage PCIA rates applicable to non-exempt departing load and uncapped vintage PCIA rates authorized in D.20-02-047 and Advice 5781-E, multiplied by the May through December 2020 non-exempt departed sales forecast by vintage that has been updated in this application. Based on this forecast methodology, the forecast year-end PUBA undercollection is $277 million, as reflected in Table 14-1, Line 6, as well as in Table 14-3 below that shows the balances by eligible departed customer vintages.

TABLE 14-3
2020 FORECAST YEAR-END PUBA BALANCE
(THOUSANDS OF DOLLARS)

Line No.	Eligible Departed Customer Vintages	Forecast Year-End Balance	RF&U @ 0.011349	Forecast Year-End Balalance with RF&U
		(A)	(B)	(C) = (A) + (B)
1	Vin 2009	$5,635	$64	$5,699
2	Vin 2010	17,029	193	17,222
3	Vin 2011	8,529	97	8,626
4	Vin 2012	1,407	16	1,423
5	Vin 2013	8,191	93	8,284
6	Vin 2014	13,995	159	14,154
7	Vin 2015	2,283	26	2,309
8	Vin 2016	57,528	653	58,181
9	Vin 2017	87,983	999	88,981
10	Vin 2018	69,769	792	70,561
11	Vin 2019	1,901	22	1,923
12	**Total**	**$274,252**	**$3,112**	**$277,364**

Totals may not add due to rounding.

In accordance with D.18-10-019, PG&E anticipates that the PUBA balance will exceed both the 7 percent filing level and 10 percent trigger threshold presented in PG&E's Advice Letter 5781-E. Assuming the monthly recorded PUBA balance reflects the forecast presented in this testimony, PG&E expects to file an expedited application to address the PUBA balance as required by D.18-10-019 once recorded actuals reach the thresholds established for filing. This forecast does not reflect the

anticipated, but not yet filed, PUBA Trigger application. Depending on when an expedited application may be filed, PG&E will update its PUBA balance accordingly in its November Update.

F. Conclusion

In this chapter, PG&E presents its 2020 year-end balances in Table 14-1 that includes a transfer of the 2020 ERRA balance, except for the Revenue Deferral, to PABA for amortization for in rates over 2021. These forecast balances will be consolidated with the revenue requirements presented in the other chapters of this testimony; and updated in November for recovery through the 2021 AET, or subsequent electric rate change advice letter process, as authorized by the Commission.[23]

[23] Except as modified by the Commission decisions in ERRA and PUBA trigger applications discussed in this chapter.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 15

GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION – COST CALCULATIONS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 15
GREENHOUSE GAS FORECAST REVENUE AND
RECONCILIATION – COST CALCULATIONS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 15
GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION – COST CALCULATIONS

A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) develops the necessary information to support detailed discussion of the 2021 greenhouse gas (GHG) allowance revenue return calculations appearing in Chapter 17.

This chapter partly relies on PG&E's forecast of the direct GHG emissions compliance expenses PG&E expects to incur and record to its balancing accounts in 2021.[1]

To develop the necessary information to support Chapter 17's detailed discussion of the 2021 GHG allowance revenue return calculations, this chapter:

1) Presents PG&E's estimate of the indirect GHG emissions compliance expenses that PG&E anticipates will be recorded in 2021;
2) Adds that amount to the estimate of direct GHG emissions compliance expenses that PG&E anticipates will be recorded in 2021, which is included in the cost forecasts presented in Chapters 3 through 6 of this testimony, to derive a forecast of the total amount, direct plus indirect, of GHG emissions compliance expenses that PG&E anticipates will be recorded in 2021; and
3) Presents a reconciliation of the 2019 GHG cost forecast that was included in PG&E's 2019 Energy Resource Recovery Account (ERRA) Forecast Application 18-06-001.[2]

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[1] The California Air Resources Board (CARB) Cap-and-Trade Program results in two categories of GHG compliance costs: (1) direct GHG costs; and (2) indirect GHG costs embedded in wholesale market purchases and other contract purchases.

[2] This testimony is being provided consistent with the California Public Utilities Commission's (CPUC or Commission) direction in Decision (D.) 12-12-033 and D.14-10-033. In D.12-12-033, the CPUC ordered the Investor-Owned Utilities (IOU) to file annually a GHG Forecast Revenue and Reconciliation (GHG FR&R) application, separate from the corresponding ERRA forecast application. In D.14-10-033, the CPUC ordered PG&E, beginning in 2015, to file its GHG FR&R as part of its ERRA Forecast application.

The remainder of this chapter is organized as follows:

- Section B – Calculation of Forecast GHG Costs
- Section C – Reconciliation of Forecast GHG Costs[3]
- Section D – Conclusion

B. Calculation of Forecast GHG Costs

1. Forecast Direct GHG Costs

The Direct GHG costs PG&E forecasts to incur for contracted and Utility-Owned Generation resources are included in the total costs presented in Chapters 4-6. These costs are broken out and presented in Table 15-1.

2. Forecast Indirect GHG Costs

In addition to direct GHG costs, the Cap-and-Trade Program results in an embedded GHG compliance cost for required allowances in the market price of electricity procured in the wholesale market and from third parties, thereby increasing PG&E's cost to purchase electricity from the wholesale market, as well as from suppliers under contracts that include market-based prices. PG&E's forecast of the overall cost of electricity from third parties and in the wholesale market therefore includes these embedded, indirect GHG costs. PG&E is not directly buying allowances and surrendering them to CARB for these electricity supplies. Indirect GHG compliance costs are presented in this chapter for the purpose of allocating GHG allowance revenue return, which is presented in Chapter 17.

The GHG emissions embedded in market energy cannot be determined precisely. Suppose that PG&E purchases 1 megawatt-hour (MWh) from the wholesale market at $50/MWh, on a day when the price of natural gas to generators is $5/Millions of British Thermal Units (MMBtu). At $50/MWh and $5/MMBtu, the marginal, price-setting generator could be any of the following:

- The marginal generator was a gas-fired unit with a heat rate of 10 MMBtu/MWh, with zero variable operations and maintenance (O&M) costs and zero profit. 10 MMBtu were burned to provide the 1 MWh purchase, resulting in 0.53 metric tons (MT) of GHG emissions.

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[3] This section includes a detailed discussion of the weighted-average cost (WAC) of GHG compliance instruments calculation used to calculate recorded direct GHG costs.

- The marginal generator was a gas-fired unit with a heat rate of 9 MMBtu/MWh, with $5/MWh variable O&M costs and zero profit. 9 MMBtu were burned to provide the 1 MWh purchase, resulting in 0.48 MT of GHG emissions.
- The marginal generator was a gas-fired unit with a heat rate of 8 MMBtu/MWh, with $5/MWh variable O&M costs and $5/MWh profit. 8 MMBtu were burned to provide the 1 MWh purchase, resulting in 0.42 MT of GHG emissions.
- The marginal generator was a hydroelectric unit bidding its opportunity cost. No gas was burned to provide the 1 MWh purchase, resulting in zero GHG emissions.

These examples demonstrate that it is not possible to pinpoint the emissions embedded in market purchases. Therefore, estimation is necessary.

Wholesale Purchases: To estimate the GHG cost embedded in wholesale energy, PG&E currently uses marginal GHG-emission rate assumptions from the GHG calculator developed for the CPUC by Energy and Environmental Economics, Inc. (E3).[4] As stated above, PG&E's estimate of GHG exposure associated with energy from the wholesale market does not represent direct purchase of compliance instruments by PG&E; instead, it is a GHG cost, embedded in market energy.

Other Contract Purchases: In some contracts (e.g., certain contracts with Qualifying Facilities and Combined Heat and Power (CHP) facilities), the energy price changes in tandem with a change in the GHG allowance price. Such variation exposes PG&E's customers to fluctuations in the GHG allowance price. It is not a direct exposure—PG&E customers are not actually paying a different price for GHG compliance instruments. Instead, the change in the GHG allowance price will be passed through to customers indirectly, via contract terms for energy prices.

The sensitivity of contractual energy prices to the GHG allowance price varies across contracts. For example, under one CHP contract option,

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4 See E3 GHG Calculator Version 3c, "Calibration" tab, cells F213:F216, showing time of use emission rates in short tons per MWh. Available at: http://ethree.com/public_projects/cpuc2.php.

PG&E pays the seller's GHG cost at a rate of 0.435 MT per MWh, multiplied by the lesser of: (1) the GHG allowance price, or (2) $20/MT. In other words, the exposure is capped. Some CHP contracts include a heat rate of 8,125 MMBtu per kilowatt-hour, which corresponds to a GHG emission rate of 0.43 MT per MWh for a natural-gas-fueled facility.

For those contracts that pose an indirect GHG exposure, PG&E uses an emission rate of 0.43 MT per MWh to estimate indirect GHG exposure from such contracts.

Table 15-1 presents PG&E's confidential forecast of the total amount, direct plus indirect, of GHG emissions compliance expenses that PG&E anticipates will be recorded in the Portfolio Allocation Balancing Account (PABA) in 2020.[5]

To provide greater transparency, as ordered by the CPUC in D.14-10-033, PG&E also presents an illustrative 2021 GHG cost forecast in Table 15-2.[6] PG&E calculates the illustrative 2021 GHG cost forecast by multiplying forecast GHG emissions by a forecast proxy GHG allowance price. PG&E uses the April 14, 2020 settlement price of an Intercontinental Exchange California Carbon Allowance futures contract with a 2021 vintage year for delivery in December 2021 as the forecast proxy GHG allowance price, as ordered by the CPUC in D.14-10-033.[7]

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5 PG&E's GHG cost forecast is calculated by multiplying forecast GHG emissions by confidential GHG allowance prices from PG&E's proprietary Market Data System (MDS) model.

6 D.14-10-033, as corrected by D.15-01-024, included attachments that provided templates for IOUs to use when presenting certain information in ERRA forecast applications. Tables 15-1 and 15-2 are equivalent to Template D-2: Annual GHG Emissions and Associated Costs. Table 15-3 in this application is equivalent to Template C: Reporting Template to Calculate WAC of Compliance Instruments in those decisions.

7 The proxy GHG allowance price quote date is consistent with the quote date for natural gas and electricity forward prices used to calculate PG&E's 2021 procurement cost forecast in this application, based on a process adopted by the Commission in D.06-20-018, Ordering Paragraph 5. While GHG procurement costs included in PG&E's 2021 revenue request are calculated using PG&E's confidential forecast GHG allowance prices from MDS, rather than a proxy GHG allowance price, the quote date is the same for both prices. On April 21, 2020, the CPUC's executive director granted PG&E's request for (1) additional time to file the ERRA Forecast Application, from June 1 to July 1, due to the logistical challenges associated COVID-19 safety measures; and (2) keeping the single day price quote tied to the original June 1, 2020 filing date.

C. Reconciliation of Forecast GHG Costs

For the purpose of adjusting the return of GHG allowance revenues discussed in Chapter 17, PG&E is also including with this application a reconciliation of GHG procurement costs previously forecasted for 2019 in PABA with recorded direct GHG costs and an updated estimate of indirect GHG costs. The 2020 GHG cost forecast will be partially reconciled later this year in PG&E's Update to Prepared Testimony, to be submitted in November 2020, and fully-reconciled next year in the 2022 ERRA Forecast Application.

PG&E's GHG cost reconciliation included here is intended only for adjusting the 2021 distribution of GHG allowance revenues to eligible customers. The balancing accounts already includes a true-up mechanism to reconcile differences between forecast and actual procurement costs, including GHG costs.

1. Recorded Direct GHG Costs

PG&E calculates direct GHG costs for all generation resources for which PG&E has a direct GHG compliance cost. This includes PG&E-owned natural gas-fired power plants, tolling agreements, pre-scheduled CHP facilities, and electricity imports. Direct GHG emissions compliance expenses recorded in PABA for a particular year reflect: (1) the cost of compliance instruments PG&E uses out of its inventory to meet PG&E's annual direct GHG compliance obligation for that year; plus (2) the financial settlement PG&E pays to generators, where PG&E has a contractual provision to reimburse the generator for GHG compliance costs, for the annual GHG compliance obligation PG&E incurs to the generator for that year.[8]

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[8] PG&E has the option to elect financial settlement of GHG emissions obligations with some of its tolling counterparties. Additionally, some contracts require PG&E to provide financial settlement of GHG emissions obligations to the counterparty. In both cases, the GHG emission costs recorded in the PABA are embedded within the contract payments made to the counterparty and; therefore, recorded in the same PABA accounting procedure as the contract costs, rather than the accounting procedure for direct GHG emissions costs. For example, 2019 financially settled tolling agreement costs for both the contract and GHG emissions payments made to the counterparty are recorded, pursuant to tariff line item 5.z. for bilateral contracts.

a. Calculation of GHG Compliance Instrument Expense Recorded

This section provides a detailed discussion of how PG&E calculates the costs of GHG compliance instruments PG&E uses out of its inventory to meet PG&E's GHG emissions compliance obligation in a given year. PG&E uses the weight-average cost (WAC) methodology to calculate and record its monthly direct GHG emissions expense for all generation resources for which PG&E procures compliance instruments to cover the compliance obligation. The WAC sets the unit cost that PG&E used to record, each month of 2019 in PABA, the direct GHG emissions expense PG&E incurred for its physically settled emissions obligations.

The costs associated with PG&E's purchase of GHG compliance instruments in a given year will not necessarily match with the direct emissions costs recorded in that same period. For example, GHG allowances and offset credits purchased from other third-party sellers are recorded to PG&E's inventory when they are received. Such purchased quantities of compliance instruments may be greater or lesser than PG&E's monthly emissions. For each month in 2019, GHG emissions costs were recorded in PABA based on the accrual method of accounting using the best available volume of emissions and WAC price at the time the emissions costs are recorded. Physical compliance obligation costs were calculated as the WAC price of Eligible Compliance Instruments held in inventory at the end of a month multiplied by the quantity of emissions generated in that month. The accrual amount will continue to be trued-up in subsequent months as new or additional information becomes available for emission quantities and for WAC price changes.[9]

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9 When the cost, or debit, is recorded in the PABA, a corresponding entry, a credit, is recorded to a liability account, reflecting PG&E's liability to surrender GHG compliance instruments to the CARB. The inventory and liability accounts are reduced when the GHG compliance instruments have been surrendered to the CARB and/or transferred to a third party.

PG&E's current methodology for calculating the WAC is consistent with D.19-04-016 adopting the Petition for of D.15-01-024.[10] The WAC is calculated for each specified compliance period. When compliance instruments are purchased, they are held in Inventory at the purchase price. When compliance instruments are added, the Inventory increases, and the WAC price may change. The cost of inventory also increases when there are payments in fees or premiums related to the compliance instruments. The WAC is calculated as the total cost, inclusive of fees and premiums, of eligible compliance instruments in inventory, divided by the total quantity of eligible compliance instruments in inventory. Compliance instruments held in inventory are segregated by their eligible compliance periods (based on the vintage year). This methodology is done in accordance with generally accepted accounting practices.

The accounting expense is then determined by comparing the total change in the expected gross emissions expense inception to date less the total cumulative recorded emissions expense inception to date. The emissions expense is based on the current WAC of inventory ($/metric tons of carbon dioxide equivalent ($mtCO_2e$)) multiplied by emissions volumes ($/$mtCO_2e$).

Table 15-3 shows the WAC calculation and direct emissions expense recorded to the PABA in 2019, as ordered in D.14-10-033, Appendix C, corrected and replaced Attachment C in its entirety in D.15-01-024.

2. Estimated Indirect GHG Costs

Section B.2 above describes how PG&E estimates indirect GHG costs embedded in wholesale market energy and other contract purchases tied to market-based prices. As discussed, forecast indirect GHG costs are estimated and cannot be precisely determined. For the purpose of an annual GHG cost reconciliation to adjust 2020 GHG allowance revenue

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10 The PFM clarifies the calculation of the WAC and makes the calculation consistent for PG&E, Southern California Edison Company, and San Diego Gas & Electric Company. It does not change the calculation methodology for PG&E.

distribution for eligible customers, PG&E uses the following simplified method to update the estimate of 2019 indirect GHG costs.

PG&E calculates the updated estimate of indirect GHG emissions amounts using 2019 recorded energy volumes from wholesale market energy and Power Purchase Agreements with energy pricing based on market prices: a market power price, market heat rate, or GHG allowance price. Recorded energy volumes from these generation resources are multiplied by the applicable CARB default emission factor for unspecified sources[11] to estimate indirect GHG emissions amounts.

To reconcile indirect GHG costs, the updated estimate of indirect GHG emissions amounts is multiplied by a historical average GHG allowance price for the applicable forecast year.[12] PG&E uses the annual average of the California Independent System Operator Corporation's (CAISO) daily GHG Allowance Price Index for 2019 to calculate the historical average GHG allowance price in this calculation, per the methodology adopted in D.14-10-033.[13]

Tables 15-1 and 15-2 show the total 2019 GHG cost forecast included in the 2020 ERRA forecast, the reconciled 2019 GHG cost forecast and the difference between the two forecasts. The cost difference will be used to adjust GHG allowance revenue return to eligible customers.

D. Conclusion

In this chapter, PG&E presents forecasted direct and estimated indirect GHG costs for 2021, and a reconciliation of the 2019 GHG cost forecast, including a detailed report of the monthly WAC and direct GHG emissions quantities for 2019 used to calculate 2019 recorded direct GHG costs. These are presented in this chapter for the purpose of allocating 2021 GHG allowance revenue return to eligible customers, as discussed in Chapter 17.

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11 See Chapter 7, Section B, for details regarding CARB's default emission factor.

12 As part of the compensation structure, some contracts have estimated indirect GHG emissions for which PG&E estimated a fixed $10/MT GHG expense. For those contracts, indirect GHG costs are estimated using the $10/MT assumption, instead of the historical average GHG allowance price.

13 D.14-10-033 directed the IOUs to compute the annual average of CAISO's daily GHG Allowance Price Index by summing the published daily price for the recorded year and dividing by the number of days in that year.

TABLE 15-1
CONFIDENTIAL ANNUAL GHG EMISSIONS AND ASSOCIATED COSTS
(TEMPLATE D-2)

Line No.	Description	2019 Forecast	2019 Recorded	2019 Final	2020 Forecast	2020 Recorded	2020 Final	2021 Forecast	2021 Recorded	2021 Final
1	Direct GHG Emissions (MT CO2e)									
2	Utility Owned Generation (UOG)									
3	Tolling Agreements									
4	Energy Imports (Specified)									
5	Energy imports (Unspecified)									
6	Qualifying Facility (QF) Contracts									
7	Contracts with Financial Settlement									
8	Subtotal									
9	Indirect GHG Emissions (MT CO2e)									
10	CAISO Market Purchases (Net Physical)									
11	Contract Purchases									
12	Subtotal									
13	**Total Emissions (MT CO2e)**	**(229,481)**	**(4,858,020)**	**(1,458,828)**	**(1,847,720)**	**(1,847,720)**	**-**	**(3,759,525)**	**-**	**-**
14	Proxy GHG Price ($/MT) (a)	16.33	17.29	17.28	17.78	17.78	-	16.80	-	-
15	GHG Costs ($)									
16	Direct GHG Costs (b)									
17	Direct GHG Costs - Financial Settlement									
18	Indirect GHG Costs									
19	Previous Year's Forecast Reconciliation (Line 21)	1,242,241	1,242,241		7,227,812	(78,093,722)		48,772,379	-	
20	**Total Costs ($)**	**(4,639,991)**	**(82,733,714)**	**(33,961,335)**	**(25,616,101)**	**(110,947,660)**		**(10,739,757)**	**-**	
21	Forecast Variance ($)	N/A	(78,093,722)	48,772,379	N/A	-		N/A	-	

(a) The difference between PG&E's confidential 2021 forecast GHG price and the 2021 forecast GHG proxy price is less than five percent.
(b) D.15-01-024 directs utilities to calculate recorded direct GHG Costs as the sum of each month's weighted average cost (WAC) of compliance instruments held in inventory multiplied by that month's actual GHG emissions. Recorded and Final Direct GHG Costs presented here are consistent with the requirements of D.15-01-024, including accounting true-ups and adjustments to reflect updated information.
Note: Totals may not add due to rounding.

TABLE 15-2
ILLUSTRATIVE ANNUAL GHG EMISSIONS AND ASSOCIATED COSTS
(TEMPLATE D-2)

Line No.	Description	2019 Forecast	2019 Recorded	2019 Final	2020 Forecast	2020 Recorded	2020 Final	2021 Forecast	2021 Recorded	2021 Final
1	Direct GHG Emissions (MT CO2e)									
2	Utility Owned Generation (UOG)									
3	Tolling Agreements									
4	Energy Imports (Specified)									
5	Energy imports (Unspecified)									
6	Qualifying Facility (QF) Contracts									
7	Contracts with Financial Settlement									
8	Subtotal									
9	Indirect GHG Emissions (MT CO2e)									
10	CAISO Market Purchases (Net Physical)									
11	Contract Purchases									
12	Subtotal									
13	**Total Emissions (MT CO2e)**	**(229,481)**	**(4,858,020)**	**(1,156,643)**	**(1,847,720)**	**(1,847,720)**	**-**	**(3,759,525)**	**-**	**-**
14	Proxy GHG Price ($/MT) (a)	16.33	17.29	17.28	17.78	17.78	-	16.80	-	-
15	GHG Costs ($)									
16	Direct GHG Costs (b)									
17	Direct GHG Costs - Financial Settlement									
18	Indirect GHG Costs									
19	Previous Year's Forecast Reconciliation (Line 21)	N/A	N/A		7,227,812	(80,228,529)		53,370,957	-	
20	**Total Costs ($)**	**(3,747,426)**	**(83,975,954)**	**(30,604,997)**	**(25,626,126)**	**(113,082,466)**		**(9,789,061)**	**-**	
21	Forecast Variance ($)	N/A	(80,228,529)	53,370,957	N/A	-		N/A	-	

(a) The difference between PG&E's confidential 2021 forecast GHG price and the 2021 forecast GHG proxy price is less than five percent.
(b) D.15-01-024 directs utilities to calculate recorded direct GHG Costs as the sum of each month's weighted average cost (WAC) of compliance instruments held in inventory multiplied by that month's actual GHG emissions. Recorded and Final Direct GHG Costs presented here are consistent with the requirements of D.15-01-024, including accounting true-ups and adjustments to reflect updated information.

Note: Totals may not add due to rounding.

TABLE 15-3
REPORTING TEMPLATE TO CALCULATE WEIGHTED AVERAGE COST OF COMPLIANCE INSTRUMENTS AND DIRECT COSTS
(TEMPLATE C-1 OF REVISED ATTACHMENT C OF D.19-04-016)

	Compliance Period 3[(a)]								
	Date	Transaction Type (b)	Quantity	Cost ($/MT)	Sales price($/unit)	Total Cost ($)	Inventory Balance($)	Total Qty in Inventory	WAC ($)
592									
593									
594									
595									
596									
597									
598									
599									
600									
601									
602									
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617									
618									
619									
620									

TABLE 15-3
REPORTING TEMPLATE TO CALCULATE WEIGHTED AVERAGE COST OF COMPLIANCE INSTRUMENTS AND DIRECT COSTS
(TEMPLATE C-1 OF REVISED ATTACHMENT C OF D.19-04-016)
(CONTINUED)

	Compliance Period 3[(a)]								
	Date	Transaction Type (b)	Quantity	Cost ($/MT)	Sales price($/unit)	Total Cost ($)	Inventory Balance($)	Total Qty in Inventory	WAC ($)
621									
622									
623									
624									
625									
626									
627									
628									
629									
630									
631									
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651									

TABLE 15-3
REPORTING TEMPLATE TO CALCULATE WEIGHTED AVERAGE COST OF COMPLIANCE INSTRUMENTS AND DIRECT COSTS
(TEMPLATE C-1 OF REVISED ATTACHMENT C OF D.19-04-016)
(CONTINUED)

Compliance Period 4[(a)]

Date	Transaction Type (b)	Quantity	Cost ($/MT)	Sales price($/unit)	Total Cost ($)	Inventory Balance($)	Total Qty in Inventory	WAC ($)
[redacted]								

	Direct GHG Costs			True-Ups	Monthly BA Entry
Month	Direct Monthly Emissions (MT)	WAC Pricing ($/MT)	WAC x Direct Emissions Qty ($)	True-Up Value +/- ($)	Monthly Balancing Account Entries ($)
[redacted]					

Transaction Type Definition:

Purchase	Purchase of compliance instruments
Retirement	Compliance instruments retired to CARB or transferred to a third-party
[redacted]	
Wacog Adjustment	Premium paid to a third-party relating to the purchase of compliance instruments.

Notes:

[redacted]

(b) Retirements refer to transfers to third-party. There is no sales price for the transaction as we do not sell these compliance instruments to third-parties. We reduce our inventory based on the WAC as of the transferred-out date multiplied by the total quantity transferred.

(c) For monthly quantity emissions, the quantity reported is the snapshot of the best available data as of the last day of the respective month. Emissions quantity are continuously updated on at least a quarterly basis, and adjustments are made in subsequent month.

(d) Adjustments include quantity changes and/or revaluation of GHG direct costs based on latest WAC for quantities not yet surrendered or retired.

(e) Balancing account entry based on forecasted volumes and WAC; subject to change depending on adjustments described in (d) above.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 16

GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION – ADMINISTRATIVE AND OUTREACH EXPENSES

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 16
GREENHOUSE GAS FORECAST
REVENUE AND RECONCILIATION –
ADMINISTRATIVE AND OUTREACH EXPENSES

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 16
GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION – ADMINISTRATIVE AND OUTREACH EXPENSES

A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) presents its 2019 recorded greenhouse gas (GHG) administrative and outreach (A&O) expenses for reasonableness review, as directed by the California Public Utilities Commission (CPUC or Commission) in Decisions (D.) 12-12-033, 14-10-033,[1] and 16-06-041;[2] and Resolutions (Res.) E-4611 and E-4716, as well as its forecast for 2021 GHG A&O expenses.

B. GHG Administrative Expenses Forecast and Reconciliation

1. Recorded GHG Administrative Expenses

In 2019, PG&E incurred expenses relating to implementation and administration of the GHG allowance revenue return to customers. Specifically, PG&E continued to administer the twice-annual electric California Climate Credit (CCC) for residential households and the facility-specific California Industry Assistance Credits for Emissions-Intensive and Trade-Exposed (EITE) customers. With a 2018 Energy Resource Recovery Account (ERRA) approval to set 2019 tariff values equal to zero for the small and medium business volumetric credits, there was little administrative work needed for these climate credits in 2019.[3] The activities associated with GHG A&O included general program management, Information Technology (IT)/billing system enhancements, and customer inquiry support costs.

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1 D.12-12-033, Ordering Paragraph (OP) 23; and D.14-10-033, OPs 5 and 10.

2 D.16-06-041 (addressing customer Education and Outreach (E&O) plans for GHG allowance proceeds return).

3 D.19-02-023 (approving as reasonable, PG&E's 2019 forecast of GHG A&O program costs).

The actual 2019 recorded administrative expenses were less than forecasted. A comparison between the forecast and recorded 2019 administrative costs by expense category is presented in Table 16-3. The main variance between the forecast and recorded administrative expenses was due to a 2018 CPUC emission leakage study invoice that cited the incorrect decision.[4] As a result, PG&E's 2019 recorded expenses includes a credit of $103,052, for payment made in 2018, and a forecast cost of $151,398, to anticipate an invoice for the remainder of the reimbursement.

PG&E's recorded expenses for General Program Management were also lower than forecasted due to a reduction in headcount from 3 to 2 full-time equivalent (FTE) employees midway through 2019. Cost reduction can also be attributed to improved onboarding documentation and process improvements, as well as the implementation of customized Tableau dashboards allowing for an improved method to verify facility information in PG&E's billing system and query customer historical data.

The IT/billing System Enhancements recorded expenses tracked lower than forecasted due to minimal issues with the billing system and EITE attestation website during 2019's credit distribution.

The Customer Inquiry Support costs for 2019 also tracked lower than forecasted due to customer, call center staff, and business account representatives' familiarity with the GHG programs.

2. Forecast 2021 GHG Administrative Expenses

In 2021, PG&E expects to incur expenses associated with the GHG allowance revenue return for the following activities: General Program Management, IT/Billing System Maintenance, and Customer Inquiry Support costs.

The forecasted General Program Management expense for 2021 is noted in Table 16-3. This includes approximately $370,000 of expense associated with managing GHG revenue return, including ensuring that GHG revenue return is implemented in accordance with the Commission's requirements. The program management function is responsible for:

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4 See, PG&E's 2020 ERRA Forecast A.19-06-001, Exhibit 6R, GHG A&O Expenses, p. 20.

ensuring credits are returned to customers; identifying and reviewing billing system exceptions; managing and reconciling revenue reporting; developing the necessary training for call center staff; billing operations staff and account representatives; managing customer inquiries; and related work.

Due to the continued complexities associated with managing the California Industry Assistance Credit for EITE customers, dedicated resources will continue to support the program. For example, these resources will be responsible for accurately verifying and identifying facility information in PG&E's billing system. This process is manual and has required many hours of working directly with customers to resolve discrepancies.

The IT/billing system maintenance expenses for 2021 is noted in Table 16-3. This includes approximately $21,500 of expense associated with maintaining the custom programs developed to administer the semi-annual and volumetric CCC, including costs associated with potential verbiage or timing changes for bill messages. For the California Industry Assistance Credit, it includes approximately $32,500 associated with issuing the credits and approximately $17,000 associated with annual attestation website operation and maintenance costs.

The customer inquiry support expense forecast for 2021 is approximately $258,000, as noted in Table 16-3. In addition to outreach support from assigned account representatives with EITE customers, the customer inquiry support expenses include call support for the California Industry Assistance and the CCC. PG&E's forecast for 2021 call volume for the GHG credits assumes a higher call volume than 2019 to anticipate the possible need to address moving the credit distribution timing due to possible catastrophic events like health pandemics, wildfires, etc. which would increase program inquiries. For EITE customers, PG&E has included costs for call center support, assuming approximately 25 percent of customers who have received outreach will call for information, and that the average cost per call for the California Industry Assistance Program will remain consistent with the cost per call associated with the CCC in 2019.

C. GHG Customer Outreach Expenses Forecast and Reconciliation

1. Recorded GHG Customer Outreach Expenses

In compliance with Res. E-4611 and D.16-06-041,[5] PG&E forecasted $182,776 in proposed expenditures for outreach to residential, small business, and EITE customers. In 2019, the actual total recorded expenses were $111,201 for the CCC outreach, EITE outreach, and associated labor to plan, execute and manage outreach efforts.

A breakdown of PG&E's total expenses for GHG electric outreach in 2019 included:

TABLE 16-1
2019 GHG ELECTRIC OUTREACH EXPENSES

Line No.	Outreach	2019 Expenses
1	CCC	$71,178
2	EITE Credit	2,526
3	Labor	37,497
4	Total 2019 Expenses	$111,201

When factoring variances for activities related to the CCC and EITE credits, the net effect was overall expenditures that were approximately $72,000 less than forecasted for outreach and labor costs. The primary drivers for the differences in actual costs incurred are described in the CCC, EITE, and labor sections below.

a. California Climate Credit

For the CCC, pursuant to Res. E-4611 and D.16-06-041,[6] PG&E conducted the approved outreach activities which included CPUC Energy Division approved messaging to customers through bill inserts and e-mail, as well as managing content on PG&E's websites and for its call centers.[7]

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5 D.16-06-041 (addressing customer E&O plans for GHG allowance proceeds return).

6 D.16-06-041 OPs 1 and 2.

7 Res.E-4611, p. 28.

Of the total 2019 expenditures of $111,201, PG&E incurred $71,178 for outreach conducted to notify customers of the April and October CCC distributions for residential electric customers.[8] PG&E informed customers about the CCC distribution by means of a letter from the Commission distributed as a 1-panel bill insert that was included in the customer's bill package.

Customers who are electronically billed by PG&E or by their financial institution were sent an e-mail about the CCC. The e-mail content was provided by the Commission's Energy Division staff.

