Application: 26-05-007
(U 39 E)
Exhibit No.:
Date: July 17, 2026
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2027 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION

ERRATA TO PREPARED TESTIMONY

(CLEAN PUBLIC VERSION)

PG&E®

PACIFIC GAS AND ELECTRIC COMPANY
2027 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION
A.26-05-007

CORRECTIONS TO MAY 15, 2026 PREPARED TESTIMONY

DATED July 17, 2026

Line Item	Prepared Testimony Chapter	Page Number	Witness	Description of Errata	As Stated in May 15, 2026 Prepared Testimony	As Corrected in Errata July 17, 2026 Updated Testimony
1	1	1-2	Christina Syriani	Line 8	Power Charge Indifference Adjustment (PCIA) forecast revenue requirement of $835 million	Power Charge Indifference Adjustment (PCIA) forecast revenue requirement of $815 million
2	1	1-2	Christina Syriani	Line 10	ERRA forecast revenue requirement of $2,895 million	ERRA forecast revenue requirement of $2,914 million
3	1	1-3	Christina Syriani	Correct Table 1-1	Delete the entire Table 1-1	Replace with new Table 1-1
4	1	1-17	Christina Syriani	Line 16	PCIA forecast of $835 million	PCIA forecast of $815 million
5	1	1-17	Christina Syriani	Line 17	ERRA forecast revenue requirement of $2,895 million	ERRA forecast revenue requirement of $2,914 million
6	8	8-24	Angelia Vega	Correct Table 8–6, Line 2, PCIA	656,676	636,852
7	8	8-24	Angelia Vega	Correct Table 8–6, Line 3, Total	$645,916	$626,092
8	8	8-25	Angelia Vega	Correct Table 8-7	Delete the entire Table 8-7	Replace with the new Table 8-7
9	8	8-26 and 8-27	Angelia Vega	Correct Table 8-9	Delete the entire Table 8-9	Replace with the new Table 8-9

PACIFIC GAS AND ELECTRIC COMPANY
2027 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION
A.26-05-007

CORRECTIONS TO MAY 15, 2026 PREPARED TESTIMONY

DATED July 17, 2026

Line Item	Prepared Testimony Chapter	Page Number	Witness	Description of Errata	As Stated in May 15, 2026 Prepared Testimony	As Corrected in Errata July 17, 2026 Updated Testimony
10	11	11-3	Angelia Vega	Correct Table 11-1	Delete the entire Table 11-1	Replace with the new Table 11-1
11	12	12-6	Angelia Vega	Correct Table 12-1	Delete the entire Table 12-1	Replace with the new Table 12-1
12	12	12-7	Angelia Vega	Correct the forecast year-end PABA undercollected balance in Line 9	through 29, which total to a $351 million undercollection.	through 29, which total to a $364 million undercollection.
13	12	12-7	Angelia Vega	Correct ERRA Balance Transfer to PABA in Line 12 and reference to details of the balance transfers in Line 14.	The balance transfers to PABA reflected in Line 30 is $175 million. Details of these balance transfers are discussed in Section H.	The balance transfer to PABA reflected in Line 30 is $188 million. Details of the balance transfer is discussed in Section G.
14	12	12-8	Angelia Vega	Correct Table 12-2	Delete the entire Table 12-2	Replace with the new Table 12-2
15	12	12-14	Angelia Vega	Correct the forecast year-end PABA undercollected balance in Line 1	$351 million	$364 million
16	12	12-14	Angelia Vega	Correct Table 12-3	Delete the entire Table 12-3	Replace with the new Table 12-3

PACIFIC GAS AND ELECTRIC COMPANY
2027 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION
A.26-05-007

CORRECTIONS TO MAY 15, 2026 PREPARED TESTIMONY

DATED July 17, 2026

Line Item	Prepared Testimony Chapter	Page Number	Witness	Description of Errata	As Stated in May 15, 2026 Prepared Testimony	As Corrected in Errata July 17, 2026 Updated Testimony
17	12	12-16	Angelia Vega	Correct the “Retained RPS Value” driver for the PABA undercollected balance as stated in Lines 4 through 6	4. Higher Retained RPS Value. Retained RPS value increased by approximately $5 million primarily due to slightly lower RPS sales volumes	4. Lower Retained RPS Value. Retained RPS value decreased by approximately $30 million primarily due to lower RPS generation, partially offset by slightly lower RPS sales volumes.
18	12	12-16	Angelia Vega	Correct the “Retained RA value increase” amount in Line 8	$85 million	$100 million
19	12	12-16	Angelia Vega	Correct the forecast year-end ERRA overcollected balance in Line 21	$177 million	$190 million
20	12	12-17	Angelia Vega	Correct Table 12-4	Delete the entire Table 12-4	Replace with the new Table 12-4

PACIFIC GAS AND ELECTRIC COMPANY
2027 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION
A.26-05-007

CORRECTIONS TO MAY 15, 2026 PREPARED TESTIMONY

DATED July 17, 2026

Line Item	Prepared Testimony Chapter	Page Number	Witness	Description of Errata	As Stated in May 15, 2026 Prepared Testimony	As Corrected in Errata July 17, 2026 Updated Testimony
21	12	12-18	Angelia Vega	Correct the “Retained RPS Value” driver for the ERRA overcollected balance as stated in Lines 18 through 20 and reference to the corresponding drivers reflected in the PABA balance in Line 21.	ERRA’s Retained RPS value is approximately $5 million higher than forecast and the Retained RA value is approximately $75 million higher than forecast. This is primarily due to the corresponding drivers for Retained RPS and Retained RA discussed for the PABA overcollection in Section F above.	ERRA’s Retained RPS value is approximately $30 million lower than forecast and the Retained RA value is approximately $95 million higher than forecast. This is primarily due to the corresponding drivers for Retained RPS and Retained RA discussed for the PABA balance in Section E above.
22	12	12-19	Angelia Vega	Correct the “final ERRA overcollection” amount stated in Line 15 and 16	$175 million	$188 million
23	13	13-3	Angelia Vega	Correct Table 13-1	Delete the entire Table 13-1	Replace with the new Table 13-1
24	13	13-5	Mark Coughlan	Correct the “overcollection of $177 million” amount in Line 2	$177 million	$190 million
25	13	13-5	Mark Coughlan	Correct Table 13-2	Delete the entire Table 13-2	Replace with the new Table 13-2
26	13	13-5	Mark Coughlan	Correct the “decrease of 4.2” in Line 9	decrease of 4.2	decrease of 4.3

PACIFIC GAS AND ELECTRIC COMPANY
2027 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION
NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS
FORECAST REVENUE RETURN AND RECONCILIATION
A.26-05-007

CORRECTIONS TO MAY 15, 2026 PREPARED TESTIMONY

DATED July 17, 2026

Line Item	Prepared Testimony Chapter	Page Number	Witness	Description of Errata	As Stated in May 15, 2026 Prepared Testimony	As Corrected in Errata July 17, 2026 Updated Testimony
27	13	13-6	Mark Coughlan	Correct Table 13-3	Delete the entire Table 13-3	Replace with the new Table 13-3
28	13	13-8	Mark Coughlan	Correct Table 13-4	Delete the entire Table 13-4	Replace with the new Table 13-4
29	13	13-9	Mark Coughlan	Correct Table 13-5	Delete the entire Table 13-5	Replace with the new Table 13-5
30	14	14-9 through 14-21	Akshay Mehmi	Correct Tables 14-3 through 14-15	Delete entire Tables 14-3 through 14-15	Replace with new Tables 14-3 through 14-15

PACIFIC GAS AND ELECTRIC COMPANY
2027 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION
ERRATA TESTIMONY

TABLE OF CONTENTS

Chapter	Title	Witness
1	INTRODUCTION AND POLICY	Christina Syriani
2	SALES AND PEAK DEMAND FORECAST (NO ERRATA)	Andrew Klingler Jorge Meraz Daniel Nelli
3	ELECTRIC GENERATION PORTFOLIO BACKGROUND (NO ERRATA)	George Clavier Christa Hoffman
4	GENERATION SUPPLY PORTFOLIO COSTS AND VOLUMES (NO ERRATA)	George P. Clavier Christa Hoffman Nicholas J. Markevich
5	BUNDLED PORTFOLIO OPEN POSITIONS AND OTHER COSTS (NO ERRATA)	Avery Arjo George P. Clavier Christa Hoffman Nicholas Manuel
6	CENTRAL PROCUREMENT ENTITY PROCUREMENT COST AND REVENUE REQUIREMENT (NO ERRATA)	Mehul Patel
7	COST ALLOCATION MECHANISM (NO ERRATA)	Angelia Vega
8	POWER CHARGE INDIFFERENCE ADJUSTMENT AND ONGOING COMPETITION TRANSITION CHARGE	Christa Hoffman Angelia Vega
9	TREE MORTALITY REVENUE REQUIREMENT (NO ERRATA)	Angelia Vega
10	BIOENERGY MARKET ADJUSTMENT TARIFF REVENUE REQUIREMENT (NO ERRATA)	Angelia Vega
11	ENERGY RESOURCE RECOVERY ACCOUNT	Angelia Vega

PACIFIC GAS AND ELECTRIC COMPANY
2027 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION
NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST
REVENUE RETURN AND RECONCILIATION
ERRATA TESTIMONY

TABLE OF CONTENTS
(CONTINUED)

Chapter	Title	Witness
12	BALANCING ACCOUNTS FORECASTS	Ryan A. Stanley Angelia Vega
13	RATE PROPOSAL	Mark Coughlan Angela Vega
Attachment A	ILLUSTRATIVE TOTAL RATES BY CLASS	Mark Coughlan
14	GREEN TARIFF SHARED RENEWABLES	Akshay Mehmi
15	GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION – COST CALCULATIONS (NO ERRATA)	George P. Clavier Ryan A. Stanley
16	GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION – ADMINISTRATIVE AND OUTREACH EXPENSES (NO ERRATA)	Simon Yu
17	GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION – REVENUE CALCULATIONS (NO ERRATA)	Michelle Patrick Angelia Vega Thomas Yu

PACIFIC GAS AND ELECTRIC COMPANY
2027 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION
ERRATA TESTIMONY

TABLE OF CONTENTS
(CONTINUED)

Chapter	Title	Witness
Appendix A	STATEMENT(S) OF QUALIFICATIONS	Avery Arjo George P. Clavier Mark Coughlan Christa Hoffman Andrew Klingler Nicholas Manuel Nicholas J. Markevich Akshay Mehmi Jorge Meraz Daniel Nelli Mehul Patel Michelle Patrick Ryan A. Stanley Christina Syriani Angelia Vega Simon Yu Thomas Yu

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

INTRODUCTION AND POLICY

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
INTRODUCTION AND POLICY

TABLE OF CONTENTS

A. Introduction 1-1

1. Summary of PG&E's Requests 1-1

2. Considerations and Forecasting Assumptions for This Year's ERRA Forecast Cycle 1-5

a. PG&E's GRC 1-5

b. PG&E's 2024 ERRA Forecast Proceeding and Track 2 Fixed Generation Costs 1-5

c. PG&E's 2025 ERRA Forecast Proceeding, Load Forecast Stipulation 1-6

d. OIR to Update and Reform ERRA and PCIA Policies and Processes (R.25-02-005) 1-7

e. Order Instituting Rulemaking to Update the California Climate Credit R.25-07-013 1-7

3. Testimony Overview 1-8

B. Energy Resource Recovery Account 1-11

1. Annual ERRA Forecast Revenue Requirement Proceeding 1-11

2. ERRA Trigger Mechanism 1-12

C. GHG Revenue Return and Reconciliation 1-14

D. Fall Update 1-15

E. Master Data Request 1-15

F. Amortization of Year-End Balances 1-16

G. Conclusion 1-17

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
INTRODUCTION AND POLICY

A. Introduction

This testimony supports Pacific Gas and Electric Company's (PG&E) 2027 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges (NBC) Forecast and Greenhouse Gas (GHG) Forecast Revenue Return and Reconciliation Application (Application).

1. Summary of PG&E's Requests

In this Application, PG&E is requesting that the California Public Utilities Commission (CPUC or the Commission) adopt PG&E's 2027 ERRA Forecast Application total revenue requirement of approximately $3,176 million, with a revenue requirement for rate-setting purposes of $4,409 million due to the inclusion of $1,233 million of revenue requirement approved in other Commission proceedings.[1] Inclusion of such costs is necessary to adopt a forecast of PG&E's electric procurement costs revenue requirement for rate setting purposes. The final revenue requirement implemented in 2027 rates will be subject to adjustments for recorded year-end balancing account balances and the final decisions of any other proceedings, through the Annual Electric True-Up (AET) process. As described throughout this chapter, the requests presented in this Application and testimony are subject to PG&E's Update to Prepared Testimony (Fall Update), which PG&E has proposed to serve to the Administrative Law Judge (ALJ), Commission staff, and interested parties on October 16,

1 Includes PG&E's 2023 General Rate Case (GRC) base generation revenue requirement with attrition through 2026, as authorized in Decision (D.) 23-11-069, as well as other Utility-Owned Generation (UOG)-related costs authorized in other proceedings.

2026.[2] Additionally, as the need arises, PG&E may also provide supplemental testimony.

PG&E's 2027 ERRA Forecast request is presented here as a preliminary showing, subject to PG&E's Fall Update. PG&E requests approval of the administration/labor costs in the Voluntary Allocation Market Offer Memorandum Account (VAMOMA) of $0.5 million, Power Charge Indifference Adjustment (PCIA) forecast revenue requirement of $815 million, a credit for the Ongoing Competition Transition Charge (CTC) forecast revenue requirement of $20 million, and ERRA forecast revenue requirement of $2,914 million. PG&E also requests approval to credit the Public Purpose Charge Procurement (PPCP) subaccount $0.8 million, to recover approximately $30 million forecast revenue requirement for the Tree Mortality Non-Bypassable Charge (TMNBC), to recover approximately $659 million for Cost Allocation Mechanism (CAM), and to recover $11 million forecast revenue requirement for Bioenergy Market Adjusting Tariff (BioMAT). These forecast revenue requirements are shown in Table 1-1 below.

---

[2] Ordering paragraph (OP) 5 of D.06-12-018 requires PG&E to "[u]se price quotes for natural gas and electricity taken from a single day that is the median price day during the week that is 45 days prior to the ERRA update." The Fall Update will reflect the actual market prices that PG&E incurs to serve its bundled customers this summer as well as an updated forecast of 2027 market prices based on the Commission's order. Market volatility has the potential to swing PG&E's updated revenue requirement and resulting rate request that will be presented in PG&E's Fall Update upward or downward.

TABLE 1-1
SUMMARY OF 2027 FORECAST ENERGY PROCUREMENT REVENUE REQUIREMENTS
(THOUSANDS OF DOLLARS)

Line No.		Revenue Requirement
1	CAM	658,567
2	Ongoing CTC	(19,903)
3	PCIA	815,084
4	VAMOMA	524
5	ERRA	2,914,908
6	PPCP	(796)
7	TMNBC	30,087
8	BioMat	10,800
9	Revenue Requirement for Rate Setting	4,409,270
10	Adjustments from Other Proceedings	
11	UOG-Related Costs	(1,229,145)
12	RUBA-E	(2,186)
13	CCA BioMat	(1,533)
14	Adjustments from Other Proceedings	(1,232,865)
15	**2027 ERRA Application Revenue Requirement Request**	**3,176,405**

PG&E requests that the rate changes associated with Commission disposition of this Application become effective on January 1, 2027, when consolidated with other approved electric rate changes through the AET process. In addition to the 2027 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 D.14-10-033, 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 2027: (1) 2025 recorded administrative and outreach (A&O) expenses of $0.867 million; (2) 2027 forecast A&O expenses of $1.1 million; (3) 2027 GHG allowance revenue return requirement of $530.1 million; (4) GHG A&O expense set-aside of $0.637 million; (5) $5.9 million related to a CEEE program duplicative entry accounting error; and (6) 2027 semi-annual residential and eligible small business California Climate Credit (CCC) amount of $41.74 per household. PG&E also requests $36.4 million in PPP funds for those Clean Energy and Energy Efficiency (CEEE) programs formerly funded in whole or in part by GHG funds. PG&E anticipates updating these forecasts, costs, and funding allocations in its Fall Update.

As a result of the revenue requirements requested for approval in this application, the system average Bundled rate, including the impact of the GHG revenue return, will increase by approximately 5.7 percent to 35.7 cents per kilowatt-hour (kWh) when compared to the present system average Bundled rate of 33.8 cents per kWh, effective March 1, 2026. The system average rate for Direct Access (DA) and Community Choice Aggregation (CCA) customers, whose average rates exclude commodity charges that are provided by third-party service providers, would decrease by approximately 7.3 percent to 21.7 cents per kWh, when compared to the present system average rate for DA and CCA customers of 23.4 cents per kWh, which was effective March 1, 2026.[3]

While PG&E currently estimates an increase in average rates for bundled customers due to the revenue requirements presented in this Application, PG&E's estimates are subject to change during the course of this proceeding due to changes in input prices and decisions by the Commission on proposals included herein. PG&E's Fall Update will reflect the latest market conditions, which may be priced higher or lower than today, and will also reflect the latest balancing account balances. As a result, the initial 2027 rates and rate changes described in this Application may end up higher or lower than presented in the Fall Update.

Finally, PG&E requests that the Commission approve the 2027 retail sales forecast.

[3] Average DA and CCA customer rates presented herein are for PG&E provided services only and exclude commodity charges that are provided by DA and CCA service providers.

2. Considerations and Forecasting Assumptions for This Year's ERRA Forecast Cycle

Stakeholders to this year's Application will be interested in PG&E's forecast assumptions with regard to various Commission decisions, such as the implementation of the PCIA Order Instituting Rulemaking (PCIA OIR) GHG-Free resource decision (D.23-06-006), PG&E's GRC, and other proceedings such as the OIR to Update and Reform ERRA and PCIA Policies and Processes issued as Rulemaking (R.) 25-02-005.

a. PG&E's GRC

As of the date of this Application, PG&E's 2027 GRC proceeding (Application (A.) 25-05-009) is ongoing, and the test year 2027 GRC revenue requirement has not yet been adopted by the CPUC. Accordingly, revenue requirements derived from the Commission's previously approved D.23-11-069 in PG&E's 2023 GRC proceeding, plus attrition, are utilized herein. When a final decision is adopted in PG&E's 2027 GRC, such revenue requirements will be incorporated into PG&E's 2027 ERRA Forecast Fall Update, and/or PG&E's 2027 AET, if available at time of filing, superseding the 2023 GRC revenue requirements used in the calculations for the May presentation of this Application.

b. PG&E's 2024 ERRA Forecast Proceeding and Track 2 Fixed Generation Costs

In its 2024 ERRA Forecast, A.23-05-012, PG&E proposed to change the methodology for allocating Electric Supply Administration and other common costs of its electric generation portfolio (collectively Common Costs). The proposal was deferred by ALJ Long to a second phase of the proceeding (2024 ERRA Forecast Track 2) in a Scoping Memo issued on October 9, 2023.[4] Parties filed testimony and then prehearing conference statements prior to the Commission's January 9, 2024 prehearing conference for the 2024 ERRA Forecast Track 2. The Scoping Memo that followed on April 2, 2024,[5] which was further

---

[4] A.23-05-012 ALJ Ruling, October 9, 2023, Scoping Issue 9a.

[5] A.23-05-012 ALJ Ruling, April 2, 2024.

clarified by ALJ Sisto's email response to a motion for party status,[6] narrowly set the scope for the 2024 ERRA Forecast Track 2 with a singular focus on establishing a definition for "Fixed Generation Costs" that could be applied across all ERRA Forecast proceedings.

The 2024 ERRA Forecast Track 2 was later closed on July 24, 2025, with the Commission's adoption of a formal definition for Fixed Generation Costs in D.25-07-014. In OP 1, D.25-07-014 instructed PG&E, San Diego Gas & Electric Company, and Southern California Edison Company to ensure that all Fixed Generation Costs identified in future ERRA Forecast applications follow the explicit definition of "costs that do not change based on the amount of electricity customers use or the amount of operating time associated with the electricity generation."[7] While PG&E did opine in Rebuttal Testimony[8] on other parties' proposed categories of fixed costs prior to the issuance of the 2024 ERRA Forecast Track 2 Scoping Memo, PG&E has, upon close review of the Decision, concluded that PG&E does not have any fuel and power costs that meet the definition established by D.25-07-014. Chapter 4 of this supporting testimony details PG&E's Capacity Costs and Central Procurement Entity Costs, and Chapter 8 identifies UOG-related costs, but PG&E does not consider these costs as Fixed Generation Costs to meet the Commission's currently adopted definition as each of these identified non-ERRA cost recovery mechanism costs are recovered proportionally from applicable customers based on the current cost recovery assignments and respective load share of the costs.

c. PG&E's 2025 ERRA Forecast Proceeding, Load Forecast Stipulation

During the course of PG&E's 2025 ERRA Forecast proceeding (A.24-05-009), PG&E and the Small Business Utility Advocates entered

---

6 A.23-05-012 et al: E-Mail Ruling granting Alliance Retail Energy Market limited party status dated April 9, 2024.

7 D.25-07-014 Commission Decision Adopting a Definition of Fixed Generation, dated July 24, 2025 and issued on July 31, 2025; COL 1, OP 1.

8 A.23-05-012 PG&E's 2024 ERRA Forecast – Consolidated Track 2 Rebuttal Testimony dated November 22, 2023

into a stipulation agreeing that PG&E would, in future ERRA Forecast Applications, identify in its load forecast workpapers (WPs) whether a post-regression adjustment is applied to any customer class. This showing is demonstrated in the WPs associated with Chapter 2 of this supporting testimony for PG&E's 2027 ERRA Forecast Application.

d. OIR to Update and Reform ERRA and PCIA Policies and Processes (R.25-02-005)

In 2025, the Commission opened a Rulemaking to explore and resolve the immediate and ongoing concerns relating to the ERRA proceedings and the PCIA mechanism. While this does not reopen the PCIA OIR (R.17-06-026), it does seek to update and reform certain policies relating to the PCIA and ERRA in order to mitigate fluctuating market prices. At this time the proceeding has been divided into three separate tracks: the first track has implemented what was meant to be an interim solution for the Resource Adequacy (RA) Market Price Benchmark (MPB) as it relates to the ERRA Forecast proceedings; the second track is still underway and is focused on the valuation of pre-2019 banked Renewable Energy Credits; and the scope for the third track is not yet established. A proposed decision on Track 2 is anticipated later this summer and is expected to affect PG&E's Fall Update.

e. Order Instituting Rulemaking to Update the California Climate Credit R.25-07-013

The Commission initiated R.25-07-013 in July 2025 to consider changes to the CCC pursuant to Assembly Bill (AB) 1207. AB 1207 amended Public Utilities Code (Pub. Util. Code) § 748.5, including eliminating the use of GHG allowance revenue proceeds to fund CEEE programs and requiring that five percent of such revenues be remitted to the State Treasury. This rulemaking addresses both interim and long-term changes to the CCC, the allocation and disposition of GHG allowance revenues, and the remittance of a portion of such revenues to the State Treasury, consistent with statutory direction.

While R.25-07-013 remains open with future decisions expected to be issued, the Commission has already adopted D.26-03-013 and D.26-04-036, both of which have an impact on the 2027 ERRA Forecast cycle. In D.26-03-013, the Commission paused the distribution of the residential electric credit pending further decisions. Just last month, the Commission also adopted D.26-04-036, which directs the distribution of the residential electric credit in August and September 2027. Applicable to this proceeding, D.26-04-036 also specified that IOUs, including PG&E, should include forecasts of their Treasury remittances in their ERRA Forecast Applications.

D.26-04-036 also revised Template D-1, which was originally ordered by OP 1 of D.15-01-024 and subsequently modified by D.21-08-026. PG&E and the other IOUs are required to file a Template D-1 to reflect the "Annual Allowance Revenue Receipts and Customer Returns" in their respective ERRA Forecast proceedings.

Given the timing of the Commission's updated final Decision, PG&E did not have time to prepare an updated Template D-1 reflecting the revisions included D.26-04-036 and the accompanying template. Accordingly, the forecasts, methodologies, and amounts presented in this chapter do not include any adjustment or forecast related to potential Treasury remittance requirements. Although PG&E has not forecasted or included any Treasury remittance amounts in the GHG allowance revenue requirement, Template D-1, or related tables presented in this chapter, PG&E will include in its Fall Update revised GHG allowance revenue forecasts, CCC calculations, reporting treatment, and Treasury remittance amounts to reflect D.26-04-036 and the accompanying template.

3. 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 addresses consistency with PG&E's approved Bundled Procurement Plan (BPP) and provides an overview of the GHG forecast revenue and reconciliation information required by

D.14-10-033 and other Commission orders that are included in this Application.

- Chapter 2: Presents PG&E's sales and peak demand forecasts. It describes components and methodologies of the forecasts, including economic and regulatory variables, as well as demand-side technologies (e.g., DERs). Additionally, this chapter covers how sales are reflected across departing load types, including DA and CCA.
- Chapters 3-5: Detail components of PG&E's portfolio and associated costs prior to presenting specific revenue requirements. This includes PG&E's energy procurement costs associated with the following: (1) fuel expenses associated with PG&E's UOG; (2) pre-2003 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-Invest Program associated with generation resources are reflected in the chapter applicable to the underlying energy procurement costs and summarized in Chapter 11.
- Chapter 6: Presents a forecast of 2027 procurement costs and administrative costs from PG&E functioning as the Central Procurement Entity (CPE). These CPE costs are included in the Cost Allocation Mechanism (CAM) costs presented in Chapter 7.
- Chapters 7-14: Demonstrate how PG&E uses Commission-approved methodologies to calculate the revenue requirements and rates associated with ERRA, generation-related NBCs, and community solar programs. More specifically, Chapter 7 presents costs associated with the CAM. Chapter 8 presents costs associated with Ongoing CTC and PCIA-eligible resources in the CPUC-mandated Common IOU

Template,[9] as well as updated Energy Index MPB weighting factors pursuant to D.23-06-006.

- Chapter 9: Presents costs associated with mandated biomass generation procurement developed in response to California's tree mortality crisis, pursuant to the Governor's emergency proclamation and the Commission's implementation of SB 859 (as codified in Pub. Util. Code Section 399.20.3(f)).
- Chapter 10: Presents the costs for both PG&E and CCA BioMAT contracts, as part of the Public Purpose Program (PPP) rate component.
- Chapter 11: Presents the bundled load cost forecast for the ERRA revenue requirement.
- Chapter 12: Presents recorded balancing account balances from January to March 2026 and a forecast of the balancing account balances for April through December 2026. Chapter 12 also contains PG&E's balancing account transfer proposals as well as a request for authorized recovery of VAMOMA activity.
- Chapter 13: Presents the revenue requirement forecasts for the CAM, VAMOMA, PCIA, Ongoing CTC, Tree Mortality, PPCP, BioMAT, and ERRA capturing the procurement cost forecasts shown throughout PG&E's Testimony. This Chapter then presents PG&E's preliminary proposal for collecting the procurement revenue requirements in rates (including forecasted 2026 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 13. Chapter 13 also includes 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 2027 rates are subject to the AET process, Chapter 13 shows the illustrative effect of the revenue requirements and revenue return proposal presented in this application on rates. The illustrative

---

9 See D.06-07-030 (as modified by D.17-08-026 and affirmed in D.18-10-019); see also, D.21-03-051 (correcting capacity calculation by eliminating line loss adjustment).

rates presented in Chapter 13, and summarized in Attachment A, are calculated utilizing the revenue allocation and rate design methodology used to design current rates effective as of March 1, 2026. Final rates implemented in 2027 will be subject to adjustments for recorded year-end balancing account balances and the final decisions of any other proceedings, through the AET process.

- Chapter 14: Presents PG&E's 2027 rate proposal for bill charges and credits associated with PG&E's Green Tariff Shared Renewables (GTSR) Program, which includes the green tariff electric rate schedule (E-GT) for PG&E's Solar Choice Program. The GTSR Program rate components are detailed in Tables 14-3 through 14-13.
- Chapters 15-17: Address GHG-related matters. Specifically, Chapter 15 presents the reconciliation of various 2025 GHG costs. Chapter 16 presents both the 2027 forecast and 2025 recorded GHG A&O expenses. Chapter 17 presents the forecast GHG allowance revenue return to customers and the proposed forecast CCC amount. The chapter also includes a request to update the A&O set aside to reflect recorded and forecast A&O costs, the customer programs formerly funded through GHG allowance proceeds, and shows the methodology for returning revenue to eligible customers.
- Appendix A: Includes the statements of qualifications for PG&E witnesses sponsoring PG&E's Prepared Testimony.
- Appendix B: Includes the declarations of PG&E witnesses attesting to those portions of their testimony that meet the Commission's confidentiality requirements, in accordance with D.06-06-066, D.08-04-023, D.14-10-033, and D.21-11-029 (amending D.06-06-066). A matrix identifying the data and information for which these witnesses are seeking confidential treatment is also provided.

B. 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' forecast 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 collected from customers.

D.02-10-062, as modified by D.22-01-023, also directed PG&E to file its annual ERRA Forecast Application on May 15 of each year, to allow the Commission to issue a decision by the end of the calendar year and ensure timely cost recovery in rates.[10] 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 Pub. Util. 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. Of note, while this mechanism is intended to ensure that the utility has sufficient funds within a year to cover its generation-related costs and to provide relief for customers in the event that

---

10 See D.02-10-062, pp. 59-64; D.22-01-023, OP 3.

generation costs are meaningfully less than forecast within a year, the mechanism as currently designed only applies to a subset of the generation costs recovered by PG&E.

The Commission implemented this statutory provision by adopting the ERRA "trigger" mechanism in D.02-10-062.[11] Each IOU is required to submit an AL 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.[12] 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.[13] 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 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.[14] PG&E's 2026 ERRA trigger amount—4 percent of the actual recorded generation revenues for the prior calendar year excluding revenues collected for the CDWR—is $166.5 million (4 percent ERRA Trigger). PG&E's 2026 ERRA threshold amount—5 percent of the actual recorded generation revenues for the prior calendar year excluding revenues collected for the CDWR—is $208 million (5 percent ERRA Threshold). These amounts are effective as of March 2, 2026.[15]

---

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

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

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

14 *Ibid.*

15 PG&E's compliance AL 7851-E, was submitted on March 2, 2026, pursuant to D.04-01-050 (hyperlink at: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7515-E.pdf).

C. GHG Revenue Return and Reconciliation

CARB adopted the regulations to implement a Cap-and-Trade (later renamed Cap-and-Invest) Program under AB 32, the “Global Warming Solutions Act of 2006,” on 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-Invest Program in January 2013.

CARB acknowledged that the electricity sector incurs costs associated with the Cap-and-Invest Program. In order to mitigate the cost burden in the electricity bills associated with the Cap-and-Invest Program, CARB allocates allowances to the IOUs on behalf of their electric customers. CARB further determined that the IOUs will consign these allocated allowances in quarterly auctions and distribute the proceeds as a credit, known as the California Climate Credit, to their residential, small business and eligible industrial EITE (emission-intensive and trade-exposed) customers.[16] The Cap-and-Invest Program was reauthorized in 2025, and CARB is currently in the process of reallocating electricity sector allowances.

PG&E filed its first GHG revenue and reconciliation application in 2014. The CPUC directed the IOUs to file the GHG forecast revenue and reconciliation request[17] as an additional chapter or section within the annual ERRA or Energy Cost Adjustment Clause forecast applications, utilizing CPUC approved templates provided in Appendix D of the decision. The Commission considered modifications to these required templates in D.21-08-026 authorizing CPUC staff to facilitate a workshop to discuss updates among the parties. On October 26, 2021, Energy Division approved the IOUs request to modify and/or remove specific templates in future GHG showings.

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 formerly funded by GHG allowance revenue proceeds and requests a set-aside of PPP revenues to fund these customer programs, as well as incurred and forecast A&O expenditures.

---

16 D.12-12-033, OP 1.

17 D.14-10-033, OP 10

D. Fall Update

Consistent with the previous ERRA and GHG forecast proceedings, PG&E proposes to update its 2027 forecasts of ERRA, NBCs, and revenue requirements, as well as its GHG cost and revenue forecasts and reconciliation amounts, after Energy Division staff releases new MPBs in October to reflect market conditions closer to the time when 2027 rates go into effect.[18] At that time, PG&E will update certain NBC calculations according to the MPB, and will also update balancing account balances.

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 Fall Update. PG&E will be providing more current load forecast information based on the timing of the proceeding as modified by D.22-01-023.

E. Master Data Request

In D.20-12-038, approving PG&E's 2021 ERRA Forecast revenue requirement and rate proposal, the Commission determined that good cause existed for parties to receive confidential data and information related to ERRA, Portfolio Allocation Balancing Account (PABA), and PCIA Undercollection Balancing Account (PUBA)[19] accounting entries prior to the Fall Update.[20] For many years, PG&E has provided this data and information to the CPUC's Energy Division pursuant to D.02-12-074, OP 19. However, OP 4 of D.20-12-038 directs PG&E to submit a master data request to any party to this proceeding on a routine basis that includes an expanded showing of the following:[21]

1) Confidential versions of the monthly ERRA/PABA/PUBA activity reports;

---

[18] 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.

[19] PUBA was closed via AL 7469-E.

[20] This data and information is presented annually in the ERRA Compliance Review Application as WPs in support of accounting entries. These WPs are reviewed by the Public Advocates Office at the California Public Utilities Commission and the Joint CCA parties for compliance with CPUC decisions, resolutions, orders, and long-standing precedent under BPP authority.

[21] As discussed herein, D.20-12-038 does not modify the Commission's rules for obtaining confidential information.

2) Additional detail supporting the monthly PABA reports, including subcategories for summarized line items, such as UOG costs and contracts (e.g., provide by resource type, and whether RPS or non-RPS eligible);

3) Actual volumetric quantities underlying each relevant dollar figure; such categories include UOG generation, power purchases and sales, California Independent System Operator market sales, and retail customer sales;

4) Monthly volumes of Actual Sold, Retained, and Unsold RA capacity; and

5) Monthly volumes of Actual Sold, Retained, and Unsold RPS-eligible energy.[22]

Consistent with the COL 11 and the OP 4 directive, PG&E will provide this information to parties' reviewing representatives under an executed Non-Disclosure Agreement (NDA) with PG&E as it contains protectable material that the Commission has deemed to be confidential pursuant to D.06-06-066, Appendix I, Item XI; D.14-10-033; and Pub. Util. Code Section 454.5(g). Page 31 of the decision established the expected delivery of such market sensitive information to be five days after PG&E submits the Activity Reports to the Energy Division, once the annual ERRA Forecast Application has been filed and throughout its duration.

Subsequently, in D.22-02-002, adopting PG&E's 2022 ERRA Forecast revenue requirement request, the Commission required PG&E to produce the final prior year PCIA WPs as part of the ERRA master data request, noting that the prior year's PCIA rates in effect will not be subject to further scrutiny in this proceeding.[23] PG&E will also provide any confidential information ordered by D.22-02-002 to parties' reviewing representatives once a NDA has been executed, as described herein.

F. 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 2026

---

[22] D.20-12-038, COL 11.

[23] D.22-02-002, OP 7.

CAM,[24] VAMOMA, PABA, Modified Transition Cost Balancing Account,[25] PPCP, TMNBC, BioMAT, and ERRA balances in rates over the following calendar year, through the AET process.[26] To accomplish this, PG&E will update its recorded and forecast year end balances in its Fall Update.

G. Conclusion

The purpose of this testimony is to present PG&E's 2027 ERRA Forecast Application total revenue requirement of $3,176 million. PG&E requests approval of the 2027 ERRA Forecast Application total revenue requirement of $3,176 million, with a revenue requirement for rate-setting purposes of $4,409 million which includes $1,233 million of revenue requirements approved in other Commission proceedings. The component revenue requirements for rate setting purposes are comprised of a VAMOMA forecast of $0.5 million, PCIA forecast of $815 million, Ongoing CTC forecast revenue requirement of $20 million, ERRA forecast revenue requirement of $2,914 million, PPCP subaccount forecast revenue requirement credit of $0.8 million, TMNBC forecast revenue requirement recovery of $30 million, CAM forecast recovery of approximately $659 million, and BioMat forecast revenue requirement of approximately $11 million. The final revenue requirement implemented in 2027 rates will be subject to adjustments for recorded year-end balancing account balances and the final decisions of any other proceedings, through the AET process.