PG&E sent a direct mail letter to all master meter customers, informing them of the CCC and their responsibility to pass along the credit to tenants, as well as to post the notification in a conspicuous place on their premises.

With a 2018 ERRA approval to set 2019 tariff values equal to zero for the small and medium business volumetric credits, there was little work necessary for these climate credits in 2019.

In summary, the variance between the original forecast and the actual execution costs for the CCC outreach was relatively nominal. PG&E outreach costs for the CCC were approximately $15,000 lower than initially forecasted due to a lower than estimated cost for e-mail and direct mail deployments.

b. EITE Credit

Of the total 2019 expenditures of $111,201, PG&E incurred $2,526 to develop and deploy multiple communications via e-mail and one direct mail letter. The outreach notified customers about their upcoming credit, and transmitted checks to the Mandatory Reporting Required facilities who requested them, as well as select customers who chose the "cash out" option if any remaining credit amount exceeded their total bill amount.

The execution costs for these efforts were lower than originally forecasted, due to a lower than estimated cost for e-mail deployments.

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8 This expenditure does not include PG&E labor.

The communications resulted in PG&E incurring approximately $4,000 less than initially estimated for EITE communications.

c. Labor

In 2019, PG&E incurred labor costs of $37,497, which was lower than initially expected for the development of the marketing planning, execution, and regulatory coordination related to the residential CCC and the EITE credit calculations and communications. This was due to cost efficiencies in labor resulting from combining outreach activities between the electric credit and gas credit that took effect in April 2019. The actual incurred expenditures represented approximately 25 percent of one FTE employee for labor across both the EITE and electric CCC programs.

2. Forecast GHG Customer Outreach Expenses

For 2021, PG&E estimates that it will spend a total of $148,356 on CCC, EITE outreach, and labor. The outreach estimate includes $67,280 for the CCC, $6,076 for the EITE credit, and $75,000 in labor for both the CCC and the EITE Program.

TABLE 16-2
2021 GHG CUSTOMER OUTREACH EXPENSES

Line No.	Outreach	2021 Forecast
1	CCC	$67,280
2	EITE Credit	6,076
3	Labor	75,000
4	Total 2021 Forecast	$148,356

a. California Climate Credit

In 2021, PG&E forecasts that it will incur expenses of $67,280 for outreach to customers receiving the CCC. Based on continued authorizations for the CCC in D.16-06-041, PG&E plans to inform residential customers of the distribution of credits by means of a letter from the Commission distributed as a 1-panel bill insert and an e-mail to electronically-billed customers in April and October 2021. The content of these communications was previously provided by Energy Division

staff and the same content is expected to be authorized for use in 2021. PG&E will have the letter formatted and tested to ensure proper printing for the bill inserts. The decision authorized, and PG&E plans to use, the following outreach methods for notifying residential customers of the CCC in April and October, similar to what was executed in 2019 and planned for 2020:

1. A 1-panel bill insert in the April and October 2021 bill packages to approximately 3.4 and 2.7 million electric customers, respectively.
2. An e-mail message to residential customers who are electronically billed through PG&E with the same content as provided in the bill inserts.
3. An e-mail message sent by third-party financial institutions, on behalf of PG&E, to residential customers who use those institutions' electronic billing systems to pay their utility bills. Third-party institutions bill PG&E for the costs associated with sending the e-mail to customers using their e-bill system.
4. A letter to approximately 40,000 and 15,000 master meter customers sent in April and October, informing them of their requirement to pass along the credit to tenants, and to post the notification of the credit in a conspicuous place on their premises.
5. Inclusion in PG&E's residential eNewsletter as a way to leverage a cost-efficient communication channel and direct customers to learn more at the CPUC's CCC website.

PG&E has developed these forecasts based on the regulatory approvals and authorizations that are current as of May 7, 2020. Any future Commission decisions that change the requirements for outreach to customers, delays, or additional communications deemed necessary by PG&E and the Energy Division staff, may affect the forecasts.

b. EITE Credit

In 2021, PG&E forecasts that it will incur expenses of $6,076 for outreach to EITE customers. This outreach will include:

1. An e-mail once during the year to customers to notify them of the EITE credit being issued. Three separate e-mails are required for the following:

a) Customers receiving an on-bill credit;
b) Customers receiving an on-bill credit and are also a Mandatory Reporting Requirement facility; and
c) Customers receiving a check in the mail and are also a Mandatory Reporting Requirement facility.

2. A letter/check mailed once during the year to customers who have requested their EITE distribution be in the form of a check, rather than as an on-bill credit.

c. Labor

PG&E estimates expenses of $75,000, which is 50 percent of a FTE for 2021 labor, for EITE communications necessary in a non-attestation year and the regularly-occurring CCC outreach efforts. The forecasted labor costs include: planning; execution; monitoring and managing the outreach plans and calendars; regulatory forecasting and reconciliations; and coordination with the Energy Division staff and Investor-Owned Utilities.

D. Conclusion

In this chapter, PG&E describes its 2019 recorded and 2021 forecast GHG A&O expenses, as presented in Table 16-3 below. PG&E requests that the Commission:

1. Review and approve the 2019 recorded A&O expenses of $426,000 as reasonable; and
2. Approve the 2021 forecast A&O expenses of $847,000.

TABLE 16-3
DETAIL OF A&O EXPENSES
(TEMPLATE D-3)
(THOUSANDS OF DOLLARS)

		2015		2016		2017		2018		2019		2020		2021	
Line	Description	Forecast	Recorded	Forecast	Recorded	Forecast	Recorded	Forecast	Recorded	Forecast	Recorded	Forecast	Recorded*	Forecast	Recorded
1	**Utility Administrative**														
2	General Program Management	164	262	410	611	669	504	416	482	528	86	430	82	370	
3	IT/Billing System Enhancements	193	265	138	73	623	162	103	40	79	39	66	15	71	
4	Customer Inquiry Support Cost	709	224	120	129	117	179	272	256	294	190	332	55	258	
5	**Subtotal Administrative**	1,066	751	668	813	1,408	846	791	778	900	314	828	153	699	
6	**Utility Outreach**														
7	Marketing - Internal														
8	Marketing - Contract/Consultant														
9	Targetbase														
10	Customer Outreach & Education	826	332	286	209	245	206	151	124	183	111	237	41	148	
11	**Subtotal Outreach**	826	332	286	209	245	206	151	124	183	111	237	41	148	
12	**Utility Outreach and Administrative Expenses (Line 5 + Line 11)**	1,892	1,083	954	1,022	1,653	1,052	943	901	1,083	426	1,065	194	847	
13	**Additional (Non-Utility) Statewide Outreach**	-	-	-	-	-	-	-	-	-		-		-	
14	**Total Outreach and Administrative Expenses (Line 12 + Line 13)**	1,892	1,083	954	1,022	1,653	1,052	943	901	1,083	426	1,065	194	847	

Information not yet available

*The full year of 2020 recorded expenses are currently not available.
Note: Totals may not add up due to rounding

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 17

GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION – REVENUE CALCULATIONS

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GREENHOUSE GAS FORECAST REVENUE
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 17
GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION – REVENUE CALCULATIONS

A. Introduction

Pursuant to Decision (D.) 12-12-033[1] and D.14-10-033,[2] Pacific Gas and Electric Company (PG&E) presents its: (1) forecasted 2021 greenhouse gas (GHG) allowance return revenue requirement; and (2) 2020 year-end forecast balance, including reconciliation of the GHG Revenues Subaccount within the Greenhouse Gas Revenue Balancing Account (GHGRBA), as well as (3) the methodology for returning GHG allowance revenue to eligible customers. The methodologies discussed, and tables included in this testimony are in accordance with the California Public Utilities Commission (CPUC or Commission) requirements as ordered in D.12-12-033, D.14-10-033, and D.15-01-024.[3]

There is a newly created Climate Credit Program Rulemaking (Rulemaking (R.) 20-05-002) to consider changes to the GHG returns. If the Commission issues a decision modifying the calculation of the GHG revenue return applicable to 2021 prior to October 15, PG&E will include any applicable changes in its November Update.

The remainder of this chapter is organized as follows:

- Section B – Forecast 2021 Net Available GHG Allowance Proceeds
- Section C – Low-Income and Disadvantaged Community Solar Programs Funded in Whole or in Part from the GHG Allowance Revenues

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1 D.12-12-033, pp 148 states:

> Beginning in 2014, the [GHG forecast revenue and reconciliation] applications must also include a detailed accounting of actual GHG costs incurred for the previous year as well as revenues distributed to eligible customers classes.

The presentation of GHG costs is discussed in Chapter 15.

2 D.14-10-033, Ordering Paragraph (OP) 10 requires PG&E to file its:

> [G]reenhouse gas forecast revenue and reconciliation request as an additional chapter or section within its annual Energy Resource Recovery Accounts…forecast application….

3 D.12-12-033, OP 23; D.14-10-033, OPs 5, 9 and 10; and D.15-10-024, OP 1.

- Section D – Amortization of the 2020 Year-End Forecast Balance
- Section E – Forecast 2021 GHG Allowance Return Revenue Requirement
- Section F – Distribution of 2021 GHG Allowance Revenue Return
- Section G – Conclusion

B. Forecast 2021 Net Available GHG Allowance Proceeds

Pursuant to D.12-12-033 and D.14-10-033, PG&E's forecast 2021 net available GHG allowance proceeds for distribution to eligible customers is calculated after setting aside the following from its forecast 2021 GHG Allowance Revenue Proceeds:

- GHG Administrative and Outreach (A&O) Expenses
- Clean Energy and Energy Efficiency (CEEE) Funds

Below are details of the calculation of the forecast 2021 GHG allowance return.

1. GHG Allowance Revenue Proceeds

The California Air Resources Board (CARB) allocates GHG allowances to the Investor-Owned Utilities (IOU) on behalf of its customers. On page 5 of D.14-10-033, the Commission defines the responsibility of the utilities regarding the disposition of the GHG allowance revenue proceeds as follows:

> The state allocates GHG allowances to utilities on behalf of ratepayers. The utilities act as an intermediary by holding and then selling the allowances for ratepayer benefit; ARB prohibits the electric utilities from using the allowances for their own compliance obligation or for their own benefit. The revenue from the sale of these GHG allowances is then returned to ratepayers and helps to offset the increases in electricity costs that result from GHG compliance.

PG&E's forecast of 2021 GHG allowance allocation (measured in metric tons (MT)) is approximately 17.6 million MTs, based on 2021 allowances allocated to PG&E as reflected in the "Unofficial electronic version of the Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms" produced by CARB (the Cap-and-Trade Regulation).[4] This forecasted value of allowances is potentially uncertain due to several factors, including possible future

[4] The unofficial version of the Cap-and-Trade Regulation is available at: https://ww3.arb.ca.gov/cc/capandtrade/ct_reg_unofficial.pdf. Table 9-4 is provided in Section 95892. PG&E's allocation is located on page 215, third row of the table.

changes to the cap-and-trade regulation. At the December 2018 CARB Board Meeting,[5] CARB staff indicated that they intend to update the electric utility allowance allocations for 2021-2030 in a future rulemaking to reflect more stringent Renewables Portfolio Standard requirements established by Senate Bill 100, which could lower the allowance allocations under CARB's existing methodology. As of May 2020, CARB has not initiated a new cap-and-trade rulemaking to update the 2021-2030 electric utility allowance allocations. PG&E's November Update will incorporate any regulatory changes relevant to PG&E's 2021 allowance allocation.

Using the proxy price of $16.80/MT, shown in Table 17-3, Line 1, PG&E's forecasted 2021 GHG allowance revenue proceeds are $295.68 million, as shown in Table 17-3, Line 5. PG&E notes that, although it is directed to use the proxy price in D.14-10-033 to forecast allowance revenues,[6] this is not indicative of the actual auction prices as it falls below the anticipated 2021 Auction Reserve Price. CARB has not yet set this price for 2021. PG&E anticipates that the 2021 Reserve Price will be at least 5 percent higher than the 2020 Reserve Price of $16.68, consistent with CARB's Cap and Trade Regulation Section 95911. It is also possible that not all allowances will be sold in 2021, as was observed in the May 2020 auction.[7] This undersubscription would act to offset increased revenue due to the higher reserve price. PG&E will provide an updated forecast in its November Update considering market changes at that time.

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5 See CARB Presentation, Cap and Trade Regulation and Mandatory Reporting Regulation 2018 Amendments, slide 17 (identifying electric allocation updates as a future rulemaking activity), available at: https://ww3.arb.ca.gov/board/books/2018/121318/18-10-6pres.pdf.

6 OP 1 of D.14-10-033 requires PG&E to "use a proxy price to estimate forecast allowance revenues and greenhouse gas costs, except as otherwise specifically directed by the Commission." Page 12 of this decision further describe the calculation methodology of proxy price that includes "using the daily settlement price of the Intercontinental Exchange (ICE) allowance future contract with a vintage year equal to the forecast year and delivery in December of the forecast year."

7 See CARB May 2020 Auction Summary, available at: https://ww3.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf (showing 21,161,000 of 57,540,731 allowances offered sold).

2. GHG Administrative and Outreach Expenses

In D.12-12-033, OP 1, the Commission allowed the IOUs to set aside their respective utility A&O expenses from the GHG allowance revenues prior to returning the net revenues to customers. Pursuant to D.13-12-041, D.14-12-054, D.15-12 022, and D.20-02-047, PG&E had set aside a total of $8.56 million to pay for its GHG A&O expenses. The Commission found PG&E's incurred GHG A&O expenses through 2018 to be reasonable, and PG&E presents its 2019 A&O expenses as part of this Application request.[8] PG&E's forecast A&O expenses were approved as part of PG&E's 2020 Energy Resource Recovery Account (ERRA) Forecast, and PG&E's forecast 2021 A&O expenses are also presented as part of this Application request.

Total recorded and forecast GHG A&O expenses from 2013 through 2021 is $8.75 million. Therefore, PG&E is requesting to set aside $0.19 million to cover the shortfall between the amount already set aside ($8.56 million) and the recorded and forecast GHG A&O Expense through 2021 ($8.75 million), as reflected in Table 17-3, Line 10.

3. Clean Energy and Energy Efficiency Funds

California Public Utilities Code (Pub. Util. Code) Section 748.5(c) provides that the Commission may allocate up to 15 percent of the GHG allowance revenues to fund authorized CEEE projects that are not otherwise funded by another source. Accordingly, PG&E requests 15 percent or $44.35 million to be set-aside in 2021 to fund the CEEE Program for the 2021 budget year. Additionally, PG&E is also requesting to set aside a true-up of prior period Solar on Multifamily Affordable Housing (SOMAH)

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8 The Commission determined that PG&E's GHG A&O expenditures incurred through 2018 are reasonable. See D.14-12-054, Conclusion of Law (COL) 7 (considering A&O costs incurred in 2013 and partial 2014 costs); D.15-12-022, COL 1 (concerning 2014 A&O costs) D.16-12-038, COL 1 (concerning 2015 A&O costs); D.18-01-009, COL 1 (concerning 2016 A&O costs); D.19-02-023, COL 1 (concerning 2017 A&O costs); D.20-02-047, COL 1 (concerning 2018 A&O costs). D.20-02-047, COL 1 also approved PG&E's forecast 2020 A&O costs. PG&E's presents its 2019 A&O costs and forecast 2021 A&O costs in Chapter 16 of this Application. The reasonableness of PG&E's 2020 A&O costs will be considered in PG&E's 2022 ERRA Forecast.

funding of $23.42 million to comply with D.20-02-047 and D.20-04-012 for SOMAH Program true-up amounts.[9]

The total amount PG&E is proposing to set-aside in this application is $67.77 million is presented in Table 17-3, Line 14, and discussed in Section C of this testimony. These amounts are subject to further review of forecast and actual expenditures for these programs.

C. Low-Income and Disadvantaged Community Solar Programs Funded in Whole or in Part From the GHG Allowance Revenues

1. Introduction and Set Aside Analysis

PG&E has four programs funded in whole or in part from the sales of GHG allowances: (1) SOMAH; (2) Disadvantaged Communities Single-Family Affordable Solar Housing (DAC-SASH); (3) Disadvantaged Communities Green Tariff (DAC-GT); and (4) Community Solar Green Tariff (CS-GT).

In D.17-12-022, the Commission created the SOMAH Program. SOMAH, which provides incentives for solar on multi-family housing, is administered by the Center for Sustainable Energy (CSE) and is funded by 10 percent of revenue received from GHG allowance sales, up to a statewide cap of $100 million.

In D.18-06-027, the Commission created the DAC-SASH Program, the DAC-GT Program, and the CS-GT Program to incentivize the installation of solar generating systems for low-income households and disadvantaged communities. There is a statewide $10 million annual budget for the DAC-SASH Program, with funding apportioned to participating utilities. PG&E's portion of the $10 million for 2021 is $4.37 million. That decision set no budget for the DAC-GT or CS-GT programs. For all three programs created in that decision—DAC-SASH, DAC-GT, and CS-GT it authorized utilities to collect funds first through available GHG allowance proceeds, and then through Public Purpose Program (PPP) funds if the GHG allowance funds were exhausted.

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9 See D.20-02-047, p. 21 (reducing the 2020 SOMAH set-aside due to the program's potential expiry on June 30, 2020). Subsequent D.20-04-012 re-authorized the SOMAH program through 2026, and OP 5 directed PG&E to propose set-aside amounts in its 2021 ERRA Forecast to account for the July 1 to December 31, 2020 period.

Total available CEEE funds for 2021 based on 15 percent of forecasted allowance revenues are forecasted to be $44.35 million, of which two thirds or $29.57 million will be used to fund the SOMAH Program. PG&E has forecast program costs for the remaining three programs as $16.57 million. The cost for all four programs for 2021 therefore total $46.14 million, which exceeds the allotted $44.35 million for CEEE programs by $1.79 million. Pursuant to D.18-10-007, if available GHG revenues are exhausted, funding may be collected through the PPP charge in 2021 for one or some combination of the three programs authorized in that decision—DAC-SASH, DAC-GT, and CS-GT. Funding of the forecast $1.79 million exceedance will not be collected from 2021 GHG allowance revenues. The updated GHG revenue forecasts and set aside amounts will be refreshed and reviewed in the November update. If needed, PG&E may seek any needed additional PPP funds through the Annual Electric True-Up (AET) advice letter process.

In addition to the forecast 2021 program budgets which are funded by GHG auction revenues in an amount not to exceed 15 percent as described above, PG&E is also requesting two GHG auction revenue set-asides in 2021 for the SOMAH program to account for prior years. PG&E proposes to exclude these additional requests from the 15 percent cap for 2021 since they are associated with prior years. Instead PG&E has confirmed that these amounts are within the 15 percent cap as applied in the relevant year.

First, in D.20-04-012, the Commission directed that additional 2021 allowance revenues be set aside to fund SOMAH program operation for the second half of 2020. In accordance with D.20-04-012, in 2021 PG&E will set aside and amount equivalent to 10 percent of the forecasted GHG revenues received in the second half of 2020, an additional $18.97 million, to fund the SOMAH program for July 1–December 31, 2020.

Second, PG&E requests to set aside an additional $4.45 million in 2021 to correct for the actual recorded amounts of the 2016-2019 funding shortfall for the SOMAH program discussed in D.20-02-047. PG&E observed that D.20-02-047 did not use actual recorded GHG allowance revenues to calculate the SOMAH shortfall for years 2016-2019. PG&E provides the correct actual recorded GHG allowance revenues in Table 17-2, and these values yield the additional $4.45 million set aside.

Because the $18.97 million and $4.45 million amounts are associated with prior periods, PG&E proposes that these amounts be excluded from the 15 percent allowance for CEEE programs in 2021 mandated by Pub. Util. Code Section 748.5(c). Put simply, these funds ought to have been set aside in previous years and were not.[10] Therefore, PG&E proposes the total set aside amount from GHG allowance revenues for CEEE programs in 2021 is $67.77 million.

Table 17-1 below lists the program-by-program forecasted set-aside amounts. Further descriptions of the budgets for the programs follow.

[10] When comparing the correct set aside amounts to the years the funds ought to have been collected, the clean energy funding did not exceed the 15 percent allowance for CEEE programs for years 2016-2019.

TABLE 17-1
FORECASTED BUDGETS FOR GHG
FUNDED CUSTOMER GENERATION PROGRAMS
(MILLIONS OF DOLLARS)

Line No.	Clean Energy and Energy Efficiency Program	2020	2021
1	SOMAH 2016-2019 True-Up[a]	29.52	4.45
2	SOMAH 2020 True-Up[b]	–	18.97
3	True-Up Subtotal	29.52	23.42
4	SOMAH[c]	20.20	29.57
5	DAC-SASH	4.37	4.37
6	DAC-GT	2.01	9.82
7	CS-GT	3.14	2.38
8	PPP Funds[d]	–	(1.79)
9	CEEE Programs Set Aside Subtotal	29.72	44.35
10	CEEE 15% Set Aside Allowance[e]	58.75	44.35
11	Total GHG Funds	59.24	67.77

(a) For 2020: Pursuant to D.20-02-047, $30.78 million was to be set aside for the 2016-2019 shortfall; however, PG&E was able to set aside 10 percent of recorded revenue in 2019, resulting in a collection of $29.52 million in 2020 for the shortfall in years 2016-2018 only. For 2019, the recorded GHG allowance revenue was $389.04 million, 10 percent of which was set aside in 2019 for SOMAH. Note that this is instead of $37.74 million shown for 2019 in D.20-02.047, as it is based on the actual recorded GHG allowance revenues given in Table 17-2 below.

(b) For 2021: Pursuant to D.20-04-012, includes a forecasted amount of $18.97 million for July 1, 2020 – December 31, 2020. This $18.97 million set aside amount for 2020 is not included the 15 percent CEEE allowance calculation for 2021.

(c) For 2020: Pursuant to D.20-02-047, includes an updated forecasted amount of $20.20 million to be collected in 2020 for January 1, 2020 – June 30, 2020.

(d) For 2021: The 2021 budget for the four programs is estimated to be $46.14 million, which exceeds 2021's 15 percent CEEE allowance of $44.35 million by $1.79 million. $1.79 million may be collected through the PPP charge in 2021 for one or some combination of the three programs – DAC-SASH, DAC-GT, and CS-GT.

(e) 15 percent of Line 5 in Table 17-3.

Note: For 2020 cap calculation: Includes the forecasted amount of $18.97 million for July 1 to December 31, 2020 to be collected in 2021. Adding $18.97 million to $29.72 million is $48.69 million, which is under the 15 percent CEEE allowance for 2020. The $29.52 million SOMAH true-up amount for years 2016-2019 is not included in the 15 percent CEEE allowance calculation for 2020.

For 2021 cap calculation: The $4.45 million SOMAH corrected true-up amounts for years 2016-2019 and the $18.97 million for 2020 is not included in the 15 percent CEEE allowance calculation.

2. SOMAH Program

In 2015, the Legislature enacted Assembly Bill (AB) 693 establishing the SOMAH program,[11] directing the CPUC to use 10 percent of GHG allowance funding for the program, up to a state-wide total of $100 million annually. The SOMAH Program was established by the CPUC in December of 2017,[12] and in the next year the CSE was chosen to administer the program. The IOUs were directed to create balancing accounts to track the authorized funding for SOMAH.

CSE performs the calculation to ensure that total funding does not exceed $100 million. Should the total for all IOUs exceed $100 million, the amount retained in the balancing account for the CSE is decreased proportionally for the IOUs. In 2020 and 2021, PG&E does not expect the total from all IOUs to exceed $100 million. Therefore, the entire 10 percent is included in the budget forecast for the SOMAH Program.

In D.20-02-047, in order to account for a SOMAH collection shortfall from 2016-2019, the Commission ordered $30.78 million be collected in 2020.[13] The table on page 20 of D.20-02-047 did not include actual recorded GHG allowance revenue amounts. For 2019, that table showed $389.97 million in recorded GHG allowance revenues, but the actual recorded amount was $389.04 million, as shown in Table 17-2 below. When accounting for actual 2019 allowance revenues, the actual SOMAH shortfall for 2019 was $1.17 million, which was collected in a true-up and transferred to the SOMAH Balancing Account (SOMAHBA) in December 2019. The remaining amount of $29.52 million was collected and transferred to the SOMAHBA in April 2020. The collection for years 2016-2019 is not included in the 15 percent CEEE allowance calculation for 2020, but is under the 15 percent allowance for the respective year the collection should have occurred.

In a later decision, D.20-04-012, the correct actual recorded GHG allowance revenues for 2016-2019 were provided and are reflected in

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[11] This bill added Pub. Util. Code Section 2870.

[12] D.17-12-022.

[13] D.20-02-047, OP 1, p. 35.

Table 17-2 below.[14] Due to the differences in D.20-02-047 and the actual recorded amounts, years 2016 and 2017 had an additional shortfall of $4.45 million that PG&E plans to collect in 2021. The collection for the corrected amounts for years 2016 and 2017 is not included in the 15 percent CEEE allowance calculation for 2021 but is under the 15 percent allowance for the respective year each collection should have occurred.

TABLE 17-2
SOMAH SET ASIDE AMOUNTS (IN THOUSANDS OF DOLLARS)

Line No.	Calendar Year ERRA Forecast	Actual Recorded GHG Allowance Revenue	Correct Set Aside[(a)]	Actual SOMAH Set Aside in ERRA Year	Actual SOMAH Transferred Amount for Shortfall in 2020	Total Actual SOMAH Set Aside[(b)]	Difference[(c)]
1	2016[(d)]	$301,670	$15,084	$1,934	$10,962	$12,896	$2,187
2	2017	345,514	34,551	4,843	27,446	32,290	2,262
3	2018	348,099	34,810	43,700	(8,890)	34,810	–
4	2019	389,041	38,904	38,904	–	38,904	–
5	Total	$1,384,324	$123,349	$89,382	$29,518	$118,900	$4,449

(a) Based on 10% of actual recorded GHG allowance revenue.
(b) Actual SOMAH Set Aside in ERRA Year plus Actual SOMAH Transferred Amount for Shortfall in 2020.
(c) Correct Set Aside Based on 10 percent of Actual Recorded GHG Allowance Revenue minus Total Actual SOMAH Set Aside.
(d) AB 693 implemented SOMAH mid-way through 2016; therefore GHG Revenues and set aside amount are pro-rated 50 percent and totals reflect the pro-rated amounts.

In D.20-02-047, the Commission also noted that GHG revenue allocation to the SOMAH program was only authorized through June 30, 2020. The Commission directed PG&E to set aside 50 percent of the 2020 calendar year of funding and transfer set aside amounts on a quarterly basis.[15] PG&E collected the recorded amount of $10.12 million for the first quarter of 2020 and transferred this amount to the SOMAHBA in April 2020. The forecasted amount for the second quarter of 2020 is $10.08 million, which will be transferred to the SOMAHBA in July 2020.

[14] D.20-04-012, Table 1: Recorded and Forecasted GHG Revenues (Thousands), p. 3.

[15] D.20-02-047, pp. 21-22.

Several months later, in D.20-04-012, the Commission continued authorization of allocation of funds to the SOMAH program through June 30, 2026. The Commission ordered the utilities to set aside funds for the SOMAH program to cover the period from July 1, 2020–December 31, 2020 out of 2021 allowance revenues. The 2021 forecast set aside for SOMAH includes $18.97 million for July 1, 2020–December 31, 2020. This amount is not included in the 15 percent CEEE allowance calculation for 2021, but does fit within the 15 percent allowance calculation for 2020 shown in Table 17-1.[16]

3. DAC-SASH Program

In D.18-06-027, in order to implement legislative direction,[17] the Commission created the DAC-SASH Program, designed to incentivize the installation of solar generation on low-income single-family homes in disadvantaged communities. The annual budget was set at $10 million statewide, apportioned among the IOUs. PG&E's share of the $10 million is $4.4 million annually.[18]

In that same decision, the Commission established the DAC-GT and CS-GT programs, with no specific funding minimum or maximum. The total available from GHG revenues for all three programs is the 5 percent remaining of the 15 percent available for CEEE programs after 10 percent is removed for SOMAH. D.18-06-027 directed the IOUs to fund the DAC-SASH, DAC-GT, and CS-GT programs first from the 5 percent of GHG revenues, and then through PPP funds if the GHG revenues were exhausted. For 2021, the combined cost of these three programs exceeds forecasted available GHG revenues by $1.79 million. Funding of the

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16 Using figures from Table 17-1: the 2020 CEEE set aside of $29.72 million, plus $18.97 million for SOMAH funding through the second half of 2020, is less than the $58.75 million set aside cap.

17 Pub. Util. Code Section 2827.1, directed the CPUC to develop a successor tariff for the Net Energy Metering Program that included direction to:

> (1) Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities. (§ 2827.1(b)(1).)

18 See D.18-06-027, Appendix A, pp. A-5 to A-6. PG&E's share of the $10 million is 43.7 percent or $4.37 million.

$1.79 million will not be collected from 2021 GHG allowance revenues. The updated GHG revenue forecasts and set aside amounts will be refreshed and reviewed in the 2021 ERRA November update.

In 2020 and 2021, the DAC-SASH budget is $4.37 million each year. Funding for 2020 GHG revenues are sufficient to fund the entire $4.37 million. For 2021, the $4.37 million for DAC-SASH may be funded by both GHG revenues and PPP funds as, in aggregate, DAC-SASH, DAC-GT and CS-GT costs are expected to exceed available GHG revenue by $1.79 million.

4. DAC-GT Program

In D.18-06-027, in order to implement legislative direction,[19] the Commission created the DAC-GT Program, designed to overcome barriers to solar adoption for low-income customers within DACs. The DAC-GT Program is similar to PG&E's Green Tariff Program, available to all customers, with the critical differences that it is available only to low-income residential customers in DACs and that participants are provided a 20 percent bill discount, compared to their otherwise-applicable tariff.[20]

The decision set no budget for the DAC-GT Program, but—as with DAC-SASH and CS-GT—instructed IOUs to fund it first through available GHG allowance proceeds, then through PPP funds if the GHG revenues were exhausted. PG&E requested Commission approval of a program budget for 2019 and 2020 in Advice Letter (AL) 5362-E, including supplemental AL 5362-E-A. These budget requests were later updated in AL 5609-E pursuant to OPs 5 and 6 of Resolution (Res.) E-4999. AL 5609-E was suspended for a second time on December 12, 2019 and is awaiting disposition by the Commission. PG&E requested Commission approval of a program budget for 2021 in AL 5749-E; this AL was suspended effective March 1, 2020 for 120 days and has not yet been approved; however, PG&E expects approval of the DAC-GT requested budget of $2.01 million for 2020 and $9.82 million for 2021. For 2020, PG&E anticipates all funds will come from GHG revenues. For 2021, the

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19 See Pub. Util. Code § 2827.1(b)(1).

20 D.18-06-027, pp. 50-53.

program may be funded by both GHG revenues and PPP funds as, in aggregate, DAC-SASH, DAC-GT, and CS-GT costs are expected to exceed available GHG revenue by $1.79 million.

5. CS-GT Program

In D.18-06-027, in order to implement legislative direction,[21] the Commission created the CS-GT Program, creating an incentive for primarily low-income customers in DACs to benefit from the development of solar generation projects located near their communities. The program is structured similarly to DAC-GT, but is intended to drive more local, community-developed solar projects. Participation in the CS-GT Program is not strictly limited to low-income customers, but rather they must account for a minimum of 50 percent of the project's capacity.[22] CS-GT offers the same 20 percent discount to all participating customers as the DAC-GT Program.

The decision set no budget for the CS-GT Program, but—as with DAC-SASH and DAC-GT—instructed IOUs to fund it first through available GHG allowance proceeds, then through PPP funds if the GHG revenues were exhausted. PG&E requested Commission approval of a program budget for 2019 and 2020 in AL 5362-E, including supplemental AL 5362-E-A. These budget requests were later updated in PG&E's AL 5609-E pursuant to OPs 5 and 6 of Res.E-4999.[23] PG&E requested Commission approval of a program budget for 2021 in AL 5749-E, and it has not yet been approved; however, PG&E expects approval of the CS-GT requested budget of $3.14 million for 2020 and $2.38 million for 2021. For 2020, PG&E anticipates all funds will come from GHG revenues. For 2021, the program may be funded by both GHG revenues and PPP funds as, in aggregate, DAC-SASH, DAC-GT and CS-GT costs are expected to exceed available GHG revenue by $1.79 million.

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21 See PUC 2827.1(b)(1).

22 D.18-06-027, p. 56 and 78.

23 This advice letter was suspended for a second time on December 20, 2019 and is pending disposition by the Commission.

D. Amortization of the 2020 Year-End Forecast Balance

The GHG Revenues subaccount within the GHGRBA was established to record the difference between the GHG allowance revenues generated through the CARB auction, less administrative and customer outreach expenses, CARB and/or Commission authorized payments, and GHG revenues returned to customers. PG&E's 2019 year-end recorded balance of the subaccount was $25.04 million over-collected. A comparison between the recorded and forecasted 2019 transactions is shown in Table 17-3, lines 4 through 25. The primary reason for the over-collection are (1) Unspent 2019 DAC-GT and CS-GT set aside amount of $14.50 million due to implementation delays of these projects; and (2) higher-than-forecast recorded GHG allowance revenue proceeds resulted from the higher-than-forecast settled auction prices.

Based on recorded transactions through April 2020, and forecast amounts from May 2020 through December 2020, the GHG Revenue Subaccount is forecast to be $34.12 million[24] under-collected by year-end 2020, as presented in Table 17-3, Line 26. PG&E notes that the current May 2020 through December 2020 forecast GHG revenue assumes that CARB's allowances for the May, August and November are fully subscribed. However, the possibility exists that due to market conditions affected by the COVID-19 governor's proclamation in PG&E's service territory the forecast May, August, and November may need adjusting. PG&E will update the year-end 2020 balance with recorded information in November 2020 and amortize the balance in the 2021 AET process, or subsequent electric rate change advice letter process, as authorized by the Commission.

E. 2021 GHG Allowance Return Revenue Requirement

As shown in Table 17-3, line 17, PG&E's 2021 GHG allowance return revenue requirement to be included in its 2021 electric rates is $195.80 million, comprised of the following components:

- Forecast 2021 GHG allowance revenue, after setting aside the GHG Expenses and CEEE Funds is $227.72 million (see Sections B.1.a., B.1.b., and B.1.c.);

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[24] The CEEE Fund set aside in the forecast year-end balance excludes the $14.50 million unused DAC-GT, and CS-GT funding.

- Less: The forecast 2020 GHG Revenues Subaccount under-collected balance within the GHGRBA of $34.12 million (see Section D); and
- Plus: An allowance of Revenue Fees and Uncollectibles (RF&U) of $2.20 million (see Table 17-3, line 7).

The forecast 2021 GHG allowance revenue requirement will be updated in November 2020, and effective on or after January 1, 2021, through the AET, or subsequent electric rate change advice letter.

F. Distribution of 2021 GHG Allowance Revenue Return

This section describes the methodology that PG&E will use to allocate GHG allowance revenue to its customers. Table 17-3, Lines 19-21 and 25, shows how the total allowance revenue return is divided between the three types of allowance return. Table 17-4 shows the GHG allowance revenue return forecast by rate schedule. The approach described below is consistent with Commission D.12-12-033 and D.14-12-037. There is a newly created Climate Credit Program Order Instituting Rulemaking (R.20-05-002) to consider changes to the GHG returns. If any decision that modifies these rules comes out is issued before the November Update, PG&E will include any applicable changes at that time.

1. Methodology for the Distribution of GHG Allowance Revenue Return

PG&E's GHG allowance revenue return methodology will distribute allowance revenues to eligible customers over the course of each year, as ordered in D.12-12-033. Returns will be provided on either: an annual basis (for Emissions-Intensive and Trade-Exposed (EITE) entities); semi-annual basis (for the California Climate Credit (CCC) for residential households); or monthly, on a volumetric basis (for the small business volumetric returns for eligible customers).[25]

a. EITE Revenue Return

D.12-12-033 requires that EITE entities receive allowance revenues to cover all or a portion of their GHG compliance costs in the form of a yearly on-bill credit or rebate check.[26] Customers that are either

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[25] D.12-12-033, OP 1.

[26] *Id.*, OP 25.

identified as EITE by CARB, or have gone through the attestation and verification process—as prescribed in D.14-12-037 and Res.E-4716—are eligible to receive the EITE Revenue Return, now called the "California Industry Assistance."

Starting with allowance allocation for 2021 and continuing through 2030, CARB will no longer allocate allowances to utilities for the cap-and-trade cost burden of the electricity used by the large EITE entities that it regulates.[27] Instead CARB intends to directly allocate allowances to EITE entities itself for this purpose, without going through the utilities.[28] Therefore, in a change from the 2020 ERRA, PG&E will no longer be forecasting EITE returns to these entities.

In order to forecast the EITE credit, the 2021 forecasted return is set to be equal to the recorded 2020 return for each rate schedule, excluding the CARB covered entities, and adjusted for forecasted sales changes between 2020 and 2021. Total revenue for the EITE return is given in Table 17-3, line 19.

b. Volumetric Revenue Return

PG&E will distribute a portion of the GHG allowance revenue to eligible small business customers through monthly volumetric credits. The basis of calculating these volumetric revenue returns is the rate-specific cents-per-kilowatt-hour (kWh) cap-and-trade "unit cost," which is determined in the following manner:

1) PG&E will calculate the total forecasted cap-and-trade costs allocable to each applicable rate schedule, including imputed costs for Direct Access (DA)/Community Choice Aggregation (CCA)

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27 CARB 2016 Cap-and-Trade Regulation (effective Oct. 1 2017), available at: https://ww3.arb.ca.gov/regact/2016/capandtrade16/capandtrade16.htm.

28 See CARB Final Statement of Reasons for the 2016 Cap-and-Trade Regulation (e.g., Staff "Having a single agency–ARB–distribute this value to all industrial covered entities will help ensure that allocation is done in a manner that is timely and consistent with the Regulation, and will ensure that industrial covered entities in publicly owned utility (POU) and electrical cooperative (co-op) territory are provided the same leakage protection as IOU customers.") Available at: https://ww3.arb.ca.gov/regact/2016/capandtrade16/ctfinsor.pdf.

customers, based on the imputed generation cost allocators.[29] This step will determine how much of the total (bundled, DA, and CCA) cap-and-trade costs will be borne by each rate schedule. This total cost will be different than the costs calculated in Chapter 15 as they include the imputed amounts for DA/CCA customers.

2) The total costs allocable to each rate schedule will be divided by the rate schedule's forecasted annual kWh usage (bundled, DA, and CCA); this will result in a cent-per-kWh cap-and-trade "unit cost" rate for each group. The schedule-level cap-and-trade "unit cost" rates are, in turn, used to determine the amount of the volumetric allowance credit that is returned to eligible customers.

Eligible small business customers, excluding customers that have also been identified as EITE, will receive a monthly on-bill credit, included as a separate line item. The exact credit per customer will be determined by multiplying the cap-and-trade unit cost for the customer's rate schedule—see Section C.1.b. above—by the customer's monthly usage, and then adjusted by the Industry Assistance Factors determined in D.13-12-002. The Industry Assistance Factor for the 2019 true-up is 60 percent, while the Industry Assistance Factor for 2021 costs is 40 percent.

Normally, the small business return is supposed to offset PG&E's GHG costs; however—as shown in Table 15-2, and similar to the presentation in the last 3 years of testimony—the overall adjusted GHG cost for 2021 is negative. PG&E is not intending to charge customers to offset the negative costs, so the small business return will be set to zero. PG&E will update its forecasted costs in the November Update and provide a volumetric return to small business customers if the net costs are positive at that time. If so, that credit will be shown as a separate

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29 See D.12-12-033 at pp. 129-130. The imputed generation cost allocators adjust the bundled generation cost allocators by including the generation costs PG&E would incur if it were to procure generation for DA and CCA customers within its service territory. By imputing the DA and CCA generation costs in this manner, PG&E is complying with Section 5.6. of D.12-12-033, which directed the IOUs to use bundled sales data to estimate DA and CCA cap-and-trade costs and revenues owed.

rate component on the bill to ensure equitable treatment of customers with DA/CCA providers.[30] RF&U will apply to the resulting net bill. Total revenue for the Small Business Volumetric return is given in Table 17-3, Line 20.

c. Semi-Annual CCC Payment

As the Commission directed in D.12-12-003, all residential households receive a CCC distributed as a separate on-bill line item credit twice a year—every April and October billing cycle.[31] To calculate the amount of revenue included in each Climate Credit payment, PG&E will divide its annual forecasted Climate Credit revenue among all eligible residential households based on service accounts, including master-meter sub-accounts.[32] In equation form, this calculation is as follows:

$$\frac{1}{2} \times \frac{\text{Total Annual Climate Credit Revenue}}{\text{Eligible Single Meter Residential Accounts} + (\text{Master Meter Sub-accounts} - \text{Master Meter Host Accounts})}$$

The credit will be rounded to the nearest cent, and it will be applied on the distribution portion of the bill, but not necessarily applied exclusively to distribution charges. This location on the bill is important to ensure that residential DA/CCA customers receive their fair portion of allowance revenues, as required by D.12-12-033. The credit may be applied against the full balance of the bill, not just the delivery portion.[33] Total revenue for the semi-annual CCC Payment is given in Table 17-3,

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30 For some customers, particularly residential DA/CCA customers, this revenue return may exceed the value of the bill. In such cases, PG&E will apply its rollover and cash-out provisions.

31 The schedules for Electric Vehicles (EV), EVB, and EV2B, which are for separately metered EV charging, are the only residential rate schedules that will be excluded. Customers on these rate schedules have one meter and rate schedule for their home, and another meter and rate schedule to charge their EV. To avoid giving a single household two climate credit payments, PG&E will not distribute credits to customers on Schedules EVB and EV2B.

32 Since the master-meter aggregated—or "host"—account does not represent a true household, these accounts will be subtracted from the total.

33 See D.12-12-033 at p. 180 (Finding of Fact (FOF) 112: "via a delivery rate component"), and p. 182 (FOF 122: "against electricity purchases").

line 24. A summary of costs and revenue by schedule is in Table 17-4 (Template D-4).

In D.15-12-022, the Commission directed PG&E to use the public proxy price and formulas to determine the semi-annual CCC Payment.[34] Therefore, the semi-annual CCC Payment included in PG&E's request is based on the public price used to forecast GHG allowance proceeds.

G. Conclusion

In this chapter, PG&E presents the forecast and the methodology for returning GHG allowance revenue to eligible customers. Specifically, PG&E request that the Commission:

1) Adopt its 2021 GHG allowance revenue return requirement of $195.80 million, which includes a forecast of the end of 2021 overcollection;
2) Approve the GHG A&O expense set-aside of $0.19 million;
3) Approve the CEEE funds set-aside of $67.77 million;
4) Approve its revenue distribution proposals; and
5) Adopt the semi-annual residential CCC of $18.77 per household.

The forecast amounts presented in this testimony will be updated in November, and be effective on January 1, 2021, through the AET, or subsequent electric rate change advice letter.

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34 D.15-12-022, pp. 12-13, and COL 2.

TABLE 17-3
ANNUAL GHG ALLOWANCE REVENUE RECEIPTS AND CUSTOMER RETURNS
(TEMPLATE D-1)
(THOUSANDS OF DOLLARS)

Line No.	Description	2019 Forecast [1]	2019 Recorded [2]	2020 Forecast [1]	2020 Recorded [3]	2021 Forecast	2021 Recorded
1	**Proxy GHG Price ($/MT)**	$16.33	N/A	$18.25	N/A	$16.80	
2	**Allocated Allowances ('000 MT)**	23,109	23,109	22,646	22,646	17,600	
3	**Revenues**						
4	Prior Balance (From Line 26 of previous year)	14,367	26,121	(27,055)	(25,038)	34,115	
5	Allowance Revenue	(377,371)	(389,041)	(413,296)	(391,653)	(295,676)	
6	Interest		491		(129)		
7	Revenue or Franchise Fees and Uncollectibles (RF&U)	(3,642)		(4,292)		(2,197)	
8	**Subtotal Revenues**	(366,645)	(362,429)	(444,643)	(416,819)	(263,758)	
9	**Expenses [4]**						
10	Outreach and Administrative Expenses			1,206	1,206	190	
11	Franchise Fees and Uncollectibles						
12	Interest						
13	**Subtotal Expenses**	-	-	1,206	1,206	190	
14	**Allowance Revenue Approved for Clean Energy or Energy Efficiency Programs [5]**	56,606	43,274	60,966	59,241	67,767	Information not yet available
	a) SOMAH	37,700	38,904	20,665	20,199	29,568	
	b) SOMAH - True-Up			30,777	29,518	23,416	
	c) DAC-SASH	4,400	4,370	4,370	4,370	4,370	
	d) DAC-GT			2,012	2,012	9,820	
	e) CS-GT			3,142	3,142	2,380	
	f) DAC-GT and CS-GT	14,499			-	(1,786)	
15	**Net GHG Revenues (Line 8 + Line 13 + Line 14)**	(310,039)	(319,155)	(382,471)	(356,373)	(195,801)	
16	**GHG Revenues to be Distributed in Future Years ($)**						
17	**Net GHG Revenues Available for Customers in Forecast Year (Line 15 + Line 16)**	(310,039)	(319,155)	(382,471)	(356,373)	(195,801)	
18	**GHG Revenue Returned to Eligible Customers [6]**						
19	EITE Customer Return	36,466	23,477	25,920	34,017	7,825	
20	Small Business Volumetric Return	-	(2,336)	-	(1)	-	
21	Residential Volumetric Return [7]	-	2,069	-	0	-	
22	**Subtotal EITE + Volumetric Returns**	36,466	23,210	25,920	34,017	7,825	
23	**Number of Households Eligible for the California Climate Credit**	4,936,379	4,890,008	4,989,533	4,988,417	5,008,638	
24	**Per-Household Semi-Annual Climate Credit (0.5 x (Line 17 + 22) ÷ Line 23)**	(27.70)	(27.70)	(35.73)	(35.73)	(18.77)	
25	**Revenue Distributed for the Climate Credit (2 x Line 23 x Line 24)**	(273,475)	(270,906)	(356,551)	(356,471)	(187,976)	
26	**Revenue Balance (Line 15 + Line 22 - Line 25)**	(97)	(25,038)	-	34,115	-	
			-		-		

Note 1 "Forecast" are derived from corresponding tables authorized by the Commission in D.19-02-023 and D.20-02-047

Note 2 2019 "Recorded" 2019 are extracted from the transactions recorded in GHGRBA. Pursuant to Electric Preliminary Statement Part GB, RF&U are excluded the transactions recorded in GHGRBA.

Note 3 2020 "Recorded" includes January through April 2020 recorded, plus forecast through the rest of the year.

Note 4 Pursuant to Electric Preliminary Statement GB, PG&E records the CPUC authorized forecast GHG expenses in the GHG Revenue Subaccount within the GHGRBA.

Note 5 The amount includes funding for the Solar on Multi-Family Affordable Housing (SOMAH), Disadvantaged Community Single-family Affordable Solar Housing (DAC SASH), Disadvantaged Community Green Tariff (DAC-GT), and Community Solar Green Tariff (CS-GT), as stated in Table 17-1. $67.767 million is to be recovered from the GHG Allowance Proceeds and the balance of $1.786 million, shown in Line 5(f) is be recovered through the Public Purpose Program as authroized in D.18-06-027 (OP8).

Note 6 The 2020 recorded distribution of GHG Revenue and Climate Credit to eligible customers reflect actuals of April 2020, plus forecast through the rest of Similar to Note 2, RF&U are excluded from the calculation.

Note 7 The recorded column is a result of the cummulative adjustments to the residential customers' bills, that relates to the periods prior to PG&E's implementation of the Residential Rate Reform Decision (D.15-07-001).

TABLE 17-4
FORECAST REVENUE REQUIREMENT AND REVENUES BY RATE SCHEDULE
(TEMPLATE D-4)

	Bundled Customers				DA/CCA Customers			
Rate Schedule (A)	Forecast of kWh Sales (kWh) (B)	Forecast GHG Revenue Reqt ($) (C)	Rate Impact ($/kWh) (D)	Forecast GHG Revenue ($) (E)	Forecast of kWh Sales (kWh) (F)	Forecast GHG Revenue Reqt ($) (G)	Rate Impact ($/kWh) (H)	Forecast GHG Revenue ($) (I)
E-1	8,076,230,160	($25,393,584)	($0.00314)	$54,097,731	12,335,372,705	($38,785,339)	($0.00314)	$86,968,888
EL-1	4,220,292,807	($7,061,805)	($0.00167)	$28,156,806	2,231,130,262	($3,733,344)	($0.00167)	$18,752,442
A-1	2,436,516,527	($7,475,278)	($0.00307)	$172,283	4,305,985,655	($13,210,844)	($0.00307)	$1,920
A-6	479,371,897	($1,881,030)	($0.00392)	$246,337	751,657,729	($2,949,465)	($0.00392)	$1,323
A-15	13,390	($309)	($0.02310)	$0	365,112	($8,436)	($0.02310)	$0
TC-1	10,689,062	($39,607)	($0.00371)	$0	28,425,589	($105,328)	($0.00371)	$0
A-10 T	1,198,709	($2,793)	($0.00233)	$0	1,050,072	($2,447)	($0.00233)	$0
A-10 P	26,643,075	($66,819)	($0.00251)	$0	53,536,542	($134,267)	($0.00251)	$0
A-10 S	2,737,590,210	($10,515,788)	($0.00384)	$239,644	5,339,274,402	($20,509,527)	($0.00384)	$12,370
E-19 T	7,721,375	($19,275)	($0.00250)	$0	5,273,753	($13,165)	($0.00250)	$0
E-19 V T	10,869,473	($13,247)	($0.00122)	$0	8,211,973	($10,008)	($0.00122)	$0
E-19 P	351,945,693	($768,873)	($0.00218)	$58,787	535,815,493	($1,170,561)	($0.00218)	$27,498
E-19 V P	138,250,472	($251,787)	($0.00182)	$0	186,418,448	($339,513)	($0.00182)	$0
E-19 S	967,527,065	($4,613,303)	($0.00477)	$879,405	2,906,249,121	($13,857,399)	($0.00477)	$185,787
E-19 V S	2,290,209,088	($9,603,928)	($0.00419)	$0	6,540,814,072	($27,428,722)	($0.00419)	$0
Streetlights	65,631,713	($239,465)	($0.00365)	$0	163,144,341	($595,252)	($0.00365)	$0
Standby T	369,805,014	($636,453)	($0.00172)	$0	30,470,166	($52,441)	($0.00172)	$0
Standby P	9,299,676	($15,436)	($0.00166)	$0	6,850,304	($11,370)	($0.00166)	$0
Standby S	6,326,738	($3,562)	($0.00056)	$0	2,077,703	($1,170)	($0.00056)	$0
AG-1A	11,254,271	($64,486)	($0.00573)	$2,912	9,709,259	($55,633)	($0.00573)	$0
AG-RA	14,971,796	($14,950)	($0.00100)	$0	126,007	($126)	($0.00100)	$0
AG-VA	9,801,505	($12,494)	($0.00127)	$0	1,349,244	($1,720)	($0.00127)	$0
AG-4A	275,839,059	($378,515)	($0.00137)	$6,612	46,775,551	($64,187)	($0.00137)	$0
AG-5A	115,384,452	($164,873)	($0.00143)	$398	17,841,493	($25,494)	($0.00143)	$0
AG-1B	30,262,483	($114,539)	($0.00378)	$3,933	19,683,092	($74,498)	($0.00378)	$0
AG-RB	16,028,192	($14,839)	($0.00093)	$0	353,366	($327)	($0.00093)	$0
AG-VB	20,110,620	($33,364)	($0.00166)	$1	1,107,132	($1,837)	($0.00166)	$0
AG-4B	584,855,761	($853,696)	($0.00146)	$89,083	152,321,442	($222,339)	($0.00146)	$0
AG-4C	96,301,823	($94,474)	($0.00098)	$22,857	13,699,731	($13,440)	($0.00098)	$0
AG-5B	2,112,107,322	($2,279,607)	($0.00108)	$407,857	280,227,020	($302,450)	($0.00108)	$2,746
AG-5C	1,724,742,693	($1,847,708)	($0.00107)	$247,027	464,336,441	($497,441)	($0.00107)	$28,918
E-20 T	2,164,009,595	($5,501,014)	($0.00254)	$24,347	3,616,878,244	($9,194,275)	($0.00254)	$11,216
E-20 P	1,992,134,508	($7,213,506)	($0.00362)	$129,677	4,669,743,824	($16,909,111)	($0.00362)	$110,768
E-20 S	693,706,803	($2,654,392)	($0.00383)	$3,485,140	1,528,902,251	($5,850,174)	($0.00383)	$1,426,350
TOTALS	**32,067,643,028**	**($89,844,801)**	**($0.00280)**	**$88,270,837**	**46,255,177,540**	**($156,131,648)**	**($0.00338)**	**$107,530,226**

Residential California Climate $18.77

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 18

ENERGY PROCUREMENT REVENUE REQUIREMENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 18
ENERGY PROCUREMENT REVENUE REQUIREMENTS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 18
ENERGY PROCUREMENT REVENUE REQUIREMENTS

A. Introduction

The purpose of this chapter is to consolidate Pacific Gas and Electric Company's (PG&E) 2021 revenue requirements presented in Chapters 8 through 12 and Chapter 14, used to develop PG&E's rate proposal presented in Chapter 19. PG&E will update the consolidated revenue requirements presented in this chapter in Supplemental Testimony. Consistent with previous years, updates to these revenue requirements and balancing account amortization will be included in the Update to Prepared Testimony (November Update), and recovered as part of 2021 effective rates through the Annual Electric True-Up (AET) or subsequent rate change advice letter process.

B. Recovery of the 2021 Forecast Energy Procurement Revenue Requirements

Table 18-1 summarizes the 2021 revenue requirement recoverable through: (1) the New System Generation Charge (NSGC);[1] (2) the Power Charge Indifference Adjustment (PCIA) rate; (3) the Ongoing Competition Transition Charge (Ongoing CTC); (4) the Tree Mortality Non-Bypassable Charge (TMNBC); (5) the Energy Resource Recovery Account (ERRA); and (6) the PCIA Undercollection Balancing Account (PUBA). The Green Tariff Shared Renewables (GTSR) Program costs are not included in the revenue requirement calculation, and the GTSR dedicated resources have been excluded from the totals in Table 18-1.

C. 2021 Revenue Requirements for Rate Setting

Lines 1 through 7 of Table 18-1 shows the summation of the forecasted 2021 revenue requirements that PG&E presented in this application for setting rates, totaling $5,328.6 million. Included in this amount are the revenue requirements related to the Utility Owned Generation (UOG) costs under

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[1] The Cost Allocation Mechanism (CAM) revenue requirement is recovered through the NSGC.

consideration and/or approved in other regulatory proceedings, including PG&E's 2020 General Rate Case (GRC) Application (A.) 18-12-009 (collectively, the "UOG Related Costs") . The UOG Related Costs, totaling $2,522.5 million, are included in the NSGC (Line 1), PCIA (Line 2), and ERRA (Line 5), and presented in this application solely for rate setting purposes. PG&E is not requesting approval of these revenue requirements in this Application because their recovery is either authorized or under the California Public Utilities Commission's (Commission) consideration in other proceedings. Therefore, they are deducted from Line 7 in Table 18-1 (See Line 8).

D. 2021 ERRA Application Revenue Requirement Request

Line 9 of Table 18-1 presents PG&E's 2021 ERRA Forecast Application revenue requirement request of $2,806.1 million. This amount excludes the revenue requirements that are either authorized or under Commission consideration in other proceedings, as described in Section C above.

E. 2020 Year End Balancing Account Amortization

Consistent with the previous ERRA proceedings, PG&E will include the amortization of its 2020 year-end balancing account balances in rates over 2021, through the 2021 AET[2] or subsequent electric rate change advice letter process. Based on PG&E's forecast as part of this filing, PG&E expects to file expedited trigger applications associated with the ERRA balance by July 31, 2020 and the PUBA balance later this year. The table below reflects the forecast year-end balancing account balances without consideration of the disposition of these two anticipated applications. If an expedited PUBA trigger application does not approve full recovery of the PUBA balance, PG&E will

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2 The AET advice letter will be updated with final 2021 revenue requirements in December 2020, for rates effective on or after January 1, 2021. The AET originates from D.03 12 035 and D.04 02 062, which authorized PG&E's Master Settlement Agreement and post-bankruptcy rate implementation. Since 2005, the AET has been a vehicle for PG&E to consolidate its annual authorized revenue requirement across various regulatory accounts for rates implementation, beginning January 1 of each year. Ordering Paragraph 8 of Resolution E 4808 requires PG&E to submit its AET by September 1 to reflect, balances recorded as of July 31 of the current year, and the estimated balances for August through December.

request that any residual balance be included in the PCIA revenue requirement for recovery either as part of its November Update or through the AET process.[3]

F. Conclusion

PG&E requests that the Commission:

1) Adopt PG&E's forecasted total 2021 revenue requirement for rate setting of $5,328.6 million, including $2,522.5 million of UOG-Related Costs;
2) Adopt PG&E's 2021 ERRA Application revenue requirement request of $2,806.1 million; and
3) Approve the amortization of the 2020 year-end balancing account balances in rates during 2021.

[3] See also Chapter 14 (Section E.3) discussion regarding PG&E's proposal concerning the disposition of the end of year PUBA balance.

TABLE 18-1
SUMMARY OF 2021 FORECAST ENERGY PROCUREMENT REVENUE REQUIREMENTS
(THOUSANDS OF DOLLARS)

Line No.	Description	2021 Cost with Revenue Fees and Uncollectibles[b]	Year End Balance[c]	Total 2021 Revenue Requirement[c]
		(A)	(B)	(C) = (A) + (B)
1	CAM[a] (Chapter 8)	$181,410	$84,934	$266,344
2	PCIA (Chapter 9)	2,742,186	60,367	2,802,552
3	Ongoing CTC (Chapter 10)	45,955	(26,092)	19,863
4	TMNBC (Chapter 11)	37,354	35,265	72,619
5	ERRA (Chapter 12)	2,177,227	(287,352)[e]	1,889,875
6	PUBA	–	277,364	277,364
7	Revenue Requirement for Rate Setting	$5,184,130	$144,487	$5,328,617
8	Less: UOG-Related Costs[d]	(2,522,491)	–	(2,522,491)
9	2021 ERRA Application Revenue Requirement Request	$2,661,640	$144,487	$2,806,127

(a) The CAM revenue requirement presented in Chapter 8 is recovered through the New System Generation Charge (NSGC).

(b) Costs exclude Green Tariff Shared Renewables (GTSR) Program Costs.

(c) The year-end balancing account balances recovered in rates through the Annual Electric True-Up (AET), and or subsequent rate change Advice Letter.

(d) UOG-Related Costs in the revenue requirement components included in PCIA, ERRA and CAM are solely for rate-setting purposes, and PG&E does not request approval of these costs in this Application.

(e) The ERRA overcollection is the deferred revenue collected in generation rates because of capped departed PCIA rates. The offsetting amount is reflected in PUBA (line 6).

Totals may not add due to rounding.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 19

RATE PROPOSAL

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 19
RATE PROPOSAL

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 19
RATE PROPOSAL

A. Introduction

The purpose of this chapter is to present Pacific Gas and Electric Company's (PG&E) rate proposal for implementing the 2021 Energy Resource Recovery Account (ERRA), Ongoing Competition Transition Charge (Ongoing CTC), Power Charge Indifference Adjustment (PCIA), Cost Allocation Mechanism (CAM), and Tree Mortality Non-Bypassable Charge (TMNBC) revenue requirements, as presented in Chapters 9 through 12 and Chapter 14 and summarized in Chapter 18. In recovering these revenue requirements, PG&E will change vintage PCIA rates, generation rates,[1] Ongoing CTC rates, New System Generation Charge (NSGC) rates,[2] TMNBC rates, as total rates on January 1, 2021. Additionally, in compliance with Decision (D.) 20-02-047, PG&E's testimony will present a methodology to properly credit 2019 and 2020 vintage customers their share of the ERRA balance in a manner that does not have an adverse impact on the PCIA vintage subaccount.[3] Further, PG&E presents a going-forward proposal to address certain end-of-year ERRA balances by transferring such balances to the most recent vintage subaccount.

In this 2021 ERRA Forecast Application (Application), PG&E proposes to use the revenue allocation and non-residential rate design methodologies adopted by the California Public Utilities Commission (CPUC or Commission) in Phase 2 of PG&E's 2017 General Rate Case (GRC). Specifically, PG&E uses the revenue allocation and rate design requirements set forth in the Revenue Allocation Settlement approved by OP 1 of Decision (D.) 18-08-013 and in PG&E's Advice 5429-E. For residential rate design, PG&E uses the methodologies adopted by the CPUC in the Residential Rate Reform Order Instituting Rulemaking (OIR), D.15-07-001, including the impacts of the

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1 The proposed 2021 Generation rate has within it the 2021 Vintage PCIA rate for revenue tracking purposes.

2 The NSGC rate component collects the CAM revenue requirement.

3 See D.20-02-047, Finding of Fact (FOF) 8, and FOF 9, and Ordering Paragraph (OP) 4 (approving PG&E's 2020 ERRA Forecast Application, (A.) 18-06-001).

reductions in number of residential tiers and the prescribed rate ratios between tiers.

PG&E uses May 1, 2020 electric rates as the basis for present rate revenues.[4] PG&E will consolidate the 2021 rate changes presented in this Application with the Annual Electric True-Up (AET) rate changes scheduled to take effect on January 1, 2021 and will use the rates effective at that time to determine present rate revenues.

PG&E incorporates the following PCIA and generation related changes in this Application, driven by recent decisions:

- First, in D.18-10-019 issued in Phase 1 of the PCIA OIR, the Commission set a cap of 0.5 cents per kWh increase for non-exempt departing load customers' PCIA rate differentiated by vintage (OP 9) and established a trigger mechanism for the PCIA cap (OP 10). Capping the PCIA rate for non-exempt departing load customers will also impact the bundled generation rate.[5]
- Second, as a result of capped PCIA rates and as established through PG&E's Advice 5624-E, this Application presents a methodology to incorporate the forecasted end-of-year balance from PUBA, as outlined in Chapter 14, into vintage PCIA rates. Due to capped PCIA rates, the forecasted PUBA balance is not amortized into rates in this Application.
- Third, as directed by D.20-02-047, approving PG&E's 2020 ERRA Forecast Application, PG&E has constructed two proposals to credit ERRA balances to vintage 2019 and 2020 departing load customers which does not have adverse effects on PCIA vintage subaccounts.[6]

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4 PG&E changed rates on June 1, 2020 to temporarily reduce the High Usage Surcharge pursuant to D.20-05-013. Because the change in the High Usage Surcharge is temporary, rates effective May 1, 2020 provide a more accurate starting point for calculating rate and bill impacts for a rate change that would occur in 2021. The present rate revenue is a product of 2021 ERRA forecasted sales for calendar year 2021 as determined in this proceeding and the present rates in effect on May 1, 2020.

5 PG&E submitted Advice 5624-E on August 8, 2019, requesting the establishment of the PCIA Undercollection Balancing Account (PUBA) and describing its proposal to implement capped PCIA rates for departed load and establishing the associated Trigger Mechanism for the PUBA.

6 D.20-02-047, OP 4.

This Application results in capped PCIA rates for the 2009 through 2019 vintages. After the increase in PCIA rates for these vintages is capped at 0.5 cents per kilowatt-hour (kWh), the system average bundled rate will decrease by approximately 0.5 percent to 22.2 cents per kWh when compared to the present system average bundled rate of 22.3 cents per kWh, effective May 1, 2020. Attachment A to this chapter shows a comprehensive list of illustrative proposed revenues for bundled, Direct Access (DA), and Community Choice Aggregation (CCA) customers and the associated average present and proposed rates by schedule and functional rate component.