In addition, PG&E requests the Commission approve the following GHG-related expenses: (1) 2025 recorded A&O expenses of $0.867 million; (2) 2027 forecast A&O expenses of $1.1 million; (3) 2027 GHG allowance revenue return requirement of $530.1 million; (4) GHG A&O expense set-aside of $1 million; (5) Duplicative accounting error related to CEEE programs of $5.9 million; and (6) 2027 semi-annual residential and eligible small business CCC amount of $41.74 per household. PG&E requests the Commission

---

24 The net cost of CAM-eligible contracts is recorded in the New System Generation Balancing Account. Electric Preliminary Statement Part FS is available at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_FS.pdf.

25 To recover Ongoing CTC revenue requirements.

26 Including PG&E's balancing account transfer proposals, as presented in Chapter 12 of this Prepared Testimony.

approve $36.4 million in PPP funding for customer programs formerly funded by GHG auction revenues.

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 January 1, 2027 rates. PG&E also asks that the Commission approve PG&E's 2027 retail sales forecast, as revised in the upcoming Fall 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

TABLE OF CONTENTS

A. Introduction 2-1

1. Sales and Peak Demand Forecast 2-2

a. Economic Backdrop 2-2

b. Sales Forecast 2-4

c. Peak Demand Forecast 2-7

2. Post-Regression Forecast Adjustments 2-7

a. BTM DG 2-8

b. Conservation and EE 2-9

c. Electric Vehicles 2-10

d. Building Electrification 2-10

e. BTM Energy Storage 2-10

f. Data Centers 2-11

g. T&D Losses and UFE 2-13

3. PG&E’s Versus CEC’s Forecast Methodology 2-13

B. Departing Load 2-15

1. Departing Load Sales Methodology 2-15

2. DL Settlements 2-17

3. DL Due to DA 2-17

4. DL Due to CCA 2-18

5. CCA Load Forecast Methodology 2-19

C. Conclusion 2-20

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) 2027 sales and peak demand forecasts, and the methodology used to develop these forecasts as presented in PG&E's 2027 Energy Resource Recovery Account (ERRA) Forecast Application (Application). Summaries of PG&E's forecasted energy (sales) and capacity (peak demand) loads are shown in Table 2-3 at the end of this chapter.

PG&E forecasts distribution system sales to total about 74,558 gigawatt-hours (GWh) in 2027; this is an approximately 0.6 percent decrease from the system forecast adopted by the California Public Utilities Commission (CPUC or Commission) in Decision (D.) 25-12-027, which adopted PG&E's 2026 ERRA Forecast Application (A.)25-05-011. This decrease is primarily due to a lower baseline forecast and continued adoption of distributed generation. PG&E's bundled sales are forecast to be about 25,050 GWh, an approximately 7.5 percent decline from the bundled forecast adopted in the 2026 ERRA Forecast proceeding. The decrease is the result of a small decrease in the system forecast combined with a lower bundled data center forecast, and continuing CCA expansions.

The 2027 bundled electricity sales forecast is calculated as the residual of the total system sales forecast and forecasted Departing Load (DL). There are 10 Direct Access (DA) providers and 12 CCAs currently serving load in PG&E's service territory in 2026.[1] In total, PG&E expects CCA and DA providers to serve approximately 70 percent of PG&E's total system sales in 2027.

---

[1] CCA entities currently serving load in PG&E's service territory include: Marin Clean Energy (MCE), Sonoma Clean Power (SCP), Clean Power San Francisco (CPSF), Peninsula Clean Energy (PCE), Silicon Valley Clean Energy (SVCE), Redwood Coast Energy Authority (RCEA), Pioneer Community Energy (PIO), Central Coast Community Energy (3CE), Valley Clean Energy Alliance, Ava, formerly known as East Bay Community Energy (EBCE), King City Community Power (KCCP), and the City of San José, Administrator of San José Clean Energy (SJCE).

The 2027 annual system peak forecast is approximately 4 percent lower than the 2026 peak forecast adopted by D.25-12-027. Drivers include year-over-year changes in observed weather and updated historical data. The 2027 bundled peak forecast is approximately 11 percent lower compared to the 2026 peak forecast adopted in PG&E's 2026 ERRA Forecast proceeding. Year over year growth at the system level is generally mirrored at the bundled forecast level, but in this case, it is lessened by CCA expansion, which reduces bundled sales.

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 customer rates discussed in Chapter 13. The bundled sales forecast is derived by first forecasting total electric sales at the "retail system" level. 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). Total energy requirements for PG&E bundled customers are calculated by applying Unaccounted for Energy (UFE), and transmission and distribution (T&D) losses to forecasted sales at the meter.

1. Sales and Peak Demand Forecast

a. Economic Backdrop

The tech-focused economy in PG&E's service area is expected to struggle in the near term despite the area being the beneficiary of much of the investment in AI. Payroll losses have slowed but recovery is uncertain and no other sector except healthcare is consistently adding jobs. Population is expected to be flat; drivers include federal immigration policy, remote work practices, and living costs, all of which have become or remain bearish. The service area shares the current global economic uncertainty with additional concern around the future of the AI industry.

PG&E continues to address intervenor concerns that modeling should incorporate a "new normal" capturing changes in usage patterns (such as remote work) after the coronavirus disease 2019 (COVID-19) pandemic. However, the purpose of the sales forecast presented in this Application is to establish the test year sales forecast for ratesetting, so PG&E models long term changes in a way that is consistent with its regression models and with recent sales data rather than attempting to capture detailed (and still in flux) work practice changes across its territory. Consistent with these needs, PG&E, with almost six years of post-COVID-19 sales data, estimates persistent behavioral changes from such actual, recorded data. This is done by including in the regression model a binary or “dummy” variable for each of the first 2 post-COVID-19 years to estimate the impact of post-COVID usage patterns in each year, and one longer term binary variable covering the remainder of the years. The three binary variables allow the estimation of a long-term shift or permanent adjustment to the sales level for residential and commercial classes using a simple exponential curve.

This results in a 2027 adjustment (decrease) for small and medium commercial sales of about 5 percent, and an adjustment (increase) for residential sales of between 3 and 4 percent. PG&E’s model assumes that any further residual changes in work practices and office utilization (and any lasting changes to electricity consumption) would be captured by the economic data and drivers of the models; this assumption is consistent with some models from the California Energy Commission (CEC) and other California utilities.

TABLE 2-1
SERVICE AREA ECONOMIC INDICATORS

	2023	2024	2025	2026	2027
Real Gross Product ($ Billions)	[redacted]				
% Change	[redacted]				
Total Employment (Thous.)	[redacted]				
% Change	[redacted]				
Real Personal Income ($ Billions)	[redacted]				
% Change	[redacted]				

b. Sales Forecast

PG&E uses econometric models to forecast electric retail sales to all customers in PG&E's service territory with individual regression equations specific to each major customer class—residential, commercial, industrial, and agricultural. The models predict sales or sales per customer using various PG&E service area economic measures, price variables, and weather variables. The forecast models incorporate recorded data from December 2005 through November 2025, with historic and forecast values for the models' economic drivers from the Moody's Analytics December 2025 update of PG&E's service territory economic forecast outlook. A list of specific variables is included in this chapter's workpaper under each model's data tab. 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 supporting this testimony. The final forecast also accounts for the expected future effects of Energy Efficiency (EE), behind-the-meter (BTM) Distributed Generation (DG), electric vehicle (EV), BTM Storage and additional end use electrification. Details of these forecasts are described in Section B.2. New to the 2027 ERRA Forecast, PG&E has compiled historical electricity usage from large data centers. This historical usage was removed from historical industrial sales before performing the sales regression step. This process avoids having the regression models include trends for large data centers. Large data center load is accounted for separately as a post regression adjustment.

Weather, in particular heating and cooling degree days (Heating Degree Days (HDD) and Cooling Degree Days (CDD)), is a major driver for residential, commercial, and industrial electricity usage. As part of a continuing effort to reflect recent weather patterns as well as realistic climate change forecasts, PG&E uses its best available forecast weather dataset. This dataset uses a smoothed median of daily data based on multiple published Intergovernmental Panel on Climate Change forecasts. These global forecast data, localized for California, are provided by the CEC in their Cal-Adapt platform. This dataset was used in both the sales and peak energy forecasts.

On a recorded basis, residential sector sales to all retail customers (including PG&E bundled, CCA, and DA) decreased almost 10 percent between 2022 and 2025, as 2025 was an exceptionally cool summer (which also reduced the system peak). The Residential forecast for 2027 is 6.8 percent greater than the recorded 2025 value.

PG&E primarily attributes the gradual drop in residential sales over the past decade or so to increases in BTM DG, primarily via customer owned photovoltaic (PV) systems. The effects of various load modifiers including DG are discussed in Section B.2.

On a recorded basis, commercial (small and medium combined) sector sales to all retail customers (including PG&E bundled, CCA, and DA) declined about 3 percent between 2022 and 2025. The commercial sector has also become more efficient and has adopted increasing amounts of BTM DG, including rooftop solar and fuel cells. The commercial forecast for 2027 is 3.8 percent greater than the recorded 2025 value. Industrial class sales to all retail customers (including PG&E bundled, CCA and DA) declined about 3.3 percent between 2022 and 2025. The Industrial forecast for 2027 is 3.8 percent greater than the recorded 2025 value. The industrial sector forecast growth is driven primarily by increasing demand from data centers.

Agricultural class sales to all retail customers (including PG&E bundled, CCA, and DA) are volatile and closely tied to available water in the service territory, since farmers pump groundwater for irrigation needs. Periods of drought or (relatively) strong rainfall often persist for multiple years. The most recent multi-year drought period lasted through 2022. 2023 recorded sales fell by 38 percent as compared to 2022 levels, primarily due to significantly higher water availability that year. 2024 recorded sales recovered somewhat, but 2025 sales were still about 33 percent below 2022. PG&E's 2027 agricultural sales are currently forecast to be about 4.8 percent below PG&E's recorded 2025 agricultural sales based on the recent historical average Palmer's Drought Severity Index (PDSI) values used for the spring forecast. The midyear Agriculture forecast update described below will update PDSI values, incorporating the effect of weather conditions through the first part of 2026. PG&E currently anticipates that this will increase the forecasted agricultural sales that PG&E will present in the Update to Prepared Testimony (Fall Update) for 2027 compared to the current forecast for agricultural sales; while most of California is currently not in drought conditions, this year's warm early weather means that much of the West is more in need of water than pure drought measures may yet indicate.

The agricultural load forecast is recognized by all participants as being exceptionally variable and efforts to improve forecasts have motivated consultations between PG&E and agricultural parties.[2] In PG&E's 2020 GRC Phase 2 proceeding, PG&E and the agricultural parties agreed to a settlement (Agricultural Settlement) which, among other conditions, stipulated the models used to forecast the sales and accounts for PG&E's ERRA Forecast applications.[3]

The new models contain independent variables that differ from the agricultural sales and accounts forecasting models used to produce the electric load forecast adopted in [and prior to] the 2022 ERRA Forecast proceeding. The independent variables in the new models include a measure of value added to the U.S. economy by the agriculture sector for California, a statewide drought factor,[4] a lagged average annual statewide drought factor for the previous water year and an average agriculture rate factor for the PG&E region.

According to the Agricultural Settlement, PG&E had originally agreed to revise the sales forecast for the agricultural customer class in its Fall Update to reflect the most recent PDSI information available as of mid-July of the filing year. However, in D.22-01-023 the Commission adopted an accelerated schedule for ERRA Forecast proceedings which

---

2 The agricultural parties are the Agricultural Energy Consumers Association, and the California Farm Bureau Federation.

3 See Motion of PG&E for Adoption of Agricultural Rate Design Supplemental Settlement Agreement (SA), dated April 8, 2021.

4 The drought factor is measured by the PDSI.

advances the CPUC Energy Division's issuance of the market price benchmarks by a month to early October.[5] Consequently, PG&E has consulted in previous years with agricultural parties on the scheduling challenges posed by the accelerated timeline and agreed to use the PDSI data available by late June for the Fall Update.

The Agricultural Settlement stipulates procedures for review in the event that the variables and results fail to meet expectations. If the regression model statistics indicate that an independent variable has little or no explanatory power, the inclusion in the model will be reconsidered. If the overall explanatory power of the model or the forecast accuracy is no longer sufficient then the model will be reconsidered.

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 HDD, CDD, and household growth as forecast by Moody's Analytics. Preliminary impacts of load modifiers as described in the next part of this chapter are also included. For 2027, PG&E's projected retail peak demand is shown in Table 2-3, line 41. The new system peak forecast for 2027 is approximately 11 percent above the recorded system peak for 2025. PG&E notes that the 2025 system peak was relatively modest (compared to 2024) driven, in part, by 2025's mild weather conditions.

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 2027.

2. Post-Regression Forecast Adjustments

Although the regression-based forecasts described in Section 1 above remain at the core of PG&E's sales and peak demand forecast processes, the regression forecasts alone cannot incorporate all of the impacts of new

---

[5] See D.22-01-023, Ordering Paragraph (OP) 1.

technologies and policies. For this reason, PG&E takes an additional step to adjust its regression forecasts before arriving at final sales and peak demand forecasts. The adjustments cover BTM DG, Conservation and EE, EVs, Building Electrification, BTM Energy Storage, and data centers. Additionally, PG&E's forecasts are adjusted for T&D losses and UFE. Table 2-3 presents the impacts of each of these post-regression adjustments.

a. BTM DG

The PG&E service territory had nearly 1 million installations and approximately 9,700 megawatts (MW) of installed BTM DG capacity by the end of 2025. Although PG&E does not explicitly attribute adoption from specific drivers, PG&E generally expects continued adoption of BTM solar PV given economic and policy incentives, such as the net billing tariff, the federal Investment Tax Credit for commercially-owned systems, and Title 24 new construction mandates. However, consistent with the CEC's 2025 IEPR, PG&E expects a reduction in near-term adoptions compared to recent historical trends due to changes in federal policy such as the revocation of the Investment Tax Credit (ITC) for residential customers and the implementation of trade tariffs.

To forecast load impacts from BTM solar, PG&E forecasts customer solar PV adoption and installed capacity, and estimates generation associated with that capacity. Given the uncertainty of federal policy impacts on near-term adoption, PG&E assumed 500 MW of adoption in 2026 and 2027, approximately 50 percent of 955 MW of PV adoption observed in PG&E territory in 2025;[6] this 50 percent reduction mirrors the CEC's 2025 Integrated Energy Policy Report (IEPR) forecast projecting a 50 percent reduction in adoption due to ITC removal.[7] Generation estimates for BTM PV were developed internally using customer PV system size and capacity factor inputs that vary by

---

[6] CaliforniaDGStats, accessed April 13, 2026.

[7] 2025 IEPR Behind-the-Meter Distributed Generation Forecast Results, slide 14: "Elimination of ITC leads to 50% reduction in adoption rates in all cases starting in 2026."

location. Lines 5 and 35 of Table 2-3 show BTM PV cumulative energy and peak demand forecasts.

For non-PV BTM DG resources, PG&E used trend analysis (5-year average) to forecast fuel cell, wind, and combustion technologies (including combustion turbines, microturbines, internal combustion engines) adoption. For non-PV BTM DG technologies, generation estimates were based on annual capacity factors from the 2021-2022 Self-Generation Incentive Program Impact Evaluation study prepared by ITRON in 2024, distributed evenly throughout the year. Lines 6 and 36 of Table 2-3 show the non-PV BTM cumulative energy and peak demand forecasts.

b. Conservation and EE

PG&E incorporates the effects of conservation and EE into its sales and peak demand forecast using IEPR EE forecast data, developed by the CEC. PG&E's forecast of EE savings from new programs and codes and standards was informed by the 2023 IEPR Additional Achievable Energy Efficiency (AAEE) scenarios. A weighted average forecast of these new, or "uncommitted," savings is created by incorporating the opinions of internal subject matter experts on the AAEE scenarios. PG&E's forecast of committed EE savings—expected energy savings from "on-the-books" building codes and appliance standards (C&S), as well as programs with funding commitments or implementation plans—was derived from CEC data as well. Specifically, committed electricity savings from the 2019 California Energy Demand (CED) forecast mid-demand case were provided by the CEC directly to PG&E. Since this is an older vintage of data, it is adjusted to reflect more recent trends in savings in PG&E's service territory via the California Energy Data and Reporting System database. Both data sources are extrapolated, made incremental to calendar year 2025, and adjusted to represent only savings on PG&E's electric distribution system. Additionally, the resulting forecast is converted from net to gross savings. End-use-specific load shapes from the CEC's 2019 Investor-Owned Utility Electricity Load Shape study are used to translate annual sales impact into an hourly forecast of EE savings.

Lines 3 and 33 of Table 2-3 show energy and peak demand forecasts of AAEE incremental to 2025.

c. Electric Vehicles

PG&E's forecast is adjusted for expected load increases due to plug-in EV adoption and hydrogen fuel cell EV adoption. To consider the impact of EVs on PG&E's annual load, PG&E built a forecast informed by policies and market drivers to forecast EV population, energy demand, and hourly load. Inputs to the forecast include: (1) aggregated light-duty EV registration data available through September 2025, (2) state policy goals, (3) market drivers such as rideshare growth and direct current fast charging availability, (4) data-driven load profiles which describe the typical EV electricity consumption and charging behavior, (5) load-shifting from vehicles participating in bidirectional charging, and (6) PG&E subject matter expert judgment. Lines 9 and 37 of Table 2-3 show EV cumulative energy and peak demand forecasts.

d. Building Electrification

PG&E includes in its forecast additional electricity sales due to an expected increase in the rate of building electrification. This includes (1) newly-constructed all-electric buildings compliant with applicable California building codes (e.g., Title 24); and (2) customers responding to policy or market drivers to retrofit their building's appliances. In both cases, the residential and commercial sectors are considered, as are a variety of appliance types (e.g., space heating, water heating, cooking, and clothes drying). Lines 10 and 38 of Table 2-3 show building electrification energy and peak demand forecasts incremental to 2025.

e. BTM Energy Storage

As the market for BTM energy storage is projected to grow in California, PG&E includes in its forecast impacts due to BTM battery storage. PG&E's analysis indicates that storage at this scale will have a relatively minor impact on annual energy given the expected round-trip efficiencies of batteries, but storage will have more substantial 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. Lines 8 and 40 of Table 2-3 show BTM energy storage cumulative energy and peak demand forecasts.

f. Data Centers

PG&E's data center forecast includes impacts from large data centers expected to newly connect or expand capacity in its service territory, as well as other large data centers already online as of November 2025. The forecast scope is limited to data centers in the large commercial/industrial customer class that are expected to take electric distribution or transmission service from PG&E. The forecast assumes no offsetting impacts from on-site generation under normal operating conditions. For the purposes of the expected case presented in this ERRA Forecast, data centers' emergency generators are expected to operate exclusively in the event of a power outage. By definition, the expected case forecast assumes data centers are not experiencing a power outage; consequently, PG&E has no reason to expect emergency generators would affect system sales or peak.

For forecasting large data center facilities adding new capacity, PG&E's large load interconnection application queue—with capacity ramping schedules for each project—serves as the main source of data. The forecast only includes projects from the application queue that had reached a certain level of maturity as of forecast development—i.e., projects that either (1) are currently online and expected to increase capacity by year-end 2027 or (2) had been assigned a forecasted Operative Date (OPDAT) by year-end 2027. The OPDAT represents PG&E's internal assessment of a project's energization date based on PG&E's current construction schedule (at the time of forecast development); PG&E's Project Development team works with the customer to develop the OPDAT. For calendar year 2027, PG&E applies a 90 percent materialization rate—based on PG&E subject matter experts' judgment—to each project's capacity ramp schedule, reflecting some level of uncertainty that projects do indeed materialize and do so fully by the OPDAT. The adjusted project-level capacity ramping schedules are then aggregated for each year.

A capacity utilization rate of 85 percent is applied to the capacity forecast to forecast annual peak demand for these data centers. This assumption reflects PG&E's expectation that the new generation of data centers will exhibit high capacity utilization to maximize data center owners' use of the facility. Although not specifically related to PG&E's formulation of the capacity utilization assumption, PG&E notes that the capacity utilization assumption is within the range of estimates seen in Lawrence Berkeley National Laboratory historical analysis and future modeling of data center server operational time[8] and a survey of public estimates.[9]

For those other large data centers online as of November 2025, PG&E built a linear regression model using 10 years of historical data center demand data to forecast peak demand. That forecast is then combined with the peak demand forecast for large data centers adding new capacity. An 88 percent load factor assumption is then applied to convert peak demand for both existing and new large data centers to annual sales. This assumption is based on PG&E subject matter expert judgment. Although not specifically related to PG&E's formulation of the load factor assumption, PG&E notes that the load factor assumption is within the range of estimates seen in various reports[10,11] and PG&E's 2026 ERRA Forecast filing. Finally, assumptions around load shapes and seasonality are incorporated to create an hourly load forecast. These assumptions were developed based on internal analyses of existing data centers in PG&E's service area as well as load shapes from external reports. The 2027 ERRA Forecast uses the same data center load shape as the 2026 ERRA Forecast.

Based on discussions with CCAs, PG&E assumes any data center in a CCA territory will take service from the respective CCA.

---

8 2024 Unites States Data Center Energy Usage Report.

9 The Puzzle of Low Data Center Utilization Rates.

10 How Utilities Attract Mission-Critical Facilities.

11 Forecasting Large Loads in the Age of AI and Data Centers.

Explicitly sharing the data center forecast would not comply with the "15/15" Rule first adopted in CPUC D.97-10-031. Specifically, one customer represents greater than 15 percent of the total load in 2027. Consequently, no data center forecast results are shared here nor in Table 2-3 (i.e., lines 7 and 39 are left blank), in order to protect private customer information. Instead, PG&E includes forecasted data center load in the unmitigated retail sales (line 2) and unmitigated retail peak (line 32) data in Table 2-3. Note that forecasted large data center load is classified under the industrial customer class.

g. T&D Losses and UFE

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.[12] Distribution losses are estimated to average about 6 percent, depending on hourly load levels.

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

The CEC develops the CED forecast every two years as part of the 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, some modifications to load modifier forecasts, and making any needed corrections. The most recent CED Update, adopted in January 2026, contains a forecast of energy deliveries to PG&E bundled, CCA, and DA customers through 2045. 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 residential forecast is developed using an end use model which incorporates the results of the 2019 Residential Appliance Saturation Survey. Certain end uses were adjusted to reflect the impact of COVID-19, and the results are calibrated to recent history. The CEC's commercial forecast is not an end use model and does not include any special

---

[12] D.05-10-042, p. 42.

adjustment for COVID-19, though the model includes economic and demographic drivers which reflect COVID-19 impacts. 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. The key predictors are economic variables, price 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. For that reason, both PG&E and the CEC adjust sales forecasts to account for AAEE savings reasonably expected to occur, as well as DG and EVs. Both approaches, the end-use bottom-up approach, and the econometric 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. The reasons for this are twofold. First, PG&E performs a full sales forecast update at least once a year in order to incorporate the most recent data available. For example, this 2027 ERRA forecast relies on data through November 2025. This frequency of forecasting is important as the energy landscape is changing rapidly. 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 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 2027 sales.

B. Departing Load

1. Departing Load Sales Methodology

In this filing, PG&E reflects seven DL types,[13] 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 Western Area Power Administration (WAPA), PG&E uses the most recent available recorded DL sales as a proxy for 2027 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) California Department of Water Resources Bond;
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 (for 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 2027.

---

[13] The first five categories are Transferred Municipal, New Municipal, Split-Wheeling, Customer Generation and New 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.

TABLE 2-2
2027 DEPARTED LOAD SALES ESTIMATED BY CATEGORY (MWh)

Line No.	Departing Load Category	Total DL	Ongoing CTC	PCIA	NSGC
1	Transferred Municipal DL (a)(b)	645,728	522,969	Exempt	Exempt
2	New Municipal DL (a)	256,936	0	Exempt	Exempt
3	Customer Generation DL (a)	15,827,629	217,610	Exempt	Exempt
4	New WAPA DL (a)	52,586	2,493	0	2,493
5	Split Wheeling DL (a)	6,527	6,527	0	6,527
6	Direct Access less Continuous D.12-04-012 (a)	11,257,632	11,257,632	7,188,334	11,257,632
7	Continuous DA D.12-04-012 (a)	228,722	228,722	Exempt	228,722
8	Total Direct Access	11,486,353	11,486,353	7,188,334	11,486,353
9	CCA	40,152,873	40,152,873	40,152,873	40,152,873
10	**Total Departing Load**	**68,428,634**	**52,388,826**	**47,341,207**	**51,648,247**

(a) This item will be updated in PG&E's Fall Update.
(b) Includes a de-minimus amount of non-exempt, vintaged NSGC-eligible load that does not impact ratemaking.

2. DL Settlements

PG&E entered into four SAs regarding the collection of DL charges. The SAs with: (1) the **Power and Water Resources Pooling Authority;**[14] (2) the Modesto Irrigation District and the Merced Irrigation District;[15] (3) the Turlock Irrigation District;[16] and (4) the Center for Accessible Technology, MCE, the Public Advocates Office at the California Public Utilities Commission, The Utility Reform Network, and Brightline Defense[17] 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. DL Due to DA

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 bundled customer 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 Senate Bill (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 permitted to increase over this period from 5,574 GWh to a

---

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

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

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

17 D.18-09-013.

new total cap of 9,520 GWh. In 2013, PG&E's cap was met as defined in D.10-03-022.

In September 2018, SB 237[18] 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 2027 DA load forecast includes existing DA authorized under SB 695. PG&E relied on DA contract allocations in 2025 to estimate the amount of DA departed from bundled and CCA service for the 2027 ERRA Forecast filing.

Pursuant to D.19-06-026, Load-Serving Entities that anticipate load migration are required to meet and confer to discuss load migration forecast adjustments.[19] At the time of the preparation of its DA forecast, scheduled DA departed load was close to the annual cap and PG&E did not forecast any additional DA departures in 2027.

Similar to PG&E's 2026 Fall ERRA forecast, PG&E's 2027 Spring ERRA Forecast assumes that data center growth on sites that are currently served by ESPs will continue to be served by ESPs in 2027. Due to the data center load growth on sites currently serviced by ESPs, total DA load forecast in 2027 totals 11,486 GWh—93 GWh above the current cap of 11,393 GWh. Given the current DA cap, PG&E welcomes further guidance from the CPUC to clarify rules regarding future data center or other load growth on existing DA customer sites.

4. DL Due to CCA

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) MCE;
2) SCP;

---

[18] SB 237 (Stats. 2018, Chapter 800).

[19] See D.19-06-026, OP 14 (describing requirements of meet-and-confer process concerning ESP load forecast).

3) CPSF;
4) PCE;
5) SVCE;
6) RCEA;
7) PIO;
8) 3CE;
9) Ava (formerly EBCE);[20]
10) Valley Clean Energy Authority;
11) KCCP; and
12) SJCE.

This forecast reflects the 12 CCAs above that are expected to serve load in 2027. See Table 2-3, lines 15-26 for PG&E's forecast of energy requirements for each CCA. In this filing, there is one expected CCA expansion: 16 areas are scheduled to join Pioneer starting in October 2027.

5. CCA Load Forecast Methodology

In order to forecast year-ahead DL due to CCA growth, PG&E follows a meet-and-confer process[21] with CCAs that plan to serve load in 2027. In January 2026, PG&E submitted e-mail requests for load, peak demand, and customer forecasts from the 12 CCAs planning to provide service in PG&E's territory. PG&E received the requested forecasts from all 12 CCAs. After reviewing the CCAs' forecast methodologies and comparing against PG&E's internal forecast for CCA DL for reasonableness, PG&E accepted CCA-provided 2027 monthly sales forecasts for seven CCAs and is including those forecasts in this application. None of these seven CCAs have forecasted new data center load.

Of the remaining 5 CCAs, 3 acknowledged that they expect new data center load growth in their areas in 2027. Recognizing this new source of load growth, PG&E continued the meet-and-confer discussions in an effort to generate alignment. Given the differences PG&E communicated to the CCAs with expected data center load, PG&E will use its own forecast for this

---

[20] Name changed to Ava as of Oct. 24, 2023.

[21] 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).

May filing and continue discussions prior to the Fall Update. The remaining two CCAs for which the difference between PG&E’s forecast and the CCA’s forecast substantially differ, PG&E and the CCA will continue discussions during the summer months and the Fall 2026 meet-and-confer to generate alignment. For the purpose of the initial forecast, PG&E will use its own forecast for these CCAs as well.

PG&E also communicated with Pioneer on monthly non-coincident peak demand forecasts for its expansion scheduled for 2027 as part of the RA Forecast filing meet-and-confer.

For peak demand, PG&E calculated its bundled peak coincident with system peak using internal methods and data.

The load forecast presented in this chapter was developed in March 2026 using the best available information at that time, except where noted. PG&E will provide the most up-to-date CCA forecast in its Fall Update following the Fall 2026 meet-and-confer process.

C. 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 will provide with its Fall Update.

TABLE 2-3
2027 ENERGY (GWH) AND PEAK DEMAND (MW) REQUIREMENTS

		2027 ENERGY REQUIREMENTS (GWh)												
Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	**Energy Load (GWh)**													
2	Unmitigated Retail Sales (incl Large Data Centers)	[redacted]												91,067
3	Conservation and Energy Efficiency	(193)	(174)	(190)	(189)	(216)	(249)	(282)	(275)	(238)	(213)	(181)	(197)	(2,597)
4	Distributed Generation													
5	Solar	(708)	(843)	(1,286)	(1,529)	(1,733)	(1,778)	(1,801)	(1,718)	(1,482)	(1,256)	(878)	(741)	(15,752)
6	Non-PV DG	(262)	(237)	(263)	(256)	(264)	(256)	(265)	(266)	(258)	(267)	(259)	(268)	(3,121)
7	Large Data Centers													
8	Storage	16	15	18	18	18	17	18	17	17	17	17	17	206
9	Electric Vehicles	352	322	362	355	372	365	382	388	380	398	390	408	4,474
10	Building Electrification	31	26	25	22	21	19	19	19	19	23	26	31	281
11	Retail Sales	[redacted]												74,558
12	Direct Access													
13	Direct Access	(888)	(871)	(885)	(885)	(949)	(973)	(1,009)	(1,056)	(1,094)	(1,058)	(998)	(821)	(11,486)
14	Community Choice Aggregation													
15	Marin Clean Energy	[redacted]												
16	Sonoma Clean Power	[redacted]												
17	Clean Power San Francisco	[redacted]												
18	Peninsula Clean Energy	[redacted]												
19	Silicon Valley Clean Energy	[redacted]												
20	Redwood Coast Energy Authority	[redacted]												
21	Pioneer Community Energy	[redacted]												
22	Central Coast Community Power	[redacted]												
23	Ava Community Energy	[redacted]												
24	San Jose Clean Energy	[redacted]												
25	Valley Clean Energy	[redacted]												
26	King City Community Power	[redacted]												
27	Community Choice Aggregation Total	(3,516)	(3,229)	(3,134)	(2,858)	(3,008)	(3,194)	(3,548)	(3,585)	(3,494)	(3,505)	(3,573)	(3,510)	(40,153)
28	UFE, Transmission & Distribution Losses	[redacted]												2,132
29	Total Requirement	[redacted]												25,050
30	Retail Sales excludes BART energy requirements.													

TABLE 2-3
2027 ENERGY (GWH) AND PEAK DEMAND (MW) REQUIREMENTS
(CONTINUED)

Line No.		2027 PEAK REQUIREMENTS (MW)											
31	**Peak Load (MW)**												
32	Unmitigated Retail Peak (incl Large Data Centers)	[redacted]											
33	Conservation and Energy Efficiency	(166)	(200)	(145)	(173)	(425)	(442)	(537)	(398)	(307)	(204)	(177)	(204)
34	Distributed Generation												
35	Solar	(588)	0	(352)	0	(32)	(154)	(136)	(600)	(96)	0	0	0
36	Non-PV DG	(352)	(353)	(354)	(355)	(354)	(355)	(356)	(357)	(358)	(359)	(360)	(360)
37	Electric Vehicles	318	391	318	391	396	401	406	423	428	433	436	444
38	Building Electrification	67	56	54	40	35	32	33	33	32	38	52	60
39	Large Data Centers												
40	Storage	19	(501)	29	(486)	(483)	(483)	(484)	(509)	(474)	(500)	(474)	(474)
41	Retail Peak with distribution losses	[redacted]											
42	Direct Access with distribution losses	(1,423)	(1,587)	(1,535)	(1,546)	(1,944)	(2,218)	(2,113)	(1,976)	(1,960)	(2,415)	(1,639)	(1,236)
43	Community Choice Aggregation with dist losses	(6,845)	(7,080)	(6,425)	(6,096)	(7,388)	(8,322)	(8,649)	(8,007)	(8,401)	(8,030)	(6,883)	(6,442)
44	UFE & Transmission Losses	[redacted]											
45	Puget Sound Power & Light (Return)												
46	Total Requirement												
47	Retail Peak excludes BART demand requirements.												

Notes:

Distributed generation, large data centers, storage, and EV impacts are cumulative, whereas energy efficiency and building electrification impacts are incremental to end-of-year 2025. Large data centers have been represented with zeros and their impacts rolled into the "unmitigated" lines in this filing because quantities and/or customer counts were outside of limits allowed for explicit sharing of customer information.

EE data represents savings from additional achievable energy efficiency programs and codes & standards, incremental to 2025, based on the CPUC's Potential and Goals study. Importantly, this does not include committed savings from energy efficiency programs and codes & standards. Additionally, PG&E develops a simplified "daytype" forecast for energy efficiency hourly impacts, rather than a comprehensive 8760 forecast. This data reflects the peak daytype from said daytype forecast (compared to non-peak weekday and weekend daytypes).

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

ELECTRIC GENERATION PORTFOLIO BACKGROUND

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
ELECTRIC GENERATION PORTFOLIO BACKGROUND

TABLE OF CONTENTS

A. Introduction 3-1

B. UOG Resources 3-1

1. Diablo Canyon Power Plant 3-2

2. Hydroelectric Generation 3-2

3. Fossil Generation 3-2

a. Gateway Generating Station 3-2

b. Colusa Generating Station 3-3

c. Humboldt Bay Generating Station 3-3

4. Solar Resources 3-3

5. Energy Storage 3-3

C. Legacy Contracted Resources 3-4

1. Irrigation District and Water Agency Contracts 3-4

2. Metropolitan Water District Contract 3-4

3. Qualifying Facilities 3-4

4. Puget Sound Power & Light Company Exchange Contract 3-4

D. Post-2002 Contracted Resources 3-4

1. RPS-Eligible Resources 3-5

2. RPS Sales and Short-term Transactions 3-6

3. Conventional Resources 3-6

a. Fossil Contracts 3-6

b. Large Hydro 3-7

c. Energy Storage 3-7

d. Qualifying Facilities 3-9

e. RA Contracts – Executed 3-10

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
ELECTRIC GENERATION PORTFOLIO BACKGROUND

TABLE OF CONTENTS
(CONTINUED)

f. Emergency Summer Peak Transactions 3-10

4. Central Procurement Entity 3-11

E. Conclusion 3-12

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
ELECTRIC GENERATION PORTFOLIO BACKGROUND

A. Introduction

This chapter provides a broad overview of the electric generation portfolio included in Pacific Gas and Electric Company's (PG&E) 2027 Energy Resource Recovery Account (ERRA) Forecast. The following sections breakdown PG&E's portfolio between: (1) utility-owned generation (UOG); (2) resources contracted prior to 2003 (Legacy); and (3) resources contracted after 2002 (Post-2002). Legacy resources are primarily comprised of Irrigation District and Water Agency and Qualifying Facility (QF) contracts while Post-2002 resources are primarily Renewables Portfolio Standard (RPS)-eligible and energy storage contracts. Post-2002 contracts also include RPS-eligible generation sales, as well as any ordered emergency reliability procurement. Detailed assessments of the different products forecasted to be provided by these resources and their subsequent costs are presented in Chapter 4.

The remainder of this chapter is organized as follows:

- Section B – UOG Resources;
- Section C – Legacy Contracts;
- Section D – Post-2002 Contracts; and
- Section E – Conclusion.