B. Revenue Allocation and Rate Design

1. Vintage PCIA Rates

The Commission approved stranded cost recovery for new generation resource commitments in D.04-12-048 and, as discussed in Chapter 9, the calculation methodology to determine the vintage PCIA revenue requirements was adopted in D.08-09-012, as modified in D.11-12-018.[7] As prescribed in D.18-10-019, OP 4 Modifying the PCIA Methodology, the rate design approved for the non-California Department of Water Resources (CDWR) cost portion of the indifference calculation was a generation cost allocation and rate design methodology approved for ongoing CTC. The PCIA rate for each vintage year by customer class is developed by utilizing the same proportional ratio of the customer class average generation rate to the total system average generation rate. The proportional ratio is then multiplied by the total system average PCIA portfolio Indifference Amount rate by vintage year to calculate the PCIA rate by vintage year and by rate class. Proportional generation ratios have been calculated using PG&E's 2021 forecast generation rates in this Application at the 2021 forecast bundled sales by customer class. In all cases, the final PCIA rates include franchise fees for the CDWR bond charge. The resulting PCIA rates are shown in Table 19-5, using proposed vintage billing determinants.

In D.18-10-019 the Commission set a cap of a 0.5 cent per kWh increase for non-exempt departing load customers' PCIA rate

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7 Modifications to the calculation methodology approved in D.11-12-018 were implemented, in part, in Resolution 4475-E.

differentiated by vintage (OP 9) and established a trigger mechanism for the PCIA cap (OP 10). Consistent with PG&E's implementation of the PCIA cap in its 2020 ERRA Forecast Application, as approved in D.20-02-047, PG&E proposes that the evaluation of whether the 0.5 cent per kWh PCIA cap has been reached be measured based on the system average PCIA rate by vintage. If the system average PCIA rate by vintage increases more than 0.5 cent per kWh, then all PCIA rates for that vintage would be capped and the capped PCIA rates by customer class would be determined based on the revenue allocation among classes. The net result is that some customer classes may pay an increase that is slightly more than 0.5 cent per kWh and some customer classes may pay slightly less than the 0.5 cent per kWh increase. Utilization of the currently authorized generation revenue allocation factors to determine the class-specific capped PCIA rates maintains the proper rate design within the vintage subaccount so each customer class has responsibility for any balance in the vintage subaccount in proportion to the generation allocation rate design.

In this Application, PG&E proposes the following adjustments when calculating vintage PCIA rates:

- First, PG&E proposes a framework to amortize the end-of-year PUBA balance in vintage PCIA rates, subject to the capped increase of 0.5 cents per kWh.
- Second, as directed by D.20-02-047 issued in PG&E's 2020 ERRA Forecast Application, PG&E has developed a methodology to credit a proportional share of the 2019 ERRA end-of-year balance to 2019 vintage departing load customers through a one-time PCIA rate adder.
- Third, PG&E is recommending that going forward, the end-of-year ERRA balance, less the departing load revenue shortfall financed by bundled customers due to the PCIA cap, be amortized in the most recent vintage subaccount in PABA, which in this Application would be the 2020 vintage subaccount. PG&E proposes to directly transfer this end-of-year balance to the most recent vintage PABA subaccount and the balance in that subaccount would be amortized as part of the uncapped PCIA rates.

a. Methodology to Amortize Forecasted PUBA Balance into Vintage PCIA Rates

In Advice 5624-E, PG&E proposed a process for disposing of any year-end PUBA balance not authorized for recovery through a PUBA trigger application in the PCIA revenue requirement as part of its ERRA forecast application. The CPUC's Energy Division issued a non-standard disposition letter approving this advice letter on December 4, 2019. At the time of filing this Application, PG&E has not requested or received authorization to recover the PUBA balance through an expedited trigger application. As such, this Application attempts to recover the forecasted PUBA balance as outlined in Chapter 14 through PCIA rates.

To amortize the PUBA balance by vintage into PCIA rates, PG&E has calculated a vintage specific PCIA rate adder. This rate adder is determined by dividing the forecasted year-end PUBA balance by vintage (Table 14-3) by the departing load billing determinants specific to each vintage. PG&E then determines whether this PCIA rate adder by vintage can be applied to the uncapped PCIA rates, subject to the capped increase. If the uncapped system average PCIA rate has already increased above the capped amount, the rate adder cannot be applied. If the uncapped system average PCIA rate has increased less than the capped amount, then the rate adder can be applied incrementally until the cap is reached. Once the incremental rate adder by vintage is determined, PG&E calculates the estimated revenues by vintage that would be collected through this rate. PG&E then applies the incremental rate adder by vintage to each customer class by utilizing the proportional generation ratios and scaling the rates to collect the estimated revenues.

In this Application, the uncapped PCIA rates for PCIA vintages 2009 through 2019, which amortize only the PCIA Indifference Amount and PABA balance, exceed the allowable increase of 0.5 cents per kWh. Because of this exceedance, none of the forecasted PUBA balance is amortized in PCIA rates in this Application. PG&E will revisit the incorporation of the PUBA balance in its Update to Prepared Testimony

served on November 9, 2020 (November Update). At that time, PG&E will follow the same approach to request recovery of any outstanding forecasted PUBA balance not previously authorized for recovery.

b. Methodology to Credit ERRA balances to 2019 and 2020 Vintage Customers

The issue of crediting the ERRA balance to the most recent PABA vintage subaccount first came up in PG&E's 2020 ERRA Forecast proceeding as a recommendation from the CCA parties in their comments on PG&E's November Update as well as in comments on the proposed decision.[8] Rather than fully adopt the Joint CCA's proposal, D.20-02-047 instead required PG&E to propose a methodology to credit the balance in ERRA to vintage 2019 and 2020 departing load customers in a way that would not have adverse effects on PCIA vintage subaccounts.

In its 2020 ERRA Forecast application, Southern California Edison Company (SCE) made a recommendation to amortize the end-of-year ERRA balance for both bundled and departing load customers by transferring the balance to the most recent PABA subaccount.[9] As PG&E stated in its February 18, 2020 Reply Comments on the proposed decision in its 2020 ERRA Forecast Application, PG&E was not fundamentally opposed to the CCA's proposal. However, PG&E wanted to develop a thoughtful proposal given there was no record in PG&E's application and testimony for such a ratemaking treatment, the projected ERRA balance was large given the transitional accounting year, and the PCIA rates were capped. Specifically, PG&E's Reply comments stated that:

> While PG&E agrees that load that departs in later vintages should be refunded or charged its share of any ERRA over- or undercollection, there is no record established in this proceeding to support this last-minute change in rate design. As such, the record is silent on how this refund should occur in order to avoid the rate volatility that could occur if the current overcollection is credited into

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8 See, e.g., A.19-06-001. Joint CCA Comments (December 6. 2019), pp. 26-28.

9 See, e.g., A.19-06-002. Updated Testimony Energy Resource Recovery Account (ERRA) 2020 Forecast of Operations (Exhibit SCE-6). (October 30. 2019), pp. 85.

the PABA vintage subaccounts. PG&E believes it is appropriate to develop a full record to implement this refund in PG&E's 2021 ERRA forecast prepared testimony, which is scheduled for June 1, 2020.[10]

PG&E describes two proposals for returning the end-of-year ERRA balances to the appropriate vintage departing load customers. First, PG&E proposes to return a proportional share of the 2019 end-of-year ERRA balance through a rate adder that would be applicable to the 2019 vintage departing load customers only. This is a one-time adjustment to satisfy the requirements from D.20-02-047. Second, PG&E proposes that the end-of-year ERRA balance going forward, less the deferred revenue financed by bundled customers due to capped PCIA rate, be returned through a standard ratemaking approach where such balance is transferred to the most recent vintage subaccount, which would be the 2020 vintage subaccount in this Application.

c. 2019 ERRA Forecast Balance Return to 2019 Vintage Departing Load

For the 2019 vintage departing load customers, PG&E proposes a one-time rate adder which would be applied on top of the applicable PCIA rate, which initially will be capped. The final PCIA rate, including this PCIA rate adder, will reduce the final 2019 vintage PCIA rate below the capped amount.

The ERRA balance to be amortized in the 2019 PCIA rate adder was derived by first calculating a 2019 departing load pro rata allocation factor. This factor was calculated by dividing the recorded 2019 bundled sales associated with customers who departed on or after July 1, 2019,[11] and thus joined the 2019 vintage, by the total bundled sales recorded in 2019.[12] This allocation factor was multiplied by the total 2019 ERRA balance of $386 million that was amortized in bundled

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10 A. 19-06-001, PG&E's Reply Comments on Proposed Decision (February 18, 2020), p.4.

11 This value represents the total sales that vintage 2019 departing load customers paid into the 2019 ERRA overcollection.

12 Since bundled customers may depart and join the 2019 vintage from July 1, 2019 through June 30, 2020, PG&E will update this allocation factor in its November ERRA Update with a full set of historical data.

generation rates on May 1, 2020. Finally, the allocated 2019 ERRA balance was divided by the proposed 2019 vintage departing load billing determinants proposed in this Application. As shown in Table 19-1 below, the 2019 departing load pro rata Allocation factor is approximately 1.58 percent, resulting in an allocated balance of $6.096 million. This results in a system average PCIA rate adder of approximately negative 0.7 cents per kWh.

TABLE 19-1[(a)]
PROPOSED 2021 PCIA RATE ADDER FOR 2019 VINTAGE DEPARTING LOAD
($/KWh)

Line No.	Category	Updated D.20-02-047 Year-End ERRA Balance[(b)]	2019 Vintage Departing Load Pro Rata Allocation	Allocated Balance	Applicable Load (kWh)[(c)]	System Average PCIA Rate Adder
1	ERRA	$(386,177,444)	1.58%	$(6,096,199)	818,333,287	$(0.00745)

(a) This table is impacted by the load forecasting error described in Section A3 of Chapter 1 and will be updated through supplemental testimony.
(b) 2019 ERRA overcollection amortized into bundled generation rates on May 1, 2020.
(c) 2021 forecasted billing determinants for 2019 vintage departing load customers.

Since the vintage 2019 PCIA rate is capped before this rate adder is applied, PG&E proposes that this one-time rate adjustment be excluded when determining capped PCIA rates for future PCIA rate changes. Using rates with this adjustment would artificially lower the allowed increase for the vintage 2019 PCIA rates. Instead, PG&E proposes using PCIA rates without this adjustment as the foundation to determine future capped PCIA rates. Similarly, since this adjustment is applied after the capped increase is in effect, using PCIA rates with this adjustment to determine PUBA balances would incorrectly overstate the difference between uncapped PCIA rates and proposed PCIA rates. PG&E proposes using PCIA rates without this adjustment as the foundation to determine the rate difference between capped and uncapped rates used to track balances in PUBA. Due to these reasons, PG&E will continue to refer to the 2019 vintage as being capped.

d. 2020 ERRA Balance Return to 2020 Vintage Departing Load

As noted in Chapter 18, PG&E expects to file an expedited trigger application associated with the ERRA balance by July 31, 2020. Since PG&E has not yet filed this application or received authorization to recover the forecasted ERRA balance, this Application requests recovery of the entire forecasted 2020 end-of-year ERRA balance. PG&E will update the end-of-year ERRA balance in its November Update to request recovery of any outstanding ERRA balance not authorized for recovery through a trigger application.

To return the forecasted 2020 end-of-year ERRA balance to vintage 2020 departing load customers and remaining bundled customers, PG&E is proposing a standard ratemaking approach where the ERRA balance would be transferred to the most recent vintage subaccount in PABA, the 2020 vintage subaccount. PG&E proposes transferring the entire end-of-year balance, less the deferred revenue financed by bundled customers due to capped PCIA rates, to the most recent PABA subaccount.[13] For this Application only, PG&E then removes $6.1 million of the overcollection (Table 19-1) from the 2020 PABA subaccount in order to facilitate the one-time PCIA rate adder for vintage 2019 departing load customers resulting from the 2019 ERRA overcollection. Amortizing the forecasted 2020 end-of-year ERRA balance in the 2020 vintage subaccount will allow the balance to be applied to both bundled customers and departing load customers that depart on or after July 1, 2020. While the forecasted overcollection is still large at $471 million, it is not as large as it was projected to be in 2019.[14] Nevertheless, the $471 million credit to the 2020 vintage subaccount will result in a reduction to the PCIA rates for 2020 and 2021 vintages, resulting in uncapped PCIA rates for these two vintages.[15]

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[13] In D.18-10-019, Conclusion of Law 23, the Commission concluded that any balances in the PCIA undercollection balancing account will be repaid to bundled customers with interest so that the PCIA cap does not violate statutes that forbid cost-shifting.

[14] A.19-06-001, Second Amended Update to Prepared Testimony Submitted on November 8, 2019 (December 19, 2019). p.2.

[15] The 2021 vintage PCIA rate is naturally uncapped without this adder since there are no existing rates for this vintage, and thus, no incremental increase to cap.

Incrementally, the balance transfer independent of other forecast activity will result in a rate impact of approximately 1.3 cents per kWh, as shown in the table below:

TABLE 19-2[(a)]
IMPACT OF AMORTIZATION OF THE FORECASTED 2020 YEAR-END ERRA BALANCE IN 2020 VINTAGE PABA SUBACCOUNT

Line No.	Applicable 2020 ERRA End-of-Year Balance ($000)[(b)]	2020 Vintage Billing Determinants (kWh)	Average PCIA Rate Impact ($/kWh)
1	$(471,336)	36,140,689,959	$(0.01304)

(a) This table is impacted by the load forecasting error described in Section A3 of Chapter 1 and will be updated through Supplemental testimony.

(b) While a total of $(477.4) million is transferred to PABA, $(6.1) million is then allocated to the vintage 2019 departing load customers through the rate design process to facilitate the one-time adjustment for the 2019 ERRA end-of-year balance.

e. Summary of Proposed 2021 Vintage PCIA Rates

The PCIA revenue requirement resulted in capped PCIA rates for all vintages and all classes except the 2020 and 2021 vintages. In Table 19-3 below, PG&E first shows uncapped PCIA rates, where the increase in rates above the 2020 levels range between -0.95 cents per kWh and 1.56 cents per kWh. Uncapped PCIA rates for vintages 2009 through 2019 exceed the 0.5 cent per kWh cap increase. The next two tables show the derivation of the proposed PCIA rates for these vintages, which starts with the currently effective 2020 PCIA rates (Table 19-4) and Table 19-5 presents the proposed PCIA rates including the cap, if applicable. The capped PCIA rates are derived by adding 0.5 cents per kWh to the system average rate and then multiplying the system average rate by the Generation Rate Ratios (GRR) to derive the class specific rates.[16] The one-time 2019 vintage PCIA rate adder is applied after the 2019 vintage PCIA rate is capped, resulting in the proposed PCIA rate for this vintage being slightly below the cap. The

[16] The Generation Rate Ratios implement the generation revenue allocation approved in PG&E's most recent GRC.

2021 vintage PCIA rates are not capped because there are no existing rates for this vintage and, thus, no incremental increase to cap.

TABLE 19-3[(a)]
UNCAPPED PCIA RATES BY CLASS AND VINTAGE (WITH DWR FRANCHISE FEE)
($/KWH)

Line No.	Customer Class	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage
1	Residential	$0.03708	$0.04344	$0.04518	$0.04698	$0.04750	$0.04762	$0.04790	$0.04785	$0.04873	$0.04903	$0.04899	$0.03223	$0.03223
2	Small L&P	$0.03704	$0.04338	$0.04512	$0.04692	$0.04744	$0.04756	$0.04784	$0.04779	$0.04867	$0.04896	$0.04893	$0.03219	$0.03219
3	Medium L&P	$0.03818	$0.04472	$0.04652	$0.04837	$0.04890	$0.04903	$0.04932	$0.04926	$0.05018	$0.05048	$0.05044	$0.03318	$0.03318
4	E19	$0.03519	$0.04122	$0.04287	$0.04458	$0.04507	$0.04518	$0.04545	$0.04540	$0.04624	$0.04652	$0.04648	$0.03058	$0.03058
5	Streetlights	$0.02956	$0.03462	$0.03601	$0.03744	$0.03785	$0.03795	$0.03817	$0.03813	$0.03884	$0.03907	$0.03904	$0.02569	$0.02569
6	Standby	$0.02675	$0.03133	$0.03259	$0.03389	$0.03426	$0.03435	$0.03455	$0.03451	$0.03515	$0.03536	$0.03534	$0.02325	$0.02325
7	Agriculture	$0.03320	$0.03889	$0.04045	$0.04206	$0.04252	$0.04263	$0.04289	$0.04284	$0.04363	$0.04389	$0.04386	$0.02886	$0.02886
8	E20 T (Excluding FPP)	$0.03022	$0.03539	$0.03681	$0.03828	$0.03870	$0.03880	$0.03903	$0.03898	$0.03971	$0.03994	$0.03991	$0.02626	$0.02626
9	E20 P (Excluding FPP)	$0.03236	$0.03791	$0.03943	$0.04100	$0.04145	$0.04156	$0.04180	$0.04176	$0.04253	$0.04278	$0.04275	$0.02813	$0.02813
10	E20 S (Excluding FPP)	$0.03410	$0.03994	$0.04154	$0.04320	$0.04367	$0.04378	$0.04404	$0.04399	$0.04481	$0.04508	$0.04504	$0.02964	$0.02964
11	System Average PCIA Rate by Vintage	$0.03566	$0.04178	$0.04346	$0.04520	$0.04569	$0.04581	$0.04608	$0.04603	$0.04688	$0.04716	$0.04713	$0.03115	$0.03115

(a) This table is impacted by the load forecasting error described in Section A3 of Chapter 1 and will be updated through Supplemental testimony.

TABLE 19-4
CURRENTLY EFFECTIVE PCIA RATES BY CLASS AND VINTAGE (WITH DWR FRANCHISE FEE)
($/KWH)

Line No.	Customer Class	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage
1	Residential	$0.02561	$0.02877	$0.03122	$0.03109	$0.03325	$0.03372	$0.03354	$0.03340	$0.03334	$0.03336	$0.03555	$0.04243
2	Small L&P	$0.02453	$0.02756	$0.02990	$0.02979	$0.03186	$0.03230	$0.03213	$0.03199	$0.03194	$0.03196	$0.03406	$0.04065
3	Medium L&P	$0.02643	$0.02969	$0.03222	$0.03209	$0.03432	$0.03480	$0.03461	$0.03447	$0.03441	$0.03443	$0.03669	$0.04379
4	E19	$0.02422	$0.02721	$0.02952	$0.02941	$0.03145	$0.03189	$0.03172	$0.03158	$0.03153	$0.03155	$0.03362	$0.04013
5	Streetlights	$0.02042	$0.02293	$0.02488	$0.02479	$0.02651	$0.02688	$0.02673	$0.02662	$0.02658	$0.02660	$0.02834	$0.03383
6	Standby	$0.01850	$0.02079	$0.02256	$0.02247	$0.02403	$0.02437	$0.02423	$0.02413	$0.02409	$0.02411	$0.02569	$0.03067
7	Agriculture	$0.02289	$0.02571	$0.02790	$0.02779	$0.02972	$0.03014	$0.02998	$0.02985	$0.02980	$0.02982	$0.03178	$0.03793
8	E20 T (Excluding FPP)	$0.02079	$0.02335	$0.02534	$0.02524	$0.02699	$0.02737	$0.02722	$0.02711	$0.02706	$0.02708	$0.02886	$0.03445
9	E20 P (Excluding FPP)	$0.02240	$0.02516	$0.02730	$0.02720	$0.02908	$0.02949	$0.02933	$0.02921	$0.02916	$0.02918	$0.03109	$0.03711
10	E20 S (Excluding FPP)	$0.02330	$0.02617	$0.02840	$0.02829	$0.03026	$0.03068	$0.03051	$0.03039	$0.03033	$0.03036	$0.03235	$0.03861
11	System Average PCIA Rate by Vintage	$0.02435	$0.02735	$0.02968	$0.02956	$0.03162	$0.03206	$0.03189	$0.03175	$0.03170	$0.03172	$0.03380	$0.04062

TABLE 19-5[(a)]
PROPOSED 2021 PCIA RATES BY CLASS AND VINTAGE (WITH DWR FRANCHISE FEE)
($/KWH)

Line No.	Customer Class	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage
1	Residential	$0.03076	$0.03391	$0.03635	$0.03622	$0.03838	$0.03884	$0.03866	$0.03852	$0.03846	$0.03849	$0.03312	$0.03223	$0.03223
2	Small L&P	$0.03072	$0.03386	$0.03630	$0.03618	$0.03833	$0.03879	$0.03861	$0.03847	$0.03841	$0.03844	$0.04138	$0.03219	$0.03219
3	Medium L&P	$0.03167	$0.03491	$0.03742	$0.03730	$0.03951	$0.03999	$0.03981	$0.03966	$0.03960	$0.03963	$0.04266	$0.03318	$0.03318
4	E19	$0.02919	$0.03217	$0.03449	$0.03437	$0.03641	$0.03685	$0.03668	$0.03655	$0.03649	$0.03652	$0.03142	$0.03058	$0.03058
5	Streetlights	$0.02451	$0.02701	$0.02896	$0.02886	$0.03058	$0.03095	$0.03080	$0.03069	$0.03065	$0.03067	$0.02639	$0.02569	$0.02569
6	Standby	$0.02218	$0.02445	$0.02621	$0.02612	$0.02767	$0.02801	$0.02788	$0.02778	$0.02773	$0.02775	$0.02388	$0.02325	$0.02325
7	Agriculture	$0.02754	$0.03035	$0.03254	$0.03243	$0.03436	$0.03477	$0.03461	$0.03448	$0.03443	$0.03445	$0.02965	$0.02886	$0.02886
8	E20 T (Excluding FPP)	$0.02506	$0.02762	$0.02961	$0.02951	$0.03126	$0.03164	$0.03149	$0.03138	$0.03133	$0.03135	$0.02698	$0.02626	$0.02626
9	E20 P (Excluding FPP)	$0.02684	$0.02958	$0.03171	$0.03161	$0.03349	$0.03389	$0.03373	$0.03361	$0.03356	$0.03358	$0.02890	$0.02813	$0.02813
10	E20 S (Excluding FPP)	$0.02828	$0.03117	$0.03342	$0.03330	$0.03528	$0.03571	$0.03554	$0.03541	$0.03536	$0.03538	$0.03045	$0.02964	$0.02964
11	System Average PCIA Rate by Vintage	$0.02935	$0.03235	$0.03468	$0.03456	$0.03662	$0.03706	$0.03689	$0.03675	$0.03670	$0.03672	$0.03160	$0.03115	$0.03115

(a) This table is impacted by the load forecasting error described in Section A3 of Chapter 1 and will be updated through Supplemental testimony.

f. Departing Load PCIA Revenue Shortfall Financed by Bundled Customers due to Capped PCIA Rates

Implementing capped PCIA rates for departing load customers will result in a revenue shortfall that will be financed by bundled customers through their generation rates. The revenue shortfall that is expected to accrue is calculated by first summing the revenue associated with the uncapped PCIA rates and the unamortized 2020 end-of-year PUBA balance. Next, the difference is taken between this quantity and the expected departing load PCIA revenues associated with the proposed PCIA rates, which are subject to the cap. These results are presented in the table below.

TABLE 19-6[a]
DEPARTING LOAD REVENUE SHORTFALL FINANCED BY BUNDLED CUSTOMERS
($000)

Line No.	Description	(A) Expected PCIA Revenues from Proposed PCIA Rates[b]	(B) Expected PCIA Revenues from Uncapped PCIA Rates[b]	(C) Unamortized 2020 End-of-Year PUBA Balance	(D) Revenue Shift to Bundled Generation Rates (B) + (C) - (A)
1	Bundled Customers	$984,917	$984,917	–	–
2	DA/CCA Customers	1,470,319	1,817,635	277,364	624,680
3	Total Revenues	$2,455,237	$2,802,552	$277,364	$624,680

(a) This table is impacted by the load forecasting error described in Section A3 of Chapter 1 and will be updated through Supplemental testimony.

(b) Includes the one-time adjustment for the 2019 ERRA overcollection return to 2019 departing load customers.

g. Revenue Shift Resulting from Capped PCIA Rates

OP 10 in D.18-10-019 established a trigger mechanism for the capped PCIA rates applicable to non-exempt departing load customers, which will be measured against the PCIA obligation owed by departing load customers that will accrue in the PUBA vintage subaccount balances.

Specifically, the framework for the trigger mechanism discussed in OP 10 sets the trigger threshold at 10 percent of the forecast PCIA revenues. If the undercollection reaches 7 percent, and PG&E forecasts that the balance will reach 10 percent, then it shall file an expedited

application to change the PCIA rates to bring the balance back down below 7 percent.

Departing load customers share of PCIA revenues is $1,817.6 million. The 7 percent filing level is $127.2 million, and the 10 percent Trigger Threshold is $181.8 million.

2. Generation

The generation revenue requirement for rates reflected in this chapter are shown in Table 18-1 of Chapter 18 of this Application.[17] The Commission approved the methodology for implementing generation rate changes between GRCs in PG&E's 2017 GRC Phase 2, D.18-08-013. The approved methodology allocates incremental generation revenue using an equal percentage of functional revenues. The bundled customers' current generation revenue, as determined using current rates and sales forecast for the test year (TY), is adjusted by subtracting non-allocated revenue and each rate schedule's incremental change in Ongoing CTC to create the "Present Rate Revenue less non-Allocated" generation revenues to calculate the generation allocation factors given the TY forecasted bundled sales. Incremental generation revenue resulting from the ERRA Application is then allocated on an equal percentage basis, i.e., each customer group gets the same percentage change for generation. The sum of the updated generation revenue plus the allocated incremental generation revenue equals the proposed generation revenue for generation rate design.

The change in generation revenue for each schedule will be implemented in rates as an equal percentage change to each bundled service generation demand charge component for that rate schedule. That is, the percentage change to each generation demand charge component on a specific rate schedule would be equal to the percentage change in the schedule-level generation demand charge-related revenue. As prescribed in D.18-08-013 rate design requirements, the change in generation energy charge-related revenue for each schedule will be implemented in rates as either an equal-cent-per-kWh change to each bundled service generation

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17 PG&E is presenting generation rates with a revenue requirement that has been amortized over one year. This is consistent with the amortization proposal summarized in Chapter 18 of this testimony.

energy charge component for that rate schedule, or as an equal-percentage change to the generation energy rate.

Table 19-7 presents the proposed total average generation rates for bundled customers resulting from the methodology described in D.18-08-013. The residual part of the generation revenue requirement for ratemaking has been set at Revenue at Present Rates established by rates implemented May 1, 2020 and the 2021 TY forecasted sales.[18] Further, the average generation rates below will be adjusted for PG&E's 2021 AET reflecting balancing account(s) trued up prior to January 1, 2021.

TABLE 19-7[(a)]
PROPOSED 2021 AVERAGE TOTAL GENERATION RATES FOR BUNDLED CUSTOMERS USING SYSTEM TOTAL BILLING DETERMINANTS IN PCIA RATE DESIGN ($/KWH)

Line No.	Customer Class	Proposed Rate
1	Residential	$0.11531
2	Small Commercial	$0.11151
3	Medium Commercial	$0.11873
4	Large Commercial	$0.10940
5	Streetlights	$0.09188
6	Standby	$0.08316
7	Agriculture	$0.10323
8	E-20 T	$0.09393
9	E-20 P	$0.10062
10	E-20 S	$0.10600

(a) This table is impacted by the load forecasting error described in Section A3 of Chapter 1 and will be updated through Supplemental testimony.

3. Ongoing CTC

Pursuant to D.18-10-019, PG&E is using the same methodology, approved in PG&E's 2017 GRC Phase 2 (D.18-01-013), to allocate Ongoing CTC revenue requirements (Chapter 10) by customer class (and voltage level of service, for Schedule E-20) as is used to allocate generation revenue to customer class for bundled customers, adjusted for the 2021 sales forecast proposed in this Application. In its November Update in this

18 PG&E's Advice 5661-E-A.

proceeding, PG&E will revise the generation allocation factors to reflect the updated 2021 (bundled) sales forecast.

Ongoing CTC rates are designed for each customer class (and voltage level of service, for Schedule E-20). As approved in PG&E's 2008 ERRA Forecast proceeding (D.08-02-018), eligible Departing Load (DL) customers pay the same class-differentiated ongoing CTC rates as bundled, DA and CCA customers. The rates are calculated by dividing the allocated revenue for the class (and voltage level of service, for Schedule E-20) by the corresponding 2021 forecast kilowatt-hours.

Table 19-8 presents the proposed Ongoing CTC rates for bundled, DA, CCA, and eligible DL customers.

TABLE 19-8[(a)]
PROPOSED 2021 ONGOING CTC RATES
($/KWH)

Line No.	Customer Class	Proposed Rate
1	Residential	$0.00026
2	Small Commercial	$0.00026
3	Medium Commercial	$0.00027
4	Large Commercial	$0.00025
5	Streetlights	$0.00021
6	Standby	$0.00019
7	Agriculture	$0.00023
8	E-20 T	$0.00021
9	E-20 P	$0.00023
10	E-20 S	$0.00024

(a) This table is impacted by the load forecasting error described in Section A3 of Chapter 1 and will be updated through Supplemental testimony.

4. New System Generation Charge

In D.10-12-035, the Commission adopted a settlement which established a non-bypassable charge that utilized the CAM approved by D.06-07-029, D.07-09-044, and D.08-09-012, with limited exceptions, to recover the net capacity costs of Combined Heat and Power contracts. PG&E subsequently labeled this new non-bypassable charge as NSGC in Advice 3896-E-B.

NSGC rates are based on the 12-Coincident Peak methodology, as approved by the Commission in D.11-12-031 and subsequently in D.15-08-005. To determine the rates, PG&E first allocates the net capacity costs determined in Chapter 9 to each customer class using each customer class' contribution to 12-month coincident peak load. Proposed rates set forth herein are based on 2019 recorded data. Rates for each customer class will then be set by dividing the allocated revenue by each customer class' forecast usage.[19] Proposed NSGC rates are shown in Table 19-9 below.

TABLE 19-9[(a)]
PROPOSED 2021 NSGC RATES
($/KWH)

Line No.	Customer Class	Proposed Rate
1	Residential	$0.00436
2	Small Commercial	$0.00328
3	Medium Commercial	$0.00294
4	Large Commercial	$0.00294
5	Streetlights	$0.00256
6	Standby	$0.00622
7	Agriculture	$0.00286
8	E-20 T	$0.00256
9	E-20 P	$0.00256
10	E-20 S	$0.00256

(a) This table is impacted by the load forecasting error described in Section A3 of Chapter 1 and will be updated through Supplemental testimony.

5. Tree Mortality Non-Bypassable Charge

To determine TMNBC rates, PG&E first allocates the TMNBC revenue requirement determined in Chapter 11 to each customer class using the same allocation factors as used for the NSGC rates. Proposed rates set forth herein are based on 2019 recorded data. Rates for each customer class will then be set by dividing the allocated revenue by each customer class' forecast usage.

19 For the E-20 class, federal preference power customer accounts are excluded from this calculation.

TABLE 19-10[(a)]
PROPOSED 2021 TMNBC RATES
($/KWH)

Line No.	Customer Class	Proposed Rate
1	Residential	$0.00119
2	Small Commercial	$0.00089
3	Medium Commercial	$0.00077
4	Large Commercial	$0.00077
5	Streetlights	$0.00070
6	Standby	$0.00108
7	Agriculture	$0.00078
8	E-20 T	$0.00061
9	E-20 P	$0.00061
10	E-20 S	$0.00061

(a) This table is impacted by the load forecasting error described in Section A3 of Chapter 1 and will be updated through Supplemental testimony.

6. Changes to Total Rates

Total bundled rates are determined by summing the current rate components that are not changing in this proceeding (e.g., non-ERRA utility-owned Generation, nuclear decommissioning, distribution and transmission) and the proposed rates for 2021 ERRA-related Generation, Ongoing CTC, PCIA, NSGC and TMNBC. For illustrative residential rates, PG&E sets the total rates by tier using the adopted structure and methodology for implementing residential rate changes as of May 1, 2020. The total rates are then unbundled with the Conservation Incentive Adjustment determined residually which establishes the tier ratios (i.e., Tier 1: Tier 2 and Tier 1: High Usage Surcharge).

All illustrative non-ERRA rate components, including the portion of Generation Rates proposed under PG&E's 2020 GRC Phase I proceeding, have been designed and maintained at Present 2020 Rate levels[20] and thus do not reflect the cost recovery (i.e., total 2021 revenue requirements) subject to CPUC approval through PG&E's 2021 AET for year-end balancing account adjustments.

20 Present 2020 rate levels are those filed in Advice 5661-E-A, effective May 1, 2020.

Attachment A summarizes the illustrative proposed bundled and DA/CCA revenues and average rates by schedule and functional rate component resulting from the 2021 ERRA-related Generation, Ongoing CTC, PCIA, NSGC, and TMNBC rate changes proposed by PG&E in this 2021 ERRA Forecast proceeding, as well as the forecasted 2021 Greenhouse Gas allowance revenue return included in rates for eligible customers. Other functional rate components, such as non-ERRA-related Generation, Nuclear Decommissioning, PPPs, Distribution and Transmission that are not part of this proceeding are also presented in Attachment A at present rate levels to provide comprehensive illustration of the total rate impact to bundled and DA/CCA customers from this 2021 ERRA forecast. The TMNBC rate change included in the PPP rate has been added and illustrated in the System average PPP rate for both the bundled and the DA/CCA customer average rate tables. Any revenue requirement component changes approved in this proceeding will be implemented in the 2021 AET. Therefore, the rates set forth in Attachment A are to illustrate the rate impact of this Application only.

C. Conclusion

In this chapter, PG&E presents the Vintage PCIA, Generation, Ongoing CTC, NSGC, and TMNBC rates by customer class based on the proposed revenue requirements summarized in Chapter 18, Table 18-1. Attachment A shows illustrative total rates for both bundled and DA/CCA by customer class and rate schedule.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 19

ATTACHMENT A

ILLUSTRATIVE TOTAL RATES BY CLASS

Pacific Gas & Electric Company
2021 ERRA Forecast - Application dated July 1, 2020
Effective Friday, January 1, 2021

BDLD RESULTS

Class/Schedule	Total Revenue At Present	Generation Revenue	TO Revenue	TAC Revenue	TRBAA Revenue	T-ECRA Revenue	RS Revenue	Dist Revenue	PPP Revenue	ND Revenue	DWR Bond Revenue	CTC Revenue	ECRA Revenue	NSGC Revenue	Residential & Small Business AB32 Credit Revenue	Climate Credit & EITE Revenue	CIA Revenue	PCIA Revenue	Total Proposed Revenue
RESIDENTIAL																			
E-1	$2,134,922,146	$931,279,387	$290,350,932	$49,910,891	-$24,589,398	$0	-$5,327,806	$829,854,691	$102,717,758	$8,196,119	$44,047,822	$2,111,257	$368,052	$35,198,909	$0	-$54,097,743	($57,655,605)		$2,152,365,265
EL-1	$677,367,227	$486,647,777	$151,725,364	$26,081,363	-$12,849,400	$0	-$2,784,050	$49,097,771	$18,980,833	$4,283,010	$0	$1,103,253	$192,328	$18,393,446	$0	-$28,156,806	($20,274,318)		$692,440,572
TOTAL RES	$2,812,289,373	$1,417,927,164	$442,076,296	$75,992,254	-$37,438,798	$0	-$8,111,855	$878,952,463	$121,698,591	$12,479,130	$44,047,822	$3,214,510	$560,380	$53,592,355	$0	-$82,254,549	($77,929,924)		$2,844,805,837
SMALL L&P																			
A-1	$633,412,681	$264,222,562	$65,240,447	$14,576,874	-$7,181,530	$0	-$1,197,134	$235,335,365	$28,922,985	$2,393,736	$13,650,137	$615,816	$107,492	$7,747,387	$0	-$167,497			$624,266,640
A-6	$139,104,997	$61,054,735	$15,425,643	$3,444,494	-$1,696,985	$0	-$283,054	$48,699,909	$6,336,440	$565,636	$3,227,031	$145,516	$25,400	$1,830,696	$0	-$283,864			$138,491,599
A-15	$12,686	$1,444	$354	$79	-$39	$0	-$7	$10,503	$157	$13	$74	$3	$1	$42	$0	$0			$12,626
TC-1	$2,747,121	$1,096,175	$295,632	$66,058	-$32,545	$0	-$5,425	$1,136,585	$41,366	$10,848	$61,997	$2,791	$487	$35,109	$0	$0			$2,709,079
TOTAL SMALL	$775,277,484	$326,374,915	$80,962,076	$18,087,505	-$8,911,098	$0	-$1,485,619	$285,182,363	$35,300,949	$2,970,233	$16,939,239	$764,126	$133,380	$9,613,234	$0	-$451,361			$765,479,943
MEDIUM L&P																			
A-10 T	$197,191	$107,428	$31,727	$7,408	-$3,650	$0	-$582	$25,028	$13,660	$1,217	$6,953	$323	$55	$3,524	$0	$0			$193,091
A-10 P	$5,965,140	$2,850,866	$948,258	$164,654	-$81,119	$0	-$17,400	$1,432,252	$303,798	$27,039	$153,119	$7,171	$1,214	$78,336	$0	$0			$5,868,186
A-10 S	$656,290,529	$325,376,960	$92,612,864	$16,918,262	-$8,335,052	$0	-$1,699,406	$161,780,775	$31,504,392	$2,778,226	$15,812,428	$736,844	$124,758	$8,049,035	$0	-$239,644			$645,420,441
TOTAL MEDIUM	$662,452,860	$328,335,253	$93,592,850	$17,090,324	-$8,419,821	$0	-$1,717,389	$163,238,054	$31,821,850	$2,806,481	$15,972,500	$744,338	$126,027	$8,130,895	$0	-$239,644			$651,481,718
E-19 CLASS																			
E-19 FIRM T	$1,477,297	$812,786	$274,109	$47,718	-$23,509	$0	-$2,899	$156,779	$86,489	$7,836	$44,784	$1,915	$352	$22,702	$0	$0			$1,429,061
E-19 V T	$1,776,781	$1,087,235	$274,894	$67,173	-$33,094	$0	-$2,936	$103,377	$121,751	$11,031	$63,043	$2,696	$495	$31,958	$0	$0			$1,727,623
Total E-19 T	$3,254,078	$1,900,020	$549,003	$114,891	-$56,603	$0	-$5,835	$260,155	$208,240	$18,867	$107,828	$4,611	$847	$54,661	$0	$0			$3,156,684
E-19 FIRM P	$66,077,472	$34,597,597	$8,718,641	$2,175,019	-$1,071,558	$0	-$92,478	$12,879,981	$3,942,057	$357,170	$2,041,302	$87,294	$16,039	$1,034,787	$0	-$58,787			$64,627,063
E-19 V P	$25,729,437	$13,518,990	$3,447,751	$854,386	-$420,927	$0	-$36,473	$4,796,270	$1,543,758	$140,303	$798,508	$34,291	$6,300	$406,483	$0	$0			$25,089,638
Total E-19 P	$91,806,909	$48,116,586	$12,166,391	$3,029,404	-$1,492,484	$0	-$128,951	$17,676,251	$5,485,815	$497,472	$2,839,810	$121,584	$22,339	$1,441,270	$0	-$58,787			$89,716,701
E-19 FIRM S	$212,118,952	$110,278,339	$24,866,211	$5,979,301	-$2,945,798	$0	-$263,343	$48,542,669	$11,025,571	$981,889	$5,611,705	$239,978	$44,092	$2,844,713	$0	-$879,405			$206,325,920
E-19 V S	$479,466,395	$251,779,369	$52,314,840	$14,153,454	-$6,972,925	$0	-$553,391	$108,022,502	$26,014,030	$2,324,204	$13,223,836	$568,045	$104,370	$6,733,650	$0	$0			$467,711,983
Total E-19 S	$691,585,347	$362,057,708	$77,181,050	$20,132,755	-$9,918,723	$0	-$816,734	$156,565,171	$37,039,600	$3,306,093	$18,835,541	$808,022	$148,462	$9,578,363	$0	-$879,405			$674,037,904
E-19 T	$3,254,078	$1,900,020	$549,003	$114,891	-$56,603	$0	-$5,835	$260,155	$208,240	$18,867	$107,828	$4,611	$847	$54,661	$0	$0			$3,156,684
E-19 P	$91,806,909	$48,116,586	$12,166,391	$3,029,404	-$1,492,484	$0	-$128,951	$17,676,251	$5,485,815	$497,472	$2,839,810	$121,584	$22,339	$1,441,270	$0	-$58,787			$89,716,701
E-19 S	$691,585,347	$362,057,708	$77,181,050	$20,132,755	-$9,918,723	$0	-$816,734	$156,565,171	$37,039,600	$3,306,093	$18,835,541	$808,022	$148,462	$9,578,363	$0	-$879,405			$674,037,904
TOTAL E-19	$786,646,334	$412,074,314	$89,896,445	$23,277,050	-$11,467,811	$0	-$951,520	$174,501,577	$42,733,655	$3,822,432	$21,783,179	$934,218	$171,649	$11,074,293	$0	-$938,192			$766,911,289
STREETLIGHTS	$20,951,823	$6,030,057	$1,474,695	$405,603	-$199,827	$0	-$27,060	$12,129,968	$259,889	$66,606	$380,667	$13,670	$2,991	$168,109	$0	$0			$20,705,369
STANDBY																			
STANDBY T	$67,885,972	$30,489,146	$19,000,198	$2,285,389	-$1,125,933	$0	-$348,645	$10,551,554	$4,469,140	$375,294	$2,144,887	$69,709	$16,853	$2,301,474	$0	$0			$70,229,066
STANDBY P	$4,345,961	$984,260	$576,311	$57,472	-$28,314	$0	-$10,575	$2,685,142	$122,196	$9,438	$53,939	$1,753	$424	$57,876	$0	$0			$4,509,921
STANDBY S	$1,768,766	$579,564	$206,875	$39,099	-$19,263	$0	-$3,796	$773,636	$81,707	$6,421	$36,695	$1,193	$288	$39,374	$0	$0			$1,741,794
TOTAL STANDBY	$74,000,699	$32,052,971	$19,783,384	$2,381,960	-$1,173,511	$0	-$363,017	$14,010,333	$4,673,043	$391,153	$2,235,521	$72,655	$17,565	$2,398,725	$0	$0			$76,480,781
AGRICULTURE																			
AG-1A	$4,688,245	$1,295,916	$247,843	$69,551	-$34,266	$0	-$4,594	$2,844,216	$137,296	$11,421	$65,275	$2,634	$513	$32,154	$0	-$2,912			$4,665,048
AG-RA	$4,814,611	$1,473,580	$329,711	$92,525	-$45,584	$0	-$6,112	$2,601,544	$182,648	$15,194	$86,837	$3,504	$682	$42,775	$0	$0			$4,777,305
AG-VA	$3,138,442	$939,177	$215,850	$60,573	-$29,842	$0	-$4,001	$1,716,001	$119,573	$9,947	$56,849	$2,294	$447	$28,003	$0	$0			$3,114,871
AG-4A	$100,203,119	$27,355,254	$6,074,567	$1,704,681	-$839,838	$0	-$112,603	$59,363,984	$3,365,094	$279,934	$1,599,880	$64,552	$12,571	$788,084	$0	-$6,612			$99,649,546
AG-5A	$31,550,554	$12,394,532	$2,541,013	$713,074	-$351,307	$0	-$47,102	$13,349,212	$1,407,631	$117,097	$669,236	$27,002	$5,258	$329,658	$0	-$398			$31,154,906
AG-1B	$10,373,215	$3,591,325	$666,445	$187,022	-$92,139	$0	-$12,354	$5,289,251	$361,356	$30,712	$175,524	$7,082	$1,379	$86,461	$0	-$3,933			$10,288,131
AG-RB	$5,420,378	$1,675,168	$352,975	$99,054	-$48,801	$0	-$6,543	$2,961,181	$191,388	$16,266	$92,964	$3,751	$730	$45,793	$0	$0			$5,383,928
AG-VB	$5,119,376	$1,748,807	$442,879	$124,283	-$61,230	$0	-$8,210	$2,379,726	$240,135	$20,409	$116,643	$4,706	$916	$57,457	$0	-$1			$5,066,521
AG-4B	$208,439,240	$72,816,150	$12,879,777	$3,614,399	-$1,780,691	$0	-$238,750	$106,753,403	$6,983,594	$593,537	$3,392,192	$136,869	$26,653	$1,670,957	$0	-$89,083			$206,759,007
AG-4C	$27,339,847	$9,719,627	$2,120,772	$595,144	-$293,207	$0	-$39,312	$12,872,665	$1,149,912	$97,731	$558,555	$22,537	$4,389	$275,138	$0	-$22,857			$27,061,095
AG-5B	$512,446,988	$224,098,879	$46,513,129	$13,052,788	-$6,430,665	$0	-$862,206	$185,527,218	$23,659,412	$2,143,459	$12,250,327	$494,279	$96,253	$6,034,379	$0	-$407,857			$506,169,396
AG-5C	$316,626,566	$160,225,560	$37,982,530	$10,658,881	-$5,251,268	$0	-$704,076	$72,386,432	$19,320,230	$1,750,344	$10,003,593	$403,627	$78,600	$4,927,662	$0	-$247,027			$311,535,088
Total AG A	$144,394,971	$43,458,460	$9,408,984	$2,640,405	-$1,300,838	$0	-$174,413	$79,874,958	$5,212,242	$433,593	$2,478,077	$99,986	$19,471	$1,220,674	$0	-$9,923			$143,361,677
Total AG B	$1,085,765,611	$473,875,516	$100,958,507	$28,331,571	-$13,958,001	$0	-$1,871,452	$388,169,876	$51,906,027	$4,652,458	$26,589,799	$1,072,851	$208,922	$13,097,849	$0	-$770,757			$1,072,263,165
TOTAL AG	$1,230,160,582	$517,333,975	$110,367,491	$30,971,975	-$15,258,838	$0	-$2,045,864	$468,044,834	$57,118,269	$5,086,051	$29,067,876	$1,172,837	$228,393	$14,318,523	$0	-$780,680			$1,215,624,842
E-20 CLASS																			
E-20 FIRM T	$305,264,321	$203,265,855	$48,335,897	$13,373,543	-$6,588,690	$0	-$513,323	$669,728	$22,576,795	$2,196,131	$12,551,363	$460,821	$98,619	$5,535,755	$0	-$24,347			$301,938,146
FPP T																			
TOTAL	$305,264,321	$203,265,855	$48,335,897	$13,373,543	-$6,588,690	$0	-$513,323	$669,728	$22,576,795	$2,196,131	$12,551,363	$460,821	$98,619	$5,535,755	$0	-$24,347			$301,938,146
E-20 FIRM P	$357,890,193	$200,442,974	$44,830,301	$12,311,358	-$6,065,387	$0	-$466,651	$60,908,216	$21,453,000	$2,021,705	$11,554,479	$454,404	$90,786	$5,096,081	$0	-$129,677			$352,501,590
FPP P																			
TOTAL	$357,890,193	$200,442,974	$44,830,301	$12,311,358	-$6,065,387	$0	-$466,651	$60,908,216	$21,453,000	$2,021,705	$11,554,479	$454,404	$90,786	$5,096,081	$0	-$129,677			$352,501,590
E-20 FIRM S	$140,245,526	$73,534,790	$17,583,139	$4,287,096	-$2,112,107	$0	-$182,149	$29,666,920	$7,616,109	$704,004	$4,023,534	$166,721	$31,614	$1,774,572	$0	-$3,485,140			$133,609,104
FPP S																			
TOTAL	$140,245,526	$73,534,790	$17,583,139	$4,287,096	-$2,112,107	$0	-$182,149	$29,666,920	$7,616,109	$704,004	$4,023,534	$166,721	$31,614	$1,774,572	$0	-$3,485,140			$133,609,104
E-20 T	$305,264,321	$203,265,855	$48,335,897	$13,373,543	-$6,588,690	$0	-$513,323	$669,728	$22,576,795	$2,196,131	$12,551,363	$460,821	$98,619	$5,535,755	$0	-$24,347			$301,938,146
E-20 P	$357,890,193	$200,442,974	$44,830,301	$12,311,358	-$6,065,387	$0	-$466,651	$60,908,216	$21,453,000	$2,021,705	$11,554,479	$454,404	$90,786	$5,096,081	$0	-$129,677			$352,501,590
E-20 S	$140,245,526	$73,534,790	$17,583,139	$4,287,096	-$2,112,107	$0	-$182,149	$29,666,920	$7,616,109	$704,004	$4,023,534	$166,721	$31,614	$1,774,572	$0	-$3,485,140			$133,609,104
TOTAL E-20	$803,400,040	$477,243,620	$110,749,337	$29,971,998	-$14,766,184	$0	-$1,162,123	$91,244,864	$51,645,904	$4,921,840	$28,129,375	$1,081,945	$221,019	$12,406,408	$0	-$3,639,165			$788,048,839
SYSTEM	**$7,165,179,196**	**$3,517,372,270**	**$948,902,572**	**$198,178,669**	**-$97,635,887**	**$0**	**-$15,864,447**	**$2,087,304,457**	**$345,252,150**	**$32,543,925**	**$158,556,180**	**$7,998,300**	**$1,461,403**	**$111,702,542**	**$0**	**-$88,303,591**	**-$77,929,924**	**$0**	**$7,129,538,620**

Pacific Gas & Electric Company
2021 ERRA Forecast - Application dated July 1, 2020
Effective Friday, January 1, 2021

BDLD RESULTS

Class/Schedule	Total Sales (kWh)	Revenue At Present Rates	Generation Rates	TO Rates	TAC Rates	TRBAA Rates	T-ECRA Rates	RS Rates	Dist Rates	PPP Rates	ND Rates	DWR Bond Rates	CTC Rates	ECRA Rates	NSGC Rates	Residential & Small Business AB32 Credit Rates	Climate Credit & EITE Rates	CIA Rates	Total Proposed Rates	Percent Change
RESIDENTIAL																				
E-1	8,076,230,160	$0.26435	$0.11531	$0.03595	$0.00618	-$0.00304	$0.00000	-$0.00066	$0.10275	$0.01272	$0.00101	$0.00545	$0.00026	$0.00005	$0.00436	$0.00000	-$0.00670	-$0.00714	$0.26651	0.8%
EL-1	4,220,292,807	$0.16050	$0.11531	$0.03595	$0.00618	-$0.00304	$0.00000	-$0.00066	$0.01163	$0.00450	$0.00101	$0.00000	$0.00026	$0.00005	$0.00436	$0.00000	-$0.00667	-$0.00480	$0.16407	2.2%
TOTAL RES	12,296,522,968	$0.22871	$0.11531	$0.03595	$0.00618	-$0.00304	$0.00000	-$0.00066	$0.07148	$0.00990	$0.00101	$0.00358	$0.00026	$0.00005	$0.00436	$0.00000	-$0.00669	-$0.00634	$0.23135	1.2%
SMALL L&P																				
A-1	2,358,723,802	$0.26854	$0.11202	$0.02766	$0.00618	-$0.00304	$0.00000	-$0.00051	$0.09977	$0.01226	$0.00101	$0.00579	$0.00026	$0.00005	$0.00328	$0.00000	-$0.00007		$0.26466	-1.4%
A-6	557,363,011	$0.24958	$0.10954	$0.02768	$0.00618	-$0.00304	$0.00000	-$0.00051	$0.08738	$0.01137	$0.00101	$0.00579	$0.00026	$0.00005	$0.00328	$0.00000	-$0.00051		$0.24848	-0.4%
A-15	12,812	$0.99019	$0.11269	$0.02766	$0.00618	-$0.00304	$0.00000	-$0.00051	$0.81983	$0.01228	$0.00101	$0.00580	$0.00026	$0.00005	$0.00328	$0.00000	$0.00000		$0.98549	-0.5%
TC-1	10,689,062	$0.25700	$0.10255	$0.02766	$0.00618	-$0.00304	$0.00000	-$0.00051	$0.10633	$0.00387	$0.00101	$0.00580	$0.00026	$0.00005	$0.00328	$0.00000	$0.00000		$0.25344	-1.4%
TOTAL SMALL	2,926,788,686	$0.26489	$0.11151	$0.02766	$0.00618	-$0.00304	$0.00000	-$0.00051	$0.09744	$0.01206	$0.00101	$0.00579	$0.00026	$0.00005	$0.00328	$0.00000	-$0.00015		$0.26154	-1.3%
MEDIUM L&P																				
A-10 T	1,198,709	$0.16450	$0.08962	$0.02647	$0.00618	-$0.00304	$0.00000	-$0.00049	$0.02088	$0.01140	$0.00101	$0.00580	$0.00027	$0.00005	$0.00294	$0.00000	$0.00000		$0.16108	-2.1%
A-10 P	26,643,075	$0.22389	$0.10700	$0.03559	$0.00618	-$0.00304	$0.00000	-$0.00065	$0.05376	$0.01140	$0.00101	$0.00575	$0.00027	$0.00005	$0.00294	$0.00000	$0.00000		$0.22025	-1.6%
A-10 S	2,737,590,210	$0.23973	$0.11886	$0.03383	$0.00618	-$0.00304	$0.00000	-$0.00062	$0.05910	$0.01151	$0.00101	$0.00578	$0.00027	$0.00005	$0.00294	$0.00000	-$0.00009		$0.23576	-1.7%
TOTAL MEDIUM	2,765,431,994	$0.23955	$0.11873	$0.03384	$0.00618	-$0.00304	$0.00000	-$0.00062	$0.05903	$0.01151	$0.00101	$0.00578	$0.00027	$0.00005	$0.00294	$0.00000	-$0.00009		$0.23558	-1.7%
E-19 CLASS																				
E-19 FIRM T	7,721,375	$0.19133	$0.10526	$0.03550	$0.00618	-$0.00304	$0.00000	-$0.00038	$0.02030	$0.01120	$0.00101	$0.00580	$0.00025	$0.00005	$0.00294	$0.00000	$0.00000		$0.18508	-3.3%
E-19 V T	10,869,473	$0.16347	$0.10003	$0.02529	$0.00618	-$0.00304	$0.00000	-$0.00027	$0.00951	$0.01120	$0.00101	$0.00580	$0.00025	$0.00005	$0.00294	$0.00000	$0.00000		$0.15894	-2.8%
Total E-19 T	18,590,849	$0.17504	$0.10220	$0.02953	$0.00618	-$0.00304	$0.00000	-$0.00031	$0.01399	$0.01120	$0.00101	$0.00580	$0.00025	$0.00005	$0.00294	$0.00000	$0.00000		$0.16980	-3.0%
E-19 FIRM P	351,945,693	$0.18775	$0.09830	$0.02477	$0.00618	-$0.00304	$0.00000	-$0.00026	$0.03660	$0.01120	$0.00101	$0.00580	$0.00025	$0.00005	$0.00294	$0.00000	-$0.00017		$0.18363	-2.2%
E-19 V P	138,250,472	$0.18611	$0.09779	$0.02494	$0.00618	-$0.00304	$0.00000	-$0.00026	$0.03469	$0.01117	$0.00101	$0.00578	$0.00025	$0.00005	$0.00294	$0.00000	$0.00000		$0.18148	-2.5%
Total E-19 P	490,196,165	$0.18729	$0.09816	$0.02482	$0.00618	-$0.00304	$0.00000	-$0.00026	$0.03606	$0.01119	$0.00101	$0.00579	$0.00025	$0.00005	$0.00294	$0.00000	-$0.00012		$0.18302	-2.3%
E-19 FIRM S	967,527,065	$0.21924	$0.11398	$0.02570	$0.00618	-$0.00304	$0.00000	-$0.00027	$0.05017	$0.01140	$0.00101	$0.00580	$0.00025	$0.00005	$0.00294	$0.00000	-$0.00091		$0.21325	-2.7%
E-19 V S	2,290,209,088	$0.20935	$0.10994	$0.02284	$0.00618	-$0.00304	$0.00000	-$0.00024	$0.04717	$0.01136	$0.00101	$0.00577	$0.00025	$0.00005	$0.00294	$0.00000	$0.00000		$0.20422	-2.5%
Total E-19 S	3,257,736,153	$0.21229	$0.11114	$0.02369	$0.00618	-$0.00304	$0.00000	-$0.00025	$0.04806	$0.01137	$0.00101	$0.00578	$0.00025	$0.00005	$0.00294	$0.00000	-$0.00027		$0.20690	-2.5%
E-19 T	18,590,849	$0.17504	$0.10220	$0.02953	$0.00618	-$0.00304	$0.00000	-$0.00031	$0.01399	$0.01120	$0.00101	$0.00580	$0.00025	$0.00005	$0.00294	$0.00000	$0.00000		$0.16980	-3.0%
E-19 P	490,196,165	$0.18729	$0.09816	$0.02482	$0.00618	-$0.00304	$0.00000	-$0.00026	$0.03606	$0.01119	$0.00101	$0.00579	$0.00025	$0.00005	$0.00294	$0.00000	-$0.00012		$0.18302	-2.3%
E-19 S	3,257,736,153	$0.21229	$0.11114	$0.02369	$0.00618	-$0.00304	$0.00000	-$0.00025	$0.04806	$0.01137	$0.00101	$0.00578	$0.00025	$0.00005	$0.00294	$0.00000	-$0.00027		$0.20690	-2.5%
TOTAL E-19	3,766,523,166	$0.20885	$0.10940	$0.02387	$0.00618	-$0.00304	$0.00000	-$0.00025	$0.04633	$0.01135	$0.00101	$0.00578	$0.00025	$0.00005	$0.00294	$0.00000	-$0.00025		$0.20361	-2.5%
STREETLIGHTS	65,631,713	$0.31923	$0.09188	$0.02247	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.18482	$0.00396	$0.00101	$0.00580	$0.00021	$0.00005	$0.00256	$0.00000	$0.00000		$0.31548	-1.2%
STANDBY																				
STANDBY T	369,805,014	$0.18357	$0.08245	$0.05138	$0.00618	-$0.00304	$0.00000	-$0.00094	$0.02853	$0.01209	$0.00101	$0.00580	$0.00019	$0.00005	$0.00622	$0.00000	$0.00000		$0.18991	3.5%
STANDBY P	9,299,676	$0.46732	$0.10584	$0.06197	$0.00618	-$0.00304	$0.00000	-$0.00114	$0.28874	$0.01314	$0.00101	$0.00580	$0.00019	$0.00005	$0.00622	$0.00000	$0.00000		$0.48495	3.8%
STANDBY S	6,326,738	$0.27957	$0.09161	$0.03270	$0.00618	-$0.00304	$0.00000	-$0.00060	$0.12228	$0.01291	$0.00101	$0.00580	$0.00019	$0.00005	$0.00622	$0.00000	$0.00000		$0.27531	-1.5%
TOTAL STANDBY	385,431,427	$0.19199	$0.08316	$0.05133	$0.00618	-$0.00304	$0.00000	-$0.00094	$0.03635	$0.01212	$0.00101	$0.00580	$0.00019	$0.00005	$0.00622	$0.00000	$0.00000		$0.19843	3.4%
AGRICULTURE																				
AG-1A	11,254,271	$0.41657	$0.11515	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.25272	$0.01220	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	-$0.00026		$0.41451	-0.5%
AG-RA	14,971,796	$0.32158	$0.09842	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.17376	$0.01220	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	$0.00000		$0.31909	-0.8%
AG-VA	9,801,505	$0.32020	$0.09582	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.17508	$0.01220	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	$0.00000		$0.31780	-0.8%
AG-4A	275,839,059	$0.36327	$0.09917	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.21521	$0.01220	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	-$0.00002		$0.36126	-0.6%
AG-5A	115,384,452	$0.27344	$0.10742	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.11569	$0.01220	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	$0.00000		$0.27001	-1.3%
AG-1B	30,262,483	$0.34277	$0.11867	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.17478	$0.01194	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	-$0.00013		$0.33996	-0.8%
AG-RB	16,028,192	$0.33818	$0.10451	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.18475	$0.01194	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	$0.00000		$0.33590	-0.7%
AG-VB	20,110,620	$0.25456	$0.08696	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.11833	$0.01194	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	$0.00000		$0.25193	-1.0%
AG-4B	584,855,761	$0.35639	$0.12450	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.18253	$0.01194	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	-$0.00015		$0.35352	-0.8%
AG-4C	96,301,823	$0.28390	$0.10093	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.13367	$0.01194	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	-$0.00024		$0.28100	-1.0%
AG-5B	2,112,107,322	$0.24262	$0.10610	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.08784	$0.01120	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	-$0.00019		$0.23965	-1.2%
AG-5C	1,724,742,693	$0.18358	$0.09290	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.04197	$0.01120	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	-$0.00014		$0.18063	-1.6%
Total AG A	427,251,084	$0.33796	$0.10172	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.18695	$0.01220	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	-$0.00002		$0.33554	-0.7%
Total AG B	4,584,408,893	$0.23684	$0.10337	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.08467	$0.01132	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	-$0.00017		$0.23389	-1.2%
TOTAL AG	5,011,659,977	$0.24546	$0.10323	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.09339	$0.01140	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	-$0.00016		$0.24256	-1.2%
E-20 CLASS																				
E-20 FIRM T	2,164,009,595	$0.14106	$0.09393	$0.02234	$0.00618	-$0.00304	$0.00000	-$0.00024	$0.00031	$0.01043	$0.00101	$0.00580	$0.00021	$0.00005	$0.00256	$0.00000	-$0.00001		$0.13953	-1.1%
FPP T																				
TOTAL	2,164,009,595	$0.14106	$0.09393	$0.02234	$0.00618	-$0.00304	$0.00000	-$0.00024	$0.00031	$0.01043	$0.00101	$0.00580	$0.00021	$0.00005	$0.00256	$0.00000	-$0.00001		$0.13953	-1.1%
E-20 FIRM P	1,992,134,508	$0.17965	$0.10062	$0.02250	$0.00618	-$0.00304	$0.00000	-$0.00023	$0.03057	$0.01077	$0.00101	$0.00580	$0.00023	$0.00005	$0.00256	$0.00000	-$0.00007		$0.17695	-1.5%
FPP P																				
TOTAL	1,992,134,508	$0.17965	$0.10062	$0.02250	$0.00618	-$0.00304	$0.00000	-$0.00023	$0.03057	$0.01077	$0.00101	$0.00580	$0.00023	$0.00005	$0.00256	$0.00000	-$0.00007		$0.17695	-1.5%
E-20 FIRM S	693,706,803	$0.20217	$0.10600	$0.02535	$0.00618	-$0.00304	$0.00000	-$0.00026	$0.04277	$0.01098	$0.00101	$0.00580	$0.00024	$0.00005	$0.00256	$0.00000	-$0.00502		$0.19260	-4.7%
FPP S																				
TOTAL	693,706,803	$0.20217	$0.10600	$0.02535	$0.00618	-$0.00304	$0.00000	-$0.00026	$0.04277	$0.01098	$0.00101	$0.00580	$0.00024	$0.00005	$0.00256	$0.00000	-$0.00502		$0.19260	-4.7%
E-20 T	2,164,009,595	$0.14106	$0.09393	$0.02234	$0.00618	-$0.00304	$0.00000	-$0.00024	$0.00031	$0.01043	$0.00101	$0.00580	$0.00021	$0.00005	$0.00256	$0.00000	-$0.00001		$0.13953	-1.1%
E-20 P	1,992,134,508	$0.17965	$0.10062	$0.02250	$0.00618	-$0.00304	$0.00000	-$0.00023	$0.03057	$0.01077	$0.00101	$0.00580	$0.00023	$0.00005	$0.00256	$0.00000	-$0.00007		$0.17695	-1.5%
E-20 S	693,706,803	$0.20217	$0.10600	$0.02535	$0.00618	-$0.00304	$0.00000	-$0.00026	$0.04277	$0.01098	$0.00101	$0.00580	$0.00024	$0.00005	$0.00256	$0.00000	-$0.00502		$0.19260	-4.7%
TOTAL E-20	4,849,850,907	$0.16565	$0.09840	$0.02284	$0.00618	-$0.00304	$0.00000	-$0.00024	$0.01881	$0.01065	$0.00101	$0.00580	$0.00022	$0.00005	$0.00256	$0.00000	-$0.00075		$0.16249	-1.9%
SYSTEM	**32,067,840,838**	**$0.22344**	**$0.10969**	**$0.02959**	**$0.00618**	**-$0.00304**	**$0.00000**	**-$0.00049**	**$0.06509**	**$0.01077**	**$0.00101**	**$0.00494**	**$0.00025**	**$0.00005**	**$0.00348**	**$0.00000**	**-$0.00275**	**-$0.00243**	**$0.22233**	**-0.5%**