B. UOG Resources

PG&E's Legacy (pre-2003) resources are comprised of a large fleet of hydroelectric generation plants, most of which have been in operation since the early part of the last century, and the Diablo Canyon Power Plant (DCPP) nuclear facility, which came online in 1985. During the latter part of the 1990s, PG&E sold all of its large-scale steam generator gas plants as part the industry restructuring mandated by the state of California. However, rule changes initiated after the 2000 Energy Crisis allowed PG&E to own and operate new generation resources in order to help meet state reliability and RPS goals. Since 2004, PG&E has added over 1,365 megawatts (MW) of gas-fired generation, 152 MW of solar photovoltaic (PV) and a 182.5 MW storage facility to its UOG fleet. Applicable UOG operating costs are recovered through the

Portfolio Charge Indifference Adjustment (PCIA), except for those associated with the Elkhorn Storage facility, which flow through the Cost Allocation Mechanism (CAM). Additional Information detailing UOG cost recovery can be found in Chapter 7 (CAM) and Chapter 8 (PCIA).

1. Diablo Canyon Power Plant

PG&E owns and operates two nuclear power units at DCPP totaling 2,240 MW. DCPP consists of two pressurized water reactors, Units 1 and 2, which began operation in 1984 and 1985, respectively..

On September 2, 2022, Senate Bill (SB) 846 was signed into law, directing PG&E to pursue extended operations at DCPP up to an additional five years beyond its then-current license period of 2024 and 2025. In 2026,the Nuclear Regulatory Commission (NRC) has authorized PG&E to continue operating DCPP for another 20 years, though extending operations past 2030 would require action from the California Legislature. PG&E does not seek recovery for forecast DCPP costs in this Application. On March 27, 2026, PG&E submitted Application 26-03-031 to recover in customer rates 2027 DCPP extended operation costs.

2. Hydroelectric Generation

PG&E owns and operates numerous hydroelectric (Hydro) facilities totaling approximately 3,900 MW and include run-of-river, dispatchable, and one pumped storage facility, that are expected to operate in 2026. PG&E's hydroelectric fleet consists of over 60 individual powerhouses, some of which have been in continuous operation dating back to the 1920s. The Helms Pumped Storage facility began operating in 1984 and provides 1,212 MW of generating capacity.

3. Fossil Generation

PG&E's fossil generation forecast for 2027 includes Gateway Generating Station (GGS), Colusa Generating Station (CGS), and Humboldt Bay Generating Station (HBGS).

a. Gateway Generating Station

The GGS is a 563 MW Natural Gas (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.

b. Colusa Generating Station

The CGS is a 641 MW 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.

c. Humboldt Bay Generating Station

The HBGS started operation in September 2010. It consists of 10 reciprocating engines (totaling 163 MW), which use NG as their primary fuel source and 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.

4. 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 PV Program. Under this program, PG&E has developed 152 MW of dispersed, midsized (typically 1 to 20 MW) installations within PG&E's service territory.

5. Energy Storage

PG&E submitted Advice Letter (AL) 5322-E on June 29, 2018 requesting authorization for four new storage projects of which one, PG&E Moss Landing (also referred to as Elkhorn), 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/4-hour lithium-ion battery which became operational in April 2022. Since January16 , 2025, the facility has mostly been out of service starting with the fire at the Vistra Moss 300 battery energy storage facility, but is expected to be operational in 2027.

C. Legacy Contracted Resources

These resources cover power purchase contracts that were in effect as of December 20, 1995, and which are expected to continue in PG&E's 2027 forecast. These contracts are eligible for Ongoing Competition Transition Charge (CTC) recovery under Public Utilities Code Section 367 and were not re-negotiated in a manner that makes them ineligible for Ongoing CTC recovery under Section 367(a)(2). PG&E no longer has any Legacy contracts ineligible for Ongoing CTC recovery in its forecast portfolio.

1. Irrigation District and Water Agency Contracts

PG&E has one remaining Legacy contract with Solano Irrigation District for energy and capacity from their facilities. This includes the Monticello Powerhouse, an RPS-eligible hydroelectric facility located in Northern California.

2. 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 energy deliveries.

3. Qualifying Facilities

These include Legacy QF contracts in effect as of December 20, 1995, eligible for Ongoing CTC recovery. As of April 2027, PG&E has fewer than 240 MW of operating Legacy QFs remaining.

4. 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 each year. In return, PG&E is obligated to deliver a similar amount of energy to PSPL between November and February.

D. Post-2002 Contracted Resources

Starting in the early 2000s, in the aftermath of the 2000 energy crisis, investor-owned utilities (IOU) were directed to spearhead the development of new resources to: (1) help ensure the reliability of the California Independent

Operator (CAISO) system, and (2) to begin making progress towards meeting state-mandated renewable targets. Since 2000, PG&E has entered into numerous contracts for existing and new "steel-in-ground" generation and storage facilities. For the bulk of the contracted resources, costs are recovered either through the PCIA or through the CAM. However, there are additional categories of contracts such as Bioenergy Market Adjustment Tariff, Tree Mortality and Modified CAM (ModCAM) that are either recovered in their entirety or partially (ModCAM) via separate revenue requirements and rate structures.

1. RPS-Eligible Resources

Pursuant to SB 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. SB 100 had been preceded by a number of bills related to California's clean energy goals most notably the original RPS that was enacted in 2002 and which required 33 percent of state-wide electricity sales be met with renewable generation by 2020. As a result, PG&E initiated a series of solicitations beginning in 2003 for the purposes of procuring, 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 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 resources procured to meet certain California bioenergy requirements. In addition to resources procured to meet PG&E's RPS energy goals, 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.[1]

---

[1] In D.15-01-051, the Commission approved with modifications PG&E's GTSR Program and ordered the IOUs to summarize and true-up costs and revenues against charges and credits applied to GTSR customers on an annual basis, either through the annual 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 AL 4639-E and AL 4639-E-A, which were approved by the Commission on November 13, 2015.

In total, PG&E's 2027 portfolio includes over 6,200 MW of RPS contracts, with procurement and costs attributable to contracts executed pursuant to the following procurement mechanisms:

- RPS Request for Offers (RFO) solicitations from 2003 onwards;
- RFO solicitations for the PPA portion of PG&E's PV Program;
- The RAM Program including bioenergy procurement, pursuant to CPUC Res.E-4770;
- Standard tariffs offered pursuant to Assembly Bill (AB) 1969;
- Standard tariffs offered pursuant to SB 32;
- Standard tariffs offered pursuant to SB 1122;
- Bilateral negotiations; and
- PPA buyouts, if applicable.[2]

2. RPS Sales and Short-term Transactions

PG&E began RPS Contract sales in its 2016 RPS Plan and established annual RPS sale solicitation protocols. PG&E has held at least one RPS sale solicitation in each year beginning in 2017, and PG&E is authorized to continue sales solicitations . For 2027, PG&E's portfolio includes RPS sale contracts executed through the Voluntary Allocation Market Offer process ordered in D.21-05-030 and D.22-11-021. PG&E's portfolio includes Long-Term contracts for both Voluntary Allocation and Market Offer sales with contract deliveries in 2027. In 2025, PG&E executed sale contracts for [redacted] gigawatt-hours (GWh) of RPS volumes for 2026 delivery. [redacted]

3. Conventional Resources

a. Fossil Contracts

Fossil contracts include both non-Combined Heat and Power (CHP) fossil generation technology and CHP resources. In recent years, CHP PPAs have included those pursuant to the QF/CHP Settlement which converted former must-take CHP QFs to utility pre-scheduled facilities. CHP Resources include any AB 1613 PPAs.

---

[2] See for example AL-25-01-014.

The fossil facility that is expected to provide energy and capacity to PG&E during all or part of 2027 is Panoche Energy Center (CT The Panoche Energy Center contract resulted from a 2004 Long-Term RFO conducted in response to D.04-12-048, a Long-Term Procurement Plan Decision.

b. Large Hydro

Since 2002, PG&E has entered into new PPAs with various 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. Costs associated with the small-hydro generation facilities are accounted for in RPS-eligible procurement costs, with the associated small-hydro energy and capacity positions also grouped with the Post-2002 RPS resources.

In 2025, PG&E executed sales of [redacted] of large hydroelectric volumes for 2026 delivery. Any additional sales of large hydroelectric volumes will be reflected in the Fall Update.

c. Energy Storage

Pursuant to AB 2514, which became law in 2010, and D.13-10-040, the Commission established energy storage MW procurement targets for the IOUs from 2014-2020. Under D.13-10-040, PG&E was 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 Res.E-4909.[3] As a result of these various solicitations PG&E has five active storage contracts.

In 2019, D.19-11-016 from the Integrated Resource Plan (IRP) proceeding ordered PG&E to acquire 716.9 MW of system RA by 2023 for its bundled portfolio. In addition to PG&E's bundled portfolio

---

3 PG&E's 2026 ERRA Forecast reflects resource availability adjustments based on the latest available information for resources impacted by the January 16, 2025 fire at Vistra's 300 MW Moss Landing battery storage facility.

obligation, other load-serving entities (LSE) opted to have PG&E procure their respective requirements adding 48.2 MW to PG&E's procurement obligation.

For the 2027 forecast, PG&E includes the transactions executed in 2020 and submitted for approval in ALs 5826-E and 6033-E. These transactions covered the full procurement requirement of 765.1 MW covering:

- PG&E's bundled RA requirement of 716.9 MW; and
- PG&E's opt-out LSE RA requirement of 48.2 MW.

In D.19-11-016, the Commission also adopted the concept of a new ModCAM, with further details including modifications approved by the Commission in D.22-05-015, issued May 23, 2022.

D.22-05-015 ("ModCAM Decision") addresses cost-recovery for the opt-out and backstop procurement associated with D.19-11-016 and D.21-06-035[4] and sets out precedent for any future backstop procurement authorized within the IRP framework.

Ordering Paragraph (OP) 4 of D.22-05-015 approves recovery of the bundled customer portion of the resource costs through the PCIA. The decision also affirms that the D.19-11-016 contract costs will be vintaged as 2019 resources.

Pursuant to OP 5 of D.22-02-015, a new ModCAM charge applies to LSEs that opted out of their procurement obligations under D.19-11-016. Additionally, pursuant to OP 10, the associated costs for LSEs that go bankrupt or are no longer serving load in California can be recovered through the regular CAM.

Consistent with this, PG&E has allocated the total 2027 costs of D.19-11-016 transactions to bundled, active opt-out and inactive opt-out using the following respective MW procurement shares:

- 93.7 percent of bundled costs to PCIA Vintage 2019 based on 716.9 of 765.1 MW;
- 6.1 percent of costs to the active opt-out position based on 47.0 of 765.1 MW; and

[4] To date, no backstop procurement associated with D.21-06-035 has been ordered.

- 0.2 percent of costs to the inactive opt-out position based on 1.2 of 765.1 MW.

In 2021, Commission decision D.21-06-035 from the IRP proceeding ordered PG&E to acquire 2,302 MW of Net Qualifying Capacity (NQC) by 2026 for its bundled portfolio, with the procurement broken out as follows:

- 500 MW from zero-emission resources that are able to deliver 1 MW per hour daily from 5 p.m.-10 p.m.;
- 200 MW from greenhouse gas-free resources that have at least an 80 percent capacity factor;
- 200 MW from long-duration energy storage; and
- 1,402 MW from non-gas fired resources.

In 2023, Commission decision D.23-02-040 ordered PG&E to procure an additional 777 MW of NQC with delivery starting in 2026.

PG&E anticipates that 2,377 MW of MTR battery storage capacity will be operational by the end of 2026 with an additional 825 MW coming on line during 2027.

d. Qualifying Facilities

PG&E's Post-2002 QF forecast reflects PPAs signed under the QF/CHP Settlement, approved by the Commission in D.10-12-035. The QF/CHP Settlement modified Short-Run Avoided Cost 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. A Public Utility Regulatory Policies Act (PURPA) PPA for up to a 7-year term for existing QFs was available for QFs 20 MW or smaller through 2020 – the end of the QF/CHP Settlement term. An "As-Available" PPA for up to a 7-year term was available for certain eligible CHP QFs delivering less than 131,400 MW-hours annually. As of April 2025, PG&E has four executed PURPA and As-Available PPAs included in its 2027 forecast.[5]

Costs for QF/CHP Settlement contracts with non-renewable QFs are included under the CAM calculation, as discussed in detail in Chapter 7. Prior to 2022, Costs for QF/CHP Settlement contracts with renewable QFs are not CAM-eligible but have been included in the PCIA calculation described in Chapter 8. The renewable PPA authorized for non-vintaged cost recovery under Res.E-5119 is included under Public Policy Charge Procurement subaccount pursuant to D.22-02-002. In D.22-02-002, the Commission determined that the Public Policy Procurement rate component charge is now appropriate for costs otherwise approved for non-vintaged PCIA.

The Commission has also authorized new QF Standard Offer Contracts (SOC) for QFs 20 MW or smaller under D.20-05-006, issued May 15, 2020, in the PURPA Rulemaking 18-07-017. The Commission authorized contract terms of up to seven years for existing QFs, and up to twelve years for new QFs. Pursuant to D.20-05-006, OP 15, these new SOCs were originally approved for non-vintaged PCIA cost recovery. Now they are included in the Public Policy Procurement rate component charge consistent with D.22-02-002. As of April 2026, PG&E does not have any of the PURPA SOCs in its 2027 forecast.

e. RA 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. There is no energy associated with these contracts.

f. Emergency Summer Peak Transactions

On December 28, 2020, an Assigned Commissioner's Ruling was issued that directed the large IOUs to seek contracts for additional

---

[5] These include the non-standard bilaterally-negotiated Chevron Richmond As-Available PPA, approved June 27, 2014 in Res.E-4648. Two PPAs were approved by the Commission in Res.E-5119 issued on April 16, 2021, including a renewable PPA approved for non-vintaged PCIA cost recovery.

power capacity to be available by the summer of 2021 or 2022 because of rotating outages that occurred within the CAISO in August 2020. In D.21-02-028, the CPUC limited the directed procurement to the summer of 2021 only, and PG&E presented proposed procurement in ALs 6088-E and 6089-E.[6]

The CPUC subsequently issued D.21-03-056, which directed the IOUs to take actions to prepare for potential extreme weather in the summers of 2021 and 2022. In ALs 6289-E, 6323-E, and 6469-E, PG&E presented proposed procurement pursuant to D.21-03-056 for summers 2021 and 2022.[7]

On December 2, 2021, the CPUC issued D.21-12-015, directing IOUs to solicit additional resources for summers 2022 and 2023. In response, PG&E presented proposed procurement in AL 6504-E[8] which included firm energy imports.

Of the various supply arrangements signed in response to the aforementioned emergency procurement orders, three storage contracts with a combined capacity of 260 MW will continue on as part of PG&E's supply portfolio in 2027. If applicable, PG&E will reflect any additional expected procurement for the summer of 2027 as part of PG&E's Fall Update forecast.

4. Central Procurement Entity

D.20-06-002, issued June 17, 2020, orders PG&E to serve as the Central Procurement Entity (CPE) for PG&E's distribution service area for the multi-year local RA program beginning for the 2023 RA compliance year.[9] This decision established that procurement and administrative costs incurred in serving the central procurement function are recoverable under

---

6 D.21-02-028, OP 1. ALs 6088-E and 6098-E were each approved on March 18, 2021.

7 AL 6289-E was approved on August 29, 2021; AL 6323-E became effective on September 20, 2021, and AL 6469-E was approved on January 24, 2022.

8 AL 6504-E was approved on February 19, 2022.

9 D.20-06-002, OP 2.

the CAM.[10] CPE administrative and transaction costs are described in greater detail in Chapter 6.

E. Conclusion

This chapter provides an overview of the electric generation portfolio included in PG&E's 2027 ERRA Forecast by breaking down PG&E's portfolio between: (1) UOG; (2) resources contracted prior to 2003 (Legacy); and (3) resources contracted after 2002 (Post-2002). UOG resources include nuclear, hydro, conventional fossil, and energy storage. Legacy resources are primarily comprised of QF contracts. Post-2002 resources are primarily RPS-eligible purchases and sales, energy storage contracts as well as any ordered emergency reliability procurement. Detailed assessments of the different products forecasted to be provided by these resources, and their subsequent costs are presented in Chapter 4.

[10] D.20-06-002, OP 16.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

GENERATION SUPPLY PORTFOLIO COSTS AND VOLUMES

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
GENERATION SUPPLY PORTFOLIO COSTS AND VOLUMES

TABLE OF CONTENTS

A. Introduction 4-1

B. Portfolio Generation and Cost Forecast 4-1

1. Natural Gas Plants 4-2

2. Diablo Canyon Power Plant Nuclear Generation 4-3

3. Hydroelectric Generation 4-3

a. Large Hydroelectric Generation Allocation and Sales 4-4

4. Helms Pumped-Storage Facility 4-4

5. Battery Storage 4-4

6. Renewable Resources (RPS) 4-5

a. RPS Supply Contracts 4-5

b. RPS Sales 4-5

c. VAMO Transactions 4-7

7. Qualifying Facility Resources 4-8

a. QF Generation Forecast 4-8

b. QF Payment Forecast 4-8

c. QF Energy Payments 4-9

d. QF Capacity Payments 4-9

8. Other Legacy PPAs in Effect as of December 20, 1995 4-10

C. Portfolio NQC 4-10

D. Conclusion 4-11

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
GENERATION SUPPLY PORTFOLIO COSTS AND VOLUMES

A. Introduction

The purpose of this chapter is to present the forecast of Pacific Gas and Electric Company's (PG&E) 2027 generation supply portfolio costs, generation volumes, and capacity expressed in terms of Net Qualifying Capacity (NQC) and Effective Flexible Capacity. The chapter is organized as follows:

- Section B – Focuses on the various modeling approaches and inputs PG&E employs to forecast both the expected level of generation from its electric supply portfolio as well as the generation supply costs in 2027;
- Section C – Describes the composition of the supply portfolio from a Resource Adequacy (RA) perspective. Tables are provided that quantify the amount of capacity that is designated as system, local and flex; and
- Section D – Conclusion.

B. Portfolio Generation and Cost Forecast

PG&E relies on its Procurement Portfolio Planner (P^3) model to forecast the amount of generation and costs associated with its electric supply portfolio as well as anticipated market revenues resulting from energy sales into the California Independent System Operator (CAISO) System.

P^3 is a Monte Carlo simulation model developed by PG&E specifically to provide an accurate representation of PG&E's bundled electric portfolio. 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.

Due to the diverse make-up of PG&E's supply portfolio, different technology-dependent modeling protocols are used within P^3. The remainder of this section focuses on the modeling protocols and primary inputs used to develop the portfolio generation and cost forecasts organized around major generation technologies and/or regulatory classes. The forecasted generation expected to be delivered to the CAISO's day-ahead market is shown in

Table 4-3. Forecasted Renewables Portfolio Standard (RPS)-eligible generation is shown in Table 4-4, RPS-Eligible Generation. Finally, the portfolio generation costs discussed in the sub-sections below are summarized in Table 4-5, Supply Portfolio Costs.

1. Natural Gas Plants

In the case of dispatchable resources, the level of generation itself depends on anticipated market conditions. PG&E uses forecasted spot prices for energy, adjusted for Locational Marginal Price differences at different locations, natural gas burner-tip prices, and Greenhouse Gas (GHG) forward prices to simulate the economic dispatch of dispatchable resources using the PG&E-developed P^3 model.

For this 2027 forecast, PG&E is using March 26, 2026 forward electricity and natural gas prices, which are presented in Table 4-1.

TABLE 4-1
2027 FORWARD ELECTRIC AND NATURAL GAS PRICES

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

Note: Forward Energy and Natural Gas Prices were derived from March 26, 2026 broker quotes. Ave.* is simple average of monthly prices.

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 (O&M) costs, and fuel transportation charges. Since each resource has its own specific characteristics, each unit is uniquely modeled.[1] Different models are used for different technologies. For example, a Combustion Turbine is modeled differently than a Combined Cycle unit. The generation and fuel use of each unit has been compared to historical behavior, where possible, to ensure accurate modeling. For the units under contract (tolling agreements), total

---

1 The reciprocating engines at PG&E's Humboldt Generation Plant are forecast to use a small amount of diesel fuel on an annual basis. Those costs are included in Table 4-5.

costs are calculated by summing the simulated variable costs (fuel, variable O&M) with the fixed (capacity) costs specified in their respective contracts. For the Utility-Owned Generation (UOG) units only the variable costs are reported.

2. Diablo Canyon Power Plant Nuclear Generation

Both Diablo Canyon Power Plant (DCPP or Diablo Canyon) units were set to cease operations with the expiration of their original operating licenses (Unit 1 on November 3, 2024 and Unit 2 on August 26, 2025). However, on September 2, 2022, Governor Newsom signed Senate Bill 846 authorizing the extension of DCPP operations, California's only remaining nuclear power plant in operation, for up to five years beyond its original operating licenses due to concerns over system reliability and to limit GHG emissions. In Decision (D.) 23-12-036, the California Public Utilities Commission (CPUC or Commission) authorized new retirement dates for Diablo Canyon and adopted a stand-alone application process to authorize forecast DCPP extended operations costs, with subsequent true-up to actual costs and market revenues for the prior calendar year. Beginning with the 2026 test year, DCPP is not part of the Energy Resource Recovery Account (ERRA) Forecast application aside from any allocated volume that impacts any of PG&E's residual bundled compliance positions.

3. Hydroelectric Generation

PG&E uses Energy Exemplar's PLEXOS economic dispatch model to forecast its UOG hydroelectric generation (Hydro). The model forecasts generation from over 60 power plants spread across 12 different river basins.

The model computes the optimal hydroelectric dispatch that maximizes the value of forecast water supply in consideration of forecast energy and ancillary services market prices, as well as planned unit outages and applicable watershed license compliance conditions that constrain the water balance and forecast. The model operates on an hourly time-step over a forecast horizon that spans two hydrological years.

Since PG&E owns the bulk of the Hydro generation assets in its portfolio, associated capital and O&M costs are recovered outside of the

ERRA framework. However, PG&E does incur certain water-related costs that are recovered in this Application. These include payments PG&E makes to various entities for water used in some hydroelectric plants, payments for headwater improvements made by other entities, the cost of cloud seeding programs on several watersheds intended to increase the amount of snow resulting from winter storms, and water rights fees paid 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 trending historical costs and forecasting new or emerging developments for 2027. PG&E's 2027 water costs forecast is shown in Table 4-5.

a. Large Hydroelectric Generation Allocation and Sales

As required by D.23-06-006 for the 2025 through 2027 delivery period, PG&E offers interim voluntary allocations of GHG Free energy from its large hydroelectric resources to Load-Serving Entities (LSE) serving departing load in PG&E's service territory. [redacted]

4. Helms Pumped-Storage Facility

The expected generation and pumping profiles for the Helms Pumped-Storage facility are based on simulated economic dispatch based on the stochastically-modeled hourly power prices described above, subject to any assumed operating constraints and planned outages.

5. Battery Storage

Chapter 3 describes the various storage resources in PG&E's supply portfolio. For the units for which PG&E is the Scheduling Coordinator, PG&E uses a simple peak-shaving algorithm to model the units' daily charging and discharging patterns. Charging costs are included in Table 4-5. For the RA-only storage contracts with financial settlement.[2]

---

[2] Energy Settlement, which is based on market prices for energy, and, if applicable, is netted out of Buyer's monthly payment to Seller.

PG&E uses economic dispatch logic in P[3] to simulate the financial cost (charging) and revenue (discharging) streams associated with those units. The simulated financial payouts are netted against the fixed capacity costs to determine the total forecasted contract costs. For the RA-only storage contracts without financial settlement, costs are limited to fixed capacity payments.

6. Renewable Resources (RPS)

a. RPS Supply Contracts

For most of the RPS resources within PG&E's supply portfolio, the modeled generation is initially constrained to be consistent with the expected generation profiles provided with each contract. Over time, however, the profiles are calibrated based on actual average generation and actual CAISO curtailments such that resource costs are modeled based on gross generation volumes.[3] Costs are estimated for each contract based on their respective pricing terms, typically specified on a dollar-per-megawatt-hour basis. RPS contracts can also include time-of-day adjustment factors that vary based on the hour of generation and time of year. Total forecasted costs are estimated by multiplying the modeled gross hourly generation by the contract-specific prices.

After modeling RPS contract costs, PG&E adjusts the gross generation volumes based on curtailment adjustment factors for solar and wind resources in its portfolio. These factors are informed by historical CAISO market curtailment data[4] for these technology types and result in lower forecasted net generation volumes.

b. RPS Sales

PG&E also presents generation and revenues associated with Voluntary Allocation and Market Offer (VAMO) contracts, which resulted from the process established in D.21-05-030, further described in Chapter 3. Volumes available to LSEs for Voluntary Allocation are determined by each LSE's respective load share of Power Charge

---

3 [redacted]

4 See historical CAISO RPS generation and curtailment data: https://www.caiso.com/library/production-curtailments-data.

Indifference Adjustment (PCIA) vintage RPS-Eligible resources, split into Long-Term and Short-Term resource pools. Short-Term resources are defined as RPS-Eligible resources eligible for VAMO with fewer than 10 years left in their respective contract terms from the date of the initial sales contract delivery, while Long-Term resources have more than ten years remaining and include UOG resources.

Voluntary Allocation contract terms were determined using the initial delivery date of January 1, 2023, while Market Offer sale contracts began deliveries later in 2023 once sale agreements were approved by the CPUC. In 2022, LSEs had the opportunity to elect to receive portions, or all, of their available Short-Term and Long-Term available volume on a percentage basis. Voluntary Allocation forecast volumes are determined by applying the Short-Term and Long-Term election percentages to the LSE's share of each PCIA vintage, and then applying this share to the forecasted generation of that vintage's RPS-Eligible generation. Both Short-Term and Long-Term Voluntary Allocation contract prices are set at each delivery year's PCIA Renewable Energy Credit Benchmark, with all associated costs based on that price. In the forthcoming tables, executed Voluntary Allocation contracts will be presented as executed RPS Sales.

Following the Voluntary Allocation election process was the Market Offer sale process, which was split into Short-Term and Long-Term solicitations. The Market Offer consists of all of the Short-Term and Long-Term volume, which was available but not elected in the Voluntary Allocation, and gave parties an opportunity to bid on and purchase remaining volumes. For its 2027 ERRA Forecast application PG&E is assuming it will not hold any additional VAMO sales offerings, consistent with Advice Letter (AL) 7105-E.[5]

Beyond VAMO, PG&E is including RPS sales executed in 2025 which includes agreements for deliveries in 2027.

In the event PG&E anticipates or has already executed applicable transactions prior to the Fall Update, such transactions would be

---

5 AL 7105-E.

reflected in the updated forecast based on applicable, effective cost recovery requirements.

c. VAMO Transactions

PG&E ran the Voluntary Allocation process during 2022 and short-term and long-term Market Offer solicitations during 2023. For the Voluntary Allocation, of the 22 eligible LSEs, 10 LSEs took allocations and executed contracts.[6] PG&E did not participate in its 2023 Market Offer process as a buyer. For the Market Offer, 11 RPS sales agreements were executed.[7] The long-term Market Offer solicitation was completed during 2023 with the execution of six long-term Market Offer agreements that were approved in November 2023.[8]

Table 4-2 shows the forecasted quantities of RPS-eligible generation by vintage that are made available as part of the VAMO processes.

TABLE 4-2
FORECASTED 2027 RPS-ELIGIBLE VOLUMES
BY VINTAGE AVAILABLE TO NON-PG&E BUYERS
(MWh)

Line No.	Vintage	Voluntary Allocation	Market Offer
1	2009	1,079,642	747,449
2	2010	793,167	372,662
3	2011	272,029	168,890
4	2012	358,287	221,030
5	2013	224,141	134,922
6	2014	35,774	24,219
7	2015	74,927	40,362
8	2016	7,008	4,028
9	2017	40,118	19,493
10	2018	0	0
11	2019	0	0
12	2020	0	0
13	2021	0	28,198
14	2022	0	0
15	2023	0	0
16	UOG Legacy	253,982	157,666
17	Total	3,139,075	1,918,919

---

6 PG&E's Final 2022 RPS Plan, p. 21-22.

7 AL 6894-E.

8 AL 6977-E approved via Resolution E-5295.

For this Prepared Testimony, PG&E incorporated the results of the VAMO processes. PG&E's forecast reflects PG&E voluntarily electing to receive the full share of eligible RPS energy for bundled customers. As ordered in the VAMO Decision, all voluntary allocations will be paid for at the applicable year's RPS MPB price, which is presented in Chapter 8 of PG&E's testimony.

Consistent with D.19-10-001 regarding future RPS sales and D.22-11-021 addressing Market Offer ratemaking, PG&E bases all Market Offer sales revenues on the executed transaction prices. Forecast Market Offer sales revenues will provide customers that pay for vintage PCIA charges with a pro rata share of revenues resulting from Market Offer sales transaction to reduce the cost of the PCIA.

7. Qualifying Facility Resources

As mentioned in Chapter 3, PG&E's Qualifying Facility (QF) forecast includes Legacy QF Power Purchase Agreements (PPA) and PPAs signed under the QF and Combined Heat and Power (CHP) Settlement, approved by the Commission in D.10-12-035. The QF/CHP Settlement modified Short-Run Avoided Cost (SRAC) energy pricing for QFs. Below, PG&E describes its QF generation and cost forecasting assumptions. PG&E expects to update its QF generation and cost forecast in its Fall Update to reflect newly-effective PPAs.

a. QF Generation Forecast

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 Hydro QFs, PG&E bases its projections on historical production, normalized for average water year conditions.

b. 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 5.

c. QF Energy Payments

PG&E calculates QF energy payments by applying hourly energy prices to projected QF generation using the P^3 model.

Most of the QFs selling to PG&E, including the pro forma QF/CHP PPAs, receive SRAC energy payments under terms of the QF/CHP Settlement.[9] PG&E uses its stochastic forecast of California border natural gas prices derived from March 26 2026 broker quotes to forecast SRAC energy pricing, consistent with the market prices described above.

During 2006, PG&E entered into Settlement Agreements and amendments with 123 QFs.[10] Only a few of these amendments will continue to be in effect during 2027. Under these amendments, QFs receive variable energy prices, derived using a heat rate and burner tip gas price and a variable O&M adder. To forecast these variable energy prices, PG&E uses a stochastic forecast of natural gas burner tip prices, derived from March 26, 2026 broker quotes, consistent with the market prices described above.

d. 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.

---

9 QFs receiving SRAC energy payments include the QFs signing pro forma “Legacy QF amendments” under the QF/CHP Settlement.

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

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

PG&E forecasts irrigation district contract costs for Solano Irrigation District (SID) 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 energy payments are also based on contractual unit prices and tied to energy production.

C. Portfolio NQC

First adopted in 2004, the governing RA framework established in Public Utilities Code 380 requires that the Commission establish RA requirements for all LSEs and that each LSE maintain physical generating capacity and electrical demand response to meet their respective load requirements. On June 23, 2022, the Commission approved D.22-06-050 which established the current Slice-of Day (SoD) framework for system RA compliance requirements. The new program became fully operational for LSEs starting January 1, 2025 after an initial testing period in 2024. With LSEs having now transitioned to the new SoD RA compliance framework, PG&E is explicitly incorporating the SoD methodology into its ERRA forecasting process starting with 2026.

Under the SoD framework, each LSE must show sufficient capacity to meet 24 separate hourly RA requirements across each month of the year. The requirements are based on the 24-hour load profile associated with the CAISO's "worst day"[11] of the month plus the applicable Planning Reserve Margin adjustment.[12] In D.22-06-050, the Commission defined "worst day" as the day of the month that contains the hour with the highest coincident peak load forecast.

In order to accommodate the 24-hour dimension of SoD, the Commission adopted new counting rules specifying the amount of qualifying capacity individual resources can provide during each hourly slice. Resources are grouped into four main categories, each with its own specific RA counting

---

11 In D.22-06-050, the "worst day" is defined as the day of the month that contains the hour with the highest coincident peak load forecast.

12 PG&E applies an additional internal reserve quantity.

approach. The different resource categories and respective SoD RA counting rules are described as follows:

- Single Value (Baseload): These resources are assigned a flat profile, which means the same amount of qualifying capacity is available in each of the 24 hourly slices. The magnitude of the capacity underpinning the flat profiles can vary across months, depending on the type of resource. Included in this category are natural gas, hydro, geothermal, biomass, and biogas resources as well as pumped storage and other long-duration energy storage resources.
- Variable Energy Resources (Wind and Solar): These resources are assigned values that vary by hour and month based on calculations that use a top-5-day exceedance methodology.[13]
- Imports: The amount of qualifying capacity that can be counted in any given hour is determined by the underlying contract's delivery profile.
- Energy Storage: Storage discharge quantities can be counted in any of the hourly slices provided the volumes are technically feasible and that the LSE can demonstrate that its portfolio contains sufficient excess charging capacity to support that level of discharge.

Given the flexibility afforded to storage resources under SoD, there is no pre-set storage charge/discharge profile. Instead, each LSE is free to allocate storage in the manner it sees fit. In terms of the ERRA forecast, how storage is allocated across the 24 slices has a direct bearing on the portfolio's open position and, by extension, the determination of residual capacity costs and revenues. PG&E's approach to forecasting SoD RA supply from its energy storage resources and their inclusion in the portfolio position calculations is described in detail in Section C2d of Chapter 5. Tables 4-6 through 4-17 present PG&E's bundled 2027 portfolio SoD RA supply forecast for each month (excluding storage).

D. Conclusion

This chapter presents PG&E's forecasted 2027 generation portfolio supply volumes and costs.

---

[13] PG&E's adopted exceedance methodology uses a benchmark load profile consisting of the month-hour average of wind and solar performance on the top 5 days.

TABLE 4-3
2027 ENERGY SUPPLY
(GIGAWATT-HOURS (GWH))

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	Energy Supply (GWh)													
2	Cost Allocation Mechanism (CAM)													
3	Utility-Owned Generation	[redacted]												
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	Imports													
12	Power Charge Indifference Adjustment (PCIA)													
13	Utility-Owned Generation													
14	Nuclear	[redacted]												
15	Hydro													
16	Fossil													
17	Solar	14	17	20	23	27	28	30	27	24	22	16	12	260
18	Fuel Cell	[redacted]												
19	Energy Storage													
20	Pre-2003 Contracted Resources													
21	QF													
22	Post-2002 Contracted Resources													
23	RPS Eligible													
24	RPS-Eligible Contracts	691	796	963	1,133	1,352	1,416	1,455	1,342	1,136	947	732	637	12,601
25	RPS-Eligible Contracts - Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
26	RPS-Eligible Future Contracts	1	1	1	1	1	1	1	0	0	1	1	1	10
27	RPS-Eligible Future Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Other Bilateral Contracts													
29	Fossil Contracts - Non-CHP	[redacted]												
30	Fossil Contracts - CHP													
31	Large Hydro													
32	Non-RPS-Eligible Hydro Sales													
33	Energy Storage													
34	Future Imports													

TABLE 4-3
2027 ENERGY SUPPLY
(GWH)
(CONTINUED)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
35	Ongoing Competition Transition Charge (CTC)													
36	Pre-2002 Contracted Resources													
37	Irrigation District & Water Agency	[redacted]												
38	MWD Etiw anda	0	0	0	0	0	0	0	0	0	0	0	0	0
39	Puget Sound Pow er & Light Contract (Net)	[redacted]												
40	QF													
41	Public Policy Charge Procurement (PPCP)													
42	QF													
43	Bioenergy Market Adjusting Tariff (BioMAT)													
44	Post-2002 Contracted Resources													
45	RPS Eligible													
46	RPS-Eligible Contracts	9	8	8	9	11	11	12	13	12	12	12	11	127
47	Tree Mortality Non-Bypassable Charge (TMNBC)													
48	Post-2002 Contracted Resources													
49	RPS Eligible													
50	RPS-Eligible Contracts	36	35	34	29	39	32	38	41	41	42	24	24	417
51	RPS-Eligible Contracts - Sales	(33)	(30)	(30)	(33)	(39)	(31)	(36)	(41)	(43)	(42)	(23)	(1)	(382)
52	RPS-Eligible Future Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0
53	RPS-Eligible Future Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
54	Modified Cost Allocation Mechanism (MCAM)													
55	Post-2002 Contracted Resources													
56	Other Bilateral Contracts	[redacted]												
57	Energy Storage													
58	Energy Resource Recovery Account (ERRA)													
59	Post-2002 Contracted Resources													
60	Other Bilateral Contracts													
61	Future Non-RPS-Eligible Hydro Sales													
62	Non-RPS-Eligible Hydro Sales													
63	Imports													
64	RA Contracts													
65	Energy Storage													
66	Utility-Ow ned Generation													
67	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0
68	Energy Storage	[redacted]												
69	**Total Supply**													

Note: Totals may not add due to rounding.