Pacific Gas & Electric Company
2021 ERRA Forecast - Application dated July 1, 2020
Effective Friday, January 1, 2021

DA/CCA RESULTS

Class/Schedule	Total Revenue At Present	TO Revenue	TAC Revenue	TRBAA Revenue	T-ECRA Revenue	RS Revenue	Dist Revenue	PPP Revenue	ND Revenue	DWR Bond Revenue	CTC Revenue	ECRA Revenue	NSGC Revenue	Residential & Small Business AB32 Credit Revenue	Climate Credit & EITE Revenue	CIA Revenue	PCIA Revenue	Total Proposed Revenue
RESIDENTIAL																		
E-1	$2,411,049,334	$443,471,381	$76,232,067	-$37,556,946	$0	-$8,137,518	$1,279,952,862	$156,887,342	$12,518,453	$69,450,710	$3,224,666	$562,151	$53,761,675	$0	-$86,968,888	$85,104,265	$467,035,942	$2,515,538,161
EL-1	$166,570,573	$80,208,415	$13,787,707	-$6,792,734	$0	-$1,471,836	$25,108,007	$10,034,068	$2,264,179	$0	$583,253	$101,678	$9,724,011	$0	-$18,752,442	-$7,174,341	$84,577,540	$192,197,504
TOTAL RES	$2,577,619,907	$523,679,796	$90,019,774	-$44,349,680	$0	-$9,609,354	$1,305,060,869	$166,921,410	$14,782,632	$69,450,710	$3,807,919	$663,828	$63,485,686	$0	-$105,721,330	$77,929,924	$551,613,481	$2,707,735,665
SMALL L&P																		
A-1	$767,444,116	$116,064,318	$25,934,079	-$12,776,838	$0	-$2,129,730	$397,690,897	$51,465,085	$4,258,755	$24,288,407	$1,095,613	$191,242	$13,783,569	$0	-$1,867		$162,707,302	$782,570,832
A-6	$143,650,205	$23,832,732	$5,322,232	-$2,622,083	$0	-$437,320	$73,395,008	$9,762,422	$873,988	$4,961,041	$224,843	$39,247	$2,828,686	$0	-$1,525		$28,149,152	$146,328,424
A-15	$210,790	$9,750	$2,179	-$1,073	$0	-$179	$179,624	$4,329	$358	$2,034	$92	$16	$1,158	$0	$0		$13,785	$212,073
TC-1	$5,200,885	$786,179	$175,670	-$86,546	$0	-$14,426	$2,940,649	$110,005	$28,848	$164,870	$7,421	$1,295	$93,366	$0	$0		$1,061,258	$5,268,589
TOTAL SMALL	$916,505,996	$140,692,980	$31,434,160	-$15,486,541	$0	-$2,581,656	$474,206,177	$61,341,841	$5,161,949	$29,416,351	$1,327,970	$231,801	$16,706,779	$0	-$3,392		$191,931,498	$934,379,917
MEDIUM L&P																		
A-10 T	$128,093	$33,000	$6,489	-$3,197	$0	-$606	$31,124	$11,967	$1,066	$6,090	$283	$48	$3,087	$0	$0		$41,254	$130,605
A-10 P	$7,418,307	$1,484,568	$330,855	-$163,001	$0	-$27,241	$2,678,051	$614,473	$54,331	$310,515	$14,410	$2,440	$157,408	$0	$0		$2,090,542	$7,547,350
A-10 S	$805,082,476	$163,500,173	$32,996,627	-$16,256,315	$0	-$3,000,158	$325,312,727	$61,463,051	$5,418,529	$30,852,758	$1,437,109	$243,323	$15,698,480	$0	-$12,370		$198,704,189	$816,358,122
TOTAL MEDIUM	$812,628,877	$165,017,740	$33,333,971	-$16,422,513	$0	-$3,028,005	$328,021,902	$62,089,491	$5,473,925	$31,169,363	$1,451,801	$245,810	$15,858,975	$0	-$12,370		$200,835,985	$824,036,077
E-19 CLASS																		
E-19 FIRM T	$588,996	$153,928	$32,592	-$16,057	$0	-$1,628	$114,844	$59,072	$5,352	$30,588	$1,308	$240	$15,506	$0	$0		$189,808	$585,553
E-19 V T	$699,810	$153,123	$50,750	-$25,003	$0	-$1,620	$69,708	$91,984	$8,334	$47,630	$2,037	$374	$24,145	$0	$0		$289,492	$710,955
Total E-19 T	$1,288,805	$307,051	$83,342	-$41,060	$0	-$3,248	$184,552	$151,056	$13,686	$78,218	$3,345	$615	$39,651	$0	$0		$479,301	$1,296,508
E-19 FIRM P	$62,181,265	$12,622,517	$3,311,331	-$1,631,380	$0	-$133,552	$20,477,849	$6,001,537	$543,769	$3,107,756	$132,899	$24,418	$1,575,399	$0	-$27,498		$16,027,442	$62,032,489
E-19 V P	$23,099,659	$5,058,761	$1,152,063	-$567,582	$0	-$53,609	$7,441,367	$2,088,027	$189,186	$1,081,236	$46,238	$8,496	$548,106	$0	$0		$6,160,641	$23,152,928
Total E-19 P	$85,280,925	$17,681,278	$4,463,394	-$2,198,962	$0	-$187,161	$27,919,216	$8,089,565	$732,955	$4,188,993	$179,137	$32,914	$2,123,505	$0	-$27,498		$22,188,083	$85,185,417
E-19 FIRM S	$360,884,176	$65,862,571	$17,960,571	-$8,848,562	$0	-$696,992	$135,877,861	$33,063,358	$2,949,388	$16,817,479	$720,842	$132,444	$8,544,924	$0	-$185,787		$86,686,147	$358,884,246
E-19 V S	$782,449,391	$137,557,724	$40,422,122	-$19,914,604	$0	-$1,455,330	$297,903,528	$74,291,995	$6,637,903	$37,682,053	$1,622,330	$298,080	$19,231,235	$0	$0		$183,773,322	$778,050,359
Total E-19 S	$1,143,333,567	$203,420,295	$58,382,693	-$28,763,167	$0	-$2,152,321	$433,781,389	$107,355,354	$9,587,292	$54,499,532	$2,343,173	$430,524	$27,776,159	$0	-$185,787		$270,459,469	$1,136,934,605
E-19 T	$1,288,805	$307,051	$83,342	-$41,060	$0	-$3,248	$184,552	$151,056	$13,686	$78,218	$3,345	$615	$39,651	$0	$0		$479,301	$1,296,508
E-19 P	$85,280,925	$17,681,278	$4,463,394	-$2,198,962	$0	-$187,161	$27,919,216	$8,089,565	$732,955	$4,188,993	$179,137	$32,914	$2,123,505	$0	-$27,498		$22,188,083	$85,185,417
E-19 S	$1,143,333,567	$203,420,295	$58,382,693	-$28,763,167	$0	-$2,152,321	$433,781,389	$107,355,354	$9,587,292	$54,499,532	$2,343,173	$430,524	$27,776,159	$0	-$185,787		$270,459,469	$1,136,934,605
TOTAL E-19	$1,229,903,297	$221,408,623	$62,929,429	-$31,003,188	$0	-$2,342,730	$461,885,157	$115,595,974	$10,333,932	$58,766,743	$2,525,655	$464,052	$29,939,315	$0	-$213,284		$293,126,853	$1,223,416,531
STREETLIGHTS	$30,208,508	$3,665,729	$1,008,229	-$496,720	$0	-$67,265	$19,092,574	$604,135	$165,566	$946,245	$33,981	$7,435	$417,877	$0	$0		$4,864,691	$30,242,479
STANDBY																		
STANDBY T	$4,165,359	$1,483,889	$188,305	-$92,772	$0	-$27,229	$866,066	$368,236	$30,922	$176,728	$5,744	$1,389	$189,630	$0	$0		$835,976	$4,026,885
STANDBY P	$2,476,531	$386,371	$42,335	-$20,857	$0	-$7,090	$1,831,933	$90,011	$6,952	$39,732	$1,291	$312	$42,633	$0	$0		$56,765	$2,470,388
STANDBY S	$425,291	$58,738	$12,840	-$6,326	$0	-$1,078	$253,690	$26,833	$2,109	$12,051	$392	$95	$12,931	$0	$0		$54,773	$427,046
TOTAL STANDBY	$7,067,180	$1,928,998	$243,480	-$119,954	$0	-$35,396	$2,951,688	$485,080	$39,983	$228,511	$7,427	$1,795	$245,194	$0	$0		$947,513	$6,924,319
AGRICULTURE																		
AG-1A	$3,093,824	$213,819	$60,003	-$29,561	$0	-$3,964	$2,339,011	$118,448	$9,853	$56,284	$2,272	$442	$27,740	$0	$0		$316,248	$3,110,595
AG-RA	$35,704	$2,775	$779	-$384	$0	-$51	$25,752	$1,537	$128	$731	$29	$6	$360	$0	$0		$4,188	$35,851
AG-VA	$327,350	$29,713	$8,338	-$4,108	$0	-$551	$223,941	$16,460	$1,369	$7,826	$316	$61	$3,855	$0	$0		$40,164	$327,384
AG-4A	$13,428,825	$1,030,098	$289,072	-$142,416	$0	-$19,095	$9,745,430	$570,637	$47,470	$271,272	$10,946	$2,132	$133,640	$0	$0		$1,554,338	$13,493,525
AG-5A	$3,247,654	$392,908	$110,260	-$54,321	$0	-$7,283	$1,824,324	$217,657	$18,106	$103,482	$4,175	$813	$50,974	$0	$0		$590,226	$3,251,321
AG-1B	$5,326,606	$433,464	$121,641	-$59,928	$0	-$8,035	$3,783,056	$235,030	$19,975	$114,163	$4,606	$897	$56,235	$0	$0		$654,482	$5,355,587
AG-RB	$78,901	$7,782	$2,184	-$1,076	$0	-$144	$51,066	$4,219	$359	$2,050	$83	$16	$1,010	$0	$0		$11,783	$79,351
AG-VB	$247,334	$24,381	$6,842	-$3,371	$0	-$452	$159,706	$13,220	$1,124	$6,421	$259	$50	$3,163	$0	$0		$36,889	$248,234
AG-4B	$35,904,900	$3,354,445	$941,344	-$463,768	$0	-$62,181	$23,977,084	$1,818,826	$154,582	$883,472	$35,647	$6,942	$435,189	$0	$0		$4,947,975	$36,029,556
AG-4C	$2,630,395	$301,697	$84,664	-$41,711	$0	-$5,593	$1,544,627	$163,585	$13,903	$79,459	$3,206	$624	$39,141	$0	$0		$456,012	$2,639,615
AG-5B	$44,416,550	$6,171,199	$1,731,798	-$853,198	$0	-$114,395	$22,485,937	$3,139,048	$284,387	$1,625,331	$65,579	$12,771	$800,620	$0	-$2,746		$9,289,722	$44,636,054
AG-5C	$49,836,370	$10,225,683	$2,869,591	-$1,413,750	$0	-$189,552	$13,999,811	$5,201,406	$471,229	$2,693,174	$108,665	$21,161	$1,326,629	$0	-$28,918		$14,574,368	$49,859,498
Total AG A	$20,133,357	$1,669,313	$468,452	-$230,791	$0	-$30,944	$14,158,458	$924,740	$76,927	$439,594	$17,739	$3,454	$216,568	$0	$0		$2,505,164	$20,218,675
Total AG B	$138,441,056	$20,518,652	$5,758,065	-$2,836,803	$0	-$380,351	$66,001,308	$10,575,334	$945,558	$5,404,070	$218,045	$42,461	$2,661,987	$0	-$31,664		$29,971,232	$138,847,893
TOTAL AG	$158,574,413	$22,187,964	$6,226,517	-$3,067,593	$0	-$411,295	$80,159,766	$11,500,074	$1,022,485	$5,843,664	$235,784	$45,915	$2,878,555	$0	-$31,664		$32,476,395	$159,066,568
E-20 CLASS																		
E-20 FIRM T	$204,403,105	$66,509,333	$22,352,247	-$11,012,192	$0	-$689,227	-$6,860,915	$37,734,360	$3,670,566	$17,875,811	$770,205	$164,829	$9,252,339	$0	-$11,216		$63,522,175	$203,278,317
FPP T	$3,780,858	$0	$0	$0	$0	$0	$269,722	$2,851,537	$308,718	$0	$0	$0	$0	$0	$0		$0	$3,429,977
TOTAL	$208,183,963	$66,509,333	$22,352,247	-$11,012,192	$0	-$689,227	-$6,591,193	$40,585,897	$3,979,284	$17,875,811	$770,205	$164,829	$9,252,339	$0	-$11,216		$63,522,175	$206,708,294
E-20 FIRM P	$451,202,362	$100,022,846	$28,858,939	-$14,217,817	$0	-$1,039,121	$144,440,348	$50,287,777	$4,739,060	$27,084,745	$1,065,163	$212,811	$11,945,676	$0	-$110,768		$95,696,566	$448,986,224
FPP P	$531,587	$0	$0	$0	$0	$0	$301,356	$190,866	$19,949	$0	$0	$0	$0	$0	$0		$0	$512,170
TOTAL	$451,733,948	$100,022,846	$28,858,939	-$14,217,817	$0	-$1,039,121	$144,741,703	$50,478,643	$4,759,009	$27,084,745	$1,065,163	$212,811	$11,945,676	$0	-$110,768		$95,696,566	$449,498,394
E-20 FIRM S	$165,631,050	$33,344,773	$9,448,590	-$4,654,999	$0	-$345,473	$58,654,114	$16,785,602	$1,551,597	$8,867,709	$367,447	$69,676	$3,911,086	$0	-$1,426,350		$37,253,669	$163,827,441
FPP S	$2,725,816	$0	$0	$0	$0	$0	$1,571,165	$953,692	$97,567	$0	$0	$0	$0	$0	$0		$0	$2,622,424
TOTAL	$168,356,866	$33,344,773	$9,448,590	-$4,654,999	$0	-$345,473	$60,225,280	$17,739,293	$1,649,164	$8,867,709	$367,447	$69,676	$3,911,086	$0	-$1,426,350		$37,253,669	$166,449,865
E-20 T	$208,183,963	$66,509,333	$22,352,247	-$11,012,192	$0	-$689,227	-$6,591,193	$40,585,897	$3,979,284	$17,875,811	$770,205	$164,829	$9,252,339	$0	-$11,216		$63,522,175	$206,708,294
E-20 P	$451,733,948	$100,022,846	$28,858,939	-$14,217,817	$0	-$1,039,121	$144,741,703	$50,478,643	$4,759,009	$27,084,745	$1,065,163	$212,811	$11,945,676	$0	-$110,768		$95,696,566	$449,498,394
E-20 S	$168,356,866	$33,344,773	$9,448,590	-$4,654,999	$0	-$345,473	$60,225,280	$17,739,293	$1,649,164	$8,867,709	$367,447	$69,676	$3,911,086	$0	-$1,426,350		$37,253,669	$166,449,865
TOTAL E-20	$828,274,778	$199,876,951	$60,659,777	-$29,885,008	$0	-$2,073,821	$198,375,790	$108,803,834	$10,387,457	$53,828,265	$2,202,815	$447,315	$25,109,101	$0	-$1,548,334		$196,472,410	$822,656,553
SYSTEM	**$6,560,782,956**	**$1,278,458,783**	**$285,855,336**	**-$140,831,198**	**$0**	**-$20,149,520**	**$2,869,753,922**	**$527,341,839**	**$47,367,929**	**$249,649,854**	**$11,593,352**	**$2,107,953**	**$154,641,482**	**$0**	**-$107,530,374**	**$77,929,924**	**$1,472,268,826**	**$6,708,458,108**

Pacific Gas & Electric Company
2021 ERRA Forecast - Application dated July 1, 2020
Effective Friday, January 1, 2021

DA/CCA RESULTS

Class/Schedule	Total Sales (kWh)	Revenue At Present Rates	TO Rates	TAC Rates	TRBAA Rates	T-ECRA Rates	RS Rates	Dist Rates	PPP Rates	ND Rates	DWR Bond Rates	CTC Rates	ECRA Rates	NSGC Rates	Residential & Small Business AB32 Credit Rates	Climate Credit & EITE Rates	CIA Rates	PCIA Rates	Total Proposed Rates	Percent Change
RESIDENTIAL																				
E-1	12,335,372,705	$0.19546	$0.03595	$0.00618	-$0.00304	$0.00000	-$0.00066	$0.10376	$0.01272	$0.00101	$0.00563	$0.00026	$0.00005	$0.00436	$0.00000	-$0.00705	$0.00690	$0.03786	$0.20393	4.3%
EL-1	2,231,130,262	$0.07466	$0.03595	$0.00618	-$0.00304	$0.00000	-$0.00066	$0.01125	$0.00450	$0.00101	$0.00000	$0.00026	$0.00005	$0.00436	$0.00000	-$0.00840	-$0.00322	$0.03791	$0.08614	15.4%
TOTAL RES	14,566,502,967	$0.17696	$0.03595	$0.00618	-$0.00304	$0.00000	-$0.00066	$0.08959	$0.01146	$0.00101	$0.00477	$0.00026	$0.00005	$0.00436	$0.00000	-$0.00726	$0.00535	$0.03787	$0.18589	5.0%
SMALL L&P																				
A-1	4,196,464,220	$0.18288	$0.02766	$0.00618	-$0.00304	$0.00000	-$0.00051	$0.09477	$0.01226	$0.00101	$0.00579	$0.00026	$0.00005	$0.00328	$0.00000	$0.00000		$0.03877	$0.18648	2.0%
A-6	861,204,969	$0.16680	$0.02767	$0.00618	-$0.00304	$0.00000	-$0.00051	$0.08522	$0.01134	$0.00101	$0.00576	$0.00026	$0.00005	$0.00328	$0.00000	$0.00000		$0.03269	$0.16991	1.9%
A-15	352,529	$0.59794	$0.02766	$0.00618	-$0.00304	$0.00000	-$0.00051	$0.50953	$0.01228	$0.00101	$0.00577	$0.00026	$0.00005	$0.00328	$0.00000	$0.00000		$0.03910	$0.60158	0.6%
TC-1	28,425,589	$0.18296	$0.02766	$0.00618	-$0.00304	$0.00000	-$0.00051	$0.10345	$0.00387	$0.00101	$0.00580	$0.00026	$0.00005	$0.00328	$0.00000	$0.00000		$0.03733	$0.18535	1.3%
TOTAL SMALL	5,086,447,308	$0.18019	$0.02766	$0.00618	-$0.00304	$0.00000	-$0.00051	$0.09323	$0.01206	$0.00101	$0.00578	$0.00026	$0.00005	$0.00328	$0.00000	$0.00000		$0.03773	$0.18370	2.0%
MEDIUM L&P																				
A-10 T	1,050,072	$0.12199	$0.03143	$0.00618	-$0.00304	$0.00000	-$0.00058	$0.02964	$0.01140	$0.00101	$0.00580	$0.00027	$0.00005	$0.00294	$0.00000	$0.00000		$0.03929	$0.12438	2.0%
A-10 P	53,536,542	$0.13857	$0.02773	$0.00618	-$0.00304	$0.00000	-$0.00051	$0.05002	$0.01148	$0.00101	$0.00580	$0.00027	$0.00005	$0.00294	$0.00000	$0.00000		$0.03905	$0.14098	1.7%
A-10 S	5,339,274,402	$0.15078	$0.03062	$0.00618	-$0.00304	$0.00000	-$0.00056	$0.06093	$0.01151	$0.00101	$0.00578	$0.00027	$0.00005	$0.00294	$0.00000	$0.00000		$0.03722	$0.15290	1.4%
TOTAL MEDIUM	5,393,861,016	$0.15066	$0.03059	$0.00618	-$0.00304	$0.00000	-$0.00056	$0.06081	$0.01151	$0.00101	$0.00578	$0.00027	$0.00005	$0.00294	$0.00000	$0.00000		$0.03723	$0.15277	1.4%
E-19 CLASS																				
E-19 FIRM T	5,273,753	$0.11168	$0.02919	$0.00618	-$0.00304	$0.00000	-$0.00031	$0.02178	$0.01120	$0.00101	$0.00580	$0.00025	$0.00005	$0.00294	$0.00000			$0.03599	$0.11103	-0.6%
E-19 V T	8,211,973	$0.08522	$0.01865	$0.00618	-$0.00304	$0.00000	-$0.00020	$0.00849	$0.01120	$0.00101	$0.00580	$0.00025	$0.00005	$0.00294	$0.00000			$0.03525	$0.08658	1.6%
Total E-19 T	13,485,727	$0.09557	$0.02277	$0.00618	-$0.00304	$0.00000	-$0.00024	$0.01369	$0.01120	$0.00101	$0.00580	$0.00025	$0.00005	$0.00294	$0.00000			$0.03554	$0.09614	0.6%
E-19 FIRM P	535,815,493	$0.11605	$0.02356	$0.00618	-$0.00304	$0.00000	-$0.00025	$0.03822	$0.01120	$0.00101	$0.00580	$0.00025	$0.00005	$0.00294	$0.00000	-$0.00005		$0.02991	$0.11577	-0.2%
E-19 V P	186,418,448	$0.12391	$0.02714	$0.00618	-$0.00304	$0.00000	-$0.00029	$0.03992	$0.01120	$0.00101	$0.00580	$0.00025	$0.00005	$0.00294	$0.00000	$0.00000		$0.03305	$0.12420	0.2%
Total E-19 P	722,233,941	$0.11808	$0.02448	$0.00618	-$0.00304	$0.00000	-$0.00026	$0.03866	$0.01120	$0.00101	$0.00580	$0.00025	$0.00005	$0.00294	$0.00000	-$0.00004		$0.03072	$0.11795	-0.1%
E-19 FIRM S	2,906,249,121	$0.12418	$0.02266	$0.00618	-$0.00304	$0.00000	-$0.00024	$0.04675	$0.01138	$0.00101	$0.00579	$0.00025	$0.00005	$0.00294	$0.00000	-$0.00006		$0.02983	$0.12349	-0.6%
E-19 V S	6,540,814,072	$0.11963	$0.02103	$0.00618	-$0.00304	$0.00000	-$0.00022	$0.04555	$0.01136	$0.00101	$0.00576	$0.00025	$0.00005	$0.00294	$0.00000	$0.00000		$0.02810	$0.11895	-0.6%
Total E-19 S	9,447,063,193	$0.12103	$0.02153	$0.00618	-$0.00304	$0.00000	-$0.00023	$0.04592	$0.01136	$0.00101	$0.00577	$0.00025	$0.00005	$0.00294	$0.00000	-$0.00002		$0.02863	$0.12035	-0.6%
E-19 T	13,485,727	$0.09557	$0.02277	$0.00618	-$0.00304	$0.00000	-$0.00024	$0.01369	$0.01120	$0.00101	$0.00580	$0.00025	$0.00005	$0.00294	$0.00000	$0.00000		$0.03554	$0.09614	0.6%
E-19 P	722,233,941	$0.11808	$0.02448	$0.00618	-$0.00304	$0.00000	-$0.00026	$0.03866	$0.01120	$0.00101	$0.00580	$0.00025	$0.00005	$0.00294	$0.00000	-$0.00004		$0.03072	$0.11795	-0.1%
E-19 S	9,447,063,193	$0.12103	$0.02153	$0.00618	-$0.00304	$0.00000	-$0.00023	$0.04592	$0.01136	$0.00101	$0.00577	$0.00025	$0.00005	$0.00294	$0.00000	-$0.00002		$0.02863	$0.12035	-0.6%
TOTAL E-19	10,182,782,862	$0.12078	$0.02174	$0.00618	-$0.00304	$0.00000	-$0.00023	$0.04536	$0.01135	$0.00101	$0.00577	$0.00025	$0.00005	$0.00294	$0.00000	-$0.00002		$0.02879	$0.12015	-0.5%
STREETLIGHTS	163,144,341	$0.18516	$0.02247	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.11703	$0.00370	$0.00101	$0.00580	$0.00021	$0.00005	$0.00256	$0.00000	$0.00000		$0.02982	$0.18537	0.1%
STANDBY																				
STANDBY T	30,470,166	$0.13670	$0.04870	$0.00618	-$0.00304	$0.00000	-$0.00089	$0.02842	$0.01209	$0.00101	$0.00580	$0.00019	$0.00005	$0.00622	$0.00000	$0.00000		$0.02744	$0.13216	-3.3%
STANDBY P	6,850,304	$0.36152	$0.05640	$0.00618	-$0.00304	$0.00000	-$0.00103	$0.26742	$0.01314	$0.00101	$0.00580	$0.00019	$0.00005	$0.00622	$0.00000	$0.00000		$0.00829	$0.36062	-0.2%
STANDBY S	2,077,703	$0.20469	$0.02827	$0.00618	-$0.00304	$0.00000	-$0.00052	$0.12210	$0.01291	$0.00101	$0.00580	$0.00019	$0.00005	$0.00622	$0.00000	$0.00000		$0.02636	$0.20554	0.4%
TOTAL STANDBY	39,398,173	$0.17938	$0.04896	$0.00618	-$0.00304	$0.00000	-$0.00090	$0.07492	$0.01231	$0.00101	$0.00580	$0.00019	$0.00005	$0.00622	$0.00000	$0.00000		$0.02405	$0.17575	-2.0%
AGRICULTURE																				
AG-1A	9,709,259	$0.31865	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.24091	$0.01220	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	$0.00000		$0.03257	$0.32037	0.5%
AG-RA	126,007																			
AG-VA	1,349,244	$0.24262	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.16598	$0.01220	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	$0.00000		$0.02977	$0.24264	0.0%
AG-4A	46,775,551	$0.28709	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.20834	$0.01220	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	$0.00000		$0.03323	$0.28847	0.5%
AG-5A	17,841,493	$0.18203	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.10225	$0.01220	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	$0.00000		$0.03308	$0.18223	0.1%
AG-1B	19,683,092	$0.27062	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.19220	$0.01194	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	$0.00000		$0.03325	$0.27209	0.5%
AG-RB	353,366	$0.22328	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.14457	$0.01194	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	$0.00000		$0.03335	$0.22456	0.6%
AG-VB	1,107,132	$0.22340	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.14425	$0.01194	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	$0.00000		$0.03332	$0.22421	0.4%
AG-4B	152,321,442	$0.23572	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.15741	$0.01194	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	$0.00000		$0.03248	$0.23654	0.3%
AG-4C	13,699,731	$0.19200	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.11275	$0.01194	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	$0.00000		$0.03329	$0.19268	0.4%
AG-5B	280,227,020	$0.15850	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.08024	$0.01120	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	-$0.00001		$0.03315	$0.15929	0.5%
AG-5C	464,336,441	$0.10733	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.03015	$0.01120	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	-$0.00006		$0.03139	$0.10738	0.0%
Total AG A	75,801,553	$0.26561	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.18678	$0.01220	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	$0.00000		$0.03305	$0.26673	0.4%
Total AG B	931,728,224	$0.14859	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.07084	$0.01135	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	-$0.00003		$0.03217	$0.14902	0.3%
TOTAL AG	1,007,529,777	$0.15739	$0.02202	$0.00618	-$0.00304	$0.00000	-$0.00041	$0.07956	$0.01141	$0.00101	$0.00580	$0.00023	$0.00005	$0.00286	$0.00000	-$0.00003		$0.03223	$0.15788	0.3%
E-20 CLASS																				
E-20 FIRM T	3,616,878,244	$0.05651	$0.01839	$0.00618	-$0.00304	$0.00000	-$0.00019	-$0.00190	$0.01043	$0.00101	$0.00494	$0.00021	$0.00005	$0.00256	$0.00000	$0.00000		$0.01756	$0.05620	-0.6%
FPP T	304,202,831	$0.01243	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00089	$0.00937	$0.00101	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		$0.00000	$0.01128	-9.3%
TOTAL	3,921,081,075	$0.05309	$0.01696	$0.00570	-$0.00281	$0.00000	-$0.00018	-$0.00168	$0.01035	$0.00101	$0.00456	$0.00020	$0.00004	$0.00236	$0.00000	$0.00000		$0.01620	$0.05272	-0.7%
E-20 FIRM P	4,669,743,824	$0.09662	$0.02142	$0.00618	-$0.00304	$0.00000	-$0.00022	$0.03093	$0.01077	$0.00101	$0.00580	$0.00023	$0.00005	$0.00256	$0.00000	-$0.00002		$0.02049	$0.09615	-0.5%
FPP P	19,657,019	$0.02704	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.01533	$0.00971	$0.00101	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		$0.00000	$0.02606	-3.7%
TOTAL	4,689,400,843	$0.09633	$0.02133	$0.00615	-$0.00303	$0.00000	-$0.00022	$0.03087	$0.01076	$0.00101	$0.00578	$0.00023	$0.00005	$0.00255	$0.00000	-$0.00002		$0.02041	$0.09585	-0.5%
E-20 FIRM S	1,528,902,251	$0.10833	$0.02181	$0.00618	-$0.00304	$0.00000	-$0.00023	$0.03836	$0.01098	$0.00101	$0.00580	$0.00024	$0.00005	$0.00256	$0.00000	-$0.00093		$0.02437	$0.10715	-1.1%
FPP S	96,140,150	$0.02835	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.01634	$0.00992	$0.00101	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		$0.00000	$0.02728	-3.8%
TOTAL	1,625,042,402	$0.10360	$0.02052	$0.00581	-$0.00286	$0.00000	-$0.00021	$0.03706	$0.01092	$0.00101	$0.00546	$0.00023	$0.00004	$0.00241	$0.00000	-$0.00088		$0.02292	$0.10243	-1.1%
E-20 T	3,921,081,075	$0.05309	$0.01696	$0.00570	-$0.00281	$0.00000	-$0.00018	-$0.00168	$0.01035	$0.00101	$0.00456	$0.00020	$0.00004	$0.00236	$0.00000	$0.00000		$0.01620	$0.05272	-0.7%
E-20 P	4,689,400,843	$0.09633	$0.02133	$0.00615	-$0.00303	$0.00000	-$0.00022	$0.03087	$0.01076	$0.00101	$0.00578	$0.00023	$0.00005	$0.00255	$0.00000	-$0.00002		$0.02041	$0.09585	-0.5%
E-20 S	1,625,042,402	$0.10360	$0.02052	$0.00581	-$0.00286	$0.00000	-$0.00021	$0.03706	$0.01092	$0.00101	$0.00546	$0.00023	$0.00004	$0.00241	$0.00000	-$0.00088		$0.02292	$0.10243	-1.1%
TOTAL E-20	10,235,524,320	$0.08092	$0.01953	$0.00593	-$0.00292	$0.00000	-$0.00020	$0.01938	$0.01063	$0.00101	$0.00526	$0.00022	$0.00004	$0.00245	$0.00000	-$0.00015		$0.01920	$0.08037	-0.7%
SYSTEM	**46,675,190,762**	**$0.14056**	**$0.02739**	**$0.00612**	**-$0.00302**	**$0.00000**	**-$0.00043**	**$0.06148**	**$0.01130**	**$0.00101**	**$0.00535**	**$0.00025**	**$0.00005**	**$0.00331**	**$0.00000**	**-$0.00230**	**$0.00167**	**$0.03154**	**$0.14373**	**2.3%**

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

TABLE OF GREENHOUSE GAS HISTORY OF REVENUE, COSTS, AND EMISSIONS INTENSITY

(TEMPLATE D-5)

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX A
TABLE OF GREENHOUSE GAS HISTORY OF REVENUE, COSTS, AND EMISSIONS INTENSITY
(TEMPLATE D-5)

As ordered by the California Public Utilities Commission in Decision (D.) 14-10-033, Pacific Gas and Electric Company (PG&E) presents the following summary table. The table includes PG&E's forecast total 2021 Greenhouse Gas (GHG) allowance revenue and forecast 2021 GHG costs that are also presented, respectively, in Chapters 15 and 17. The table also includes a 2021 forecast emissions intensity calculation. For comparison, total GHG costs, GHG allowance revenue, and emissions intensity calculations, are shown for prior years beginning in 2014.[1]

The total GHG allowance revenue, shown in line 1, represents the Net GHG Revenues Available for Customers presented in Table 17-5 for the corresponding year.