TABLE 4-4
2027 RPS ENERGY SUPPLY
(GWH)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	Energy Supply (GWh)													
2	Cost Allocation Mechanism (CAM)													
3	Utility-Owned Generation													
4	Energy Storage	[redacted]												
5	Post-2002 Contracted Resources													
6	Other Bilateral Contracts													
7	Fossil Contracts - Non-CHP													
8	Fossil Contracts - CHP													
9	Energy Storage													
10	QF													
11	Imports													
12	Power Charge Indifference Adjustment (PCIA)													
13	Utility-Owned Generation													
14	Nuclear													
15	Hydro	78	64	58	62	84	70	62	59	58	52	46	69	762
16	Fossil	[redacted]												
17	Solar	14	17	20	23	27	28	30	27	24	22	16	12	260
18	Fuel Cell	[redacted]												
19	Energy Storage													
20	Pre-2003 Contracted Resources													
21	QF													
22	Post-2002 Contracted Resources													
23	RPS Eligible													
24	RPS-Eligible Contracts	859	939	1,101	1,294	1,525	1,591	1,609	1,496	1,291	1,117	899	807	14,529
25	RPS-Eligible Contracts - Sales	[redacted]												
26	RPS-Eligible Future Contracts	1	1	1	1	1	1	1	0	0	1	1	1	10
27	RPS-Eligible Future Sales	[redacted]												
28	Other Bilateral Contracts													
29	Fossil Contracts - Non-CHP													
30	Fossil Contracts - CHP													
31	Large Hydro													
32	Non-RPS-Eligible Hydro Sales													
33	Energy Storage													

TABLE 4-4
2027 RPS ENERGY SUPPLY
(GWH)
(CONTINUED)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
34	Ongoing Competition Transition Charge (CTC)													
35	Pre-2002 Contracted Resources													
36	Irrigation District & Water Agency	[redacted]												
37	MWD Etiwanda	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Puget Sound Power & Light Contract (Net)	[redacted]												
39	QF													
40	Public Policy Charge Procurement (PPCP)													
41	QF	[redacted]												
42	Bioenergy Market Adjusting Tariff (BioMAT)													
43	Post-2002 Contracted Resources													
44	RPS Eligible													
45	RPS-Eligible Contracts	9	8	8	9	11	11	12	13	12	12	12	11	127
46	Tree Mortality Non-Bypassable Charge (TMNBC)													
47	Post-2002 Contracted Resources													
48	RPS Eligible													
49	RPS-Eligible Contracts	36	35	34	29	39	32	38	41	41	42	24	24	417
50	RPS-Eligible Contracts - Sales	(33)	(30)	(30)	(33)	(39)	(31)	(36)	(41)	(43)	(42)	(23)	(1)	(382)
51	RPS-Eligible Future Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0
52	RPS-Eligible Future Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
53	Modified Cost Allocation Mechanism (MCAM)													
54	Post-2002 Contracted Resources													
55	Other Bilateral Contracts													
56	Energy Storage	[redacted]												
57	Energy Resource Recovery Account (ERRA)													
58	Post-2002 Contracted Resources													
59	Other Bilateral Contracts													
60	QF	[redacted]												
61	Energy Storage													
62	RPS-Eligible Future Contracts													
63	Utility-Owned Generation													
64	Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
65	Energy Storage	[redacted]												
66	**Total Supply**	[redacted]												

Note: Totals may not add due to rounding.

TABLE 4-5
2027 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	[redacted]												
5	Post-2002 Contracted Resources													
6	Other Bilateral Contracts													
7	Fossil Contracts - Non-CHP	[redacted]												
8	Fossil Contracts - CHP													
9	Energy Storage Contracts													
10	QF													
	Future RA Contracts													
11	Imports													
12	CPE Administrative	198	199	202	202	220	220	220	220	210	313	199	199	2,603
13	Power Charge Indifference Adjustment (PCIA)													
14	Utility-Owned Generation													
15	Nuclear	[redacted]												
16	Hydro													
17	Fossil													
18	Solar													
19	Fuel Cell													
20	Energy Storage													
21	Pre-2003 Contracted Resources													
22	QF													
23	Post-2002 Contracted Resources													
24	RPS Eligible													
25	RPS-Eligible Contracts	[redacted]												
26	RPS-Eligible Contracts - Sales													
27	RPS-Eligible Future Contracts													
28	RPS-Eligible Future Sales													
29	Other Bilateral Contracts													
30	Fossil Contracts - Non-CHP													
31	Fossil Contracts - CHP													
32	Large Hydro													
33	Energy Storage Contracts													
34	Future RA Contracts													
35	RA Contracts - Sales													
36	Non-RPS-Eligible Hydro Sale													

TABLE 4-5
2027 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	[redacted]												
39	Irrigation District & Water Agency													
40	MWD Etiw anda													
41	Puget Sound Pow er & Light Contract (Net)													
42	QF													
43	Public Policy Charge Procurement (PPCP)													
44	QF													
45	Bioenergy Market Adjusting Tariff (BioMAT)													
46	Post-2002 Contracted Resources													
47	RPS Eligible													
48	RPS-Eligible Contracts													
49	Tree Mortality Non-Bypassable Charge (TMNBC)													
50	Post-2002 Contracted Resources													
51	RPS Eligible													
52	RPS-Eligible Contracts													
53	RPS-Eligible Contracts - Sales													
54	RPS-Eligible Future Contracts													
55	RPS-Eligible Future Sales													
56	RA Contracts - Sales													
57	Modified Cost Allocation Mechanism (MCAM)													
58	Post-2002 Contracted Resources													
59	Other Bilateral Contracts													
60	Energy Storage Contracts													
61	Energy Resource Recovery Account (ERRA)													
62	Utility-Ow ned Generation													
63	Energy Storage													
64	Other Bilateral Contracts													
65	Future Non-RPS-Eligible Hydro Sales													
66	Non-RPS-Eligible Hydro Sales													
67	QF													
68	RA Contracts													
69	RPS-Eligible Future Contracts													
70	RPS-Eligible Future Sales													
71	**Total Costs**	**181,322**	**172,683**	**166,421**	**177,191**	**199,333**	**289,475**	**295,419**	**283,850**	**267,603**	**206,560**	**174,670**	**176,759**	**2,591,287**

TABLE 4-6
2027 BUNDLED PORTFOLIO SYSTEM RA – JANUARY
(MEGAWATTS (MW))

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Capacity Supply (MW)																								
2	Cost Allocation Mechanism (CAM)																								
3	Utility-Owned Generation	[redacted]																							
4	Energy Storage																								
5	Post-2002 Contracted Resources																								
6	Other Bilateral Contracts																								
7	Fossil Contracts - Non-CHP																								
8	Fossil Contracts - CHP																								
9	QF																								
10	Energy Storage																								
11	Imports																								
12	Power Charge Indifference Adjustment (PCIA)																								
13	Utility-Owned Generation																								
14	Hydro																								
15	Fossil																								
16	Solar																								
17	Pre-2003 Contracted Resources																								
18	QF																								
19	Post-2002 Contracted Resources																								
20	RPS Eligible																								
21	RPS-Eligible Contracts																								
22	RPS-Eligible Future Contracts																								
23	Other Bilateral Contracts																								
24	Fossil Contracts - CHP																								
25	Fossil Contracts - Non-CHP																								
26	Large Hydro																								
27	Energy Storage																								
28	RA Contracts - Sales																								
29	Future RA Contracts																								
30	Bioenergy Market Adjusting Tariff (BioMAT)																								
31	Post-2002 Contracted Resources																								
32	RPS Eligible																								
33	RPS-Eligible Contracts																								
34	Ongoing Competition Transition Charge (CTC)																								
35	Pre-2002 Contracted Resources																								
36	Irrigation District & Water Agency																								
37	MWD Etiwanda																								
38	QF																								
39	Puget Sound Power & Light (Receive)																								

TABLE 4-6
2027 BUNDLED PORTFOLIO SYSTEM RA – JANUARY
(MW)
(CONTINUED)

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
40	Public Policy Charge Procurement (PPCP)	[redacted]																							
41	QF																								
42	Energy Resource Recovery Account (ERRA)																								
43	Utility-Owned Generation																								
44	Energy Storage																								
45	Post-2002 Contracted Resources																								
46	RA Contracts																								
47	GTSR																								
48	RPS-Eligible Contracts	0	0	0	0	0	0	0	5	39	75	93	102	102	96	90	61	13	0	0	0	0	0	0	0
49	DCPP Extended Operations (DCPP_NBC_CA)	[redacted]																							
50	Nuclear																								
51	**Total Net Supply**																								

TABLE 4-7
2027 BUNDLED PORTFOLIO SYSTEM RA – FEBRUARY
(MW)

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Capacity Supply (MW)																								
2	Cost Allocation Mechanism (CAM)																								
3	Utility-Owned Generation	[redacted]																							
4	Energy Storage																								
5	Post-2002 Contracted Resources																								
6	Other Bilateral Contracts																								
7	Fossil Contracts - Non-CHP																								
8	Fossil Contracts - CHP																								
9	QF																								
10	Energy Storage																								
11	Imports																								
12	Power Charge Indifference Adjustment (PCIA)																								
13	Utility-Owned Generation																								
14	Hydro																								
15	Fossil																								
16	Solar																								
17	Pre-2003 Contracted Resources																								
18	QF																								
19	Post-2002 Contracted Resources																								
20	RPS Eligible																								
21	RPS-Eligible Contracts																								
22	RPS-Eligible Future Contracts																								
23	Other Bilateral Contracts																								
24	Fossil Contracts - CHP																								
25	Fossil Contracts - Non-CHP																								
26	Large Hydro																								
27	Energy Storage																								
28	RA Contracts - Sales																								
29	Future RA Contracts																								
30	Bioenergy Market Adjusting Tariff (BioMAT)																								
31	Post-2002 Contracted Resources																								
32	RPS Eligible																								
33	RPS-Eligible Contracts																								
34	Ongoing Competition Transition Charge (CTC)																								
35	Pre-2002 Contracted Resources																								
36	Irrigation District & Water Agency																								
37	MWD Etiwanda																								
38	QF																								
39	Puget Sound Power & Light (Receive)																								
40	Public Policy Charge Procurement (PPCP)																								
41	QF																								
42	Energy Resource Recovery Account (ERRA)																								
43	Utility-Owned Generation																								
44	Energy Storage																								
45	Post-2002 Contracted Resources																								
46	RA Contracts																								
47	GTSR																								
48	RPS-Eligible Contracts	0	0	0	0	0	0	0	34	141	177	182	173	171	170	172	146	76	4	0	0	0	0	0	0
49	DCPP Extended Operations (DCPP_NBC_CA)	[redacted]																							
50	Nuclear																								
51	**Total Net Supply**																								

TABLE 4-8
2027 BUNDLED PORTFOLIO SYSTEM RA – MARCH
(MW)

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Capacity Supply (MW)																								
2	Cost Allocation Mechanism (CAM)																								
3	Utility-Owned Generation	[redacted]																							
4	Energy Storage																								
5	Post-2002 Contracted Resources																								
6	Other Bilateral Contracts																								
7	Fossil Contracts - Non-CHP																								
8	Fossil Contracts - CHP																								
9	QF																								
10	Energy Storage																								
11	Imports																								
12	Power Charge Indifference Adjustment (PCIA)																								
13	Utility-Owned Generation																								
14	Hydro																								
15	Fossil																								
16	Solar																								
17	Pre-2003 Contracted Resources																								
18	QF																								
19	Post-2002 Contracted Resources																								
20	RPS Eligible																								
21	RPS-Eligible Contracts																								
22	RPS-Eligible Future Contracts																								
23	Other Bilateral Contracts																								
24	Fossil Contracts - CHP																								
25	Fossil Contracts - Non-CHP																								
26	Large Hydro																								
27	Energy Storage																								
28	RA Contracts - Sales																								
29	Future RA Contracts																								
30	Bioenergy Market Adjusting Tariff (BioMAT)																								
31	Post-2002 Contracted Resources																								
32	RPS Eligible																								
33	RPS-Eligible Contracts																								

TABLE 4-8
2027 BUNDLED PORTFOLIO SYSTEM RA – MARCH
(MW)
(CONTINUED)

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
34	Ongoing Competition Transition Charge (CTC)																								
35	Pre-2002 Contracted Resources	[redacted]																							
36	Irrigation District & Water Agency																								
37	MWD Etiwanda																								
38	QF																								
39	Puget Sound Power & Light (Receive)																								
40	Public Policy Charge Procurement (PPCP)																								
41	QF																								
42	Energy Resource Recovery Account (ERRA)																								
43	Utility-Owned Generation																								
44	Energy Storage																								
45	Post-2002 Contracted Resources																								
46	RA Contracts																								
47	GTSR																								
48	RPS-Eligible Contracts	0	0	0	0	0	0	7	88	165	177	168	172	170	157	145	133	94	22	0	0	0	0	0	0
49	DCPP Extended Operations (DCPP_NBC_CA)																								
50	Nuclear	[redacted]																							
51	**Total Net Supply**																								

TABLE 4-9
2027 BUNDLED PORTFOLIO SYSTEM RA – APRIL
(MW)

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Capacity Supply (MW)																								
2	Cost Allocation Mechanism (CAM)																								
3	Utility-Owned Generation	[redacted]																							
4	Energy Storage																								
5	Post-2002 Contracted Resources																								
6	Other Bilateral Contracts																								
7	Fossil Contracts - Non-CHP																								
8	Fossil Contracts - CHP																								
9	QF																								
10	Energy Storage																								
11	Imports																								
12	Power Charge Indifference Adjustment (PCIA)																								
13	Utility-Owned Generation																								
14	Hydro																								
15	Fossil																								
16	Solar																								
17	Pre-2003 Contracted Resources																								
18	QF																								
19	Post-2002 Contracted Resources																								
20	RPS Eligible																								
21	RPS-Eligible Contracts																								
22	RPS-Eligible Future Contracts																								
23	Other Bilateral Contracts																								
24	Fossil Contracts - CHP																								
25	Fossil Contracts - Non-CHP																								
26	Large Hydro																								
27	Energy Storage																								
28	RA Contracts - Sales																								
29	Future RA Contracts																								
30	Bioenergy Market Adjusting Tariff (BioMAT)																								
31	Post-2002 Contracted Resources																								
32	RPS Eligible																								
33	RPS-Eligible Contracts																								

TABLE 4-9
2027 BUNDLED PORTFOLIO SYSTEM RA – APRIL
(MW)
(CONTINUED)

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
34	Ongoing Competition Transition Charge (CTC)																								
35	Pre-2002 Contracted Resources	[redacted]																							
36	Irrigation District & Water Agency																								
37	MWD Etiwanda																								
38	QF																								
39	Puget Sound Power & Light (Receive)																								
40	Public Policy Charge Procurement (PPCP)																								
41	QF																								
42	Energy Resource Recovery Account (ERRA)																								
43	Utility-Owned Generation																								
44	Energy Storage																								
45	Post-2002 Contracted Resources																								
46	RA Contracts																								
47	GTSR																								
48	RPS-Eligible Contracts	0	0	0	0	0	4	81	180	201	201	198	204	204	201	203	194	174	80	4	0	0	0	0	0
49	DCPP Extended Operations (DCPP_NBC_CA)																								
50	Nuclear	[redacted]																							
51	**Total Net Supply**																								

TABLE 4-10
2027 BUNDLED PORTFOLIO SYSTEM RA – MAY
(MW)

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Capacity Supply (MW)																								
2	Cost Allocation Mechanism (CAM)																								
3	Utility-Owned Generation	[redacted]																							
4	Energy Storage																								
5	Post-2002 Contracted Resources																								
6	Other Bilateral Contracts																								
7	Fossil Contracts - Non-CHP																								
8	Fossil Contracts - CHP																								
9	QF																								
10	Energy Storage																								
11	Imports																								
12	Power Charge Indifference Adjustment (PCIA)																								
13	Utility-Owned Generation																								
14	Hydro																								
15	Fossil																								
16	Solar																								
17	Pre-2003 Contracted Resources																								
18	QF																								
19	Post-2002 Contracted Resources																								
20	RPS Eligible																								
21	RPS-Eligible Contracts																								
22	RPS-Eligible Future Contracts																								
23	Other Bilateral Contracts																								
24	Fossil Contracts - CHP																								
25	Fossil Contracts - Non-CHP																								
26	Large Hydro																								
27	Energy Storage																								
28	RA Contracts - Sales																								
29	Future RA Contracts																								
30	Bioenergy Market Adjusting Tariff (BioMAT)																								
31	Post-2002 Contracted Resources																								
32	RPS Eligible																								
33	RPS-Eligible Contracts																								

TABLE 4-10
2027 BUNDLED PORTFOLIO SYSTEM RA – MAY
(MW)
(CONTINUED)

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
34	Ongoing Competition Transition Charge (CTC)																								
35	Pre-2002 Contracted Resources	[redacted]																							
36	Irrigation District & Water Agency																								
37	MWD Etiw anda																								
38	QF																								
39	Puget Sound Pow er & Light (Receive)																								
40	Public Policy Charge Procurement (PPCP)																								
41	QF																								
42	Energy Resource Recovery Account (ERRA)																								
43	Utility-Ow ned Generation																								
44	Energy Storage																								
45	Post-2002 Contracted Resources																								
46	RA Contracts																								
47	GTSR																								
48	RPS-Eligible Contracts																								
49	DCPP Extended Operations (DCPP_NBC_CA)																								
50	Nuclear																								
51	**Total Net Supply**																								

TABLE 4-11
2027 BUNDLED PORTFOLIO SYSTEM RA – JUNE
(MW)

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Capacity Supply (MW)																								
2	Cost Allocation Mechanism (CAM)																								
3	Utility-Owned Generation	[redacted]																							
4	Energy Storage																								
5	Post-2002 Contracted Resources																								
6	Other Bilateral Contracts																								
7	Fossil Contracts - Non-CHP																								
8	Fossil Contracts - CHP																								
9	QF																								
10	Energy Storage																								
11	Imports																								
12	Power Charge Indifference Adjustment (PCIA)																								
13	Utility-Owned Generation																								
14	Hydro																								
15	Fossil																								
16	Solar																								
17	Pre-2003 Contracted Resources																								
18	QF																								
19	Post-2002 Contracted Resources																								
20	RPS Eligible																								
21	RPS-Eligible Contracts																								
22	RPS-Eligible Future Contracts																								
23	Other Bilateral Contracts																								
24	Fossil Contracts - CHP																								
25	Fossil Contracts - Non-CHP																								
26	Large Hydro																								
27	Energy Storage																								
28	RA Contracts - Sales																								
29	Future RA Contracts																								
30	Bioenergy Market Adjusting Tariff (BioMAT)																								
31	Post-2002 Contracted Resources																								
32	RPS Eligible																								
33	RPS-Eligible Contracts																								

TABLE 4-11
2027 BUNDLED PORTFOLIO SYSTEM RA – JUNE
(MW)
(CONTINUED)

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
34	Ongoing Competition Transition Charge (CTC)																								
35	Pre-2002 Contracted Resources																								
36	Irrigation District & Water Agency	[redacted]																							
37	MWD Etiwanda																								
38	QF																								
39	Puget Sound Power & Light (Receive)																								
40	Public Policy Charge Procurement (PPCP)																								
41	QF																								
42	Energy Resource Recovery Account (ERRA)																								
43	Utility-Owned Generation																								
44	Energy Storage	[redacted]																							
45	Post-2002 Contracted Resources																								
46	RA Contracts																								
47	GTSR																								
48	RPS-Eligible Contracts	0	0	0	0	0	42	155	212	229	233	236	237	237	235	234	228	210	154	43	1	0	0	0	0
49	DCPP Extended Operations (DCPP_NBC_CA)																								
50	Nuclear	[redacted]																							
51	**Total Net Supply**																								

TABLE 4-12
2027 BUNDLED PORTFOLIO SYSTEM RA – JULY
(MW)

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Capacity Supply (MW)																								
2	Cost Allocation Mechanism (CAM)																								
3	Utility-Owned Generation	[redacted]																							
4	Energy Storage																								
5	Post-2002 Contracted Resources																								
6	Other Bilateral Contracts																								
7	Fossil Contracts - Non-CHP																								
8	Fossil Contracts - CHP																								
9	QF																								
10	Energy Storage																								
11	Imports																								
12	Power Charge Indifference Adjustment (PCIA)																								
13	Utility-Owned Generation																								
14	Hydro																								
15	Fossil																								
16	Solar																								
17	Pre-2003 Contracted Resources																								
18	QF																								
19	Post-2002 Contracted Resources																								
20	RPS Eligible																								
21	RPS-Eligible Contracts																								
22	RPS-Eligible Future Contracts																								
23	Other Bilateral Contracts																								
24	Fossil Contracts - CHP																								
25	Fossil Contracts - Non-CHP																								
26	Large Hydro																								
27	Energy Storage																								
28	RA Contracts - Sales																								
29	Future RA Contracts																								
30	Bioenergy Market Adjusting Tariff (BioMAT)																								
31	Post-2002 Contracted Resources																								
32	RPS Eligible																								
33	RPS-Eligible Contracts																								
34	Ongoing Competition Transition Charge (CTC)																								
35	Pre-2002 Contracted Resources																								
36	Irrigation District & Water Agency																								
37	MWD Etiwanda																								
38	QF																								
39	Puget Sound Power & Light (Receive)																								
40	Public Policy Charge Procurement (PPCP)																								
41	QF																								
42	Energy Resource Recovery Account (ERRA)																								
43	Utility-Owned Generation																								
44	Energy Storage																								
45	Post-2002 Contracted Resources																								
46	RA Contracts																								
47	GTSR																								
48	RPS-Eligible Contracts	2	2	2	2	2	21	127	205	228	232	235	234	234	231	230	220	202	141	35	2	2	2	2	2
49	DCPP Extended Operations (DCPP_NBC_CA)	[redacted]																							
50	Nuclear																								
51	**Total Net Supply**																								

TABLE 4-13
2027 BUNDLED PORTFOLIO SYSTEM RA – AUGUST
(MW)

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Capacity Supply (MW)																								
2	Cost Allocation Mechanism (CAM)																								
3	Utility-Owned Generation	[redacted]																							
4	Energy Storage																								
5	Post-2002 Contracted Resources																								
6	Other Bilateral Contracts																								
7	Fossil Contracts - Non-CHP																								
8	Fossil Contracts - CHP																								
9	QF																								
10	Energy Storage																								
11	Imports																								
12	Power Charge Indifference Adjustment (PCIA)																								
13	Utility-Owned Generation																								
14	Hydro																								
15	Fossil																								
16	Solar																								
17	Pre-2003 Contracted Resources																								
18	QF																								
19	Post-2002 Contracted Resources																								
20	RPS Eligible																								
21	RPS-Eligible Contracts																								
22	RPS-Eligible Future Contracts																								
23	Other Bilateral Contracts																								
24	Fossil Contracts - CHP																								
25	Fossil Contracts - Non-CHP																								
26	Large Hydro																								
27	Energy Storage																								
28	RA Contracts - Sales																								
29	Future RA Contracts																								
30	Bioenergy Market Adjusting Tariff (BioMAT)																								
31	Post-2002 Contracted Resources																								
32	RPS Eligible																								
33	RPS-Eligible Contracts																								
34	Ongoing Competition Transition Charge (CTC)																								
35	Pre-2002 Contracted Resources																								
36	Irrigation District & Water Agency																								
37	MWD Etiwanda																								
38	QF																								
39	Puget Sound Power & Light (Receive)																								
40	Public Policy Charge Procurement (PPCP)																								
41	QF																								
42	Energy Resource Recovery Account (ERRA)																								
43	Utility-Owned Generation																								
44	Energy Storage																								
45	Post-2002 Contracted Resources																								
46	RA Contracts																								
47	GTSR																								
48	RPS-Eligible Contracts	2	2	2	2	2	5	75	172	209	220	222	224	223	221	219	205	167	75	6	2	2	2	2	2
49	DCPP Extended Operations (DCPP_NBC_CA)	[redacted]																							
50	Nuclear																								
51	**Total Net Supply**																								

TABLE 4-14
2027 BUNDLED PORTFOLIO SYSTEM RA – SEPTEMBER
(MW)

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Capacity Supply (MW)																								
2	Cost Allocation Mechanism (CAM)																								
3	Utility-Owned Generation	[redacted]																							
4	Energy Storage																								
5	Post-2002 Contracted Resources																								
6	Other Bilateral Contracts																								
7	Fossil Contracts - Non-CHP																								
8	Fossil Contracts - CHP																								
9	QF																								
10	Energy Storage																								
11	Imports																								
12	Power Charge Indifference Adjustment (PCIA)																								
13	Utility-Owned Generation																								
14	Hydro																								
15	Fossil																								
16	Solar																								
17	Pre-2003 Contracted Resources																								
18	QF																								
19	Post-2002 Contracted Resources																								
20	RPS Eligible																								
21	RPS-Eligible Contracts																								
22	RPS-Eligible Future Contracts																								
23	Other Bilateral Contracts																								
24	Fossil Contracts - CHP																								
25	Fossil Contracts - Non-CHP																								
26	Large Hydro																								
27	Energy Storage																								
28	RA Contracts - Sales																								
29	Future RA Contracts																								
30	Bioenergy Market Adjusting Tariff (BioMAT)																								
31	Post-2002 Contracted Resources																								
32	RPS Eligible																								
33	RPS-Eligible Contracts																								
34	Ongoing Competition Transition Charge (CTC)																								
35	Pre-2002 Contracted Resources																								
36	Irrigation District & Water Agency																								
37	MWD Etiwanda																								
38	QF																								
39	Puget Sound Power & Light (Receive)																								
40	Public Policy Charge Procurement (PPCP)																								
41	QF																								
42	Energy Resource Recovery Account (ERRA)																								
43	Utility-Owned Generation																								
44	Energy Storage																								
45	Post-2002 Contracted Resources																								
46	RA Contracts																								
47	GTSR																								
48	RPS-Eligible Contracts	2	2	2	2	2	2	44	152	193	200	200	198	198	201	200	188	124	26	2	2	2	2	2	2
49	DCPP Extended Operations (DCPP_NBC_CA)	[redacted]																							
50	Nuclear																								
51	**Total Net Supply**																								

TABLE 4-15
2027 BUNDLED PORTFOLIO SYSTEM RA – OCTOBER
(MW)

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Capacity Supply (MW)																								
2	Cost Allocation Mechanism (CAM)																								
3	Utility-Owned Generation	[redacted]																							
4	Energy Storage																								
5	Post-2002 Contracted Resources																								
6	Other Bilateral Contracts																								
7	Fossil Contracts - Non-CHP																								
8	Fossil Contracts - CHP																								
9	QF																								
10	Energy Storage																								
11	Imports																								
12	Power Charge Indifference Adjustment (PCIA)																								
13	Utility-Owned Generation																								
14	Hydro																								
15	Fossil																								
16	Solar																								
17	Pre-2003 Contracted Resources																								
18	QF																								
19	Post-2002 Contracted Resources																								
20	RPS Eligible																								
21	RPS-Eligible Contracts																								
22	RPS-Eligible Future Contracts																								
23	Other Bilateral Contracts																								
24	Fossil Contracts - CHP																								
25	Fossil Contracts - Non-CHP																								
26	Large Hydro																								
27	Energy Storage																								
28	RA Contracts - Sales																								
29	Future RA Contracts																								
30	Bioenergy Market Adjusting Tariff (BioMAT)																								
31	Post-2002 Contracted Resources																								
32	RPS Eligible																								
33	RPS-Eligible Contracts																								
34	Ongoing Competition Transition Charge (CTC)																								
35	Pre-2002 Contracted Resources																								
36	Irrigation District & Water Agency																								
37	MWD Etiwanda																								
38	QF																								
39	Puget Sound Power & Light (Receive)																								
40	Public Policy Charge Procurement (PPCP)																								
41	QF																								
42	Energy Resource Recovery Account (ERRA)																								
43	Utility-Owned Generation																								
44	Energy Storage																								
45	Post-2002 Contracted Resources																								
46	RA Contracts																								
47	GTSR																								
48	RPS-Eligible Contracts	6	6	6	6	6	6	18	106	172	179	176	172	173	176	174	146	53	7	6	6	6	6	6	6
49	DCPP Extended Operations (DCPP_NBC_CA)																								
50	Nuclear	[redacted]																							
51	Total Net Supply																								

TABLE 4-16
2027 BUNDLED PORTFOLIO SYSTEM RA – NOVEMBER
(MW)

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Capacity Supply (MW)																								
2	Cost Allocation Mechanism (CAM)																								
3	Utility-Owned Generation	[redacted]																							
4	Energy Storage	[redacted]																							
5	Post-2002 Contracted Resources	[redacted]																							
6	Other Bilateral Contracts	[redacted]																							
7	Fossil Contracts - Non-CHP	[redacted]																							
8	Fossil Contracts - CHP	[redacted]																							
9	QF	[redacted]																							
10	Energy Storage	[redacted]																							
11	Imports	[redacted]																							
12	Power Charge Indifference Adjustment (PCIA)	[redacted]																							
13	Utility-Owned Generation	[redacted]																							
14	Hydro	[redacted]																							
15	Fossil	[redacted]																							
16	Solar	[redacted]																							
17	Pre-2003 Contracted Resources	[redacted]																							
18	QF	[redacted]																							
19	Post-2002 Contracted Resources	[redacted]																							
20	RPS Eligible	[redacted]																							
21	RPS-Eligible Contracts	[redacted]																							
22	RPS-Eligible Future Contracts	[redacted]																							
23	Other Bilateral Contracts	[redacted]																							
24	Fossil Contracts - CHP	[redacted]																							
25	Fossil Contracts - Non-CHP	[redacted]																							
26	Large Hydro	[redacted]																							
27	Energy Storage	[redacted]																							
28	RA Contracts - Sales	[redacted]																							
29	Future RA Contracts	[redacted]																							
30	Bioenergy Market Adjusting Tariff (BioMAT)	[redacted]																							
31	Post-2002 Contracted Resources	[redacted]																							
32	RPS Eligible	[redacted]																							
33	RPS-Eligible Contracts	[redacted]																							
34	Ongoing Competition Transition Charge (CTC)	[redacted]																							
35	Pre-2002 Contracted Resources	[redacted]																							
36	Irrigation District & Water Agency	[redacted]																							
37	MWD Etiwanda	[redacted]																							
38	QF	[redacted]																							
39	Puget Sound Power & Light (Receive)	[redacted]																							
40	Public Policy Charge Procurement (PPCP)	[redacted]																							
41	QF	[redacted]																							
42	Energy Resource Recovery Account (ERRA)	[redacted]																							
43	Utility-Owned Generation	[redacted]																							
44	Energy Storage	[redacted]																							
45	Post-2002 Contracted Resources	[redacted]																							
46	RA Contracts	[redacted]																							
47	GTSR	[redacted]																							
48	RPS-Eligible Contracts	[redacted]																							
49	DCPP Extended Operations (DCPP_NBC_CA)	[redacted]																							
50	Nuclear	[redacted]																							
51	**Total Net Supply**	[redacted]																							

TABLE 4-17
2027 BUNDLED PORTFOLIO SYSTEM RA – DECEMBER
(MW)

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Capacity Supply (MW)																								
2	Cost Allocation Mechanism (CAM)																								
3	Utility-Owned Generation	[redacted]																							
4	Energy Storage	[redacted]																							
5	Post-2002 Contracted Resources	[redacted]																							
6	Other Bilateral Contracts	[redacted]																							
7	Fossil Contracts - Non-CHP	[redacted]																							
8	Fossil Contracts - CHP	[redacted]																							
9	QF	[redacted]																							
10	Energy Storage	[redacted]																							
11	Imports	[redacted]																							
12	Power Charge Indifference Adjustment (PCIA)	[redacted]																							
13	Utility-Owned Generation	[redacted]																							
14	Hydro	[redacted]																							
15	Fossil	[redacted]																							
16	Solar	[redacted]																							
17	Pre-2003 Contracted Resources	[redacted]																							
18	QF	[redacted]																							
19	Post-2002 Contracted Resources	[redacted]																							
20	RPS Eligible	[redacted]																							
21	RPS-Eligible Contracts	[redacted]																							
22	RPS-Eligible Future Contracts	[redacted]																							
23	Other Bilateral Contracts	[redacted]																							
24	Fossil Contracts - CHP	[redacted]																							
25	Fossil Contracts - Non-CHP	[redacted]																							
26	Large Hydro	[redacted]																							
27	Energy Storage	[redacted]																							
28	RA Contracts - Sales	[redacted]																							
29	Future RA Contracts	[redacted]																							
30	Bioenergy Market Adjusting Tariff (BioMAT)	[redacted]																							
31	Post-2002 Contracted Resources	[redacted]																							
32	RPS Eligible	[redacted]																							
33	RPS-Eligible Contracts	[redacted]																							
34	Ongoing Competition Transition Charge (CTC)	[redacted]																							
35	Pre-2002 Contracted Resources	[redacted]																							
36	Irrigation District & Water Agency	[redacted]																							
37	MWD Etiwanda	[redacted]																							
38	QF	[redacted]																							
39	Puget Sound Power & Light (Receive)	[redacted]																							
40	Public Policy Charge Procurement (PPCP)	[redacted]																							
41	QF	[redacted]																							
42	Energy Resource Recovery Account (ERRA)	[redacted]																							
43	Utility-Owned Generation	[redacted]																							
44	Energy Storage	[redacted]																							
45	Post-2002 Contracted Resources	[redacted]																							
46	RA Contracts	[redacted]																							
47	GTSR																								
48	RPS-Eligible Contracts	6	6	6	6	6	6	6	14	58	93	112	118	115	111	103	60	12	6	6	6	6	6	6	6
49	DCPP Extended Operations (DCPP_NBC_CA)	[redacted]																							
50	Nuclear	[redacted]																							
51	**Total Net Supply**	[redacted]																							

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

BUNDLED PORTFOLIO OPEN POSITIONS

AND OTHER COSTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
BUNDLED PORTFOLIO OPEN POSITIONS
AND OTHER COSTS

TABLE OF CONTENTS

A. Introduction 5-1

B. Electric Portfolio Hedge Transactions Costs 5-1

1. PG&E's Electric Portfolio Hedging Program 5-1

2. Costs Incurred at Trade Execution 5-3

3. Costs Incurred at Trade Settlement 5-3

4. Collateral for Physical and Financial Transactions 5-6

5. Net Interest Paid on Collateral Posted to PG&E by Its Counterparties 5-6

C. System RA Open Position and Associated Net Costs 5-7

1. Bundled System RA Requirement 5-7

2. Bundled System Open RA Position 5-8

a. Storage Heuristic 5-9

b. Unsold RA 5-11

c. Final Open Position Forecasts 5-11

d. PCIA Aggregation Under the SoD Framework 5-11

D. RPS Net Position 5-12

E. CAISO and Other Costs 5-13

1. CAISO Generator and Load Costs 5-13

2. Interstate Gas Transportation Costs 5-14

F. Conclusion 5-14

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
BUNDLED PORTFOLIO OPEN POSITIONS AND OTHER COSTS

A. Introduction

The purpose of this chapter is to present Pacific Gas and Electric Company's (PG&E) 2027 forecast of non-generator specific costs and certain bundled portfolio open positions. These include forecasts of electric portfolio hedge transactions, collateral costs, California Independent System Operator (CAISO) costs, and other procurement costs, as well as the bundled portfolio net positions for system Resource Adequacy (RA) and Renewables Portfolio Standard (RPS)-eligible generation.

B. Electric Portfolio Hedge Transactions Costs

This section presents the 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 contracts, Qualifying Facilities receiving short-run avoided cost or variable energy pricing from the Independent Energy Producers settlement,[1] the costs of greenhouse gas (GHG) compliance, as well as the natural gas cost of PG&E owned and contracted generation resources.