The total GHG costs, shown in line 2, represents the sum of direct and indirect GHG costs presented in Table 15-2 for the corresponding year. It does not include any GHG cost reconciliation amounts from prior years.

Emissions Intensity, shown in line 3, is calculated by dividing total GHG emissions that support GHG cost calculations reported in Tables 15-1 and 15-2 by the total energy load requirement to serve PG&E's bundled electricity customers for the corresponding year.

The emissions intensity in this filing is not the same calculation as the carbon dioxide (CO_2) emissions rate reported by PG&E to The Climate Registry (TCR). TCR is a leading platform for voluntary GHG emission inventories in North America, with more than 300 organizations publishing their GHG inventories to TCR. TCR has several protocols which use the generally accepted GHG accounting standards developed by the World Resources Institute. PG&E reports the CO_2 emission rate

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[1] D.14-10-033, corrected by D.15-01-024, ordered the Investor-Owned Utilities to provide a summary table showing total GHG costs, GHG allowance revenue, and GHG emissions intensity for the forecast year, and up to five preceding years. The California Air Resources Board Cap-and-Trade Program became effective in 2013; therefore, no relevant summary information is available prior to 2013.

for its delivered electricity annually to TCR in an Electric Power Sector (EPS) report, in accordance with TCR's EPS Protocol, which is the most widely recognized methodology for reporting the CO_2 emission intensity of a utility's electricity. The EPS report details PG&E's owned power generation sources and the annual megawatt-hours and CO_2 emissions produced from each source. In addition, PG&E calculates and provides the CO_2 emissions associated with purchased electricity. Together, these sources total the CO_2 emissions for the electricity PG&E delivered to its customers. GHG inventories reported to TCR, including the CO_2 emission rate, undergo rigorous third-party verification by a verification body approved by TCR. PG&E has reported the CO_2 emission rate for its delivered electricity to TCR or its predecessor, the California Climate Action Registry since 2003.

The Emissions Intensity shown in the summary table is not an input to the Energy Resource Recovery Account, Ongoing Competition Transition Charge, Power Charge Indifference Adjustment, or Cost Allocation Mechanism revenue requirements or the calculation of allowance revenue return. It is a simple calculation derived from information presented elsewhere in this forecast application and testimony filed in prior applications.

TABLE A-1
GHG HISTORY OF REVENUE, COSTS AND EMISSIONS INTENSITY
(TEMPLATE D-5)

Line No.	Description	Recorded 2014	Recorded 2015	Recorded 2016	Recorded 2017	Recorded 2018	Recorded 2019	Forecast 2020	Forecast 2021
					($000)				
1	Total GHG Revenues (Net available for customers) (a)	$578,743	$456,431	$366,996	$310,534	$387,880	$319,155	$382,471	$195,801
2	Total GHG Costs	$199,628	$212,062	$164,735	$125,738	$62,723	-$33,961	-$25,616	-$10,740
					(MT CO2e/MWh)				
3	Emissions Intensity (b)	0.210	0.216	0.176	0.165	0.081	-0.037	-0.049	-0.108

Notes:
(a) Line 1 is derived from Line 17 of Table 17-5.
(b) The emissions intensity shown here is calculated by dividing total GHG emissions reported on Line 13 of Tables 15-1 and 15-2 by the total energy load requirement to serve PG&E's bundled electricity customers for the corresponding year. The emissions intensity is not the same calculation as the CO2 emissions rate reported by PG&E to The Climate Registry (TCR).

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX B

STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ALEXANDER ALLAN

Q 1 Please state your name and business address.

A 1 My name is Alexander Allan, 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 Principal Analyst in the Business Planning Department within the Power Generation organization. I perform a variety of planning and analytical work in support of operational performance, metrics, and benchmarking with respect to PG&E's Hydro, Fossil, and Solar facilities, as well as providing a variety of support for PG&E's Hydro, Fossil, and Solar regulatory filings and data requests.

Q 3 Please summarize your educational and professional background.

A 3 I graduated with a Bachelor of Science degree in Mechanical Engineering in 2008 and a Master of Science degree in Transportation Technology and Policy in 2011, both from the University of California, Davis.

I joined PG&E in 2010 as an Analyst in the Portfolio and Resource Forecasting Department, where I worked on various energy procurement forecasts and related analysis to support PG&E in regulatory proceedings and other business processes until I joined the Power Generation organization in 2019.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 4, "Fuel Costs for Utility-Owned Generation Assets":
  - Section D.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF DONNA L. BARRY

Q 1 Please state your name and business address.

A 1 My name is Donna L. Barry, 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 Regulatory Principal in the Electric Rates and Rate Architecture Department within the Regulatory Affairs organization. I am responsible for developing testimony and analysis to support proceedings filed at the California Public Utilities Commission on matters related to energy procurement and cost recovery.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelor of Science degree in Civil Engineering from Washington State University and a Master of Business Administration degree from Santa Clara University.

I began my career with PG&E in 1989 as an Engineer in the Engineering and Construction Business Unit's Gas Construction Department, managing gas distribution and pipeline replacement construction projects. From there, I took an assignment in the Gas Supply Business Unit in the Gas Engineering and Construction (GEC) Department as a Project Manager, managing three gas backbone transmission projects before joining the Gas Planning section in GEC, where I analyzed the reliability of local transmission and distribution systems. I subsequently joined the Cost of Service section in the Rates Department, where I performed cost of service studies and marginal cost analyses supporting various gas and electric rate applications.

I joined the Electric Restructuring Cost Recovery section of the Revenue Requirements Department in 2001 and Electric Energy Revenue and Analysis and Ratemaking section in 2002. I was a Case Manager for the Energy Resource Recovery Account (ERRA) Forecast from 2004 through 2006 and sponsored testimony in the case related to PG&E's generation-related non-bypassable charges between 2004-2019 and more recently,

I have sponsored testimony supporting updates to PG&E's Green Tariff Shared Renewables (GTSR) Program rates. I was also the Principal Case Manager for the ERRA Compliance Review proceeding from 2003 through 2011 and my responsibilities included coordination of the case assessment and strategy development across multiple departments within PG&E, as well as sponsoring testimony related to the review of costs recorded to the ERRA. The department and section were renamed as the Energy Supply Proceedings Department in 2012. I moved to the Revenue Requirements and Analysis Department in 2014.

The Revenue Requirements and Analysis Department has been reorganized and renamed several times since 2014 and the current department name is Electric Rates and Rate Architecture. Over the last six years, I have sponsored written testimony related to cost recovery and rate design and/or submitted cost recovery proposals in advice letters in support of the following applications: GTSR Program, Transportation Electrification Senate Bill 350, Energy Storage System Rulemaking (2014), Energy Storage Plan (2016), Energy Storage Request for Offers (2014 and 2016), Energy Storage Plan and Assembly Bill 2868. I have also contributed significantly to two Applications that involved reform of the Power Charge Indifference Adjustment (PCIA) – the Portfolio Allocation Mechanism Application in 2017 and the PCIA in 2018, both of which were jointly filed with Southern California Edison Company and San Diego Gas & Electric Company.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 13, "Green Tariff Shared Renewables."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF REES BLANCHARD

Q 1 Please state your name and business address.

A 1 My name is Rees Blanchard, 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 Resource Forecasting Analyst in the Portfolio and Resource Forecasting Department in PG&E's Energy Policy and Procurement organization. I am responsible for producing the departing load energy forecast (e.g., Community Choice Aggregators, Direct Access), as well behind-the-meter (BTM) distributed generation forecasts.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Geological Sciences from Queen's University, Kingston, Ontario in May 2012.

I received a Master of Science degree in Natural Resources and the Environment from the University of Michigan in May 2017, and a Master of Business Administration degree from Presidio Graduate School in 2019. During my studies, I focused on energy, environmental, and financial modeling, and worked as an intern at a financial services firm to develop Environmental, Social, and Governance metrics to compare and evaluate investments in different securities. My academic work ranged from modeling the economic and environmental performance of BTM clean energy projects to carbon accounting for a large winery.

Upon completion of my Master's degree, I joined PG&E in July 2019 and assumed my current role as Resource Forecasting Analyst.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 2, "Sales and Peak Demand Forecast":
  - Section C.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF GEORGE CLAVIER

Q 1 Please state your name and business address.

A 1 My name is George Clavier, 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 Principal Analyst in the Portfolio and Resource Forecasting Department within the Energy Policy and Procurement organization, responsible for preparing, validating, and analyzing energy procurement cost and generation forecasts utilized in regulatory proceedings before the California Public Utilities Commission and the California Energy Commission.

Q 3 Please summarize your educational and professional background.

A 3 I graduated with a Bachelor of Arts in International Economics from the American College in Paris in 1982 and a Master of Science in Agricultural Economics from the University of California, Davis in 1988.

I joined PG&E in 1991 as an Analyst in the Fuels Policy Department. Since then I have held a number of different positions in the Energy Policy and Procurement organization. In my current position I have worked on various energy procurement forecasts and related analysis to support PG&E in regulatory proceedings and other business processes.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 3, "Generation Resource and Supply Cost Summary";
- Chapter 6, "Procurement Costs: Post-2002 Contracted Resources";
- Chapter 7, "Hedging, Collateral, CAISO and Other Costs":
  - Section A, D, and E.
- Chapter 11,"Tree Mortality Revenue Requirements":
  - Section C.
- Chapter 12, "Energy Resource Recovery Account";

- Chapter 15, “Greenhouse Gas Forecast Revenue and Reconciliation – Cost Calculations”:
  - Section A, B, and C.
- Appendix A, “Table of Greenhouse Gas History of Revenue, Costs and Emissions Intensity (Template D-5).”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF THOMAS A. JARMAN

Q 1 Please state your name and business address.

A 1 My name is Thomas A. Jarman, 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 Regulatory Case Manager, Principal in the CPUC Electric Proceedings Department, under the Vice President of State and Regulatory Affairs. I am responsible for managing regulatory proceedings filed at the California Public Utilities Commission (CPUC or Commission) on matters related to generation and energy procurement. In 2018, I was promoted to my current position, and since then I have managed PG&E's Energy Resource Recovery Account (ERRA) Forecast proceedings for prompt years 2019 through 2021.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Applied Economics from the University of San Francisco, and I joined PG&E in 2005. Since 2006, I have worked in the Regulatory Affairs organization on numerous rate and policy related projects before the CPUC. These projects include: (1) cost recovery reforms to the Power Charge Indifference Adjustment; (2) Senate Bill 350 Integrated Resource Planning (evolving the Commission's long-term resource planning process to consider the state's economywide greenhouse gas emission reductions goals) for the inaugural cycle; (3) 2018-2022 Demand Response programs and budgets, and refinements to Rule 24 customer authentication protocols; (4) establishing protocols for protecting market sensitive utility data and information in regulatory proceedings; (5) refinements to the Resource Adequacy Program; (6) capital and expense cost recovery associated with implementing the California Independent System Operator Corporation's market enabling technology project; (7) implementing the Qualifying Facility/Combined Heat and Power Settlement (approved in Decision 10-12-035); and, (8) seeking approval of 1,200 megawatts of new generation resulting from the 2008 all-source

competitive solicitation. I was the Regulatory Case Manager for the ERRA Compliance Review proceeding for the 2012 through 2015 review periods, and I have presented testimony before the Commission as PG&E's witness on balancing account activity for 2015 record period activity.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 1, "Introduction and Policy."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ANDREW KLINGLER

Q 1 Please state your name and business address.

A 1 My name is Andrew Klingler, 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 Senior Manager in our Rates organization with responsibility for load forecasting and certain aspects of rates forecasting and modeling.

Q 3 Please summarize your educational and professional background.

A 3 I hold a Bachelor of Arts degree in Physics from the University of California, Berkeley, and a Doctor of Philosophy Degree in Mathematics from the University of California, Santa Cruz. I have worked in various quantitative, programming, analytical, and managerial roles in the energy industry for about 20 years; I have been in the utility industry for most of that time. I left Dominion Virginia Power in 2007 to join PG&E, where I have worked as a Front Office Quantitative Analyst, a Manager of Risk Analytics, and currently a Manager of Rates and Load Forecasting.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 2, "Sales and Peak Demand Forecast":
  - Sections A, B, and D.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF BENJAMIN KOLNOWSKI

Q 1 Please state your name and business address.

A 1 My name is Benjamin Kolnowski, 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 My current position at PG&E is Supervisor of Electric Rates within the Regulatory Affairs organization. In this capacity, I am responsible for overseeing the development of electric rates, including rate design proposals for presentation, review, and approval by the California Public Utilities Commission.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mechanical Engineering from University of California, Los Angeles in June 2012. From 2012-2015, I worked as an Engineer in PG&E's Gas System Planning Department. In this role, my primary responsibility was to analyze the hydraulics of the gas system to support gas operations and customer growth. From 2015-2016, I joined the Strategy, Technology, and Support Department at PG&E, where I developed technology, processes, and procedures to support the Gas System Planning Department. This included analyzing hourly gas meter data to understand the relationship between various weather variables and gas use, resulting in an hourly forecast by climate zone.

I received a Master's degree in Business Administration (MBA) from the Anderson School of Business at University of California, Los Angeles in June 2018. I rejoined PG&E in September 2018 as an MBA Associate, working in the Rates Department within Regulatory Affairs on rotation. In April 2019, I permanently joined the Rates Department as an Expert Data Scientist. One of my main responsibilities in both roles had been to develop the electric sales and customer forecasts used for electric rate design. In February 2020 I entered my current role as the Supervisor of Electric Rates.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 19, "Rate Proposal"; and
- Attachment A, "Illustrative Total Rates By Class."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MICHAEL KOWALEWSKI

Q 1 Please state your name and business address.

A 1 My name is Michael Kowalewski, 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 Portfolio Manager in the Energy Policy and Procurement organization. I am responsible for managing the financial position of PG&E's electric portfolio, including planning and trading related financial products for PG&E's electric portfolio.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Arts degree in Economics from the University of California, Berkeley, in 1992. From 1992 to present, I have been employed by PG&E in various positions including: Portfolio Manager, Trading Manager, Project Manager, Product Manager, and Analyst.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 7, "Hedging, Collateral, CAISO and Other Costs":
  - Sections A, B, and E.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF NICHOLAS MANUEL

Q 1 Please state your name and business address.

A 1 My name is Nicholas Manuel, 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 Supervisor of Banking and Money Management in the Treasury organization, responsible for: executing financing transactions (debt, equity, and bank credit facilities) in support of PG&E's capital and liquidity requirements; managing financial risk; ensuring compliance with all financial covenants; managing the Company's relationship with the financial community (banks, credit rating agencies, etc.); and aiding in day-to-day operational banking activities for the Company, including letter of credit issuance and bank account management.

Q 3 Please summarize your educational and professional background.

A 3 I graduated with a Bachelor of Science degree in Finance in 2013 from the University of Arizona. I joined PG&E in 2013 as an Associate Financial Analyst in the Business Finance Department, working on governance and analytics, supporting the electric line of business. I moved to the Treasury organization in January 2016.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 7, "Hedging, Collateral, CAISO and Other Costs":
  - Sections C.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MARK MAYER

Q 1 Please state your name and business address.

A 1 My name is Mark Mayer, and my business address is Pacific Gas and Electric Company, Diablo Canyon Power Plant.

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

A 2 I work in the Nuclear Fuels Purchasing Department for Diablo Canyon Power Plant (Diablo Canyon) within the Generation organization. I am responsible for contracts associated with the fabrication of nuclear fuel for Diablo Canyon and the purchase of feed materials (uranium, conversion services, and enrichment services).

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Nuclear Engineering from the Massachusetts Institute of Technology. I have worked for PG&E at Diablo Canyon for over 30 years, primarily in Engineering. My previous engineering responsibilities have included reactor engineering and system and transient analysis. I am a registered Professional Engineer in the state of California.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 4, "Fuel Costs for Utility-Owned Generation Assets":
  - Section C.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF RUTH E. OSCAR

Q 1 Please state your name and business address.

A 1 My name is Ruth E. Oscar, 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 Strategic Analyst in the Portfolio and Resource Forecasting Department, in PG&E's Energy Policy and Procurement organization. I prepare a variety of forecasts of Qualifying Facility (QF) related energy, capacity, pricing, and revenue requirements for various regulatory filings, as well as for PG&E's wholesale procurement activities.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Arts degree in Economics and Urban Studies from the University of Nebraska at Lincoln. I also earned a Master of Science degree in Agricultural and Natural Resource Economics from the University of California, Berkeley.

I joined PG&E in 1996 as an Electric Resource Analyst in PG&E's Power Contracts Department, responsible for QF contract administration and regulatory matters, including QF pricing. Prior to joining PG&E, I was a Senior Associate at Barakat and Chamberlin, Inc., a management consulting firm serving regulated industries. There, I provided specialized economic analyses, forecasting, and modeling services for a variety of electricity, fuels, and litigation support projects. Earlier in my career, I was also employed as an Economics Research Assistant, Teaching Assistant, and as an Economist for the United States Department of Agriculture.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 4, "Fuel Costs for Utility-Owned Generation Assets":
  - Sections A, B, E, F, G, and H;

- Chapter 5, “Qualifying Facility and Other Legacy Purchased Power Agreement Costs”;
- Chapter 8, “Cost Allocation Mechanism”; and
- Chapter 10, “Modified Cost Allocation Mechanism.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF LARSEN PLANO

Q 1 Please state your name and business address.

A 1 My name is Larsen Plano, 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 Manager of PG&E's Distributed Generation Programs team in the Customer Energy Solutions – Clean Energy Programs organization. In this role, I supervise Managers of both low-income solar incentive programs and shared renewable programs at PG&E.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mechanical Engineering from Brown University and a Master's degree in Civil Engineering from Stanford University. I joined PG&E in 2013 as a Renewable Integration Analyst in PG&E's Energy Procurement organization. Prior to PG&E, I worked as a Project Manager at an organization focused on delivering energy efficiency improvements to low-income residents in New York City.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 17, "Greenhouse Gas Forecast Revenue and Reconciliation – Revenue Calculations":
  - Section C.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF WILLIAM REINWALD

Q 1 Please state your name and business address.

A 1 My name is William Reinwald, 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 Analyst in the Risk and Compliance Department within the Energy Policy and Procurement organization. I am responsible for preparing, validating, and submitting energy procurement reports to state and federal regulatory agencies.

Q 3 Please summarize your educational and professional background.

A 3 I graduated with a Bachelor of Science degree in Nuclear Engineering in 1994 and a Master of Business degree in 2001, both from the University of Cincinnati.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 15, "Greenhouse Gas Forecast Revenue and Reconciliation – Cost Calculations":
  - Section C.1.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF RYAN STANLEY

Q 1 Please state your name and business address.

A 1 My name is Ryan Stanley, 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 Manager in the Energy Accounting Department within the Corporate Accounting organization at PG&E. In this position, I am responsible for overseeing and advising on cost recovery. I am also responsible for leading various reporting activities on the monthly accounting entries made into the Energy Resource Recovery Account balancing account, in compliance with California Public Utilities Commission directives.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelor of Science degree in Business Administration, from the Walter A. Haas School of Business, University of California at Berkeley. I received my Master's in Business Administration from the Walter A. Haas School of Business, University of California at Berkeley.

I have over 14 years of regulated utility accounting, financial forecasting, and regulatory experience from having held positions of increasing responsibility at PG&E, in the Controller's and Regulatory Affairs organizations.

Q 4 What is the purpose of your testimony?

A 4 I am co-sponsoring the following testimony in PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 14, "Balancing Accounts Forecasts":
  - Sections A, B, C, and F; and
- Chapter 15, "Greenhouse Gas Forecast Revenue and Reconciliation – Cost Calculations":
  - Section C.1.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF TYSEN STREIB

Q 1 Please state your name and business address.

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

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

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

Q 3 Please summarize your educational and professional background.

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

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2021 Energy Resource Recovery Account and Generation Non Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 17, "Greenhouse Gas Forecast Revenue and Reconciliation – Revenue Calculations":
  - Section F.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ANGELIA (LIM) VEGA

Q 1 Please state your name and business address.

A 1 My name is Angelia (Lim) Vega, 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 Strategic Analyst, Expert in the Portfolio and Resource Forecasting (PRF) Department within the Energy Policy and Procurement organization. I am responsible for developing testimony and analysis to support proceedings filed at the California Public Utilities Commission (CPUC) on matters related to generation procurement.

Q 3 Please summarize your educational and professional background.

A 3 I am a Fellow of the Chartered Association of Certified Accountants from the United Kingdom. I joined PG&E in 2005, initially working as a Senior Accounting Analyst within the Controllers' Department, and then as an Expert Regulatory Analyst in the Rates and Regulatory Analytics Department. My assignments in these departments were: accounting for various balancing accounts; participating in the development and implementation of accounting process improvements; providing analysis on recorded and forecast electric revenue and cost; and developing testimony and analysis to support proceedings filed at the CPUC on matters related to generation procurement. My job was transferred to the PRF Department of the Energy Policy and Procurement organization at PG&E in winter 2018. I have previously sponsored testimony before the CPUC, including in prior Energy Resource Recovery Account Forecast proceedings.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2021 ERRA and Generation Non Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 9, "Power Charge Indifference Adjustment and Ongoing Competition Transition Charge";
- Chapter 14, "Balancing Accounts Forecasts":
  - Sections A, B, D through F;
- Chapter 17, "Greenhouse Gas Forecast Revenue and Reconciliation – Revenue Calculations":
  - Sections A, B, D, E, and G;
- Chapter 18, "Energy Procurement Revenue Requirements."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF SIMON YU

Q 1 Please state your name and business address.

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

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

A 2 I am a Senior Product Manager in the Pricing Products group within the Customer Care organization. I am responsible for the implementation and administration of the Greenhouse Gas allowance revenue return to non-residential customers (Emissions-Intensive and Trade-Exposed).

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Marketing from San Francisco State University, and a certification in Project Management from University of California, Berkeley Extension.

I joined PG&E in 2015 as a Project Manager in the Solutions Marketing Department, and was responsible for the education, marketing, and outreach planning and deployment of various energy efficiency programs.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 16, "Greenhouse Gas Forecast Revenue and Reconciliation – Administrative and Outreach Expenses."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX C

CONFIDENTIALITY DECLARATIONS

PACIFIC GAS AND ELECTRIC COMPANY
2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION (A.20-07-00X)

DECLARATION OF ALEXANDER ALLAN SEEKING CONFIDENTIAL TREATMENT FOR CERTAIN DATA AND INFORMATION CONTAINED IN CHAPTER 4 TESTIMONY

I, Alexander Allan, declare:

1. I am a Principal Analyst in the Business Planning Department within the Power Generation organization at Pacific Gas and Electric Company (PG&E). I perform a variety of planning and analytical work in support of operational performance, metrics and benchmarking with respect to PG&E's Hydro, Fossil and Solar facilities, as well as providing a variety of support for PG&E's Hydro, Fossil and Solar regulatory filings and data requests. This declaration is based on my personal knowledge of PG&E's practices and my understanding of the Commission's decisions protecting the confidentiality of market-sensitive information.

2. Based on my knowledge and experience, and in accordance with the Decisions 06-06-066, D.08-04-023, D.14-10-033, and relevant Commission rules, I make this declaration seeking confidential treatment for certain data and information contained in Chapter 4 ("Fuel Costs for Utility-Owned Generation Assets") of the Prepared Testimony in support of PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation Application.

3. Attached to this declaration is a matrix identifying the data and information for which PG&E is seeking confidential treatment. The matrix specifies that the material PG&E is seeking to protect constitutes confidential market sensitive data and information covered by D.06-06-066, D.08-04-023, D.14-10-033, and/or relevant Commission rules. The matrix also specifies why confidential protection is justified. Further, the data and information: (1) is not already public; and (2) cannot be aggregated, redacted, summarized or otherwise protected in a

way that allows partial disclosure. By this reference, I am incorporating into this declaration all of the explanatory text that is pertinent to my testimony in the attached matrix.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct. Executed on June 25, 2020 at Berkeley, California.

/s/
ALEXANDER ALLAN

PACIFIC GAS AND ELECTRIC COMPANY
2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION (A.20-07-00X)

DECLARATION OF REES BLANCHARD SEEKING CONFIDENTIAL TREATMENT FOR CERTAIN DATA AND INFORMATION CONTAINED IN TESTIMONY CHAPTER 2

I, Rees Blanchard, declare:

1. I am an Analyst in the Portfolio and Resource Forecasting Department within the Energy Policy and Procurement organization at Pacific Gas and Electric Company (PG&E). In this position, my responsibilities include producing the long-term departing load forecast, working with the Community Choice Aggregators (CCAs) to improve forecast alignment, and supporting analyses and regulatory proceedings. In carrying out these responsibilities, I have acquired knowledge of the Direct Access and Community Choice Aggregation policies and trends, which inform the forecasts recorded to the ERRA. This declaration is based on my personal knowledge of PG&E's practices and my understanding of the Commission's decisions protecting the confidentiality of market-sensitive information.

2. Based on my knowledge and experience, and in accordance with the Decisions 06-06-066, D.08-04-023, D.14-10-033, and relevant Commission rules, I make this declaration seeking confidential treatment for certain data and information contained in Chapter 2 of the Prepared Testimony in support of PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation Application.

3. Attached to this declaration is a matrix identifying the data and information for which PG&E is seeking confidential treatment. The matrix specifies that the material PG&E is seeking to protect constitutes confidential market sensitive data and information covered by D.06-06-066, D.08-04-023, D.14-10-033, and/or relevant Commission rules. The matrix also specifies why confidential protection is justified. Further, the data and information: (1) is not

already public; and (2) cannot be aggregated, redacted, summarized or otherwise protected in a way that allows partial disclosure. By this reference, I am incorporating into this declaration all of the explanatory text that is pertinent to my testimony in the attached matrix.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct. Executed on June 30, 2020 at Oakland, California.

/s/

REES BLANCHARD

PACIFIC GAS AND ELECTRIC COMPANY
2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION (A.20-07-00X)

DECLARATION OF GEORGE CLAVIER SEEKING CONFIDENTIAL TREATMENT FOR CERTAIN DATA AND INFORMATION CONTAINED IN TESTIMONY CHAPTERS 3, 6, 7, 11, 12, AND 15

I, George Clavier, declare:

1. I am a Principal in the Portfolio and Resource Forecasting Department within the Energy Policy and Procurement organization at Pacific Gas and Electric Company (PG&E). In this position, my responsibilities include working on various energy procurement forecasts and related analysis to support PG&E in regulatory proceedings and other business processes. In carrying out these responsibilities, I have acquired knowledge of the generation-related transactions types purchased for PG&E's electric portfolio and am familiar with the generation costs and quantities that are included in the various energy procurement cost forecasts and non-bypassable charge forecasts, applicable to non-exempt departing load. This declaration is based on my personal knowledge of PG&E's practices and my understanding of the Commission's decisions protecting the confidentiality of market-sensitive information.

2. Based on my knowledge and experience, and in accordance with Decisions 06-06-066, D.08-04-023, D.14-10-033, and relevant Commission rules, I make this declaration seeking confidential treatment for certain data and information contained in Chapters 3, 6, 7, 11, 12, and 15 of the Prepared Testimony in support of PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation Application.

3. Attached to this declaration is a matrix identifying the data and information for which PG&E is seeking confidential treatment. The matrix specifies that the material PG&E is seeking to protect constitutes confidential market sensitive data and information covered by D.06-06-066, D.08-04-023, D.14-10-033, and/or relevant Commission rules. The matrix also

specifies why confidential protection is justified. Further, the data and information: (1) are not already public; and (2) cannot be aggregated, redacted, summarized or otherwise protected in a way that allows partial disclosure. By this reference, I am incorporating into this declaration all of the explanatory text that is pertinent to my testimony in the attached matrix.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct. Executed on June 30, 2020 at Richmond, California.

/s/
GEORGE CLAVIER

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

DECLARATION SUPPORTING CONFIDENTIAL DESIGNATION
ON BEHALF OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

1. I, _Kurt Hansen_ am the _Director of Portfolio & Resource Forecasting__ of Pacific Gas and Electric Company ("PG&E"), a California corporation. __Fong Wan__ the Senior Vice President of Energy Policy and Procurement__ of PG&E, delegated authority to me to sign this declaration. My business office is located at:

   Pacific Gas and Electric Company
   77 Beale Street
   San Francisco, CA 94105

2. PG&E will produce the information identified in paragraph 3 of this Declaration to the California Public Utilities Commission ("CPUC") or departments within or contractors retained by the CPUC in response to a CPUC audit, data request, proceeding, or other CPUC request.

   Name or Docket No. of CPUC Proceeding (if applicable): PG&E's 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas (GHG) Forecast Revenue Return and Reconciliation Application

3. Title and description of document(s): PG&E's 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas (GHG) Forecast Revenue Return and Reconciliation Application Testimony Chapter 2 and associated Chapter 2 workpapers pertaining to the forecasted adoption, energy sales, and peak demand impact of load modifying technologies including behind the meter distributed

generation, conservation and energy efficiency, electric vehicles, electrification, and battery energy storage.

4. These documents contain confidential information that, based on my information and belief, has not been publicly disclosed. These documents have been marked as confidential, and the basis for confidential treatment and where the confidential information is located on the documents are identified on the following chart, with further detail provided in the two (2) Confidentiality Matrices supporting PG&E's Prepared Testimony and Workpapers, which is incorporated into this declaration:

Check	Basis for Confidential Treatment	Where Confidential Information is located on the documents
☐	Customer-specific data, which may include demand, loads, names, addresses, and billing data (Protected under PUC § 8380; Civ. Code §§ 1798 *et seq.*; Govt. Code § 6254; Public Util. Code § 8380; Decisions (D.) 14-05-016, 04-08-055, 06-12-029)	
☐	Personal information that identifies or describes an individual (including employees), which may include home address or phone number; SSN, driver's license, or passport numbers; education; financial matters; medical or employment history (not including PG&E job titles); and statements attributed to the individual (Protected under Civ. Code §§ 1798 *et seq.;* Govt. Code § 6254; 42 U.S.C. § 1320d-6; and General Order (G.O.) 77-M)	
☐	Physical facility, cyber-security sensitive, or critical energy infrastructure data, including without limitation critical energy infrastructure information (CEII) as defined by the	

	regulations of the Federal Energy Regulatory Commission at 18 C.F.R. § 388.113 (Protected under Govt. Code § 6254(k), (ab); 6 U.S.C. § 131; 6 CFR § 29.2)	
■	Proprietary and trade secret information or other intellectual property and protected market sensitive/competitive data (Protected under Civ. Code §§3426 *et seq.*; Govt. Code §§ 6254, *et seq*., e.g., 6254(e), 6254(k), 6254.15; Govt. Code § 6276.44; Evid. Code §1060; D.11-01-036)	See Two (2) Confidentiality Matrices supporting PG&E's Prepared Testimony and PG&E's workpapers for detailed locations of protected information
☐	Corporate financial records (Protected under Govt. Code §§ 6254(k), 6254.15)	

☐	Third-Party information subject to non-disclosure or confidentiality agreements or obligations (Protected under Govt. Code § 6254(k); see, e.g., CPUC D.11-01-036)		
☐	Other categories where disclosure would be against the public interest (Govt. Code § 6255(a))): _____ _____ _____		

5. The importance of maintaining the confidentiality of this information outweighs any public interest in disclosure of this information. This information should be exempt from the public disclosure requirements under the Public Records Act and should be withheld from disclosure.
6. I declare under penalty of perjury that the foregoing is true, correct, and complete to the best of my knowledge.
7. Executed on this _1st_ day of __July__, 2020 at _San Francisco_ [city], California.