Consistent with PG&E's advice letter (AL) implementing Decision (D.)18-10-019 in Phase 1 of the Power Charge Indifference Adjustment (PCIA) Rulemaking, any utility hedging costs and benefits are recorded in the Energy Resource Recovery Account (ERRA) 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.[2]

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

---

[1] D.06-07-032.

[2] PG&E AL 5440-E.

develop procurement plans that address, among other things, measurement, and management of commodity price risk. In addition, the California Public Utilities Commission (CPUC or Commission) expressly approved such procurement plans in its generation procurement decisions—specifically, 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, D.12-01-033 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, and PG&E last revised its Hedging Plan on January 21, 2024.[5] PG&E's forecasted 2027 hedging transactions are consistent with its current Hedging Plan.

PG&E's hedging forecast is based on market conditions as of March 26, 2026. The forecast assumes that hedge transactions executed after this date will be settled at the price executed. In other words, PG&E assumes the mark-to-market (MtM)[6] of future hedging transactions to be zero.[7] The estimated costs, described in more detail below, are divided into

---

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 updated Hedging Plan was submitted in AL 7108-E and approved without modification on January 21, 2024.

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.

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 2027 hedging transactions is presented in Table 5-1. PG&E's actual costs in 2027 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 2027 is listed in Table 5-1, line 2.

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 hedging instruments is detailed in its Hedging Plan. The forecast for option premium costs that PG&E will incur in 2027 is shown in Table 5-1, line 3.

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 March 26, 2026 market conditions.

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

---

[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.

futures from the hedging program with delivery periods in 2027 in PG&E's portfolio as of March 26, 2026, is listed on line 6 in Table 5-1. The MtM value of the futures contracts with delivery periods in 2027 that have not been executed, but will be executed between March 27, 2026, and December 31, 2027, is zero.

The estimated settlement value of options with delivery periods in 2027 is best represented by the current market value of the options, which is the options' premium value on March 26, 2026. PG&E calculates option premiums using the Black 76 formula with current forward prices and volatilities.[9] PG&E's estimate of the market value of executed options with delivery periods in 2027 is listed in Table 5-1, line 7.

---

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.

TABLE 5-1
2027 FORECAST OF NATURAL GAS AND ELECTRIC HEDGE TRANSACTION COSTS
(THOUSANDS OF DOLLARS)

Line No.	Description	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total
1	Costs Incurred at Trade Execution													
2	Exchange and Broker Fees	[redacted]												
3	Option Premiums													
4	Total Costs Incurred at Trade Execution													
5	Costs Incurred at Trade Settlement													
6	Mark-to-market of Futures as of March 26, 2026													
7	Mark-to-market of Options as of March 26, 2026													
8	Total Costs Incurred at Trade Settlement													
9	**Net Hedging Cost**													

PG&E separates its forecast 2027 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.

4. 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. The forecasted annual cost for posting cash is approximately 5.11 percent, on average.

PG&E's forecast includes carrying costs associated with physical GHG emissions compliance instrument inventories for PG&E's Utility-Owned Generation (UOG) and contracts.

PG&E's estimate of the fees is shown in Table 5-2.

5. 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

---

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.

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 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 5-2.

TABLE 5-2
SUMMARY OF 2027 FORECAST COLLATERAL COSTS
(THOUSANDS OF DOLLARS)

Line No.	Collateral Costs	Amount
1	Collateral on Physical and Financial Transactions	$6,835
2	GHG Inventory Carrying Costs	1,014
3	Net Interest Paid on Collateral Posted to PG&E	(332)
4	Total	$7,518

C. System RA Open Position and Associated Net Costs

This section presents PG&E's forecast of its 2027 Slice-of-Day (SoD) system RA open position volumes and associated costs. PG&E's SoD RA open position is based on a forecast of PG&E's year-ahead bundled customer SoD RA requirements and SoD supply, including supply from energy storage (storage) resources, adjusted for forecasted Unsold RA in months where PG&E projects to have excess SoD RA capacity. PG&E's proposal for 2027 is consistent with the interim process approved by the CPUC in D.25-12-027 and implemented by AL 7280-E.

1. Bundled System RA Requirement

As introduced in Chapter 4, PG&E must maintain sufficient SoD Net Qualifying Capacity (NQC) supply to meet the SoD requirements that are set by the CPUC. The requirements are developed by the CPUC in conjunction with the California Energy Commission (CEC) as part of an annual process whereby Load-Serving Entities (LSE) submit hourly load forecasts for the upcoming year to the CEC in the Spring of the current year. The CEC then harmonizes the forecasts by making adjustments for peak coincidence and other factors. Once complete, the final year-ahead SoD RA requirements are provided to LSEs by the CPUC, typically by September of the current year. Given the timing for the final year-ahead requirements, PG&E will utilize estimates of its 2027 SoD RA requirements for its initial forecast that are based on PG&E's 2026 SoD requirements adjusted for estimated changes.[11] The initial estimates will then be replaced by the Commission-issued 2027 SoD requirements as part of PG&E's Fall Update forecast.

2. Bundled System Open RA Position

PG&E follows a multi-step process to forecast the bundled system RA open position under SoD. The first step consists of calculating an initial pre-storage open position by subtracting the total available RA supply, excluding storage, from the forecasted requirement in each of the 24-hourly slices in each month of the forecast horizon. For PG&E, the pre-storage open position typically displays a pattern where the portfolio is long during hours in the middle of day and (relatively) short during the remaining hours. The mid-day length is a measure of the portfolio's available storage charging capacity. Once the pre-storage open position is determined, PG&E uses a modeling heuristic to generate an aggregate storage charge/discharge profile that spans the 24-hourly slices and satisfies the SoD RA charging sufficiency requirement. The storage heuristic takes into account the aggregate amount of storage megawatts available in the bundled supply portfolio as well as the available charging capacity in each month. The resulting charge and discharge hourly profile[12] for the aggregate storage supply is then added to the initial open position to generate a storage-adjusted open position. The final step consists of accounting for estimated unsold capacity from the storage-adjusted open position for hours projected to have excess supply.

---

[11] Initial forecast estimates of the 2027 SoD requirements were based on PG&E's 2026 SoD requirements and then scaled by the ratio of the 2025 IEPR PGE TAC coincident monthly-peak-day forecast for 2027 and the 2024 IEPR PGE TAC coincident monthly-peak-day forecast for 2026

[12] PG&E has adopted the convention where storage charging is shown as a negative number and storage discharging is shown as a positive number.

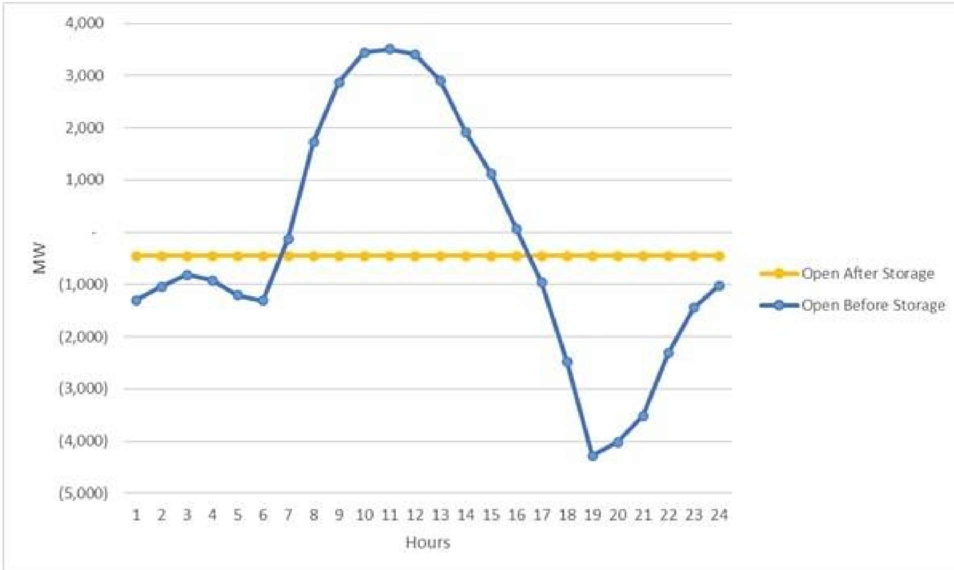
The storage heuristic and the determination of unsold capacity are outlined in more detail in the sections below.

a. Storage Heuristic

As noted in Chapter 4, there is no set storage RA charge and discharge profile under SoD as LSEs are able to apply RA supply from energy storage resources in any hours needed, as long as they meet the RA charging sufficiency requirements.[13] However, in order to forecast residual capacity purchases and sales, an estimate of the RA charge and discharge profile for storage resources is required. To that end, PG&E has developed an algorithm that allocates the available storage RA charging and discharging capacity in a manner that seeks to minimize PG&E's SoD RA open position across all hours. Figure 5-1 shows a stylized depiction of the modeling results when the portfolio contains sufficient storage capacity and charging resources so that the algorithm is able to achieve an equal (minimized) open position across all 24 hours. In this instance, the algorithm is able to find a line spanning all 24 hours, such that the area below it (aggregate discharging volume) is equal to the area above it (aggregate charging volume), minus the storage efficiency losses.

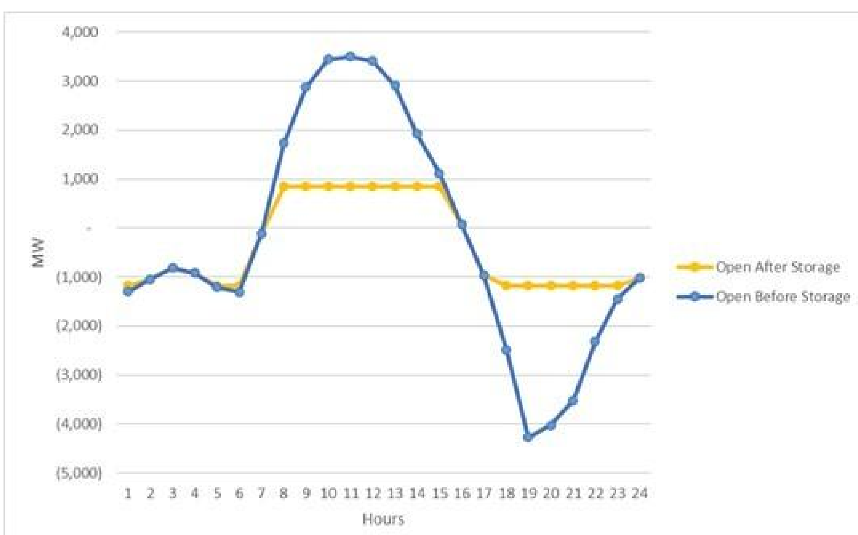
[13] Consistent with all charging sufficiency constraints.

FIGURE 5-1
CASE 1: AVAILABLE STORAGE SUFFICIENT TO REACH UNIFORM HOURLY OPEN POSITION



However, there are months when the algorithm is constrained by the amount of storage capacity and charging resources contained in the portfolio and is unable to reach a uniform minimum open position in all hours as depicted in Figure 5-1. In this instance the algorithm will fully allocate the available storage, but the resulting open position will not be uniform across all 24 hours as shown in Figure 5-2.

FIGURE 5-2
CASE 2: AVAILABLE STORAGE UNABLE TO REACH UNIFORM HOURLY OPEN POSITIONS



b. Unsold RA

Consistent with D.19-10-001 and adopted retained RA settlement processes, PG&E incorporates an adjustment for forecasted Unsold RA capacity during months when PG&E forecasts significant excess system RA supply and when the market has historically shown little ability to absorb the excess resources. PG&E proposes to continue basing the Unsold RA allocation factors on historical monthly peak data. The monthly factors are calculated as the ratio of the historic Unsold RA to the open position, before considering RA sales, and then averaged to form quarterly unsold factors. These Unsold RA factors are then applied to the hourly storage-adjusted open positions in each month to calculate the final hourly unsold adjustment amounts.

c. Final Open Position Forecasts

Tables 5-4 through 5-15, showing the full calculation of the bundled portfolio open positions for each hourly slice in each month, are appended to the end of this chapter.

d. PCIA Aggregation Under the SoD Framework

While the SoD framework introduced an hourly dimension to RA compliance, the underlying cost-recovery mechanisms (e.g., the PCIA) continue to rely on single monthly values for retained RA supply within the bundled portfolio. These monthly values include forecasted Sold and Unsold RA volumes. The appropriate method for forecasting retained RA volumes under the SoD framework was a central issue in PG&E’s 2026 ERRA Forecast proceeding. Ultimately, the Commission approved an interim SoD retained RA methodology in D.25-12-027. For purposes of the 2027 ERRA forecast, PG&E has fully implemented the methodology adopted in D.25-12-027.

In its opening 2026 ERRA testimony, PG&E initially proposed a weighting scheme based on the 2024 IEPR peak-day forecast to collapse the 24 hourly positions in each month into a single weighted-average monthly position. These monthly average positions were then averaged across the year to produce a single annual average position, which served as the basis for calculating the annual retained

RA volumes at the applicable RA market price benchmark. However, PG&E's initial proposal was contested by California Community Choice Association (CalCCA). Thereafter, PG&E amended its weighting approach to apply a 100 percent weight to the peak-hour position and a zero percent weight to the remaining 23 hourly positions. This modification effectively replaced the weighted-average monthly positions with each month's peak-hour position. Under the methodology that was adopted by the Commission, and as reflected in the uncontested AL 7820-E, retained RA volumes for non-storage resources are tied to the NQC each resource can provide during the peak hour, as specified in the Commission-maintained Master Resource Database. For battery storage resources, PG&E's model follows the formula adopted by the Commission for calculating retained RA from battery storage resources:

$$NQC - (NQC \times 4 / 24 / \text{Round-Trip Efficiency})$$

Where: NQC represents the maximum discharge capacity of the storage resource.

These approaches for both battery storage and non-battery storage resources are consistent with the Commission's directive in D.25-12-027 that approved the interim SoD retained RA methodology for PG&E and is currently in effect for 2026 rates.

D. RPS Net Position

In D.20-02-047, the CPUC determined that PG&E's retained Renewable Energy Credit (REC) entry in its PCIA net cost calculation should incorporate an incremental REC volume equal to PG&E's bundled net RPS position in the event that it is forecasted to fall below PG&E's bundled RPS target for the applicable ERRA year. In order to determine whether a minimum retained RPS forecast is applicable as part of the PCIA revenue requirement presented in Chapter 10, PG&E first presents its forecasted 2027 net RPS position in Table 5-3 based on the following methodology.

TABLE 5-3
2027 BUNDLED RPS OPEN POSITION

Line No.	Description	Total
1	Bundled Load (MWh) – RPS Customer	22,992,758
2	RPS Req. %	52%
3	RPS Req (MWh)	11,956,234
4	RPS Sales (MWh)	[redacted]
5	Unsold RPS	–
6	Net RPS Generation	[redacted]
7	Expected RPS Open Position	[redacted]

PG&E's bundled net RPS position is calculated by comparing the net bundled share of RPS-Eligible generation in its portfolio against its applicable annual RPS requirement target. The RPS requirement targets are calculated by applying the annual RPS requirement percentage targets adopted by the CPUC in D.19-06-023 to PG&E's bundled customer sales subject to the RPS compliance requirements for the applicable year. The bundled net RPS generation is composed of all RPS-eligible generation, less forecasted RPS sales from executed contracts, such as the Voluntary Allocation sale agreements and executed Market Offer contract sales

PG&E's executed Voluntary Allocation and Market Offer sales are described further in Chapter 4. PG&E expects to be physically short of the 2027 RPS requirement and forecasts use of Banked RECs to meet the compliance requirement.

E. CAISO and Other Costs

1. CAISO Generator and Load Costs

PG&E's forecast of costs and revenues from the CAISO in 2027 are based on both volumetric forecasts and extrapolations from historical remittances over the previous three years. Costs based on volumetric forecasts 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 2027 is shown in Table 5-19.

2. Interstate Gas Transportation Costs

Under tolling agreements and UOG generators discussed in Chapter 4, PG&E supplies natural gas fuel to the generators. Interstate gas transportation costs are incurred for delivery of the fuel to the generator's facility. Forecast fuel transportation costs for applicable contracts and UOG generators are included in the total costs presented in Table 4-5. PG&E's 2027 forecast of interstate gas transportation costs is shown in Table 5-19.

F. Conclusion

In this chapter, PG&E presents its 2027 forecast for electric and natural gas hedging transactions and collateral costs, and CAISO and other costs. PG&E also forecasts bundled portfolio net positions such as system RA, RPS-eligible generation, and open positions, as well as associated costs. These forecast costs are reflected in the forecast revenue requirements presented in Chapter 11.

TABLE 5-4
2027 SYSTEM RA OPEN POSITION (MEGAWATTS (MW))
JANUARY

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Peak ERRA Load (MW)																								
1	PG&E Bundled Peak load Forecast	[redacted]																							
2	CPUC RA Compliance Requirement Adjustment																								
3	Reserve Requirement																								
4	Demand Response																								
5	Portfolio Reserve																								
6	**Total ERRA Capacity Requirement**																								
7	**Total Net Supply**																								
8	Position Before Adjustment for Unsold Long / (Short)																								
9	Unsold Capacity																								
10	**Position after Adjustment for Unsold**																								

TABLE 5-5
2027 SYSTEM RA OPEN POSITION (MW)
FEBRUARY

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Peak ERRA Load (MW)																								
1	PG&E Bundled Peak load Forecast	[redacted]																							
2	CPUC RA Compliance Requirement Adjustment																								
3	Reserve Requirement																								
4	Demand Response																								
5	Portfolio Reserve																								
6	**Total ERRA Capacity Requirement**																								
7	**Total Net Supply**																								
8	Position Before Adjustment for Unsold Long / (Short)																								
9	Unsold Capacity																								
10	**Position after Adjustment for Unsold**																								

TABLE 5-6
2027 SYSTEM RA OPEN POSITION (MW)
MARCH

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Peak ERRA Load (MW)																								
1	PG&E Bundled Peak load Forecast	[redacted]																							
2	CPUC RA Compliance Requirement Adjustment	[redacted]																							
3	Reserve Requirement	[redacted]																							
4	Demand Response	[redacted]																							
5	Portfolio Reserve	[redacted]																							
6	**Total ERRA Capacity Requirement**	[redacted]																							
7	**Total Net Supply**	[redacted]																							
8	Position Before Adjustment for Unsold Long / (Short)	[redacted]																							
9	Unsold Capacity	[redacted]																							
10	**Position after Adjustment for Unsold**	[redacted]																							

TABLE 5-7
2027 SYSTEM RA OPEN POSITION (MW)
APRIL

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Peak ERRA Load (MW)																								
1	PG&E Bundled Peak load Forecast	[redacted]																							
2	CPUC RA Compliance Requirement Adjustment	[redacted]																							
3	Reserve Requirement	[redacted]																							
4	Demand Response	[redacted]																							
5	Portfolio Reserve	[redacted]																							
6	**Total ERRA Capacity Requirement**	[redacted]																							
7	**Total Net Supply**	[redacted]																							
8	Position Before Adjustment for Unsold Long / (Short)	[redacted]																							
9	Unsold Capacity	[redacted]																							
10	**Position after Adjustment for Unsold**	[redacted]																							

TABLE 5-8
2027 SYSTEM RA OPEN POSITION (MW)
MAY

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Peak ERRA Load (MW)	[redacted]																							
1	PG&E Bundled Peak load Forecast																								
2	CPUC RA Compliance Requirement Adjustment																								
3	Reserve Requirement																								
4	Demand Response																								
5	Portfolio Reserve																								
6	**Total ERRA Capacity Requirement**																								
7	**Total Net Supply**																								
8	Position Before Adjustment for Unsold Long / (Short)																								
9	Unsold Capacity																								
10	**Position after Adjustment for Unsold**																								

TABLE 5-9
2027 SYSTEM RA OPEN POSITION (MW)
JUNE

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Peak ERRA Load (MW)	[redacted]																							
1	PG&E Bundled Peak load Forecast																								
2	CPUC RA Compliance Requirement Adjustment																								
3	Reserve Requirement																								
4	Demand Response																								
5	Portfolio Reserve																								
6	**Total ERRA Capacity Requirement**																								
7	**Total Net Supply**																								
8	Position Before Adjustment for Unsold Long / (Short)																								
9	Unsold Capacity																								
10	**Position after Adjustment for Unsold**																								

TABLE 5-10
2027 SYSTEM RA OPEN POSITION (MW)
JULY

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Peak ERRA Load (MW)																								
1	PG&E Bundled Peak load Forecast	[redacted]																							
2	CPUC RA Compliance Requirement Adjustment																								
3	Reserve Requirement																								
4	Demand Response																								
5	Portfolio Reserve																								
6	**Total ERRA Capacity Requirement**																								
7	**Total Net Supply**																								
8	Position Before Adjustment for Unsold Long / (Short)																								
9	Unsold Capacity																								
10	**Position after Adjustment for Unsold**																								

TABLE 5-11
2027 SYSTEM RA OPEN POSITION (MW)
AUGUST

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Peak ERRA Load (MW)																								
1	PG&E Bundled Peak load Forecast	[redacted]																							
2	CPUC RA Compliance Requirement Adjustment																								
3	Reserve Requirement																								
4	Demand Response																								
5	Portfolio Reserve																								
6	**Total ERRA Capacity Requirement**																								
7	**Total Net Supply**																								
8	Position Before Adjustment for Unsold Long / (Short)																								
9	Unsold Capacity																								
10	**Position after Adjustment for Unsold**																								

TABLE 5-12
2027 SYSTEM RA OPEN POSITION (MW)
SEPTEMBER

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Peak ERRA Load (MW)																								
1	PG&E Bundled Peak load Forecast	[redacted]																							
2	CPUC RA Compliance Requirement Adjustment																								
3	Reserve Requirement																								
4	Demand Response																								
5	Portfolio Reserve																								
6	**Total ERRA Capacity Requirement**																								
7	**Total Net Supply**																								
8	Position Before Adjustment for Unsold Long / (Short)																								
9	Unsold Capacity																								
10	**Position after Adjustment for Unsold**																								

TABLE 5-13
2027 SYSTEM RA OPEN POSITION (MW)
OCTOBER

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Peak ERRA Load (MW)																								
1	PG&E Bundled Peak load Forecast	[redacted]																							
2	CPUC RA Compliance Requirement Adjustment																								
3	Reserve Requirement																								
4	Demand Response																								
5	Portfolio Reserve																								
6	**Total ERRA Capacity Requirement**																								
7	**Total Net Supply**																								
8	Position Before Adjustment for Unsold Long / (Short)																								
9	Unsold Capacity																								
10	**Position after Adjustment for Unsold**																								

TABLE 5-14
2027 SYSTEM RA OPEN POSITION (MW)
NOVEMBER

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Peak ERRA Load (MW)																								
1	PG&E Bundled Peak load Forecast	[redacted]																							
2	CPUC RA Compliance Requirement Adjustment																								
3	Reserve Requirement																								
4	Demand Response																								
5	Portfolio Reserve																								
6	**Total ERRA Capacity Requirement**																								
7	**Total Net Supply**																								
8	Position Before Adjustment for Unsold Long / (Short)																								
9	Unsold Capacity																								
10	**Position after Adjustment for Unsold**																								

TABLE 5-15
2027 SYSTEM RA OPEN POSITION (MW)
DECEMBER

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Peak ERRA Load (MW)																								
1	PG&E Bundled Peak load Forecast	[redacted]																							
2	CPUC RA Compliance Requirement Adjustment																								
3	Reserve Requirement																								
4	Demand Response																								
5	Portfolio Reserve																								
6	**Total ERRA Capacity Requirement**																								
7	**Total Net Supply**																								
8	Position Before Adjustment for Unsold Long / (Short)																								
9	Unsold Capacity																								
10	**Position after Adjustment for Unsold**																								

TABLE 5-16
2027 SYSTEM RA OPEN POSITION (MW)
(THOUSANDS OF DOLLARS)

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	[redacted]											
2	CPUC RA Compliance Requirement Adjustment												
3	Reserve Requirement												
4	Demand Response												
5	Portfolio Reserve												
	Total ERRA Capacity Requirement												
6	**Total Net Supply**												
7	Position Before Adjustment for Unsold Long / (Short)												
8	Unsold Capacity												
9	**Position after Adjustment for Unsold**												

TABLE 5-17
2027 SYSTEM RA RESIDUAL TRANSACTION REVENUES
(THOUSANDS OF DOLLARS)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	Residual RA Transaction Revenues	[redacted]												

TABLE 5-18
2027 BUNDLED MONTHLY PEAK SYSTEM CAPACITY (MW)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	<u>Capacity Supply (MW)</u>												
2	Cost Allocation Mechanism (CAM)												
3	Utility-Owned Generation												
4	Energy Storage	[redacted]											
5	Post-2002 Contracted Resources	[redacted]											
6	Other Bilateral Contracts	[redacted]											
7	Fossil Contracts - Non-CHP	[redacted]											
8	Fossil Contracts - CHP	[redacted]											
9	QF	[redacted]											
10	Energy Storage	[redacted]											
11	Imports	[redacted]											
12	Power Charge Indifference Adjustment (PCIA)												
13	Utility-Owned Generation												
14	Nuclear	[redacted]											
15	Hydro	[redacted]											
16	Fossil	[redacted]											
17	Solar	0	0	0	2	0	57	86	72	57	24	0	0
18	Pre-2003 Contracted Resources												
19	QF	[redacted]											
20	Post-2002 Contracted Resources												
21	RPS Eligible												
22	RPS-Eligible Contracts	213	267	333	487	547	2,035	2,853	2,394	1,888	868	175	211
23	RPS-Eligible Future Contracts	[redacted]											
24	Other Bilateral Contracts	[redacted]											
25	Fossil Contracts - CHP	[redacted]											
26	Fossil Contracts - Non-CHP	[redacted]											
27	Large Hydro	[redacted]											
28	Energy Storage	[redacted]											
29	RA Contracts - Sales	[redacted]											
30	RA Contracts	[redacted]											

TABLE 5-18
2027 BUNDLED MONTHLY PEAK SYSTEM CAPACITY (MW)
(CONTINUED)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
31	Bioenergy Market Adjusting Tariff (BioMAT)												
32	Post-2002 Contracted Resources												
33	RPS Eligible												
34	RPS-Eligible Contracts	9	9	9	9	9	9	9	9	9	11	11	11
35	Ongoing Competition Transition Charge (CTC)												
36	Pre-2002 Contracted Resources												
37	Irrigation District & Water Agency	[redacted]											
38	MWD Etiw anda												
39	QF												
40	Puget Sound Pow er & Light (Receive)												
41	Public Policy Charge Procurement (PPCP)												
42	QF												
43	Energy Resource Recovery Account (ERRA)												
44	Utility-Ow ned Generation												
45	Energy Storage												
46	Post-2002 Contracted Resources												
47	RA Contracts												
48	GTSR												
49	RPS-Eligible Contracts	0	0	0	4	0	154	202	167	124	53	6	6
49	DCPP Extended Operations (DCPP_NBC_CA)	[redacted]											
50	Nuclear												
51	Total Net Supply												

TABLE 5-19
2027 CAISO AND OTHER 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	[redacted]												
3	CTC													
4	ERRA													
5	PCIA													
6	TMNBC													
7	BIOMAT													
8	PPCP													
9	Bundled Load Requirement (ERRA)													
10	Other Load (ERRA)													
11	Interstate Gas Transportation Costs													
12	Cost Allocation Mechanism (CAM)													
13	Post-2002 Contracted Resources													
14	Other Bilateral Contracts													
15	Fossil Contracts - Non-CHP													
16	Fossil Contracts - CHP													
17	Power Charge Indifference Adjustment (PCIA)													
18	Utility-Owned Generation													
19	Fossil													
20	Fuel Cell													
21	Post-2002 Contracted Resources													
22	Other Bilateral Contracts													
23	Fossil Contracts - Non-CHP													
24	**Total Costs**													

Note: Totals may not add due to rounding.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

CENTRAL PROCUREMENT ENTITY

PROCUREMENT COST AND REVENUE REQUIREMENT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
CENTRAL PROCUREMENT ENTITY
PROCUREMENT COST AND REVENUE REQUIREMENT

TABLE OF CONTENTS

A. Introduction 6-1

B. CPE Background 6-1

C. CPE Procurement Costs 6-2

1. Compensated Self-Shown Resource Procurement 6-3

2. Compensated Offered Resources 6-4

3. 2026 CPE Procurement 6-5

D. CPE Administrative Costs 6-5

E. Conclusion 6-6

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
CENTRAL PROCUREMENT ENTITY
PROCUREMENT COST AND REVENUE REQUIREMENT

A. Introduction

This chapter discusses Pacific Gas and Electric Company's (PG&E) Central Procurement Entity (CPE) 2027 procurement and administrative cost forecast. Table 6-1 summarizes procurement costs discussed in this chapter, and Table 6-2 summarizes administrative costs relevant to PG&E's forecast 2027 CPE revenue requirement.

B. CPE Background

Pursuant to California Public Utilities Commission (CPUC or Commission) Decision (D.) 20-06-002, the Decision on Central Procurement of the Resource Adequacy (RA) Program, issued on June 17, 2020, the Commission designated PG&E to act as the CPE for the multi-year local RA program to procure local RA capacity on behalf of all load-serving entities (LSE) in its electric distribution service area beginning with the 2023 RA compliance year.[1] As such, PG&E CPE assumed the full local RA obligation as adopted by the Commission for the multi-year local RA program, accounting for 100 percent of the year 1 and 2 local RA requirements and 50 percent of the year 3 local RA requirements in each of the seven local capacity areas within the PG&E distribution service area. Subsequently, the Commission issued D.20-12-006 on December 4, 2020, the Decision on Track 3.A Issues: Local Capacity Requirement (LCR) Reduction Compensation Mechanism (RCM) and Competitive Neutrality Rules, which included additional guidance related to the process available to LSEs to receive some compensation for eligible local RA resources per the self-showing aspect of the hybrid framework adopted under D.20-06-002, and also adopted PG&E CPE's competitive neutrality rule as required pursuant to Ordering Paragraph (OP) 24 of D.20-06-002.[2]

---

1 D.20-06-002 at 91, OP 2.

2 D.20-12-006 at 49, OP 9.

In accordance with both D.20-06-002 and D.20-12-006, and to meet the local RA obligations beginning with the 2023 compliance year, the PG&E CPE launched its first annual solicitation, the 2021 PG&E CPE Local RA Request For Offers (RFO) ("2021 PG&E CPE Local RA RFO"), in April 2021. D.20-06-002 also obligates the CPE to include dispatch rights, or other means that stipulate how local resources bid into the energy markets, in its solicitation, as an optional term that bidders are encouraged to include, and encourages the CPE to procure dispatch rights along with the local RA capacity, whenever doing so is in the financial interest of all ratepayers.[3] In order to effectuate these transactions, PG&E as the CPE provides in its solicitation bid documents two variations of RA transactions—RA-only and RA-plus an energy settlement component, which differs from the RA-only agreement in that it introduces a financial settlement for energy.

Since 2020, the Commission continued to adopt modifications to the CPE framework and subsequently issued D.22-03-034, Decision on Phase 1 of the Implementation Track: Modifications to the CPE Structure, on March 18, 2022, D.23-06-029, Decision Adopting Local Capacity Obligations for 2024 and Program Refinements, on July 5, 2023, and D.24-12-003, Decision on Track 2 Issues, on December 12, 2024. Through these decisions, modifications were adopted to allow for changes in the self-shown process, RA timeline, and to clarify confidentiality protections and other reporting for CPE related procurement.

In accordance with D.20-06-002, D.20-12-006, D.22-03-034, D.23-06-029, and D.24-12-003 ("CPE Decisions"), the CPE has held a competitive solicitation each year to procure additional RA capacity to meet the local RA obligations for compliance years 2023 and beyond.

C. CPE Procurement Costs

In D.22-03-034 the Commission adopted PG&E's proposal to include CPE procurement costs in the Energy Resource Recovery Account (ERRA) Forecast

[3] D.20-06-002, OP 8.

proceeding for cost recovery purposes.[4] In accordance with that decision and as described below, PG&E CPE is only including forecasted procurement costs for CPE transactions that include compensation for the procured RA attributes within this chapter and accompanying workpapers. Further, this chapter was drafted, reviewed, and maintained by PG&E CPE and support personnel separately from the rest of the ERRA Forecast testimony to the extent it contains confidential CPE information, with only a redacted version of the chapter viewable for review prior to submittal.[5] All confidential redacted information has been identified within the confidentiality matrix accompanying this testimony in accordance with the protections as adopted in D.22-03-034 and modified most recently through OP 6 and Appendix B of D.24-12-003.[6]

In accordance with the CPE Decisions, the PG&E CPE launched its first annual solicitation to procure RA capacity in April 2021 and has held annual competitive solicitations each year following. As part of the PG&E CPE RFO process each year, the CPE issues a CPE Local RA RFO Solicitation Protocol ("Solicitation Protocol"), which outlines the resource categories being sought including compensated self-shown local RA resources and compensated offered local RA resources for Bundled RA capacity or Bundled RA capacity with energy settlement.[7] Procurement costs for each of these resource categories for 2027 are represented in Table 6-1 below.

1. Compensated Self-Shown Resource Procurement

Under D.20-12-006, local RA that is self-shown to PG&E CPE from certain preferred, energy storage, and hybrid resources may be eligible for

---

[4] D.22-03-034, OP 19 states, "[c]entral procurement entity (CPE) procurement costs shall be forecasted and implemented in rates through the annual ERRA Forecast proceeding. The CPE procurement costs shall be handled in a separate confidential chapter in ERRA Forecast testimony, whereby the confidential contents shall only be viewable to the CPE's personnel and support personnel, including staff such as contract management, law and regulatory compliance staff. Only CPE transactions that include LCR RCM compensation or sale of system RA attributes to the CPE shall be required for inclusion in supporting workpapers or other testimony."

[5] See D.22-03-034, pp. 52-53 and OP 19.

[6] See D.24-12-003, pp. 36-40, OP 6, and Appendix B, p. 3.

[7] See, for example the 2025 CPE Local RA RFO Solicitation Protocol, pp. 8-9. https://www.pge.com/assets/pge/docs/about/doing-business-with-pge/2025-cpe-local-ra-rfo-solicitation-protocol.pdf.

compensation up to an administratively pre-determined price.[8] These resources are referred to as compensated self-shown resources under the CPE's Solicitation Protocol. The compensated self-shown resource category allows for an LSE to commit to showing the local RA attribute of the resource to be counted towards the CPE's procurement obligations while retaining the system and flexible RA attribute to use towards the LSE's own compliance obligations and receiving compensation from the CPE.

Through 2025, the CPE procured local RA capacity through the compensated self-shown resource process for the 2027 compliance year, with pricing based on the local RA premium for the local capacity area that the resource is located.[9] The total procurement costs for the Compensated Self-Shown RA Capacity procured for 2027 are presented below in Table 6-1.

2. Compensated Offered Resources

Under D.20-06-002, the CPE must run an annual all-source competitive solicitation for local RA resource capacity.[10] Through solicitations run to date, the CPE has sought to procure compensated offered local RA resources that included the following product characteristics: Bundled RA and Bundled RA with Energy Settlement. The Bundled RA product is RA capacity that can be used to meet RA obligations, which includes Local, System and, if applicable, Flexible RA attributes. The Bundled RA with Energy Settlement product adds energy value through a financial settlement component and specific contracts may yield negative procurement costs if actual energy revenues offset the contracted-for capacity costs. Under these circumstances, there are potential cost savings for CPE customers.

The CPE procured Bundled RA capacity and Bundled RA with Energy Settlement capacity through a competitive offer process for the 2027

8 See LCR RCM Decision at 45-47, OP 3-6.

9 Each year, the LCR RCM Prices are published by the CPUC on the CPUC RA Compliance Materials website under Guides and Resources. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

10 D.20-06-002, p. 93, OP 8.

compliance year, with competitively offered pricing.[11] The total procurement costs for the compensated offered resources procured for 2027 are presented in Table 6-1 below.

3. 2026 CPE Procurement

On February 12, 2026, the CPE launched its 2026 CPE Local RA RFO to procure limited additional local RA capacity for the 2027 compliance year and beyond. The CPE seeks to procure a limited amount of incremental RA capacity that may result from the year-over-year changes to the 2027 local capacity area obligations as identified in California Independent System Operator's (CAISO) Local Capacity Technical Study Results.

Due to the uncertainty of how much incremental RA capacity will be identified in each local area and how much 2027 RA capacity will be offered competitively for compensation, costs of any potential purchased capacity from the 2026 CPE RFO are difficult to forecast and have not been included in Table 6-1 at this time. Instead, PG&E will provide updated forecasted CPE procurement costs for 2027 in its ERRA Forecast Fall Update to Prepared Testimony to include additional purchased capacity by the CPE. The CPE is also required to file an Annual Compliance Report (ACR) that includes the procurement efforts made by the CPE in the year and will include aggregated purchased capacity volumes from the 2026 procurement efforts. According to the timeline adopted in D.22-03-034, the CPE ACR will be due in mid-September of 2026.

D. CPE Administrative Costs

D.20-06-002 establishes that administrative costs incurred in serving the central procurement function are recoverable under the Cost Allocation Mechanism (CAM).[12]

PG&E has established a CPE organization within PG&E that provides the Commission, LSEs, and other market participants with reasonable assurances as to the neutrality and transparency of the central procurement process, while

---

[11] Specific capacity amounts procured to date by the CPE for the 2027 RA compliance year can be found on Page1 of Attachment 2 (Public Attachment A) in Advice Letter 7704-E, PG&E CPE's 2025 ACR. https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7704-E.pdf.

[12] D.20-06-002, p. 96, OP 16.

also giving the CPE appropriate flexibility and discretion to efficiently procure local resources given the existing constraints in the RA timeline. The CPE functions similarly to existing departments within PG&E that employ separation practices designed to promote competitive neutrality and perform walled-off functions within broader organizations. Using those well-developed departments as a model, the CPE utilizes some existing functions within the broader utility to promote efficiency, but a limited set of other functions are performed by a walled-off department with specially tailored separation practices in place pursuant to a competitive neutrality rule that was adopted by the Commission in Track 3 of Rulemaking 19-11-009. These practices ensure separation of market-related activities between the CPE, on the one hand, and PG&E when it is acting in its capacity as an LSE, on the other.

The CPE is tasked with a number of functions in D.20-06-002, including, but not limited to: (1) conducting one or more competitive, all-source solicitations for local RA procurement with specific requirements outlined within D.20-06-002, (2) evaluating and selecting bids in the solicitation in accordance with the all-source selection criteria, including the loading order, the least cost best fit methodology, and additional criteria, (3) complying with various regulatory requirements, (4) contracting with counterparties for procurement beginning in 2021, (5) contract administration and settlement, and (6) CPE system development.

Table 6-2 reflects PG&E's current forecasted administrative costs for 2027 associated with central procurement of local RA pursuant to D.20-06-002.

E. Conclusion

In this chapter, PG&E presents the 2027 cost forecasts associated with CPE administrative activities and PG&E CPE contracted resources. The costs, summarized in Tables 6-1 and 6-2 are included in PG&E's forecast CAM revenue requirement, and are reflected in the revenue requirements forecast presented in Chapter 7.

TABLE 6-1
2027 CPE-PROCUREMENT COST FORECAST FOR CAM
(THOUSANDS OF DOLLARS)

Line No.	Description	1/1/2027	2/1/2027	3/1/2027	4/1/2027	5/1/2027	6/1/2027	7/1/2027	8/1/2027	9/1/2027	10/1/2027	11/1/2027	12/1/2027	Total
1	Compensated Self-Shown RA Capacity	[redacted]												
2	Compensated Bundled RA Capacity													
3	Compensated Bundled RA with Energy Settlement													
4	**Total CPE Procurement**													

Notes:
Totals may not add due to rounding.

TABLE 6-2
2027 CPE-ADMINISTRATIVE COST FORECAST FOR CAM
(THOUSANDS OF DOLLARS)

Line No.	Cost Element	2027 Cost	Description	2027 Headcount
1	Solicitation and Procurement	$1,685	Manage all processes related to the CPE's annual solicitation requirement, including the preparations of solicitation materials, communication with the market, processing, and evaluation of offers, preparation of contracts, negotiation and execution of transactions, and development of all required annual and monthly CPUC and CAISO Local RA filings. Includes costs related to the required use of an Independent Evaluator for all CPE solicitations.	8
2	Contract Management and Settlements	492	Contract administration and settlements of CPE agreements.	3.5
3	Compliance	17.5	Includes oversight of all CPE-related compliance activities including the development of CPE ACR and coordination of all Procurement Review Group meetings.	0.1
4	Regulatory	17.5	Augmented regulatory expertise to manage filings and communication related to CPE transactional volume.	0.1
5	Credit/Risk and Treasury	17.5	Additional expertise to perform credit calculations and monitor and maintain adequate protections and documentation for CPE transactions.	0.1
6	Information Technology (IT)	178	Personnel required to maintain systems and functionality related to CPE operations.	0.5
7	Accounting	17.5	Personnel required to address accounting operations for additional CPE transactions.	0.1
8	Legal	78	Provide regulatory and commercial legal support to the CPE for its annual solicitation process. Includes the potential use of external counsel.	0.25
9	IT Systems	100	Includes annual cost of additional system licensing needs for CPE personnel and any system updates needed to accommodate changes driven by the CPUC and/or CAISO.	–
10	Total CPE-Admin Cost	$2,603		12.65

Note: Totals may not add due to rounding.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

COST ALLOCATION MECHANISM

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
COST ALLOCATION MECHANISM

TABLE OF CONTENTS

A. Introduction 7-1

B. Cost Allocation Mechanism 7-1

C. Conclusion 7-4

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
COST ALLOCATION MECHANISM

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E) 2027 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 (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. Any LSE 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 (QF) and Combined Heat and Power Settlement (CHP) approved in that decision and was first included in forecast year 2012.

D.20-06-002, issued June 17, 2020 (RA Central Procurement Entity (CPE) Decision), orders PG&E to serve as the CPE for PG&E's distribution service area for the multi-year local RA program beginning with the 2023 RA compliance year.[1] Consistent with the RA CPE Decision:

> The CAM methodology is adopted as the cost recovery mechanism to cover procurement costs incurred in serving the central procurement function. The

[1] D.20-06-002, Ordering Paragraph (OP) 2.

administrative costs incurred in serving the central procurement function shall be recoverable under the CAM.[2]

As indicated in Chapter 6, the CPE has executed certain procurement transactions with deliveries in 2027 and expects to include any incremental procurement for 2027 in the Fall Update.[3]

D.22-05-015, issued May 23, 2022, regarding procurement under D.19-11-016 also affirmed that the associated backstop costs for LSEs that go bankrupt or are no longer serving load in California can be recovered through the regular CAM.[4]

The Commission has approved CAM cost recovery for emergency summer reliability procurement, if applicable, which was most recently adopted in the form of effective planning reserve margins for the three IOUs in D.25-06-048 for 2026 and 2027.

For the 2027 ERRA Forecast, the CAM includes CHP generation authorized under the QF/CHP Settlement,[5] energy storage Power Purchase Agreements (PPA) approved pursuant to Resolution E-4949, as well as the Collateral and Interest costs presented in Chapter 5 and Utility-Owned Generation (UOG)-related costs allocated to CAM, as presented in Chapter 8. The 2027 CAM also includes CPE costs presented in Chapter 6. Forecasted costs associated with CHP, storage and UOG positions are presented in Chapter 4.

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

---

2 D.20-06-002, OP 16.

3 PG&E as CPE submitted these transactions to the Commission in its Annual Compliance Reports through Advice Letter (AL) 6386-E and AL 6706-E.

4 D.22-05-015, OP 10.

5 D.10-12-035.

articulated a calculation method to determine the market value of the resource.[6] 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 individual contract net capacity costs are summed with the total then allocated to bundled and departed load customers.

This forecast of the total net capacity cost is then used to set the CAM rate, as discussed in Chapter 13, Rate Proposal. 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."[7]

PG&E's calculation of the forecasted 2027 CAM revenue requirement is presented in Table 7-1.

TABLE 7-1
2027 CAM FORECAST REVENUE REQUIREMENT
(THOUSANDS OF DOLLARS)

Line No.	Description	Revenue Requirement
1	Total CAM-eligible Contract, UOG and CPE Costs	[redacted]
2	CAISO Market Revenues	
3	Net Capacity Costs	$351,284
4	Revenue Fees and Uncollectibles	4,779
5	CAM Revenue Requirement	$356,063

6 D.14-02-040, 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.

7 The under/over collected net CAM cost/revenue is recorded in the New System Generation Balancing Account for amortization in the New System Generation rates as discussed in Chapter 13 (Rate Proposal).

C. Conclusion

In this chapter, PG&E presents its forecast for the CAM revenue requirement which is based on the forecasted net costs to be incurred in 2027, as presented in Table 7-1. PG&E will update the CAM revenue requirement in its Fall Update.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

POWER CHARGE INDIFFERENCE ADJUSTMENT AND ONGOING COMPETITION TRANSITION CHARGE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
POWER CHARGE INDIFFERENCE ADJUSTMENT AND
ONGOING COMPETITION TRANSITION CHARGE

TABLE OF CONTENTS

A. Introduction 8-1

B. Regulatory Background 8-1

1. PCIA and Ongoing CTC 8-2

2. Common Template for Calculating the PCIA and Ongoing CTC 8-3

3. D.20-05-006 and D.10-12-035 Qualifying Facilities Contracts 8-4

4. Order Instituting Rulemaking to Update and Reform ERRA and PCIA Policies and Processes (Order Instituting Rulemaking 25-02-005) 8-5

C. Total Portfolio Costs 8-5

1. UOG-Related Costs 8-6

D. EP Costs 8-6

E. UOG Base and Other Related Costs 8-6

1. Authorized 2023 GRC Revenue Requirement 8-7

2. Other Authorized UOG-Related Cost 8-7

F. UOG Related Costs Currently Under Consideration by the Commission 8-8

1. 2027 GRC 8-8

2. 2024 Wildfire Mitigation and Catastrophic Events 8-9

3. Wildfire and Gas Safety Costs 8-9

4. Billing Modernization Initiative 8-9

5. Recovery of Costs Associated With the 2019 Kincade Fire and 2021 Dixie Fire Under Assembly Bill 1054 8-10

G. Generation Resource Product Forecast 8-10

1. Resource Adequacy Capacity 8-10

a. RA Supply and Sales 8-11

b. Unsold RA 8-11

TABLE OF CONTENTS
(CONTINUED)

2. Energy 8-12

3. Renewable Energy Credits 8-12

a. Minimum Retained Requirement Volume 8-12

1) Historical Initial Annual Net RPS Positions 8-13

2) Historical Minimum RPS Entries 8-16

3) Determination of Additional Retained RECs for 2027 8-17

4) Monthly RPS Net Short 8-18

4. Large Hydroelectric Allocation 8-19

H. Market Price Benchmark 8-19

1. Background 8-19

2. Components 8-20

a. Energy Index 8-21

b. GHG Free Index 8-21

c. Green/Renewable Portfolio Standard Adder 8-22

d. Capacity/Resource Adequacy Adder 8-22

3. 2027 Market Price Benchmark 8-22

I. Indifference Amount Calculation 8-23

J. Conclusion 8-24

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
POWER CHARGE INDIFFERENCE ADJUSTMENT AND ONGOING COMPETITION TRANSITION CHARGE

A. Introduction

This chapter addresses Pacific Gas and Electric Company's (PG&E or the Utility) 2027 revenue requirement forecasts for the vintaged Power Charge Indifference Adjustment (PCIA), and Ongoing Competition Transition Charge (CTC). As required by state law,[1] the purpose of these rate components is to fairly allocate the above-market costs associated with procurement made by the investor-owned utilities (IOU) to those customers on whose behalf the procurement was made, including both bundled customers and customers that have departed from IOU service to receive generation services from an alternative supplier (i.e., departed load (DL)).

B. Regulatory Background

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 from customers when they: (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 D.04-12-048, the amount of the NBC is determined based on the timing of the customers' departure (i.e., customer vintage) and the commitment date of a new resource in PG&E's electric generation portfolio. D.08-09-012 approved a calculation methodology associated with new generation resource commitments authorized in D.04-12-048 using a vintaged total portfolio indifference calculation.[2] The NBCs discussed in this chapter are the PCIA, Ongoing CTC, and Public Purpose Charge Procurement (PPCP).

---

1 See D.08-09-012, D.11-12-018, and D.18-10-019; see also, 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.

1. PCIA and Ongoing CTC

In D.02-11-022, the Commission established a Cost Responsibility Surcharge (CRS) to capture the uneconomic cost resulting from customers migrating from bundled to DL due to California's electric industry restructuring.[3] The CRS incorporates, among other elements, a California Department of Water Resources (CDWR) power charge and the Ongoing CTC.[4] The CDWR power charge was the share of the uneconomic portion of costs to be paid for by customers that departed from bundled services, that was incurred by the CDWR on behalf of customers in the IOUs' service territories. The Ongoing CTC includes above-market costs associated with eligible QF contracts and Power Purchase Agreement restructuring costs, as well as other Commission authorized costs. The Ongoing CTC is to be collected from all existing (as of December 20, 1995) and future consumers in PG&E's service territory,[5] for all power purchase contract costs included in CPUC rates as of that date.[6]

On July 20, 2006, the Commission issued D.06-07-030 adopting a uniform Market Price Benchmark (MPB) for calculating the indifference amount to recover stranded costs associated with the CDWR contracts, as well as the Ongoing CTC. In that decision, the CDWR power charge was replaced by the PCIA.[7] The PCIA was instituted to preserve bundled customer indifference resulting from the departure of migrated customers. PCIA costs are calculated by vintage and are applicable to both bundled and DL customers that are not exempt from the NBC associated with new generation resources, as defined in D.08-09-012.[8] Bundled customers pay their portion of PCIA costs through their generation rates while DL customers pay through the PCIA rates. On June 8, 2023, the Commission

---

3 D.02-11-022, Ordering Paragraph (OP) 2.

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

5 Pub. Util. Code § 369.

6 Pub. Util. Code § 367.

7 D.06-07-030, OP 2 and 16; see also, Section E of this chapter for more discussions on the MPB.

8 Includes DA, CCA, and 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.

issued D.23-06-006 which addressed the "greenhouse gas-free" incremental value of large hydroelectric energy resources above fossil fuel resources, as well as revising the calculation of the Energy Index MPB to improve accuracy and transparency.

In D.18-10-019, the Commission revised the PCIA and Ongoing CTC calculation methodology, adopted new accounting mechanisms to recover the above-market costs of the IOUs' portfolios, and established an annual true-up to more accurately allocate costs between bundled and DL customers. In that decision, the Commission opened a second phase to Rulemaking (R.) 17-06-026 that established three working groups to resolve various PCIA issues identified in the proceeding.

In Phase 2 of R.17-06-026, the Commission issued D.19-10-001, refining the method, data, and process requirements for the forecast and true-up of the MPB to be used in determining the PCIA rate, and also adopted vintage-specific billing determinants for use in the IOUs' rate design.[9] On May 20, 2021, the Commission issued D.21-05-030 addressing the Working Group Three proposals, with modifications, that (a) removes the PCIA rate cap and trigger framework; (b) authorizes a new Voluntary Allocation and Market Offer, as well as a Request for Information process for PCIA-eligible Renewables Portfolio Standard (RPS) contracts; and (c) other compliance related directives that are consistent with existing RPS compliance requirements. The Commission addressed matters related to Energy Resource Recovery Account (ERRA) and PCIA deadlines in D.22-01-023 and OP 1 modified the MPB release date to October 1 of each year or the first business day thereafter if October 1 is on a Saturday or Sunday.[10] Additionally, OP 2 of D.21-05-023 requires PG&E to file its ERRA Forecast Applications no later than May 15 of each year.

2. Common Template for Calculating the PCIA and Ongoing CTC

In D.17-08-026, the Commission modified D.06-07-030 by requiring the IOUs to utilize a common template to improve transparency of the

---

9 The PCIA calculations incorporate MPBs as defined by D.18-10-019 and revised by D.19-10-001, D.22-01-023, and D.23-06-006.

10 This is a modification from the "Beginning of November each year" in D.19-10-001, OP 1.

calculation underlying the Ongoing CTC and PCIA Revenue Requirements. In D.21-03-051, the Commission granted the Petition for Modification filed by the IOUs to modify D.17-08-026 and eliminate the calculation errors in the workpaper (WP) template related to the mis-application of line losses. Additionally, D.23-06-006, the Commission directed the addition of a new MPB related to the "greenhouse gas free" incremental value of large hydroelectric energy resources above fossil fuel resources, to be applied in PCIA WPs in the event PG&E does not timely elect to provide an allocation of large hydroelectric energy.

D.23-06-006 also revised the calculation of the Energy Index MPB as described in Section G of this testimony. Tables 8-6 through 8-8 presented in this testimony reflect the methodologies in the common template authorized by the Commission in D.17-08-026, as modified by D.21-03-051 and D.23-06-006.

3. D.20-05-006 and D.10-12-035 Qualifying Facilities Contracts

In the 2022 ERRA Forecast Application (A.) 21-06-001, PG&E requested to recover its costs associated with new Public Utility Regulatory Policies Act of 1978 (PURPA) contracts approved pursuant to D.20-05-006 and certain Standard Contract for QFs under 20 MW or less eligible for non-vintaged PCIA cost recovery through the Public Policy Purpose charge.[11] PG&E's proposal was adopted by the Commission in D.23-02-022, which ordered that PG&E establish a new subaccount in the Public Policy Charge Balancing Account (PPCBA) to recover any current or future public policy costs associated with the new PURPA contracts. On March 14, 2022, PG&E submitted Advice Letter (AL or Advice) 6524-E to: (1) establish the PPCP Subaccount in the PPCBA to record the recovery of the above-market costs associated with new PURPA contracts (excluding contracts resulting from certain other PURPA procurement channels), and (2) retire the non-vintaged PCIA subaccount authorized in D.20-05-006. The Commission approved AL 6524-E as submitted. The PURPA contract

---

[11] Prior to D.23-02-022, the recovery of these costs was through the non-vintaged PCIA subaccount, as authorized in D.20-05-006.

recoverable in the PPCP Subaccount of the PPCBA will expire by December 31, 2026, and there is currently no cost forecasted for 2027.

4. Order Instituting Rulemaking to Update and Reform ERRA and PCIA Policies and Processes (Order Instituting Rulemaking 25-02-005)

On February 20, 2025, the Commission opened R.25-02-005 to update and reform ERRA and PCIA policies and processes in multiple tracks. Track 1 addressed changes to the Resource Adequacy (RA) MPB used in the PCIA calculation, and on June 26, 2025, the Commission issued D.25-06-049 adopting changes to the RA MPB methodology, including directing Energy Division to calculate a single RA MPB for use in the annual PCIA, among other refinements. Track 2 is addressing the valuation, if any, of pre-2019 banked Renewable Energy Credits (REC) for purposes of calculating the PCIA; the Assigned Commissioner issued a scoping memo and ruling on February 3, 2026, and a decision is currently targeted for September 2026 in advance of PG&E’s Fall Update. Track 3 was initiated by an Administrative Law Judge ruling issued February 20, 2026 soliciting party comments on broader ERRA/PCIA reform issues. The scope for Track 3 will be set in a subsequent scoping memo. PG&E will reflect any applicable Commission directives adopted in R.25-02-005 in the Fall Update of this ERRA Forecast proceeding, consistent with Commission directives in effect at that time.

C. Total Portfolio Costs

The total portfolio indifference calculation is applied to the Revenue Requirements of the 2027 PCIA and Ongoing CTC. 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 8-7 presents the 2027 forecast total eligible portfolio cost, including PG&E’s forecast of total portfolio costs of generation, generation gigawatt-hours and net qualifying capacity, 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.[12] Eligible portfolio costs of the applicable generation resources included in the total portfolio indifference calculation, are broadly categorized as UOG-Related Costs and Energy Procurement (EP) Costs. These costs will be updated in the Fall Update of this application

1. UOG-Related Costs

UOG-Related Costs are PG&E's General Rate Case (GRC) or other approved costs in other regulatory proceedings.[13] Section D below provides more discussions of the UOG-Related Costs included in the indifference calculation. The inclusion of UOG-Related Costs is solely for rate-setting purposes only. PG&E is not requesting approval of these costs in this application.

D. EP Costs

The EP Costs reflect PG&E's assessment of the supply cost of PG&E's electric generation resources. These costs are summarized and discussed in Chapters 4 and 5. Based on the capacity and energy forecasts of these resources, further adjustments were made to the total portfolio indifference calculation as described in this testimony.

E. UOG Base and Other Related Costs

PG&E is forecasting to recover a total of $1,229 million of UOG Related Costs authorized by the Commission as presented in Table 8-1 below.

---

12 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 total portfolio indifference calculation presented in Table 8-8.

13 Pursuant to OP 10 of D.18-10-019, PG&E submitted AL 5440-E to establish the Portfolio Allocation Balancing Account (PABA) which, among other things, allowed PG&E to recover certain categories of UOG related cost from the PCIA rates. AL 5440-E was approved by the Commission on May 3, 2019. In AL 5440-E, the Commission authorized PG&E to recover certain categories of UOG related costs in the PCIA.

TABLE 8-1
AUTHORIZED UOG-RELATED COSTS
(THOUSANDS OF DOLLARS)

Line No.	Description	Authorization	Total
1	2023 GRC + attrition	D. 23-11-069	$1,203,524
2	Cost of Capital	Advice 7856-E	13,266
3	Hydro Sale	Advice 7856-E	(8,866)
4	Non-Wildfire Self Insurance Adjustment	Advice 7856-E	(14,314)
5	Pension	Advice 7856-E	17,476
6	Purchase of Oakland General Office	D.24-08-009	9,286
7	2023 WMCE	D.26-02-004	8,774
8	Total		$1,229,145
9	Recovered in		
10	PCIA		$1,183,494
11	CAM		45,651

Note: Includes Revenue Franchise and an Allowance of Uncollectible (RF&U) of $16 million.

1. Authorized 2023 GRC Revenue Requirement

The 2023 GRC including the 2024, 2025 and 2026 attrition (2023 GRC + attrition) revenue requirement is the amount authorized in D.23-11-069, plus an update of an allowance of the RF&U currently in effect for 2026 rates. The Energy Supply Cost is allocated between PCIA and Cost Allocation Mechanism (CAM) based on the methodology authorized by the Commission in D.24-12-038. PG&E will update its GRC revenue requirement upon the Commission's approval of its 2027 GRC A.25-05-009 in the Fall Update, if applicable, as discussed in Section E of this testimony.

2. Other Authorized UOG-Related Cost

The UOG-related costs authorized by the Commission for recovery in 2027 are as follows:

a) Adopted Rolling Electric Generation Revenue Requirement authorized in Advice 5188-G/7856-E [14] as follows:

- Cost of Capital (COC) Adjustment based on the formula authorized by the Commission in AL 4996-G/7423-E effective January 1, 2025;
- Sale of PG&E's three hydro generation facilities authorized in D.22-11-002, D.19-10-011, and D.20-11-024;
- Non-Wildfire Self Insurance Adjustments authorized in D.25-03-008; and
- Pension calculated based on the methodology authorized in D.23-11-069.

b) Purchase of Oakland General Office authorized in D.24-08-009.

c) 2023 Wildfire Mitigation and Catastrophic Events (WMCE) authorized in D.26-02-004.

F. UOG Related Costs Currently Under Consideration by the Commission

In PG&E's 2022 ERRA Forecast proceeding, the Commission issued a Scoping Memo and Ruling ordering PG&E to exclude from its Prepared Testimony certain UOG-related cost forecasts pending Commission approval because inclusion was untimely.[15] Consistent with this Commission direction, PG&E does not include a forecast of UOG-related costs that are currently pending before the Commission in this initial Prepared Testimony. However, PG&E provides updates on pending UOG-related costs potentially relevant to PG&E's 2027 PCIA rates. Upon authorization by the Commission, any approved costs will be included in the PCIA Revenue Requirement presented in the Fall Update.

1. 2027 GRC

On May 15, 2025, PG&E filed its 2027 GRC (A.25-05-009) requesting the Commission's authorization to adopt test year 2027 revenue requirements and associated post test-year attrition mechanisms for PG&E's gas distribution, gas transmission and storage, electric distribution, and electric generation functions. The procedural schedule set forth in the

---

14 Advice 5188-G/7856-E is accepted by the Commission on March 6, 2026.

15 A.21-06-001, Assigned Commissioner Scoping Memo and Ruling (August 11, 2021), pp. 2, 10.

Assigned Commissioner's scoping memo targets issuance of a final decision by December 1, 2026, with adopted revenue requirements anticipated to be implemented in rates effective January 1, 2027.

2. 2024 Wildfire Mitigation and Catastrophic Events

On November 21, 2024, PG&E filed its 2024 WMCE Application to approve recovery of approximately $412 million in revenue requirements (excluding interest) for recorded costs incurred primarily during 2018–2023 and 2023 calendar year activities related to catastrophic event response, wildfire mitigation, and other Commission-directed initiatives.

On February 24, 2026, parties convened with the Commission for a Status Conference; parties jointly proposed a schedule setting the deadline for a Proposed Decision at August 12, 2026. On April 9, 2026, in response to a joint motion filed by PG&E and the Public Advocates Office at the California Public Utilities Commission, the Commission ruled to extend this deadline to September 1, 2026.

3. Wildfire and Gas Safety Costs

On June 15, 2023, PG&E filed its Wildfire and Gas Safety Costs (WGSC) application (A.23-06-008) to recover amounts recorded to various memorandum accounts in prior years. The proposed Generation Revenue Requirement is $32.5 million.[16] On March 7, 2024, the Commission authorized PG&E to recover 75 percent of the requested revenue requirement on an interim basis, subject to refund based on the amount authorized for recovery in the Final Decision in the WGSC proceeding.[17] PG&E began collecting this interim rate recovery on April 1, 2024 and completed recovery on August 31, 2025. The statutory deadline for the proceeding is extended to October 30, 2026.[18]

4. Billing Modernization Initiative

On October 23, 2024, PG&E filed its Billing Modernization Initiative (BMI) Application (A.24-10-014) to recover forecasted costs to upgrade and

---

16 The Generation Revenue Requirement is for Track 1 of the proceeding only. Track 2 does not include a Generation Revenue Requirement.

17 D.24-03-006, OP 1 and OP 2.

18 D.26-02-044.

replace PG&E’s aging billing systems, which are critical to serving its customers in areas of billing, customer service, and customer data management. The forecasted electric generation revenue requirement for 2027 is $10.7 million per the Supplemental Testimony submitted on March 17, 2026. As of this filing, a proposed decision has not been issued in this proceeding. PG&E is hopeful that a final decision will be issued before year-end, however the current statutory deadline for the proceeding is February 23, 2027 (D.26-04-010).

5. Recovery of Costs Associated With the 2019 Kincade Fire and 2021 Dixie Fire Under Assembly Bill 1054

On November 14, 2026 PG&E filed its 2019 Kincade Fire and the 2021 Dixie Fire Assembly Bill (AB) 1054 Application, covering expenses recorded in its Wildfire Expense Memorandum Account (WEMA) and Catastrophic Event Memorandum Account (CEMA). The application seeks approval to recover approximately $2.27 billion in wildfire-related costs, net of insurance, Wildfire Fund reimbursements, and Federal Energy Regulatory Commission-jurisdictional exclusions, including third-party claims, litigation and financing costs, and facility repair and restoration expenses. The filing asks the Commission to find the costs reasonable, authorize rate recovery, and approve mechanisms for updating and recovering remaining trailing costs. As required by the Scoping Memo, PG&E will update WEMA and CEMA balances on May 29, 2026 and July 10, 2026. Evidentiary hearings are scheduled for August 17-21, 2026, and a proposed decision is expected November 13, 2026.

G. Generation Resource Product Forecast

The EP Costs reflect the total Ongoing CTC and PCIA costs associated with PG&E’s capacity and energy forecasts presented in Chapter 5.

1. Resource Adequacy Capacity

The Commission previously issued specific RA MPBs for each of the system, local, and flexible categories. D.25-06-049 revised the methodology to value RA by establishing a single RA MPB, utilizing system, flexible, and local RA procurement data.

a. RA Supply and Sales

PG&E's forecast of expected RA capacity from its supply portfolio under the Slice-of-Day (SoD) framework approved in D.22-06-050 is discussed in Chapter 4, Section C, *Portfolio Net Qualifying Capacity*, and in Chapter 5, Section D, *System RA Open Position and Associated Net Costs*. As noted in Chapter 5, while the SoD framework has introduced an hourly dimension to RA compliance, the underlying cost recovery mechanisms (e.g., PCIA) continue to be based on single monthly values for the RA supply. Thus, to calculate the annual volumes to be retained at the applicable RA MPBs for ratesetting, the SoD volumes have been translated to single monthly values based on the interim SoD methodology described in Chapter 5 and are then averaged across all months to produce a single value.[19]

The final RA capacity position from PG&E's supply portfolio is presented in Table 5-18[20] and serves as the basis for PG&E's forecast of residual 2027 system RA sales. Table 5-16 includes PG&E's forecast of residual system RA sales. Pursuant to D.19-10-001, OP 2, Attachment B, revenues from RA sales are valued in the PCIA as follows:

- Executed transactions for the sale of RA products are valued using the terms applicable to the respective executed transactions; and
- Residual RA sales (expected future sales) are valued using the assigned applicable MPB.[21]

b. Unsold RA

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 Unsold RA

---

19 A more detailed discussion of PG&E's methodology to implement the SoD framework including the development of the system RA open position and PCIA aggregation under the SOD framework is included in Chapter 5, Section D, pp. 5-12 to 5-13.

20 Consistent with D.19-10-001, individual resource RA is treated as either local, flex, or system when calculating forecast retained RA value.

21 As described in Section F of this testimony.

capacity based on recent historical experience, which is described further in Chapter 5, Section D.2.b, *Unsold RA*. Pursuant to D.19-10-001, OP 3(e), the value of forecast unsold RA is zero.

2. Energy

The energy included in the calculation of the total portfolio cost reflects the forecast generation that PG&E expects to sell into California Independent System Operator (CAISO) market, as described in Chapter 5.

3. Renewable Energy Credits

California Pub. Util. Code Sections 399.11-399.33 established a requirement that 60 percent of total retail sales of electricity in California be from eligible renewable energy resources by December 31, 2030. The renewable and environmental attributes associated with eligible RPS energy are recognized through a certificate, issued by the Western Renewable Energy Generation Information System, commonly known as a REC.

As part of the RPS Program, PG&E is required to submit an Annual RPS Compliance Report to report the Utility's progress towards reaching the RPS compliance requirements, as implemented by D.12-06-038, and subsequent decisions. Compliance with the RPS Program is measured in eligible RECs retired towards RPS compliance and evaluated on a multi-year compliance period basis.

Based on its initial forecasting assumptions, PG&E forecasts that its future bundled customer Net Physical RPS position for 2027 will be short of PG&E's RPS compliance target. Therefore, PG&E will incorporate the applicable ratemaking adjustment required by D.20-02-047 that is associated with meeting PG&E's 2027 RPS compliance target and described further in the following testimony. Pursuant to D.25-12-027, PG&E will also present a monthly breakdown of its forecasted 2026 Net RPS Position. While PG&E will present a 'Monthly Net Short,' minimum retained RPS entries for 2026, and all other years, will be based on the annual net short.

a. Minimum Retained Requirement Volume

In D.20-02-047, addressing PG&E's 2020 ERRA Forecast Application, the Commission established that the annual RPS target quantities provided in D.11-12-020 for calculating the RPS compliance period requirement served as appropriate minimum quantities for PG&E to consider for its annual retained RPS volumes as part of the PABA true-up.[22] D.19-06-023 established quantities applicable to the forecast year.

1) Historical Initial Annual Net RPS Positions

In order to determine how accounting adjustments will address PG&E's forecast RPS positions, PG&E must first establish how much surplus RPS generation exists from the same compliance period as well as the amounts of surplus RPS generation from applicable years in the prior compliance period. To do so, a net available RPS quantity for each applicable year must first be calculated. This information is presented in Table 8-2, with column A showing the delivery year, which also represents the applicable ERRA Forecast year. Table 8-2 includes the net physical RPS position, expected open position, excess RPS volumes, unsold RPS volumes, and PG&E bundled sales. RPS generation for 2026 includes both actual RPS generation, as well as forecasted data.

Columns E and F include the annual RPS compliance target percentages and quantities respectively that need to be met by PG&E. The quantities included in Table 8-2 reflect rules and requirement quantities applicable to the current RPS compliance period, as laid out in D.19-06-023.[23] In D.19-06-023, the Commission maintained RPS target quantities that are ultimately based on a straight-line trend to reach each compliance period's RPS target.

With data captured annually for recorded RPS generation, Bundled Sales and RPS requirement targets, the net available RPS

---

[22] D.20-02-047, p. 13-14. This minimum retained amount was reinforced in D.20-12-012, p. 5 (stating "thus, the Decision merely stated that PG&E should procure "no less than," i.e., a minimum of 31 percent of retail sales by 2019. (D.20-02-047 p. 13.) PG&E fails to show how this conclusion is either unlawful or incorrect.").

[23] D.19-06-023, p. 11, OP 1 and OP 2, pp. 11-12, adopt RPS procurement quantity requirements for the years 2021-2024 and 2025-2027, respectively.

compliance period generation quantity in each year can be calculated by subtracting Columns G and H from Column F. The next section details how the net available RPS compliance period generation quantities from Table 8-3 have been adjusted for any prior minimum retained RPS entries.

Table 8-2 below shows both the total annual net RPS generation volumes for the current RPS compliance period up through 2027 as well as the applicable years from the prior compliance period needed in order to meet a forecasted minimum retained RPS entry for 2027.

TABLE 8-2
ANNUAL AVAILABLE COMPLIANCE PERIOD RPS GENERATION

Line No.	(A) Delivery Year	(B) Bundled Sales (MWH)	(C) Annual RPS Compliance Target (%)	(D) = (B*C) Annual RPS Compliance Target (MWh)	(E) Net Physical RPS Position (MWH)	(F) Expected Net Open (MWH)	(G) Unsold RPS (MWH)	(H) Excess RPS (MWH)	(I) = (F - G - H) Net Available Compliance Period RPS Generation (MWH)
1	**2013**	75,705,039	20%	15,141,008	17,069,488	1,928,480	-	-	1,928,480
2	**2014**	74,546,865	22%	16,176,670	20,156,687	3,980,017	-	-	3,980,017
3	**2015**	72,112,848	23%	16,802,294	21,284,772	4,482,478	-	-	4,482,478
4	**2016**	68,440,794	25%	17,110,199	22,489,623	5,379,425	-	-	5,379,425
5	**2017**	61,397,214	27%	16,577,248	20,281,522	3,704,274	-	-	3,704,274
6	**2018**	48,832,111	29%	14,161,312	18,934,717	4,773,405	-	-	4,773,405
7	**2019**	35,956,100	31%	11,146,391	10,444,565	(701,826)	-	-	(701,826)
8	**2020**	35,838,070	33%	11,826,563	12,271,881	445,318	-	-	445,318
9	**2021**	33,149,379	36%	11,850,903	17,250,635	5,399,732	-	-	5,399,732
10	**2022**	30,307,095	39%	11,668,232	13,000,793	1,332,561	-	-	1,332,561
11	**2023**	26,017,569	41%	10,732,247	10,092,084	(640,163)	3,073,161	-	(3,713,324)
12	**2024**	26,722,965	44%	11,758,105	6,826,487	(4,931,618)	412,848	-	(5,344,466)
13	**2025**	24,051,617	47%	11,224,890	9,162,864	(2,062,025)	-	-	(2,062,025)
14	**2026**	24,915,099	49%	12,290,618	[redacted]	[redacted]	-	-	[redacted]
15	**2027**	22,992,758	52%	11,956,234	[redacted]	[redacted]	-	-	[redacted]

2) Historical Minimum RPS Entries

As referenced above, the CPUC established the minimum retained RPS requirement in D.20-02-047, with 2019 being the first effective year of this requirement. In order to satisfy this requirement for 2019, PG&E recorded accounting entries crediting earlier PCIA vintages through PABA. For 2020, 2021 and 2022, no minimum retained RPS entries were necessary as PG&E's bundled RPS position exceeded the annual target in each of those years. For 2023 through 2026, PG&E's accounting entries for crediting PABA vintages were based on the applicable methodologies approved by the CPUC for those ratesetting years. Table 8-3 provides the adjusted net RPS position for each applicable year in Column D by accounting for all prior year minimum RPS entries (Column C). D.25-12-027 adopted PG&E's methodology to value pre-2019 banked RECs at zero dollars on an interim basis. Therefore, for RECs defined by the Commission as 'Pre-2019 Banked RECs', which include RECs generated in 2018 and earlier, PG&E will show a 'Credit Vintage' which corresponds to the year the pre-2019 Banked RECs were applied to.