/ S /
Kurt Hansen
Director, Portfolio & Resource Forecasting
Pacific Gas and Electric Company

PACIFIC GAS AND ELECTRIC COMPANY
2020 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION (A.19-06-00X)

DECLARATION OF ANDREW KLINGLER SEEKING CONFIDENTIAL TREATMENT FOR CERTAIN DATA AND INFORMATION CONTAINED IN TESTIMONY CHAPTER 2

I, Andrew Klingler, declare:

1. I am a Senior Manager in the Rates Department within the Regulatory and External Affairs organization at Pacific Gas and Electric Company (PG&E). In this position, my responsibilities include the development of PG&E's energy sales and peak demand forecasts. In carrying out these responsibilities, I have acquired knowledge of the various policy, economic, demographic, environmental, and technology trends which impact energy sales and peak demand. This declaration is based on my personal knowledge of PG&E's practices and my understanding of the Commission's decisions protecting the confidentiality of market-sensitive information.

2. Based on my knowledge and experience, and in accordance with the Decisions 06-06-066, D.08-04-023, D.14-10-033, and relevant Commission rules, I make this declaration seeking confidential treatment for certain data and information contained in Chapter 2 of the Prepared Testimony in support of PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation Application.

3. Attached to this declaration is a matrix identifying the data and information for which PG&E is seeking confidential treatment. The matrix specifies that the material PG&E is seeking to protect constitutes confidential market sensitive data and information covered by D.06-06-066, D.08-04-023, D.14-10-033, and/or relevant Commission rules. The matrix also specifies why confidential protection is justified. Further, the data and information: (1) is not already public; and (2) cannot be aggregated, redacted, summarized or otherwise protected in a

way that allows partial disclosure. By this reference, I am incorporating into this declaration all of the explanatory text that is pertinent to my testimony in the attached matrix.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct. Executed on June 30, 2020 at Lafayette, California.

/s/
ANDREW KLINGLER

PACIFIC GAS AND ELECTRIC COMPANY
2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION (A.20-07-00X)

DECLARATION OF MICHAEL KOWALEWSKI SEEKING CONFIDENTIAL TREATMENT FOR CERTAIN DATA AND INFORMATION CONTAINED IN CHAPTER 7 TESTIMONY

I, Michael Kowalewski, declare:

1. I am a Portfolio Manager in the Energy Policy and Procurement organization at Pacific Gas and Electric Company (PG&E). In this position, my responsibilities include managing the financial position of PG&E's electric portfolio, including planning and trading related financial products for PG&E's electric portfolio. This declaration is based on my personal knowledge of PG&E's practices and my understanding of the Commission's decisions protecting the confidentiality of market-sensitive information.

2. Based on my knowledge and experience, and in accordance with the Decisions 06-06-066, D.08-04-023, D.14-10-033, and relevant Commission rules, I make this declaration seeking confidential treatment for certain data and information contained in Chapter 7 ("Hedging, Collateral, CAISO, and Other Costs") of the Prepared Testimony in support of PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation Application.

3. Attached to this declaration is a matrix identifying the data and information for which PG&E is seeking confidential treatment. The matrix specifies that the material PG&E is seeking to protect constitutes confidential market sensitive data and information covered by D.06-06-066, D.08-04-023, D.14-10-033, and/or relevant Commission rules. The matrix also specifies why confidential protection is justified. Further, the data and information: (1) is not already public; and (2) cannot be aggregated, redacted, summarized or otherwise protected in a way that allows partial disclosure. By this reference, I am incorporating into this declaration all of the explanatory text that is pertinent to my testimony in the attached matrix.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct. Executed on June 30, 2020 at San Francisco, California.

/s/
MICHAEL KOWALEWSKI

PACIFIC GAS AND ELECTRIC COMPANY
2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION (A.20-07-00X)

DECLARATION OF MARK MAYER
SEEKING CONFIDENTIAL TREATMENT FOR CERTAIN DATA AND INFORMATION CONTAINED IN TESTIMONY CHAPTER 4

I, Mark Mayer, declare:

1. I am presently employed by Pacific Gas and Electric Company (PG&E) and have been an employee for over 31 years. My current title is Manager, Nuclear Fuels Purchasing for Diablo Canyon Power Plant (DCPP). In this position, my responsibilities include purchasing and managing nuclear fuel contracts associated with the fabrication of nuclear fuel and the purchase of feed materials (uranium, conversion, and enrichment services). This declaration is based on my personal knowledge of PG&E's practices and my understanding of the Commission's decisions protecting the confidentiality of market-sensitive information.

2. Based on my knowledge and experience, and in accordance with the Decisions 06-06-066, D.08-04-023, D.14-10-033, and relevant Commission rules, I make this declaration seeking confidential treatment for certain data and information contained in Chapter 4 ("Fuel Costs for Utility-Owned Generation Assets") of the Prepared Testimony in support of PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation Application.

3. Attached to this declaration is a matrix identifying the data and information for which PG&E is seeking confidential treatment. The matrix specifies that the material PG&E is seeking to protect constitutes confidential market sensitive data and information covered by D.06-06-066, D.08-04-023, D.14-10-033, and/or relevant Commission rules. The matrix also specifies why confidential protection is justified. Further, the data and information: (1) is not already public; and (2) cannot be aggregated, redacted, summarized or otherwise protected in a

way that allows partial disclosure. By this reference, I am incorporating into this declaration all of the explanatory text that is pertinent to my testimony in the attached matrix.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct. Executed on June 30, 2020 at Avila Beach, California.

/s/

MARK MAYER

PACIFIC GAS AND ELECTRIC COMPANY
2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION (A.20-07-00X)

DECLARATION OF RUTH E. OSCAR
SEEKING CONFIDENTIAL TREATMENT FOR CERTAIN DATA AND INFORMATION CONTAINED IN CHAPTERS 4, 5, 8 AND 10 TESTIMONY

I, Ruth E. Oscar, declare:

1. I am an Expert Analyst in the Portfolio and Resource Forecasting Department within the Energy Policy and Procurement organization at Pacific Gas and Electric Company (PG&E). In this position, my responsibilities include forecasting Qualifying Facility energy, capacity, pricing and revenue requirements for various regulatory filings, as well as for PG&E's wholesale procurement activities. This declaration is based on my personal knowledge of PG&E's practices and my understanding of the Commission's decisions protecting the confidentiality of market-sensitive information.

2. Based on my knowledge and experience, and in accordance with the Decisions 06-06-066, D.08-04-023, D.14-10-033, and relevant Commission rules, I make this declaration seeking confidential treatment for certain data and information contained in Chapter 4 ("Fuel Costs for Utility-Owned Generation Assets"), Chapter 5 ("Qualifying Facility and Other Legacy Purchased Power Agreement Costs"), Chapter 8 ("Cost Allocation Mechanism"), and Chapter 10 ("Modified Cost Allocation Mechanism") of the Prepared Testimony in support of PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation Application.

3. Attached to this declaration is a matrix identifying the data and information for which PG&E is seeking confidential treatment. The matrix specifies that the material PG&E is seeking to protect constitutes confidential market sensitive data and information covered by D.06-06-066, D.08-04-023, D.14-10-033, and/or relevant Commission rules. The matrix also specifies why confidential protection is justified. Further, the data and information: (1) are not

already public; and (2) cannot be aggregated, redacted, summarized or otherwise protected in a way that allows partial disclosure. By this reference, I am incorporating into this declaration all of the explanatory text that is pertinent to my testimony in the attached matrix.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct. Executed on June 29, 2020 at El Cerrito, California.

/s/

RUTH E. OSCAR

PACIFIC GAS AND ELECTRIC COMPANY
2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION (A.20-07-00X)

DECLARATION OF WILLIAM REINWALD SEEKING CONFIDENTIAL TREATMENT FOR CERTAIN DATA AND INFORMATION CONTAINED IN CHAPTER 15 TESTIMONY

I, William Reinwald, declare:

1. I am a Principal Analyst in the Risk, Compliance, and Reporting Department within the Strategy and Policy organization at Pacific Gas and Electric Company (PG&E). In this position, my responsibilities include preparing, validating, and submitting energy procurement reports to state and federal regulatory agencies. This declaration is based on my personal knowledge of PG&E's practices and my understanding of the Commission's decisions protecting the confidentiality of market-sensitive information.

2. Based on my knowledge and experience, and in accordance with the Decisions 06-06-066, D.08-04-023, D.14-10-033, and relevant Commission rules, I make this declaration seeking confidential treatment for certain data and information contained in Chapter 15 ("Greenhouse Gas Forecast Revenue And Reconciliation – Cost Calculations") of the Prepared Testimony in support of PG&E's 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation Application.

3. Attached to this declaration is a matrix identifying the data and information for which PG&E is seeking confidential treatment. The matrix specifies that the material PG&E is seeking to protect constitutes confidential market sensitive data and information covered by D.06-06-066, D.08-04-023, D.14-10-033, and/or relevant Commission rules. The matrix also specifies why confidential protection is justified. Further, the data and information: (1) is not already public; and (2) cannot be aggregated, redacted, summarized or otherwise protected in a

way that allows partial disclosure. By this reference, I am incorporating into this declaration all of the explanatory text that is pertinent to my testimony in the attached matrix.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct. Executed on June 29, 2020 at San Francisco, California.

/s/
WILLIAM REINWALD

PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION (A.20-07-XXX)
PREPARED TESTIMONY SERVED ON JULY 1, 2020

IDENTIFICATION OF CONFIDENTIAL INFORMATION

Redaction Reference	Category from D.06-06-066, Appendix 1, or Separate Confidentiality Order That Data Corresponds To	Justification for Confidential Treatment	Length of Time Data To Be Kept Confidential
Document: Chapter 2			
TABLE 2-1	Proprietary and trade secret information or other intellectual property and protected market sensitive/competitive data (Protected under Civ. Code §§3426 *et seq.*; Govt. Code §§ 6254, *et seq.*, e.g., 6254(e), 6254(k), 6254.15; Govt. Code § 6276.44; Evid. Code §1060; D.11-01-036).	Proprietary information is owned by Moody's Analytics and, therefore, is a protected trade secret under California law.	Indefinite
TABLE 2-3, Lines 14 through 26	V.G – IOU Planning Area Total Load Forecast (MWh)	Forecasts of confidential monthly energy forecast of service area, including DA/CCA load.	Front three years
TABLE 2-3, Lines 2, 10, 28, 29, 32, 40, 43, 45, 46	V.B – Bundled Customer Peak Load Forecast (MW) V.C.- Bundled Customer Total Energy Forecast (MWh) V.D – Service Area Peak Load Forecast (MW)	Table 2-3 includes confidential information on PG&E's monthly service area and bundled energy and peak load forecasts.	Front three years.

PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION (A.20-07-XXX)
PREPARED TESTIMONY SERVED ON JULY 1, 2020

IDENTIFICATION OF CONFIDENTIAL INFORMATION

Redaction Reference	Category from D.06-06-066, Appendix 1, or Separate Confidentiality Order That Data Corresponds To	Justification for Confidential Treatment	Length of Time Data To Be Kept Confidential
	V.E – Service Area Total Energy Forecast (MWh)		
TABLE 2-3 Lines 3, 5, 6, 7, 8, 9, 33, 35, 36, 37, 38, 39	Proprietary and trade secret information or other intellectual property and protected market sensitive/competitive data including forecasts of conservation and energy efficiency, distributed generation, electric vehicles, electrification and behind the meter battery energy storage (Protected under Civ. Code §§3426 *et seq.*; Govt. Code §§ 6254, *et seq*., e.g., 6254(e), 6254(k), 6254.15; Govt. Code § 6276.44; Evid. Code §1060; D.11-01-036).	Table 2-3 includes confidential, trade secret information. Specifically, PG&E redacts those components associated with proprietary internal forecast of load constituents.	Indefinite

PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION (A.20-07-XXX)
PREPARED TESTIMONY SERVED ON JULY 1, 2020

IDENTIFICATION OF CONFIDENTIAL INFORMATION

Redaction Reference	Category from D.06-06-066, Appendix 1, or Separate Confidentiality Order That Data Corresponds To	Justification for Confidential Treatment	Length of Time Data To Be Kept Confidential
Document: Chapter 3			
TABLES 3-1 and 3-2	IV.A – Production Forecast of Utility-Owned Generation (MW and MWh)	Confidential forecast of capacity rating and/or expected output of utility-owned generation resources. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three years
	IV.B – Production Forecast of QF facilities	Confidential forecast of capacity rating and/or expected output of QF resources. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three years
	IV.C – Production Forecast of Utility-Owned Hydro Greater than 30 MW	Confidential forecast of capacity rating and/or expected output of utility-owned hydroelectric generation resources greater than 30 MW.	Three years
	IV.E – Production Forecast of Pre-1/1/2003 contracts	Confidential forecast of capacity rating and/or expected output for individual contracts. Aggregated annual capacity and energy data from all pre-1/1/2003 contracts public.	Three years or one year following expiration of contract
	IV.F – Production Forecast of Post-1/1/2003 contracts	Confidential forecast of capacity rating and/or expected output for individual contracts. Aggregated annual capacity and energy data from all post-1/1/2003 contracts public.	Three years or one year following expiration of contract
	V.B – Bundled Customer Peak Load Forecast (MW)	Confidential forecast of bundled customer peak load.	Front three years
	V.C – Bundled Customer Total Energy Forecast (MWh)	Confidential forecast of bundled customer total energy requirements.	Front three years
	V.E – Service Area Total Energy Forecast (MWh)	Confidential forecast of service area total energy requirements.	Front three years
	V.H – Net capacity and energy forecasts for bundled customers	Confidential forecast of bundled customer net capacity and energy.	Front three years

PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION (A.20-07-XXX)
PREPARED TESTIMONY SERVED ON JULY 1, 2020

IDENTIFICATION OF CONFIDENTIAL INFORMATION

Redaction Reference	Category from D.06-06-066, Appendix 1, or Separate Confidentiality Order That Data Corresponds To	Justification for Confidential Treatment	Length of Time Data To Be Kept Confidential
	VI.A – Bundled Customer Net Open Capacity (MW)	Confidential forecast of bundled customer net open position (capacity).	Front three years
	VI.B – Bundled Customer Net Open Energy (MWh)	Confidential forecast of bundled customer net open position (energy).	Front three years
TABLE 3-3	I.A.2 – Gas Price Forecast (Utility)	Utility forecast of gas prices – front three years of the forecast are confidential.	Front three years
	I.A.3 – Gas Demand Forecast (Utility)	Utility forecast of gas demand for utility purchases -- front three years of the forecast are confidential.	Front three years
	I.A.4 – Hedging Plan (PG&E)	Information regarding PG&E's confidential Hedging Plan.	3 years past expiration of the last trade executed under the hedging plan
	II.B.1 – Generation Cost Forecast (Utility-Owned Generation)	Confidential generation cost forecast for utility-owned generation. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three Years
	II.B.3 – Generation Cost Forecast (QFs)	Confidential generation cost forecast for QF generation. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three Years
	II.B.4 – Generation Cost Forecast (Non-QF Bilaterals)	Confidential generation cost forecast for Non-QF generation. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three Years
	D.14-10-033, Attachment A	Information concerning GHG compliance instrument procurement strategy and/or activities. The release of this commercially sensitive information could cause harm to PG&E's customers and put PG&E at an unfair business advantage by the disclosure of a GHG procurement strategy. This information could be used by other market participants to gain a commercial advantage. In addition, this information may reveal whether or not PG&E participated in California Air Resources Board ("ARB") auctions and PG&E's net open position for GHG compliance.	Indefinite

PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION (A.20-07-XXX)
PREPARED TESTIMONY SERVED ON JULY 1, 2020

IDENTIFICATION OF CONFIDENTIAL INFORMATION

Redaction Reference	Category from D.06-06-066, Appendix 1, or Separate Confidentiality Order That Data Corresponds To	Justification for Confidential Treatment	Length of Time Data To Be Kept Confidential
TABLE 3-4	I.A.2 – Gas Price Forecast (Utility)	Utility forecast of gas prices – front three years of the forecast are confidential.	Front three years
	II.A.2 – Electric Price Forecast (Utility)	Utility forecast of electric prices.	Three years
Document: Chapter 4			
TABLES 4-1, 4-2, and 4-3	I.A.2 – Gas Price Forecast (Utility)	Utility forecast of gas prices – front three years of the forecast are confidential.	Front three years
	I.A.3 – Gas Demand Forecast (Utility)	Utility forecast of gas demand for utility purchases -- front three years of the forecast are confidential.	Front three years
	I.A.4 – Long-term Fuel Buying (PG&E)	Information regarding confidential fuel buying plan for PG&E-owned or contracted resources.	Three years
	II.B.1 – Generation Cost Forecast (Utility-Owned Generation)	Confidential generation cost forecast for utility-owned generation. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three Years
	Item XI	Information concerning nuclear fuel procurement strategy, transactions, and/or costs. Release of this market sensitive information could put PG&E at a competitive disadvantage with regard to other market participants and could detrimentally impact PG&E customers.	Three Years
Document: Chapter 5			
TABLE 5-1	II.B.3 – Generation Cost Forecast (QFs)	Confidential generation cost forecast for QF generation. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three Years
	II.B.4 – Generation Cost Forecast (Non-QF Bilaterals)	Confidential generation cost forecast for Non-QF generation. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three Years

PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION (A.20-07-XXX)
PREPARED TESTIMONY SERVED ON JULY 1, 2020

IDENTIFICATION OF CONFIDENTIAL INFORMATION

Redaction Reference	Category from D.06-06-066, Appendix 1, or Separate Confidentiality Order That Data Corresponds To	Justification for Confidential Treatment	Length of Time Data To Be Kept Confidential
	IV.B – Production Forecast of QF facilities	Confidential forecast of capacity rating and/or expected output of QF resources. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three years
	IV.E – Production Forecast of Pre-1/1/2003 contracts	Confidential forecast of capacity rating and/or expected output for individual contracts. Aggregated annual capacity and energy data from all pre-1/1/2003 contracts public.	Three years or one year following expiration of contract
	IV.F – Production Forecast of Post-1/1/2003 contracts	Confidential forecast of capacity rating and/or expected output for individual contracts. Aggregated annual capacity and energy data from all post-1/1/2003 contracts public.	Three years or one year following expiration of contract
Document: Chapter 6			
TABLE 6-1	II.B.4 – Generation Cost Forecast (Non-QF Bilaterals)	Confidential generation cost forecast for QF generation. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three Years
	VI.A – Bundled Customer Net Open Capacity (MW)	Confidential forecast of bundled customer net open position (capacity).	Front three years
	VI.B – Bundled Customer Net Open Energy (MWh)	Confidential forecast of bundled customer net open position (energy).	Front three years
Document: Chapter 7			
PAGE 7-3, 7-4 and TABLE 7-1	I.A.4 – Hedging Plan, D.11-01-037, Resolution E-4276, p. 5-6 and Finding 8.	The redacted testimony identifies transactions conducted under PG&E's hedging Plan reveal hedging strategy and is market sensitive information with regard to hedging transactions.	3 years past expiration of the last trade executed under the hedging plan

PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION (A.20-07-XXX)
PREPARED TESTIMONY SERVED ON JULY 1, 2020

IDENTIFICATION OF CONFIDENTIAL INFORMATION

Redaction Reference	Category from D.06-06-066, Appendix 1, or Separate Confidentiality Order That Data Corresponds To	Justification for Confidential Treatment	Length of Time Data To Be Kept Confidential
TABLE 7-3	II.B.1 – Generation Cost Forecast (Utility-Owned Generation)	Confidential generation cost forecast for utility-owned generation. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three Years
	II.B.3 – Generation Cost Forecast (QFs)	Confidential generation cost forecast for QF generation. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three Years
	II.B.4 – Generation Cost Forecast (Non-QF Bilaterals)	Confidential generation cost forecast for Non-QF generation. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three Years
	V.B – Total Peak Load Forecast Bundled Customer (MW)	Each LSE's own forecast of its bundled customer peak load.	Front three years
	V.C – Total Energy Forecast Bundled Customer (MWh)	Each LSE's own forecast of its bundled customer total energy requirement.	Front three years
Document: Chapter 8			
TABLE 8-1	II.B.3 – Generation Cost Forecast (QFs)	Confidential generation cost forecast for QF generation. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three Years
	II.B.4 – Generation Cost Forecast (Non-QF Bilaterals)	Confidential generation cost forecast for Non-QF generation. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three Years
	II.B.1 – Generation Cost Forecast (Utility-Owned Generation)	Confidential generation cost forecast for utility-owned generation. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three Years

PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION (A.20-07-XXX)
PREPARED TESTIMONY SERVED ON JULY 1, 2020

IDENTIFICATION OF CONFIDENTIAL INFORMATION

Redaction Reference	Category from D.06-06-066, Appendix 1, or Separate Confidentiality Order That Data Corresponds To	Justification for Confidential Treatment	Length of Time Data To Be Kept Confidential
Document: Chapter 10			
Page 10-3 and TABLE 10-1	II.B.4 – Generation Cost Forecast (Non-QF Bilaterals)	Confidential generation cost forecast for Non-QF generation. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three Years
Document: Chapter 11			
TABLE 11-1	II.B.4 – Generation Cost Forecast (Non-QF Bilaterals)	Confidential generation cost forecast for Non-QF generation. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three Years
Document: Chapter 12			
TABLE 12-1	II.B.1 – Generation Cost Forecast (Utility-Owned Generation)	Confidential generation cost forecast for utility-owned generation. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three Years
	II.B.3 – Generation Cost Forecast (QFs)	Confidential generation cost forecast for QF generation. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three Years
	II.B.4 – Generation Cost Forecast (Non-QF Bilaterals)	Confidential generation cost forecast for QF generation. Public by resource category (*e.g.*, hydro, conventional, etc.) after three years.	Three Years
	V.B – Total Peak Load Forecast Bundled Customer (MW)	Each LSE's own forecast of its bundled customer peak load.	Front three years

PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION (A.20-07-XXX)
PREPARED TESTIMONY SERVED ON JULY 1, 2020

IDENTIFICATION OF CONFIDENTIAL INFORMATION

Redaction Reference	Category from D.06-06-066, Appendix 1, or Separate Confidentiality Order That Data Corresponds To	Justification for Confidential Treatment	Length of Time Data To Be Kept Confidential
	V.C – Total Energy Forecast Bundled Customer (MWh)	Each LSE's own forecast of its bundled customer total energy requirement.	Front three years
Document: Chapter 15			
TABLES 15-1, 15-2, and 15-3	D. 14-10-033, Attachment A	Information concerning GHG compliance instrument procurement strategy and/or activities. The release of this commercially sensitive information could cause harm to PG&E's customers and put PG&E at an unfair business advantage by the disclosure of a GHG procurement strategy. This information could be used by other market participants to gain a commercial advantage. In addition, this information may reveal whether or not PG&E participated in ARB auctions and PG&E's net open position for GHG compliance.	Indefinite

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation U 39 E	Application 20-07-002

DECLARATION SUPPORTING TESTIMONY

I, Alexander Allan, declare under penalty of perjury that the statements contained in the foregoing testimony attributed to me are true and correct to the best of my knowledge, information, and belief. If I were called to testify at hearing, I would testify as to the truth and correctness of my portion of the prepared testimony.

Executed on this 23rd day of October, 2020.

Executed at San Francisco, California.

By: */s/ Alexander Allan*
ALEXANDER ALLAN

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation U 39 E	Application 20-07-002

DECLARATION SUPPORTING TESTIMONY

I, Donna Barry, declare under penalty of perjury that the statements contained in the foregoing testimony attributed to me are true and correct to the best of my knowledge, information, and belief. If I were called to testify at hearing, I would testify as to the truth and correctness of my portion of the prepared testimony.

Executed on this 23rd day of October, 2020.

Executed at San Francisco, California.

By: */s/ Donna Barry*
DONNA BARRY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation U 39 E	Application 20-07-002

DECLARATION SUPPORTING TESTIMONY

I, Rees Blanchard, declare under penalty of perjury that the statements contained in the foregoing testimony attributed to me are true and correct to the best of my knowledge, information, and belief. If I were called to testify at hearing, I would testify as to the truth and correctness of my portion of the prepared testimony.

Executed on this 23rd day of October, 2020.

Executed at San Francisco, California.

By: */s/ Rees Blanchard*
REES BLANCHARD

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation U 39 E	Application 20-07-002

DECLARATION SUPPORTING TESTIMONY

I, George Clavier, declare under penalty of perjury that the statements contained in the foregoing testimony attributed to me are true and correct to the best of my knowledge, information, and belief. If I were called to testify at hearing, I would testify as to the truth and correctness of my portion of the prepared testimony.

Executed on this 23rd day of October, 2020.

Executed at San Francisco, California.

By: */s/ George Clavier*
GEORGE CLAVIER

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation U 39 E	Application 20-07-002

DECLARATION SUPPORTING TESTIMONY

I, Thomas Jarman, declare under penalty of perjury that the statements contained in the foregoing testimony attributed to me are true and correct to the best of my knowledge, information, and belief. If I were called to testify at hearing, I would testify as to the truth and correctness of my portion of the prepared testimony.

Executed on this 23rd day of October, 2020.

Executed at San Francisco, California.

By: */s/ Thomas A. Jarman*
THOMAS A. JARMAN

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation U 39 E	Application 20-07-002

DECLARATION SUPPORTING TESTIMONY

I, Andrew Klingler, declare under penalty of perjury that the statements contained in the foregoing testimony attributed to me are true and correct to the best of my knowledge, information, and belief. If I were called to testify at hearing, I would testify as to the truth and correctness of my portion of the prepared testimony.

Executed on this 23rd day of October, 2020.

Executed at San Francisco, California.

By: */s/ Andrew Klingler*
ANDREW KLINGLER

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation U 39 E	Application 20-07-002

DECLARATION SUPPORTING TESTIMONY

I, Benjamin Kolnowski, declare under penalty of perjury that the statements contained in the foregoing testimony attributed to me are true and correct to the best of my knowledge, information, and belief. If I were called to testify at hearing, I would testify as to the truth and correctness of my portion of the prepared testimony.

Executed on this 23rd day of October, 2020.

Executed at San Francisco, California.

By: */s/ Benjamin Kolnowski*
BENJAMIN KOLNOWSKI

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation U 39 E	Application 20-07-002

DECLARATION SUPPORTING TESTIMONY

I, Michael Kowalewski, declare under penalty of perjury that the statements contained in the foregoing testimony attributed to me are true and correct to the best of my knowledge, information, and belief. If I were called to testify at hearing, I would testify as to the truth and correctness of my portion of the prepared testimony.

Executed on this 23rd day of October, 2020.

Executed at San Francisco, California.

By: */s/ Michael Kowalewski*
MICHAEL KOWALEWSKI

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation U 39 E	Application 20-07-002

DECLARATION SUPPORTING TESTIMONY

I, Nicholas Manuel, declare under penalty of perjury that the statements contained in the foregoing testimony attributed to me are true and correct to the best of my knowledge, information, and belief. If I were called to testify at hearing, I would testify as to the truth and correctness of my portion of the prepared testimony.

Executed on this 23rd day of October, 2020.

Executed at San Francisco, California.

By: */s/ Nicholas Manuel*
NICHOLAS MANUEL

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation U 39 E	Application 20-07-002

DECLARATION SUPPORTING TESTIMONY

I, Mark Mayer, declare under penalty of perjury that the statements contained in the foregoing testimony attributed to me are true and correct to the best of my knowledge, information, and belief. If I were called to testify at hearing, I would testify as to the truth and correctness of my portion of the prepared testimony.

Executed on this 23rd day of October, 2020.

Executed at San Francisco, California.

By: */s/ Mark Mayer*
MARK MAYER

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation U 39 E	Application 20-07-002

DECLARATION SUPPORTING TESTIMONY

I, Ruth E. Oscar, declare under penalty of perjury that the statements contained in the foregoing testimony attributed to me are true and correct to the best of my knowledge, information, and belief. If I were called to testify at hearing, I would testify as to the truth and correctness of my portion of the prepared testimony.

Executed on this 22nd day of October, 2020.

Executed at El Cerrito, California.

By: */s/ Ruth E. Oscar*
RUTH E. OSCAR

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation U 39 E	Application 20-07-002

DECLARATION SUPPORTING TESTIMONY

I, Larsen Plano, declare under penalty of perjury that the statements contained in the foregoing testimony attributed to me are true and correct to the best of my knowledge, information, and belief. If I were called to testify at hearing, I would testify as to the truth and correctness of my portion of the prepared testimony.

Executed on this 23rd day of October, 2020.

Executed at San Francisco, California.

By: */s/ Larsen Plano*
LARSEN PLANO

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation U 39 E	Application 20-07-002

DECLARATION SUPPORTING TESTIMONY

I, William Reinwald, declare under penalty of perjury that the statements contained in the foregoing testimony attributed to me are true and correct to the best of my knowledge, information, and belief. If I were called to testify at hearing, I would testify as to the truth and correctness of my portion of the prepared testimony.

Executed on this 23rd day of October, 2020.

Executed at San Francisco, California.

By: */s/ William Reinwald*
WILLIAM REINWALD

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation U 39 E	Application 20-07-002

DECLARATION SUPPORTING TESTIMONY

I, Ryan Stanley, declare under penalty of perjury that the statements contained in the foregoing testimony attributed to me are true and correct to the best of my knowledge, information, and belief. If I were called to testify at hearing, I would testify as to the truth and correctness of my portion of the prepared testimony.

Executed on this 23rd day of October, 2020.

Executed at San Francisco, California.

By: */s/ Ryan Stanley*
RYAN STANLEY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation U 39 E	Application 20-07-002

DECLARATION SUPPORTING TESTIMONY

I, Tysen Streib, declare under penalty of perjury that the statements contained in the foregoing testimony attributed to me are true and correct to the best of my knowledge, information, and belief. If I were called to testify at hearing, I would testify as to the truth and correctness of my portion of the prepared testimony.

Executed on this 23rd day of October, 2020.

Executed at San Francisco, California.

By: */s/ Tysen Streib*
TYSEN STREIB

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation U 39 E	Application 20-07-002

DECLARATION SUPPORTING TESTIMONY

I, Angelia (Lim) Vega, declare under penalty of perjury that the statements contained in the foregoing testimony attributed to me are true and correct to the best of my knowledge, information, and belief. If I were called to testify at hearing, I would testify as to the truth and correctness of my portion of the prepared testimony.

Executed on this 23rd day of October, 2020.

Executed at San Francisco, California.

By: */s/ Angelia (Lim) Vega*
ANGELIA (LIM) VEGA

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation U 39 E	Application 20-07-002

DECLARATION SUPPORTING TESTIMONY

I, Simon Yu, declare under penalty of perjury that the statements contained in the foregoing testimony attributed to me are true and correct to the best of my knowledge, information, and belief. If I were called to testify at hearing, I would testify as to the truth and correctness of my portion of the prepared testimony.

Executed on this 23rd day of October, 2020.

Executed at San Francisco, California.

By: */s/ Simon Yu*
SIMON YU