TABLE 8-3
HISTORICAL MINIMUM RETAINED RPS ENTRIES

Line No.	(A) Delivery/ Vintage Year	Vintage Credited	(B) Net Available Compliance Period RPS Generation (MWH)	(C) * Applied Prior Years Minimum RPS Entry	(D) Adjusted Net RPS Position
1	2013	[redacted]	1,928,480	[redacted]	[redacted]
2	2014	[redacted]	3,980,017	[redacted]	[redacted]
3	2015	[redacted]	4,482,478	[redacted]	[redacted]
4	2016	[redacted]	5,379,425	[redacted]	[redacted]
5	2017	[redacted]	3,704,274	[redacted]	[redacted]
6	2018	[redacted]	4,773,405	[redacted]	[redacted]
7	2019	[redacted]	(701,826)	701,826	-
8	2020	[redacted]	445,318	[redacted]	[redacted]
9	2021		5,399,732	[redacted]	-
10	2022		1,332,561	[redacted]	-
11	2023		(3,713,324)	[redacted]	-
12	2024		(5,344,466)	[redacted]	-
13	2025		(2,062,025)	2,062,025	-
14	2026		[redacted]	[redacted]	
15	Total		[redacted]	701,826	[redacted]

**No minimum retained RPS entry was needed related to 2021 and 2022 since both years RPS generation exceeded the respective annual RPS targets resulting in a surplus.*

The adjusted net RPS position then serves as the basis for a forecasted minimum RPS entry for 2027, if applicable.

3) Determination of Additional Retained RECs for 2027

As shown in Table 8-2, PG&E is initially forecasting a short RPS position in 2027 and expects to use banked RECs in order to meet the RPS compliance target.

Initially, PG&E forecasts utilizing RECs generated and retained before January 1, 2019 (Pre-2019 Banked RECs) to meet the compliance target.[24] For any utilized Pre-2019 Banked RECs, PG&E will credit applicable ERRA Forecast year vintage customers (e.g., vintage 2027 for the 2027 ERRA Forecast), regardless of delivery year, as adopted in D.25-12-027.

Table 8-4 presents PG&E's forecasted minimum retained RPS entry for 2027.

---

24 To the extent that a non-zero dollar valuation of the Pre-2019 Banked RECs is not the lowest cost option for its bundled service customers, future ERRA Forecast cycles may reflect revisions to this strategy.

TABLE 8-4
2027 MINIMUM RETAINED RPS ENTRY

Line No.	(A) Delivery Year	Vintage Credited	(B) Pre-2027 Adjusted Net RPS Position	(C) Minimum 2027 Entry	(D) = (B + C) Post-2027 Adjusted Net RPS Position
1	2013	[redacted]			
2	2014				
3	2015				
4	2016				
5	2017				
6	2018		-	-	-
7	2019		-	-	-
8	2020	[redacted]			
9	2021		-	-	-
10	2022		-	-	-
11	2023		-	-	-
12	2024		-	-	-
13	2025		-	-	-
14	2026		-	-	-
15	2027		[redacted]	[redacted]	-
16	Total		[redacted]	-	[redacted]

PG&E will update the forecasted 2027 minimum retained RPS entry in its Fall Update based on updated portfolio forecast assumptions and any applicable Commission orders.[25] The entries associated with the 2027 minimum retained RPS, if applicable, will be true-ed up through the applicable balancing accounts and presented as part of PG&E's 2027 ERRA Compliance Review Application.

4) Monthly RPS Net Short

D.25-12-027 ordered PG&E to present a monthly breakdown of banked RECs being used to meet PG&E's forecasted 2026 shortfall. Table 8-5 below shows preliminary actual and forecast net RPS generation, RPS target and 'net short' for each month in 2026. PG&E then shows the estimated vintage of bank which would be used to meet the shortfall in that month. As generation and bundled

---

25 PG&E's Fall Update may also be impacted by any changes that may arise as a result of a PCIA rulemaking regarding Pre 2019 Banked RECs.

customer sales vary across months, there may be months when PG&E forecasts a long position. These volumes will be used in future months within the year and referred to as 'Current Year.' While PG&E may be long in some months, it does not classify these volumes as banked RECs as RPS compliance is calculated on an annual and compliance period basis.

TABLE 8-5
2026 MONTHLY NET RPS SHORT

Line No.	Delivery Year	Delivery Month	Net Physical RPS Position	RPS Target	Monthly Net Short	Estimated Bank Vintage Used
1	2026	1	[redacted]			
2	2026	2				
3	2026	3				
4	2026	4				
5	2026	5				
6	2026	6				
7	2026	7				
8	2026	8				
9	2026	9				
10	2026	10				
11	2026	11				
12	2026	12				
13		Total				

4. Large Hydroelectric Allocation

OP 3 of D.23-06-006 ordered PG&E to indicate whether it would offer an interim allocation of Large Hydroelectric energy in its ERRA filing in the first year of the corresponding RPS compliance period. PG&E elected to offer interim allocations of Large Hydroelectric energy for the period of 2025-2027 as stated in its 2025 ERRA Forecast testimony. PG&E may offer additional Large Hydroelectric GHG-free energy from the Bundled service customer share of the portfolio for sale. Any executed transactions, or changes in volume assumption, will be included in PG&E's Fall Update.

H. Market Price Benchmark

1. Background

MPBs are used to calculate the Ongoing CTC and the PCIA indifference amounts described in this testimony. The indifference amounts are derived by taking the difference between the total cost forecast of the portfolio of resources and the market value forecast of those resources to determine the above-market costs associated with the portfolio. The market value for the portfolio is determined by multiplying the Commission-approved MPBs by the applicable volumes from the portfolio to determine an equivalent market value for the generation portfolio.

The MPB calculation was originally adopted in D.06-07-030 and modified in D.07-01-025, D.11-12-018, Res.E-4475 and D.23-06-006.[26] In D.23-06-006, the Commission addressed the "greenhouse gas-free" incremental value of large hydroelectric energy resources above fossil fuel resources. In that decision, the Commission also revised the calculation of the Energy Index MPB to apply on- and off-peak weightings that are based on time weightings, as well as calculate a "portfolio weighting" that reflects the 3-year historical variance between the energy revenues received from PCIA-eligible resources and the actual average NP15 (or applicable trading hub) day-ahead market prices over that same time period.

A revised methodology to calculate two components of the MPB, the RPS and RA Adders, was adopted in D.18-10-019 and D.19-10-001, and RA Adders were further revised in D.25-06-049. D.22-01-023, OP 1 stated that the Commission's Energy Division shall calculate the components of the MPB and make them available by October 1 of each year. PG&E will incorporate updated MPBs in the Fall Update consistent with Commission directives in effect at that time.

2. Components

The MPB consists of the following components:

a) <u>Energy Index</u> – Represents the CAISO market energy value of the vintaged portfolio;[27]

b) <u>GHG Free Index</u> – Represents the GHG-Free MPB, if any, for a given year;[28]

---

26 See Appendix 1 of D.06-07-030.

27 Formally known as Brown Power MPB.

28 D.23-06-006, p. 27.

c) 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

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

a. Energy Index

OP 1(a) of D.18-10-019 stated that the Energy Index shall be calculated annually by the Commission's Energy Division, based on the methodology adopted in D.06-07-030, and modified in D.11-12-018, as follows:

- Apply on- and off-peak weightings that are based on time weightings as opposed to bundled service load weightings to the on- and off-peak Platts data provided by Energy Division;[29]
- After the IOUs complete the time weighting described immediately above, each IOU will then calculate a "portfolio weighting" that reflects the 3-year historical variance between the energy revenues received from PCIA-eligible resources and the actual average NP15 (or applicable trading hub) day-ahead market prices over that same time period; and
- Pursuant to OP 6 of D.23-06-006, the 3-year historical data exclude market results for retired/expired 300 MWs or larger resources that are not included in PG&E's portfolio from 2021 through 2023. In compliance with D.23-06-006, PG&E includes the Energy Index MPB weighting factors and underlying data in the WPs supporting this Application.

b. GHG Free Index

OP 4 of D.23-06-006 stated that if PG&E does not timely elect to provide an interim allocation of large hydroelectric energy during a given year, the Utility shall add a new line item to the PCIA WPs in its ERRA Forecast Application to identify the output and incremental value of large hydroelectric resources, if any. Consistent with its election for the

[29] D.06-07-030, Appendix 1 as modified in D.22-01-023, OP 1 which required the CPUC to release the MPB by October 1, instead of November 1.

2026-2027 period in A.25-05-011, there is no need for a new line item for an MPB for large hydroelectric energy.

c. Green/Renewable Portfolio Standard 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, CCAs and ESPs during the years prior to the forecast year (year n-2 and year n-1) for delivery in the forecast year (year n).

d. Capacity/Resource Adequacy Adder

OP 1(c) of D.18-10-019 stated that the Capacity/RA Adder shall be calculated using reported purchase and sales transactions submitted by the IOUs, CCAs, and ESPs during the years prior (year n-2 and year n-1) for deliveries in the forecast year (year n).[30] Capacity expected to remain unsold is assigned a price of zero.[31] The RA Adder shall be calculated in a manner that reflects the three types of RA capacity: system, local, and flexible. PG&E's Fall Update will reflect any relevant Commission directives.

3. 2027 Market Price Benchmark

The 2027 MPBs used in this testimony, and presented in Table 8-8, are calculated using data consistent with the methodology described above, except as described below. PG&E will incorporate any change to these MPBs published by the Commission in the Fall Update.

a) Energy Index

The final forecast MPBs from Energy Division are not available at this time. Therefore, as a placeholder, PG&E is using the average On-Peak and Off-Peak 2027 Forward Electric Prices presented in Table 4-1, weighted by factors required in D.23-06-006 to calculate the Energy Index.

b) GHG Free Index

Since PG&E elects to provide an allocation of large hydroelectric energy for the 2027 delivery year, no new line item to its 2027 PCIA

---

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

31 See D.19-10-001, COL 22.

WPs identifying the output and incremental value of large hydroelectric resources is required

c) Green/RPS Adder

The Green/RPS Adder uses a placeholder value of $62.45/MWh as issued by the Energy Division in its 2026 Forecast MPB Calculations.

c) Capacity/RA Adders

The Capacity/RA Adders use placeholder values as included in the MPB Publication for 2026, as follows:

- System: $11.53/kilowatt (kW)-month;
- PG&E Local: $11.53/kW-month;
- Southern California Edison Company (SCE) Local: $11.53/kW-month; [32]
- San Diego Gas & Electric Company (SDG&E) Local: $11.53/kW month; and
- Flexible: $11.53/kW-month.

I. Indifference Amount Calculation

Table 8-9 presents the costs, energy, and capacity[33] volumes, (lines 1 through 8) for the total portfolio, derived from Table 8-7. The market value of the portfolio is derived by multiplying the appropriate MPB, presented in Table 8-8, by the portfolio's generation and capacity. The cost is compared to the market value for each vintage to determine the level of indifference.[34]

Line 35 of Table 8-8 shows the Indifference Amount indicating if 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 adjusted and cumulative indifference amounts by vintages are shown on line 39 and 40, respectively.

---

32 Certain of PG&E's contracted generation resources are located in SCE and SDG&E RA area.

33 Reflects the SoD weightings proposed in Chapter 5 to derive the annual supply volumes.

34 Also applies to the Ongoing CTC portfolio.

J. Conclusion

The allocation of Indifference Amount discussed includes the net above market Revenue Requirements are recoverable from PG&E's bundled and eligible DL customers. A summary of these Revenue Requirements is provided in Table 8-6 below. PG&E will update these amounts in the Fall Update of this testimony.

TABLE 8-6
SUMMARY OF INDIFFERENCE AMOUNT REVENUE REQUIREMENTS
(THOUSANDS OF DOLLARS)

Line No.	Rate Component	Revenue Requirement
1	Ongoing CTC	$(10,760)
2	PCIA	636,852
3	Total	$626,092

TABLE 8-7
IOU TOTAL PORTFOLIO SUMMARY
PURSUANT TO D.17-08-026, AND MODIFIED TO COMPLY WITH OP 3 OF D.18-10-019, AND D.21-03-051

Line No.		Ongoing CTC-Eligible Portfolio	UOG Legacy and Vintaged PCIA Portfolio									
			UOG Legacy	2009	2010	2011	2012	2013	2014	2015	2016	2017
1.	CRS Eligible Portfolio Costs [(a)] ($000)	$17,306	$837,700	$1,430,729	$433,300	$124,042	$153,883	$49,831	$4,062	$5,376	$1,866	$9,326
2.	CRS Eligible Non-Renewable Supply at Generation Meter (GWh)	79	8,206	7,751	-214	429	743	354	60	115	11	60
3.	CRS Eligible Renewable Supply at Generation Meter (GWh)	95	351	3,573	3,231	842	1,015	543	32	37	27	118
4.	CRS Eligible Total Net Qualifying Capacity (MW)											
5.	CRS Eligible System NQC (System only, No flex or local)	88	290	405	92	49	51	53	3	0	0	9
6.	CRS Eligible Local NQC - PG&E (System and local, with or without flex)	18	1,508	595	74	32	90	5	1	1	3	40
7.	CRS Eligible Local NQC - SCE (System and local, with or without flex)	0	0	0	23	0	5	0	2	11	0	0
8.	CRS Eligible Local NQC - SDG&E (System and local, with or without flex)	0	0	0	0	0	0	0	0	0	0	0
9.	CRS Eligible Flexible NQC (System and flex only, No local)	0	284	756	0	0	0	0	0	0	0	16

Line No.		UOG Legacy and Vintaged PCIA Portfolio										IOU Total Portfolio
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
1.	CRS Eligible Portfolio Costs [(a)] ($000)	$1	$40,254	$1	$200,709	$1	$29,738	$430	$829	$490	$0	$3,339,875
2.	CRS Eligible Non-Renewable Supply at Generation Meter (GWh)	0	0	0	-501	0	0	0	0	0	0	17,092
3.	CRS Eligible Renewable Supply at Generation Meter (GWh)	0	0	0	693	0	14	6	11	10	0	10,599
4.	CRS Eligible Total Net Qualifying Capacity (MW)											
5.	CRS Eligible System NQC (System only, No flex or local)	0	25	0	8	0	1	0	3	5	0	1,083
6.	CRS Eligible Local NQC - PG&E (System and local, with or without flex)	0	175	0	207	0	0	0	0	0	0	2,747
7.	CRS Eligible Local NQC - SCE (System and local, with or without flex)	0	94	0	183	0	0	0	0	0	0	317
8.	CRS Eligible Local NQC - SDG&E (System and local, with or without flex)	0	67	0	0	0	0	0	0	0	0	67
9.	CRS Eligible Flexible NQC (System and flex only, No local)	0	89	0	1,024	0	152	0	0	0	0	2,322

TABLE 8-8
INDIFFERENCE CALCULATION INPUTS AND SOURCES
PURSUANT TO D.17-08-026, AND MODIFIED TO COMPLY WITH OP 3 OF D.18-10-019, D.21-03-051, AND D.23-06-006

Line No.	Description	Source of Data	Value
1.	On Peak Energy Index ($/MWh)	TABLE 4-1	[redacted]
2.	Off Peak Energy Index ($/MWh)	TABLE 4-1	
3.	On Peak Time Weight (%)	Based on 2027 Calendar and NERC Holiday Schedule	56.1%
4.	Off Peak Time Weight (%)	Based on 2027 Calendar and NERC Holiday Schedule	43.9%
5.	Portfolio Weights	2023-2025 PCIA revenue less the actual average NP15	0.88
6.	Load Weighted Average Price ($/MWh)	(line 1 x line 3 + line 2 x line 4) x line 5	[redacted]
7.	Green/RPS Adder ($/MWh)	2026 forecast Benchmark	$62.45
8.	Green Benchmark ($/MWh)	Line 6 + Line 7	[redacted]
9.	System RA Benchmark ($/kW-Year)	2026 forecast Benchamrk ($$11.53 kW-Month x 12)	$138.36
10.	Local RA Benchmark ($/kW-Year) - PG&E	2026 forecast Benchamrk ($$11.53 kW-Month x 12)	$138.36
11.	Local RA Benchmark ($/kW-Year) - SCE	2026 forecast Benchamrk ($$11.53 kW-Month x 12)	$138.36
12.	Local RA Benchmark ($/kW-Year) - SDG&E	2026 forecast Benchamrk ($$11.53 kW-Month x 12)	$138.36
13.	Flexible RA Benchmark ($/kW-Year)	2026 forecast Benchamrk ($$11.53 kW-Month x 12)	$138.36
14.	Revenue Fee and Uncollectible Factor	Advice 5128-G/7727-E	0.013604

TABLE 8-9
INDIFFERENCE AMOUNT CALCULATION
PURSUANT TO D.17-08-026, AND MODIFIED TO COMPLY
WITH OP 3 OF D.18-10-019, D.21-03-051, AND D.23-06-006

Line		Equation	Unit	Ongoing CTC-Eligible	UOG Legacy and Vintaged PCIA									
					UOG Legacy	2009	2010	2011	2012	2013	2014	2015	2016	2017
	Cost of Portfolio													
1.	Portfolio Total Cost		$000	$17,306	$837,700	$1,430,729	$433,300	$124,042	$153,883	$49,831	$4,062	$5,376	$1,866	$9,326
2.	CRS Eligible Non-Renewable Supply at Generation Meter		GWh	79	8,206	7,751	-214	429	743	354	60	115	11	60
3.	CRS Eligible Renewable Supply at Generation Meter		GWh	95	351	3,573	3,231	842	1,015	543	32	37	27	118
4.	CRS Eligible System NQC		MW	88	290	405	92	49	51	53	3	0	0	9
5.	CRS Eligible Local NQC - PG&E		MW	18	1,508	595	74	32	90	5	1	1	3	40
6.	CRS Eligible Local NQC - SCE		MW	0	0	0	23	0	5	0	2	11	0	0
7.	CRS Eligible Local NQC - SDG&E		MW	0	0	0	0	0	0	0	0	0	0	0
8.	CRS Eligible Flexible NQC		MW	0	284	756	0	0	0	0	0	0	0	16
9.	**Portfolio Unit Cost**	**Line 1 / (Line 2 + Line 3)**	**$/MWh**	**$99.64**	**$97.90**	**$126.34**	**$143.64**	**$97.61**	**$87.52**	**$55.53**	**$43.95**	**$35.34**	**$48.94**	**$52.58**
10.	**Market Value of Portfolio**													
11.	**Market Value of Brown Portfolio**													
12.	Non-Renewable Energy		GWh	79	8,206	7,751	-214	429	743	354	60	115	11	60
13.	Weighted Average Brown Benchmark		$/MWh	[redacted]										
14.	**Market Value of Brown Portfolio**	**Line 10 x Line 11**	**$000**											
15.	**Market Value of Green Portfolio**													
16.	Renewable Energy		GWh	95	351	3,573	3,231	842	1,015	543	32	37	27	118
17.	Weighted Average Green Benchmark		$/MWh	[redacted]										
18.	**Market Value of Green Portfolio**	**Line 16 x Line 17**	**$000**											
19.	**Capacity Adder**													
20.	Average Monthly System NQC		MW	88	290	405	92	49	51	53	3	0	0	9
21.	System RA Benchmark		$/kW-Year	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36
22.	Average Monthly Local Area NQC - PG&E		MW	18	1,508	595	74	32	90	5	1	1	3	40
23.	Local RA Benchmark - PG&E		$/kW-Year	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36
24.	Average Monthly Local Area NQC - SCE		MW	0	0	0	23	0	5	0	2	11	0	0
25.	Local RA Benchmark - SCE		$/kW-Year	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36
26.	Average Monthly Local Area NQC - SDG&E		MW	0	0	0	0	0	0	0	0	0	0	0
27.	Local RA Benchmark - SDG&E		$/kW-Year	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36
28.	Average Monthly Flexible NQC		MW	0	284	756	0	0	0	0	0	0	0	16
29.	Flexible RA Benchmark		$/kW-Year	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36
30.	**Market Value of Capacity**		**$000**	**$14,738**	**$287,965**	**$242,974**	**$26,085**	**$11,211**	**$20,187**	**$8,019**	**$823**	**$1,602**	**$421**	**$9,042**
31.	**Portfolio Market Value**	**Line 14 + Line 18 + Line 30**	$000	**$27,922**	**$667,043**	**$938,852**	**$353,788**	**$116,851**	**$156,987**	**$79,386**	**$6,707**	**$10,252**	**$3,705**	**$23,798**
32.	**Indifference Amount**													
33.	**Portfolio Total Cost**	**Line 1**	$000	**$17,306**	**$837,700**	**$1,430,729**	**$433,300**	**$124,042**	**$153,883**	**$49,831**	**$4,062**	**$5,376**	**$1,866**	**$9,326**
34.	**Portfolio Market Value**	**Line 31**	$000	**$27,922**	**$667,043**	**$938,852**	**$353,788**	**$116,851**	**$156,987**	**$79,386**	**$6,707**	**$10,252**	**$3,705**	**$23,798**
35.	**Total Indifference Amount (Unadjusted)**	**Line 32 - Line 33**	$000	**($10,616)**	**$170,657**	**$491,877**	**$79,511**	**$7,191**	**($3,104)**	**($29,555)**	**($2,644)**	**($4,876)**	**($1,839)**	**($14,472)**
36.	**Other Adjustments**		$000											
37.	**Adjusted Indifference Amount**	**Sum (Lines 35:36)**	$000	**($10,616)**	**$170,657**	**$491,877**	**$79,511**	**$7,191**	**($3,104)**	**($29,555)**	**($2,644)**	**($4,876)**	**($1,839)**	**($14,472)**
38.	**Revenue Franchise Fees & Uncollectibles (RF&U)**	**Advice 5128-G/7727-E**	$000	**($144)**	**$2,322**	**$6,691**	**$1,082**	**$98**	**($42)**	**($402)**	**($36)**	**($66)**	**($25)**	**($197)**
39.	**Adjusted Indifference Amount with RF&U**	**Line 37 + Line 38**	$000	**($10,760)**	**$172,979**	**$498,569**	**$80,593**	**$7,289**	**($3,146)**	**($29,957)**	**($2,680)**	**($4,943)**	**($1,864)**	**($14,669)**
40.	**Cummulative Adjusted Indifference Amount with RF&U**		$000	**($10,760)**	**$172,979**	**$671,547**	**$752,140**	**$759,429**	**$756,283**	**$726,327**	**$723,646**	**$718,704**	**$716,840**	**$702,170**

TABLE 8-9
INDIFFERENCE AMOUNT CALCULATION
PURSUANT TO D.17-08-026, AND MODIFIED TO COMPLY
WITH OP 3 OF D.18-10-019, D.21-03-051, AND D.23-06-006
(CONTINUED)

Line	ion	Equation	Unit	UOG Legacy and Vintaged PCIA									
				2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	Cost of Portfolio												
1.	Portfolio Total Cost		$000	$1	$40,254	$1	$200,709	$1	$29,738	$430	$829	$490	$0
2.	CRS Eligible Non-Renewable Supply at Generation Meter		GWh	0	0	0	-501	0	0	0	0	0	0
3.	CRS Eligible Renewable Supply at Generation Meter		GWh	0	0	0	693	0	14	6	11	10	0
4.	CRS Eligible System NQC		MW	0	25	0	8	0	1	0	3	5	0
5.	CRS Eligible Local NQC - PG&E		MW	0	175	0	207	0	0	0	0	0	0
6.	CRS Eligible Local NQC - SCE		MW	0	94	0	183	0	0	0	0	0	0
7.	CRS Eligible Local NQC - SDG&E		MW	0	67	0	0	0	0	0	0	0	0
8.	CRS Eligible Flexible NQC		MW	0	89	0	1,024	0	152	0	0	0	0
9.	**Portfolio Unit Cost**	**line 1 / (line 2 + line 3)**	**$/MWh**	**$0.00**	**$0.00**	**$0.00**	**$1,045.19**	**$0.00**	**$2,130.67**	**$70.86**	**$73.83**	**$48.68**	**$0.00**
10.	**Market Value of Portfolio**												
11.	**Market Value of Brown Portfolio**												
12.	Non-Renewable Energy		GWh	0	0	0	-501	0	0	0	0	0	0
13.	Weighted Average Brown Benchmark		$/MWh	[redacted]									
14.	**Market Value of Brown Portfolio**	**line 12 x line 13**	**$000**										
15.	**Market Value of Green Portfolio**												
16.	Renewable Energy		GWh	0	0	0	693	0	14	6	11	10	0
17.	Weighted Average Green Benchmark		$/MWh	[redacted]									
18.	**Market Value of Green Portfolio**	**line 16 x line 17**	**$000**										
19.	**Capacity Adder**												
20.	Average Monthly System NQC		MW	0	25	0	8	0	1	0	3	5	0
21.	System RA Benchmark		$/kW-Year	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36
22.	Average Monthly Local Area NQC - PG&E		MW	0	175	0	207	0	0	0	0	0	0
23.	Local RA Benchmark - PG&E		$/kW-Year	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36
24.	Average Monthly Local Area NQC - SCE		MW	0	94	0	183	0	0	0	0	0	0
25.	Local RA Benchmark - SCE		$/kW-Year	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36
26.	Average Monthly Local Area NQC - SDG&E		MW	0	67	0	0	0	0	0	0	0	0
27.	Local RA Benchmark - SDG&E		$/kW-Year	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36
28.	Average Monthly Flexible NQC		MW	0	89	0	1,024	0	152	0	0	0	0
29.	Flexible RA Benchmark		$/kW-Year	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36	$138.36
30.	**Market Value of Capacity**		**$000**	**$0**	**$62,183**	**$0**	**$196,832**	**$0**	**$21,168**	**$59**	**$361**	**$688**	**$0**
31.	**Portfolio Market Value**	**line 14 + line 18 +line 30**	$000	**$0**	**$62,183**	**$0**	**$248,130**	**$0**	**$22,622**	**$692**	**$1,532**	**$1,737**	**$0**
32.	**Indifference Amount**												
33.	**Portfolio Total Cost**	**line 1**	$000	**$1**	**$40,254**	**$1**	**$200,709**	**$1**	**$29,738**	**$430**	**$829**	**$490**	**$0**
34.	**Portfolio Market Value**	**line 31**	$000	**$0**	**$62,183**	**$0**	**$248,130**	**$0**	**$22,622**	**$692**	**$1,532**	**$1,737**	**$0**
35.	**Total Indifference Amount (Unadjusted)**	**line 33 - line 34**	$000	**$1**	**($21,929)**	**$1**	**($47,421)**	**$1**	**$7,116**	**($261)**	**($702)**	**($1,247)**	**$0**
36.	**Other Adjustments**		$000										
37.	**Adjusted Indifference Amount**	**line 35 + line 36**	$000	**$1**	**($21,929)**	**$1**	**($47,421)**	**$1**	**$7,116**	**($261)**	**($702)**	**($1,247)**	**$0**
38.	**Revenue Franchise Fees & Uncollectibles (RF&U)**	**Advice 5128-G/7727-E**	$000	**$0**	**($298)**	**$0**	**($645)**	**$0**	**$97**	**($4)**	**($10)**	**($17)**	**$0**
39.	**Adjusted Indifference Amount with RF&U**	**line 37 + line 38**	$000	**$1**	**($22,227)**	**$1**	**($48,066)**	**$1**	**$7,213**	**($265)**	**($712)**	**($1,264)**	**$0**
40.	**Cummulative Adjusted Indifference Amount with RF&U**		$000	**$702,171**	**$679,944**	**$679,945**	**$631,879**	**$631,880**	**$639,092**	**$638,828**	**$638,116**	**$636,852**	**$636,852**

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

TREE MORTALITY REVENUE REQUIREMENT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
TREE MORTALITY REVENUE REQUIREMENT

TABLE OF CONTENTS

A. Introduction 9-1

B. Program Background 9-1

C. Contract Procurement Costs and Revenue Requirement 9-2

D. Conclusion 9-3

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
TREE MORTALITY REVENUE REQUIREMENT

A. Introduction

This chapter discusses Pacific Gas and Electric Company's (PG&E) 2027 procurement cost forecast and revenue requirement for the Tree Mortality Non-Bypassable Charge (TMNBC). The discussion will cover background on 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, then-Governor Edmund G. Brown, Jr. issued a Proclamation of a State of Emergency (Proclamation) to address the tree mortality crisis in California. In response to the Proclamation, on March 17, 2016, the California Public Utilities Commission (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.[1] 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 procurement costs to satisfy this requirement be recovered from all customers on a non-bypassable basis.

---

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

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 (PPA) 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 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.[2]

C. Contract Procurement Costs and Revenue Requirement

The 2027 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 Corporation’s market energy and ancillary service revenues for unsold RPS-eligible generation 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 Fall Update.

---

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

Table 9-1 shows the 2027 TMNBC net cost revenue requirement forecast for the contract costs and the value of energy, RA sales, and REC sales.

TABLE 9-1
2027 TMNBC REVENUE REQUIREMENT
(THOUSANDS OF DOLLARS)

Line No.	Description	Revenue Requirement
1	Post-2002 Contracted Resources	
2	RPS Eligible	
3	RPS-Eligible Contracts	[redacted]
4	RPS-Eligible Contracts - Sales	
5	RPS-Eligible Future Contracts	
6	RPS-Eligible Future Sales	
7	Resource Adequacy Sales	
8	CAISO Costs (GMCs)	
9	CAISO Revenues	
10	**Net Costs**	**$26,513**
11	Revenue Fees and Uncollectibles	361
12	**Total Revenue Requirement**	**$26,874**

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 2027, as presented in Table 9-1. PG&E will update the TMNBC revenue requirement in its Fall Update.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 10

BIOENERGY MARKET ADJUSTMENT TARIFF

REVENUE REQUIREMENT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 10
BIOENERGY MARKET ADJUSTMENT TARIFF
REVENUE REQUIREMENT

TABLE OF CONTENTS

A. Introduction 10-1

B. Program Background 10-1

C. Community Choice Aggregators BioMAT Participation 10-2

D. PG&E's BioMAT Cost 10-3

E. BioMAT Contract Cost and Revenue Requirement 10-3

F. Conclusion 10-4

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 10
BIOENERGY MARKET ADJUSTMENT TARIFF
REVENUE REQUIREMENT

A. Introduction

This chapter discusses Pacific Gas and Electric Company's (PG&E) 2027 revenue requirement forecast for the Bioenergy Market Adjustment Tariff (BioMAT) resources. The discussion will cover a background of the BioMAT, the procurement cost forecast for BioMAT contracts, and the value of energy, Resource Adequacy (RA) capacity, and Renewable Energy Credits (REC) for BioMAT contracts. The derivation of the associated 2027 end-of-year balancing account balance forecast is shown in Chapter 12, while the associated 2027 BioMAT rates are shown in Chapter 13.

B. Program Background

In September 2012, Governor Brown signed Senate Bill (SB) 1122 into law, which requires PG&E, Southern California Edison Company (SCE) and San Diego Gas & Electric Company to procure 250 megawatts (MW) of Renewables Portfolio Standard (RPS)-eligible generation from bioenergy generation facilities.

In Decision (D.) 14-12-081, the California Public Utilities Commission (Commission) implemented SB 1122, setting the quantities of each type of generation to be procured by each of the investor-owned utilities (IOU), and establishing the pricing mechanism and other rules for the BioMAT Program.

On September 1, 2020 , the Commission issued D.20-08-043 and determined it is appropriate for the Commission to "exercise its broad authority to impose a NBC on all customers in each IOU's service territory."[1] The Commission further found that the administration of the BioMAT NBC "should be modeled off the tree mortality NBC, established in D.18-12-003" and noted that

---

[1] D.20-08-043, discussion at pp. 13-14, and Conclusion of Law (COL) 3.

PG&E and SCE's proposed models that are similar to the tree mortality NBC were reasonable.[2]

On October 1, 2020, PG&E submitted Advice Letter (AL) 5966-E to establish a BioMAT Non-Bypassable Charge Balancing Account (BNBCBA) and Non-Bypassable Rate Design and Implementation Plan, which was ultimately approved.[3] A new BNBCBA has subsequently been established to record billed revenues and actual net costs associated with the BioMAT NBC. Ultimately, the BioMAT NBC will be recovered through the Public Purpose Program rate using a 12-month coincident peak revenue allocation rate design as authorized in D.20-08-043. A Petition for Modification of D.20-08-043 is under consideration in Rulemaking (R.) 18-07-003.

C. Community Choice Aggregators BioMAT Participation

On December 5, 2023, the Commission issued D.23-11-084 to enable Community Choice Aggregator (CCA) participation in the BioMAT program, as authorized by Assembly Bill 843 (Stats. 2021, Ch. 234). In the decision, participating CCAs were directed to file a joint Tier 2 AL for approval of standard BioMAT CCA program documentation. Further, per Ordering Paragraph 12 of the decision, participating CCAs are each required to file an annual Tier 3 AL seeking Commission approval of eligible BioMAT forecasted revenue requirements recorded in CCA balancing accounts that reflect BioMAT program net Power Purchase Agreement (PPA) costs and other costs required for joint CCA/IOU program administration for the upcoming calendar year. Additionally, each Participating CCA is required to include in their Tier 3 AL "a report on BioMAT PPAs executed during each quarter of the prior year." Finally, prior to filing the Tier 3 AL, each participating CCA is required to convene with the IOU in whose territory the CCA is located "to identify and resolve issues as much as possible with the intent to facilitate timely approval of CCA BioMAT ALs."

After Commission approval of the advice letters, D.23-11-084 requires the IOUs to include the Commission-approved CCA BioMAT costs in their October

---

2 D.20-08-043, discussion at p. 14, and COL 4. PG&E discussed its proposed model for the BioMAT NBC in its April 5, 2020 Reply Comments to the Staff Proposal, at p. 3.

3 PG&E's AL 5966-E was approved on November 1, 2020.

Updates to their ERRA forecast applications which will be utilized by the Commission to issue final decision(s) in these proceedings.

As of the submission of this testimony, three CCAs in PG&E's service territory have submitted their Tier 3 ALs:

- Pioneer Community Energy (Pioneer) – AL 24-E;
- Redwood Coast Energy Authority (RCEA) – AL 29-E; and
- Central Coast Community Energy (3CE) – AL 51-E.

Both Pioneer and RCEA reported no BioMAT program PPAs were executed in the prior year for recovery in 2027 and hence they did not forecast any BioMAT costs. The BioMAT cost requested by 3CE is $1.5 million. The amount, plus an allowance for Revenue Fees and Uncollectibles (RF&U), is included in Table 10-1.

D. PG&E's BioMAT Cost

The formula used to calculate PG&E's BioMAT cost is as follows:

- BioMAT Portfolio Revenue Requirement = BioMAT Portfolio Contract Costs – BioMAT Portfolio Energy value – BioMAT Portfolio REC value – BioMAT Portfolio RA value where:
  - BioMAT Portfolio Energy value = hourly generation (MWh) x hourly energy price forecast summed over all BioMAT contracts;
  - BioMAT Portfolio REC value = generation (MWh) x Power Charge Indifference Adjustment (PCIA) REC benchmark ($/MWh) summed over all BioMAT contracts; and
  - BioMAT portfolio RA value = Contract NQC (MW) x PCIA RA benchmark ($/MW-year) summed over all BioMAT contracts.

Under the methodology laid out in AL 5966-E, bundled service customers retain the BioMAT portfolio's REC and RA attributes. The Bundled Portfolio's payment for the REC and RA attributes is effectuated by crediting the BNBCBA for the BioMAT portfolio RA and REC value (see above calculation description) and by debiting ERRA by an equal amount.

E. BioMAT Contract Cost and Revenue Requirement

Table 10-1 shows the total expected BioMAT costs for 2027, along with the forecasted energy revenues and imputed RA and REC values associated with the BioMAT portfolio, as well as the revenue requirement requested by 3CE in AL 51-E.[4]

TABLE 10-1
2027 BIOMAT REVENUE REQUIREMENT
(THOUSANDS OF DOLLARS)

Line No.	Description	Revenue Requirement
1	<u>PG&E BioMat Cost</u>	
2	Post-2002 Contracted Resources	
3	RPS Eligible	
4	RPS-Eligible Contracts	[redacted]
5	Grid Management Charges	[redacted]
6	CAISO Revenues	[redacted]
7	REC Market Value	(7,934)
8	RA Capacity Market Value	(1,356)
9	PG&E BioMat Net Costs	$9,848
10	CCA BioMat Net Cost	1,513
11	Total BioMat Net Costs	$11,361
12	Revenue Fees and Uncollectibles	155
13	Total Revenue Requirement	$11,515

F. Conclusion

In this chapter, PG&E presents its forecast for the PG&E and 3CE 2027 BioMAT revenue requirements as shown in Table 10-1. PG&E's Fall Update will include a revenue requirement and ratemaking update consistent with any Commission decisions.

---

4 The current forecast uses the Forecast 2027 PCIA RA and REC benchmark values. The benchmarks will be updated in the Fall Update after initial 2027 PCIA benchmarks are made available by the Commission, including, as applicable, any decisions issued in R.25-02-005. The generation volumes used to calculate the portfolio REC value and the monthly RA capacities used to calculate the portfolio RA value are presented in Chapter 4.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 11

ENERGY RESOURCE RECOVERY ACCOUNT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 11
ENERGY RESOURCE RECOVERY ACCOUNT

TABLE OF CONTENTS

A. Introduction 11-1

B. Procurement and UOG-related Cost Forecast 11-2

C. Resource Market Value Forecast 11-2

D. Conclusion 11-2

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 11
ENERGY RESOURCE RECOVERY ACCOUNT

A. Introduction

The purpose of this chapter is to present the 2027 revenue requirement forecast for the Energy Resource Recovery Account (ERRA). The 2027 ERRA revenue requirement for rate setting will be based on the summation of the Pacific Gas and Electric Company (PG&E) bundled load forecast costs, Utility-Owned Generation (UOG)-related cost, the imputed market value of Resource Adequacy (RA), and Renewable Energy Credits (REC) based on RA and Renewables Portfolio Standard (RPS) Adders, that are retained by PG&E for PG&E's bundled load.

As discussed in Chapter 5, Section D, *System RA Open Position and Associated Net Costs*, PG&E must maintain sufficient Slice-of Day (SOD) Net Qualifying Capacity supply to meet the SoD load requirements that are set by the California Public Utilities Commission (CPUC or Commission) in conjunction with the California Energy Commission (CEC) as part of the CPUC and CEC's annual peak load forecasting process which is typically not completed until September of 2026. Given the timing for the final year-ahead requirements, PG&E's estimate of its 2027 SoD RA requirements are based on its current bundled hourly load forecast.

As noted in Chapter 5, while the SoD framework has introduced an hourly dimension to RA compliance, the underlying cost recovery mechanisms (e.g., Power Charge Indifference Adjustment (PCIA)) continue to be based on single monthly values for the RA supply. Thus, to calculate the annual volumes to be retained at the applicable RA MPBs for rate setting, the SoD volumes have been translated to single monthly values based on the weighting methodology described in Chapter 5 before being averaged across all months to result in a single value.[1]

---

[1] A more detailed discussion of PG&E's methodology to implement the SoD framework including the development of the system RA open position and PCIA aggregation under the SOD framework is included in Chapter 5, Section D.

B. Procurement and UOG-related Cost Forecast

In Chapters 4 and 5, PG&E shows the 2027 procurement cost forecast related to PG&E's bundled customers below:

1) Executed short term purchase and sale transactions;
2) Hedging costs;
3) Collateral interest expenses; and
4) California Independent System Operator (CAISO) market costs consisting of the following:
   a) Energy purchases based on PG&E's forecasted 2027 bundled load;
   b) Volumetric load charges for ancillary services, uplift charges, and grid management charges; and
   c) Other miscellaneous, non-volumetric CAISO costs.

The ERRA portion of the General Rate Case and UOG-related costs that are discussed in Chapter 8 are included only for ratemaking purposes. The total cost forecasts for these items are included in the ERRA revenue requirement forecast shown in Table 11-1.

C. Resource Market Value Forecast

Similar to prior years, and as authorized by the Commission, PG&E's bundled customer ERRA costs include the imputed costs of RA and RECs attributable to the bundled portfolio's retention of resources eligible for the PCIA, Ongoing Competition Transition Charge and Bioenergy Market Adjusting Tariff cost recovery at forecasted RA and RPS Adders.[2] The 2027 imputed market value forecast of applicable RA and RECs that is presented in Chapters 8 and 10 is presented in the ERRA revenue requirement forecast shown in Table 11-1.

D. Conclusion

Based on the procurement cost and resource market value forecast described above, the forecasted 2027 ERRA revenue requirement, plus an allowance of Revenue Franchise and Uncollectibles, for rate setting is shown in Table 11-1 below. PG&E will update the ERRA revenue requirement in the Fall Update.

---

[2] D.18-10-019, D.19-10-001, and D.20-02-047.

TABLE 11-1
2027 ERRA REVENUE REQUIREMENT
(THOUSANDS OF DOLLARS)

Line No.	Description	Revenue Requirement
1	Bundled Load Requirement	[redacted]
2	Other Load	
3	Grid Management Charges	
4	Utility-Owned Generation	
5	Energy Storage	
6	Other Bilateral Contracts	
7	Future Non-RPS-Eligible Hydro Sales	
8	Non-RPS-Eligible Hydro Sales	
9	QF	
10	RA Contracts	
11	RPS-Eligible Future Contracts	
12	RPS-Eligible Future Sales	
13	Residual RA Purchases	
14	Hedging Costs	
15	Collateral & Interest Expense	5,791
16	Resource RA and REC Market Benchmark Value	
17	PCIA REC Value	655,948
18	PCIA RA Value	889,620
19	CTC REC Value	5,933
20	CTC RA Value	14,738
21	BioMAT REC Value	7,934
22	BioMAT RA Value	1,356
23	**Total Costs**	**$2,875,786**
24	RF&U @	39,122
25	**Total RRQ**	**$2,914,908**

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 12

BALANCING ACCOUNTS FORECASTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 12
BALANCING ACCOUNTS FORECASTS

TABLE OF CONTENTS

A. Introduction 12-1

1. Summary of Forecast Methodology and Amortization 12-1

2. Balancing Accounts Included in This Testimony 12-2

a. PABA 12-2

b. ERRA 12-2

c. Public Policy Charge Balancing Account – Public Policy Charge Procurement Subaccount 12-3

d. Modified Transition Cost Balancing Account 12-3

e. Modified Cost Allocation Mechanism Balancing Account 12-3

f. New System Generation Balancing Account 12-4

g. Tree Mortality Non-Bypassable Charge Balancing Account 12-4

h. Bioenergy Market Adjusting Tariff Non-Bypassable Charge Balancing Account 12-5

i. Voluntary Allocation Market Offer (MO) Memorandum Account 12-5

3. Summary of Forecasted 2026 Year-End Balancing Account Balances ... 12-5

B. PABA Subaccounts 12-7

1. Recorded and Forecast PABA Subaccount Balances 12-7

2. Balance Transfers 12-7

3. 2026 Forecast Year-End PABA, After Balance Transfers 12-7

C. PABA Balances Recorded Through March 2026 12-9

1. Customer Revenue 12-9

2. Portfolio Costs 12-9

3. Energy Value 12-10

4. Retained Renewable Portfolio Standard and Resource Adequacy Values 12-10

TABLE OF CONTENTS
(CONTINUED)

5. One-Time Adjustments 12-10

a. Approved Transfers to and from PABA 12-10

6. Balancing Account Interest 12-12

D. PABA Forecast From April Through December 2026 12-12

1. Customer Revenue 12-12

2. Portfolio Costs and Energy Value 12-13

a. Energy Procurement Costs and Energy Value 12-13

b. UOG Related Cost 12-13

3. Retained RPS and RA Values 12-13

4. Balancing Account Interest 12-13

E. 2026 Forecast Year-End PABA 12-13

1. Higher Customer Revenues 12-15

2. Lower Expected CAISO Revenues 12-15

a. Lower Market Electricity Prices 12-15

b. Less Generation From PCIA-Eligible Resources 12-15

3. Lower Procurement Costs 12-15

a. Lower Net RA Transaction Revenues 12-15

b. Lower Natural Gas-Fired Generator Costs 12-15

4. Lower Retained RPS Value 12-16

5. Higher Retained RA Value 12-16

6. Higher Recorded Undercollections Brought Forward From 2025 12-16

7. Balancing Account Interest 12-16

F. 2026 Forecast Year-End ERRA 12-16

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 12
BALANCING ACCOUNTS FORECASTS

TABLE OF CONTENTS
(CONTINUED)

1. Lower Customer Revenues 12-17

2. Lower Expected Net CAISO Costs 12-18

a. Lower Market Electricity Prices 12-18

b. Lower Bundled Load Requirement 12-18

3. Lower Procurement Costs 12-18

4. Retained RPS and RA 12-18

5. Balancing Account Interest 12-18

G. Balance Transfers 12-19

1. Residential Uncollectibles Balancing Account – Electric 12-19

2. ERRA 12-19

H. 2026 Forecast Year End NSGBA 12-19

1. Higher Procurement Costs 12-19

2. Higher Recorded Undercollection Brought Forward From 2025 12-20

I. VAMOMA 12-20

1. VAMO Administrative Support 12-20

2. Request for Recovery 12-21

J. Conclusion 12-24

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 12
BALANCING ACCOUNTS FORECASTS

A. Introduction

The purpose of this chapter is to: (1) provide an overview of Pacific Gas and Electric Company's (PG&E) electric procurement balancing accounts and amortization of 2026 year-end balances for inclusion in 2027 electric rates; and (2) seek approval to recover the accumulated Voluntary Allocation and Market Offer (VAMO) Memorandum Account (VAMOMA) balance for disposition through the Power Charge Indifference Adjustment (PCIA) rates.

The remaining sections in this testimony are organized as follows:

- Section B – Overview of Portfolio Allocation Balancing Account (PABA) Subaccounts;
- Section C – Description of the balances recorded in the PABA;
- Section D – Description of the transactions forecast in PABA;
- Section E – Primary Drivers of the forecasted 2026 year-end PABA;
- Section F – Primary Drivers of the forecasted 2026 year-end Energy Resource Recovery Account (ERRA);
- Section G – Summary of Balance Transfers;
- Section H - Primary Drivers of the forecasted 2026 year-end New System Generation Balancing Account (NSGBA)
- Section I – Overview and request for recovery of the VAMO Administrative Cost and VAMOMA; and
- Section J – Conclusion.

1. Summary of Forecast Methodology and Amortization

Similar to previous years and as adopted by the California Public Utilities Commission (Commission), the forecasted 2026 year-end balancing account balances are based on the balances recorded through March 31, 2026, plus forecasted transactions from April 1 through December 31, 2026. These balances will be the subject of PG&E's Update to Prepared Testimony (Fall Update). Further, except as described herein and as may be subject to PG&E's Fall Update proposals, balances are amortized for recovery through the 2027 Annual Electric True-Up (AET) Advice Letter (AL) process, or a subsequent electric rate change AL.[1]

2. Balancing Accounts Included in This Testimony

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

a. PABA

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. Costs authorized to be recorded in PABA include those that are related to contracts executed with third parties, as well as Utility-Owned Generation (UOG).

PCIA-eligible generation resources are assigned PCIA vintages based on the year the resource commitment was made (i.e., contract execution date or construction start date in the case of UOG). Departing load customers are assigned cost responsibility for vintages of generation resources based on when the customer departed bundled service.

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. Disposition of the PABA is through PCIA rates.

b. ERRA

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 current year (e.g. 2026) bundled customers. Pursuant to Decision (D.) 22-01-023 disposition of ERRA balance is through the last vintage of the PABA.

---

1 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.

c. Public Policy Charge Balancing Account – Public Policy Charge Procurement Subaccount

As stated in Electric Preliminary Statement Part HM, the purpose of the PPCBA is to track revenues and actual costs incurred to implement adopted programs that may be funded through public policy funds. In D.22-02-002, the Commission adopted PG&E's proposal to recover Public Utility Regulatory Policies Act modified Qualifying Facility (QF) contracts of 20 megawatt (MW) or less through the PPCBA. As such, PG&E modified its tariffs associated with contracts approved, pursuant to D.20-05-006 and any new or existing Under 20 MW QFs, pursuant to D.10-12-035 (QF Settlement) authorized by the Commission.[2] The non-vintage PABA subaccount[3] was consequently eliminated, pursuant to D.22-02-002. Disposition of the PPCBA is through the Public Program Purpose (PPP) Charge.

d. Modified Transition Cost Balancing Account

As stated in 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 authorized by the Commission, as defined by the Pub. Util. Code Section 367(a)(1)-(6). Disposition of the MTCBA is through the Ongoing Competition Transition Charge rates.

e. Modified Cost Allocation Mechanism Balancing Account

In Resolution (Res.) E-5239, the Commission approved PG&E's Compliance AL 6654-E-A which proposed a new Modified Cost Allocation Mechanism Balancing Account (MCAMBA) to recover contract expenses for Active Load Serving Entities (LSE) that opted-out of procurement associated with the Modified Cost Allocation Mechanism (MCAM) procurement established in D.19-11-016 and potential future contract expenses associated with backstop procurement PG&E may be required purchase for LSEs that fail to meet procurement obligations

---

2 See PG&E AL 6524-E, effective on March 14, 2023; hyperlink at: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6524-E.pdf.

3 The nonvintage PABA subaccount was established in D.20-05-006.

ordered in D.21-06-035. Disposition of the balances in the account shall be through the MCAMBA rate components for customers of Deficient LSEs, and as authorized by the Commission.

Ordering Paragraph (OP) 2 of Res.E-5239 required PG&E to provide "details related to cost-recovery and ratemaking in its 2024 ERRA Forecast Application, filed in 2023." Consistent with this order, the cost recovery and ratemaking presentation for the portion of the MCAM contracts associated with active LSEs was presented in PG&E's 2024 ERRA Forecast, Rate Proposal testimony. At the time of the Rate Proposal, PG&E does not expect implementation of the MCAM rate to occur in 2027. Hence, there is no showing of the forecast year-end balance of MCAM in this testimony.

f. New System Generation Balancing Account

As stated in Electric Preliminary Statement Part FS, the purpose of the NSGBA is to record the benefits and 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.

Pursuant to Res.E-5239, PG&E modified its Electric Preliminary Statement Part FS to establish a MCAM Subaccount in the NSGBA associated with inactive opt-out LSEs no longer serving customers in California and for which PG&E procured MCAM resources on their behalf. The related forecast cost is included in the NSGBA forecast year-end balance.

g. Tree Mortality Non-Bypassable Charge Balancing Account

As stated in 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 (SB) 859, and Res.E-4770 and Res.E-4805 as defined in D.18-12-003. The TMNBCBA is collected as part of the non-bypassable PPP charge.

h. Bioenergy Market Adjusting Tariff Non-Bypassable Charge Balancing Account

As stated in Electric Preliminary Statement Part IJ, the Bioenergy Market Adjusting Tariff (BioMAT) Non-bypassable Charge Balancing Account (BNBCBA) is a balancing account to record and recover the net costs of BioMAT contracts in compliance with SB 1122, as revised in D.20-08-043. The BNBCBA is collected as part of the non-bypassable PPP charge.

i. Voluntary Allocation Market Offer (MO) Memorandum Account

As stated in Electric Preliminary Statement Part JC, the Voluntary Allocation and MO Memorandum Account (VAMOMA-E) is a memorandum account that tracks and records incremental costs incurred for staffing and information technology systems needed for administering the VAMO. Disposition of the balance in the account is determined through the ERRA Forecast application each year for recovery in PABA.

3. Summary of Forecasted 2026 Year-End Balancing Account Balances

PG&E presents a summary of the forecasted 2026 year-end balancing account balances in Table 12-1 below. Column A shows the recorded balances as of March 2026. This is added to the April through December 2026 forecast for revenue (Column B), net cost and balancing account interest forecasts (Columns C) to derive forecasted year-end balances in Column D. The cumulative end of year forecast undercollection of $474 million that PG&E is requesting to amortize in 2027 rates in Column I is derived after adjusting for the balance transfers between Residential Uncollectibles Balancing Account-Electric (RUBA-E),[4] ERRA, and PABA reflected in Columns E and F, plus an allowance for Revenue Fees and Uncollectibles (RF&U) in Column G.[5]

These balances may change significantly in the Fall Update as a result of potential volatility in electric and gas commodity prices, and changes to the Commission-issued MPBs.

---

[4] See also Section G for discussions of the balance transfer from RUBA-E.

[5] Authorized in D.22-01-023, D.22-12-044, D.23-12-022, and D.25-12-027.

TABLE 12-1
2026 FORECAST YEAR-END BALANCES
(THOUSANDS OF DOLLARS)

Line No.		March Recorded Balance	Forecast Customer Revenue	Forecast Cost and Interest	Forecast Year End Balance	Balance Transfers of RUBA to ERRA authorized in D. 20-06-003	Balance Transfers of ERRA to PABA authorized in D. 22-01-023	RF&U per Advice 5128-G/ 7727-E 0.01360	Forecast Year End Balance after Balance Transfers, including RF&U	The Recorded/Forecast Year End Balance (including RF&U) as presented in Table 13-1, for amortization in 2027 Rates comprises		
										Recorded/ Forecast Year End Balance with RF&U	Balance Transfers of RUBA to ERRA authorized in D. 20-06-003	Balance Transfers of ERRA to PABA authorized in D. 22-01-023
		(A)	(B)	(C)	(D)= Σ (A..C)	(E)	(F)	(G)	(H)= Σ (D..G)	(I)	(J)	(K)
1	Non-PPP											
2	NSGBA	$254,313	($325,280)	$369,410	$298,444			$4,060	$302,504	$302,504	$0	
3	MTCBA	17,639	(15,072)	(11,586)	(9,020)			(123)	(9,143)	(9,143)		
4	PABA	772,649	(957,073)	548,185	363,761		(187,921)	2,392	178,232	368,710	0	(190,478)
5	VAMOMA	517			517			7	524	524		
6	ERRA	(73,957)	(2,330,916)	2,214,794	(190,078)	2,157	187,921	0	0	(192,664)	2,186	190,478
7	RUBA-E	2,157			2,157	(2,157)		0	0	2,186	(2,186)	
8	Subtotal (Non-PPP)	$973,318	($3,628,341)	$3,120,803	$465,781	$0	$0	$6,336	$472,117	$472,117	$0	$0
9	PPP											
10	PPCP	($6,260)	$6,245	($771)	($785)			($11)	($796)	($796)		
11	TMNBCBA	7,866	(32,064)	27,368	3,170			43	3,213	3,213		
12	BNBCBA	1,496	(10,165)	7,963	(706)			(10)	(716)	(716)		
13	Subtotal (PPP)	$3,102	($35,984)	$34,560	$1,678	$0	$0	$23	$1,701	$1,701	$0	$0
14	**Total (Non-PPP and PPP)**	**$976,420**	**($3,664,324)**	**$3,155,363**	**$467,459**	**$0**	**$0**	**$6,359**	**$473,818**	**$473,818**	**$0**	**$0**

Totals may not add due to rounding

B. PABA Subaccounts

1. Recorded and Forecast PABA Subaccount Balances

PG&E presents the 2026 forecast year-end PABA subaccount balances in Table 12-2. Line 2 shows the recorded January 1, 2026, PABA subaccount balances. Lines 3 through 10 summarize the recorded PABA subaccount balances through March 2026, discussed in Section D. Lines 11 through 19 reflect the forecast transactions discussed in Section E. The summations of recorded and forecast items are reflected in lines 20 through 29, which total to a $364 million undercollection. The primary driver of the PABA undercollection is discussed in Section F.

2. Balance Transfers

The balance transfers to PABA reflected in Line 30 is $188 million overcollection from ERRA.[6] Details of the balance transfer is discussed in Section G.

3. 2026 Forecast Year-End PABA, After Balance Transfers

The forecasted 2026 year-end PABA subaccounts, <u>after accounting for the balance transfers</u>, plus an allowance for RF&U, is an under-collection of $178 million (Table 12-2, line 33, Column "Total").[7] This balance will be consolidated with the PCIA revenue requirement presented in Chapter 8 for recovery through the PCIA rates.

---

6 The amount transferred from ERRA includes the recovery of RUBA-E balance.

7 Also shown in Table 12-1, line 4, Column I.

TABLE 12-2
2026 FORECAST YEAR-END VINTAGED PABA BALANCES
(THOUSANDS OF DOLLARS)

Line No.		UOG Legacy	Vintage Subaccounts																		Total
			2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	
1	Recorded from January to March (a)																				
2	Recorded Beginning Balance as of January	$499,070	$823,281	$199,006	$80,097	$129,018	$53,224	$4,906	$367	$5,877	$5,752	($47,564)	$45,002	($29,675)	$507,967	$28,076	$18,060	($100,681)	$48,708	$0	$2,270,492
3	PCIA Customer Revenue	(144,973)	(304,470)	(60,689)	(18,936)	(27,168)	(4,848)	3,095	821	(876)	3,116	(2,753)	(3,903)	6,281	(101,728)	(644)	(6,513)	16,170	303,132	0	(344,885)
4	Portfolio Costs	209,226	229,724	65,041	19,726	28,736	9,699	5,501	3,745	399	1,820	(125)	12,735	(876)	45,790	9	(14)	25	27	(7)	631,180
5	Energy Value	(114,864)	(19,320)	(7,189)	(2,376)	(4,751)	(1,913)	(358)	(596)	(124)	(541)	0	0	0	(163)	0	(10)	0	0	0	(152,203)
6	RPS Value	(1,634)	(31,818)	(35,799)	(7,763)	(11,049)	(5,630)	(1,275)	(2,200)	(258)	(970)	0	0	0	(4,726)	0	(60)	0	(23,232)	23,232	(103,180)
7	RA Value	(53,439)	(62,145)	(10,585)	(5,402)	(6,401)	(5,204)	(380)	(314)	(74)	(1,712)	0	(10,308)	0	(31,796)	0	(2,562)	(39)	(180)	0	(190,543)
8	One Time Adjustments	102,120	15,519	1,890	1,294	1,549	65	10	18	10	417	413	407	486	491	485	0	62	(1,476,514)	0	(1,351,279)
9	Interest	6,574	9,086	2,144	896	1,465	577	83	4	66	84	(580)	559	(328)	5,776	346	175	(1,128)	(12,874)	142	13,067
10	Recorded March Balance	502,080	659,856	153,820	67,536	111,400	45,969	11,582	1,845	5,021	7,965	(50,608)	44,492	(24,112)	421,612	28,271	9,076	(85,591)	(1,160,933)	23,366	772,649
11	Forecast from April to December (b)																				
12	PCIA Customer Revenue	(519,158)	(1,001,126)	(198,679)	(61,884)	(88,730)	(15,520)	10,252	2,743	(2,815)	10,707	(6,142)	(11,853)	22,522	(357,831)	(1,640)	(22,109)	63,231	1,220,960	0	(957,073)
13	Portfolio Costs	764,278	964,326	355,848	102,203	130,608	52,683	7,940	12,471	1,583	7,600	42	33,214	0	108,852	(0)	14,402	363	524	133	2,557,070
14	Energy Value	(487,692)	(137,137)	(72,030)	(32,587)	(41,866)	(23,831)	(4,234)	(6,941)	(882)	(4,156)	0	0	0	(2,537)	0	(395)	(145)	(208)	(110)	(814,751)
15	RPS Value	(12,538)	(185,596)	(163,447)	(44,045)	(48,029)	(34,566)	(6,428)	(10,037)	(1,348)	(6,127)	0	0	(445)	(30,430)	0	(874)	(324)	(440)	288	(544,386)
16	RA Value	(299,557)	(87,121)	(26,275)	(11,208)	(19,075)	(9,978)	(1,822)	(3,388)	(447)	(8,233)	0	(51,443)	0	(143,660)	0	(10,821)	(65)	(281)	(370)	(673,744)
17	One Time Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Interest	9,100	18,406	4,506	1,819	3,156	1,242	548	(15)	116	291	(2,026)	1,103	(500)	7,964	1,039	(42)	(2,080)	(21,511)	877	23,996
19	Forecast transactions from April to December	(545,565)	(428,248)	(100,077)	(45,703)	(63,936)	(29,970)	6,256	(5,166)	(3,793)	81	(8,125)	(28,979)	21,577	(417,642)	(601)	(19,840)	60,981	1,199,043	818	(408,888)
20	Forecast Year End Balance (c) = (a) + (b)																				
21	Recorded Beginning Balance as of January	499,070	823,281	199,006	80,097	129,018	53,224	4,906	367	5,877	5,752	(47,564)	45,002	(29,675)	507,967	28,076	18,060	(100,681)	48,708	0	2,270,492
22	PCIA Customer Revenue	(664,131)	(1,305,597)	(259,368)	(80,820)	(115,898)	(20,368)	13,347	3,564	(3,691)	13,823	(8,895)	(15,756)	28,803	(459,559)	(2,284)	(28,622)	79,402	1,524,092	0	(1,301,958)
23	Portfolio Costs	973,504	1,194,050	420,890	121,928	159,344	62,381	13,441	16,216	1,982	9,419	(83)	45,949	(876)	154,643	9	14,388	387	551	126	3,188,251
24	Energy Value	(602,555)	(156,457)	(79,220)	(34,963)	(46,617)	(25,743)	(4,591)	(7,536)	(1,006)	(4,697)	0	0	0	(2,700)	0	(405)	(145)	(208)	(110)	(966,954)
25	RPS Value	(14,172)	(217,413)	(199,246)	(51,807)	(59,077)	(40,196)	(7,703)	(12,236)	(1,606)	(7,098)	0	0	(445)	(35,156)	0	(934)	(324)	(23,672)	23,519	(647,566)
26	RA Value	(352,996)	(149,266)	(36,860)	(16,610)	(25,476)	(15,182)	(2,202)	(3,702)	(521)	(9,946)	0	(61,751)	0	(175,456)	0	(13,383)	(104)	(461)	(370)	(864,287)
27	One Time Adjustments	102,120	15,519	1,890	1,294	1,549	65	10	18	10	417	413	407	486	491	485	0	62	(1,476,514)	0	(1,351,279)
28	Interest	15,674	27,492	6,650	2,716	4,621	1,819	631	(11)	183	375	(2,605)	1,662	(827)	13,740	1,385	133	(3,208)	(34,386)	1,019	37,063
29	Forecast Year End Balance before Transfers	(43,485)	231,609	53,743	21,833	47,464	15,999	17,839	(3,321)	1,229	8,046	(58,734)	15,513	(2,536)	3,970	27,671	(10,763)	(24,611)	38,110	24,185	363,761
30	Balance Transfers from ERRA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(187,921)	(187,921)
31	Forecast Year End Balance after Balance Transfers	(43,485)	231,609	53,743	21,833	47,464	15,999	17,839	(3,321)	1,229	8,046	(58,734)	15,513	(2,536)	3,970	27,671	(10,763)	(24,611)	38,110	(163,736)	175,840
32	RF&U per Advice 5128-G/7727-E @ 0.013604	(592)	3,151	731	297	646	218	243	(45)	17	109	(799)	211	(34)	54	376	(146)	(335)	518	(2,227)	2,392
33	**Forecast Year End Balance after Balance Transfers (Including RF&U)**	**(44,076)**	**234,759**	**54,474**	**22,130**	**48,109**	**16,217**	**18,081**	**(3,366)**	**1,245**	**8,156**	**(59,533)**	**15,724**	**(2,570)**	**4,024**	**28,047**	**(10,910)**	**(24,945)**	**38,629**	**(165,964)**	**178,232**

C. PABA Balances Recorded Through March 2026

The PABA balances recorded through March 2026 include customer revenue, authorized cost, transfers/adjustments, and balancing account interest, in accordance with the Generally Accepted Accounting Principles, as well as Electric Preliminary Statement Part HS. These transactions will be reviewed by the Commission in PG&E's 2026 ERRA Compliance Review Application to be filed in February 2027 after recording all 12 months of 2026.[8]

The components of January through March transactions recorded in PABA are listed in Table 12-2, lines 3 through 9. Below is a high-level description of these components.

1. Customer Revenue

Customer revenue appearing on Table 12-2, line 3 includes revenue from both eligible departing load and bundled customers calculated from the PCIA rates effective as of January 1, 2026, and March 1, 2026. 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 12-2, 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;[9] (3) fuel, related transportation costs and direct greenhouse gas costs; (4) renewable and/or resource adequacy (RA) sale transaction revenues allocated to the vintage subaccounts; and (5) miscellaneous costs or credits approved to be recovered via the PABA from bundled and departing load customers.

---

8 D.20-02-047, pp. 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."

9 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 (Table 12-2, line 5) consists of California Independent System Operator (CAISO) related revenues and charges from energy and ancillary services market.

4. Retained Renewable Portfolio Standard and Resource Adequacy Values

The retained Renewable Portfolio Standard (RPS) and RA values (Table 12-2, lines 6-7) are based on the recorded Retained RPS and RA quantities. These are multiplied by the D.25-12-027 authorized RPS and RA Adders to calculate the applicable credits in PABA.[10] Additionally, PG&E has recorded 3 months of the Minimum Retained RPS credits based on the forecast amounts authorized in D.25-12-027. The Retained RPS and RA values as well as the Minimum Retained RPS credits will be updated in the Fall Update, using the latest available information at that time and the Commission revised authorized MPB for 2026.

5. One-Time Adjustments

One-time adjustment transactions recorded in the period from January through March 31, 2026, totaling a credit of $1,351 million (Table 12-2, line 8), primarily driven by balance transfers as approved by the Commission in various proceedings.

a. Approved Transfers to and from PABA

During the first three months of 2026, PG&E recorded transfers of various account balances or revenue requirements to PABA as authorized by the Commission:

1) Transfer of Diablo Canyon Retirement Balancing Account (DCRBA) 2025 balance as previously authorized in PG&E's 2020 General

---

[10] Corresponding debit entries are recorded in ERRA.

Rate Case (GRC) Settlement and authorized by D.20-12-005.[11] This resulted in a $3.8 million debit to PABA in January 2026;[12]

2) Transfer of General Office Sale Balancing Account (GOSBA) 2025 balance as authorized by D.23-11-069, and upon approval of PG&E's AET AL 7797-E. This resulted in an $8.4 million credit to PABA in January 2026;

3) Transfer of Department of Energy Litigation Balancing Account 2025 balance as authorized by D.23-11-069, and upon approval of PG&E's AET AL 7797-E. This resulted in a $0.3 million debit to PABA in January 2026;

4) Transfer of year-end ERRA Balance to most recent PABA vintage as authorized by D.22-01-023. 2025 ERRA Balance transfer resulted in a $1,502.2 million credit to PABA in January 2026.

5) Recovery of 2025 RUBA-E balance of $25.7 million;[13]

6) Transfer of amounts related to the Comprehensive Gas Advanced Metering Infrastructure (Gas AMI) Application as approved in D.25-12-029. This resulted in a debit to PABA of $6.2 million in January 2026;

7) Transfer of memorandum and balancing account balances associated with the 2022 Wildfire Mitigation and Catastrophic Events (WMCE) Application as approved in D.25-09-008. This resulted in a debit to PABA of $16.6 million in January 2026, which was transferred from various accounts, including the Wildfire Mitigation Balancing Account (WMBA), Catastrophic Events Memorandum Account (CEMA), and Microgrids Memorandum Account (MGMA);

8) Authorized recovery from 2024 Transmission Revenue Requirements Reclassification Memorandum Account (TRRRMA)

---

11 PG&E proposed to close this account in A.21-06-021, which was contested by parties. In D.23-11-069, the Commission elected to not approve any closures or modifications that were contested. Accordingly, this account is still authorized to transfer to PABA under the prior GRC Settlement.

12 This amount is related entirely to the recovery of the depreciation subaccount.

13 The 2025 RUBA-E balance was recoverable in ERRA and subsequently transferred to PABA Vintage 2025 Subaccount for recovery.

Application, as approved in D.25-12-026. This resulted in a $103.8 million debit to PABA in January 2026;

9) Authorized monthly collections of GOSMA in PABA for the first quarter as authorized in D.24-08-009. This resulted in a $2.4 million debit in PABA over the course of the first quarter of 2026; and

10) Transfer of Authorized VAMO Memorandum Account expenses as authorized in D.25-12-027. This resulted in a $0.6 million debit to PABA in January 2026.

6. Balancing Account Interest

The balancing account interest (Table 12-2, line 9) is calculated based on the methodology authorized by the Commission in D.25-12-043 and implemented via AL 7818-E, applicable to all presented balancing accounts in this chapter. Authorized balancing account interest for 2026 includes the 3-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15, plus a yield spread adjustment of 1.25 percent.

D. PABA Forecast From April Through December 2026

The components of the PABA transactions forecasted from April 1, 2026, through December 31, 2026, shown in Table 12-2, lines 12 through 18, are: (1) customer revenue; (2) portfolio costs and energy value; (3) retained RPS and RA values; and (4) balancing account interest. These components are calculated based on the same methodologies and assumptions described in the other chapters of this testimony, as well as in PG&E’s rate change ALs and/or Commission decisions. Consistent with the forecast methodology described in Section B.1 above, the forecast presented in Tables 12-1 and 12-2 will be updated in the Fall Update. For those months available, forecasted data will be replaced with recorded data.

1. Customer Revenue

The customer revenue forecast (Table 12-2, line 12) is calculated based on the PCIA rates authorized in PG&E’s 2026 AET implemented effective January 1, 2026.

2. Portfolio Costs and Energy Value

a. Energy Procurement Costs and Energy Value

PG&E's portfolio costs and energy value forecasts for April-December 2026 (Table 12-2, lines 13-14) are based on the same methodologies described in Chapters 4 and 5. The model run to determine dispatch and prices used to forecast 2026 costs and revenues is the same as used to calculate the 2027 forecast amounts (i.e., price curve date of March 26, 2026).

b. UOG Related Cost

The UOG-related cost forecast reflects the UOG revenue requirement as authorized in the Commission's decisions, and recoverable through 2026.

3. Retained RPS and RA Values

The retained RPS and RA value (Table 12-2, lines 15-16) is based on the forecasted Retained RPS and RA quantities. The updated retained RPS and RA volumes are then multiplied by the D.25-12-027 authorized RPS and RA Adders to calculate the applicable credits in PABA.[14] Additionally, PG&E updated the RPS credits in PABA associated with the Minimum Retained RPS allocation methodology authorized in D.25-12-027.

4. 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 balancing account interest forecast (Table 12-2, line 18) is calculated based on a placeholder of 4.96 percent per annum.

E. 2026 Forecast Year-End PABA

By adding the PABA balance recorded as of the March 2026 accounting close,[15] and the forecast April 2026 through December 2026 forecast transactions,[16] the forecast year-end PABA is under-collected by

---

[14] Corresponding debit entries are recorded in ERRA.

[15] See Section C for details of recorded balances.

[16] See Section D for details of forecast transactions.

$364 million.[17] The primary drivers for the undercollected balance are summarized in Table 12-3 below, which is followed by a discussion of the drivers.

TABLE 12-3
PRIMARY DRIVERS OF PABA UNDERCOLLECTION SUMMARY
(MILLIONS OF DOLLARS)

Line No.	Description		Approximate Impact (Over)/Under Collection
1	Higher Customer Revenues		($20)
2	Lower Expected CAISO Revenues		
	(a) Lower Market Electricity Prices	210	
	(b) Less Generation From PCIA eligible Resources	75	
			285
3	Lower / (Higher) Procurement Costs and Revenues		
	(a) Lower Net RA Transaction Revenues	50	
	(d) Lower Natural Gas Fired Generator Costs	(85)	
			(35)
4	Lower Retained RPS Value		30
5	Higher Retained RA Value		(100)
6	Higher recorded undercollection brought forward from 2025		
	(a) PABA	70	
	(b) ERRA	100	
			170
7	Balancing Account Interest		40
8	Other		(7)
9	**Forecast 2026 year-end PABA balance, before Balance Transfers**		**$364**

[17] See Table 15-1, line 5, Column D.

1. Higher Customer Revenues

Recorded customer revenues are approximately $20 million higher than the forecast in rates, primarily driven by variances in customer usage and customer class mix.

2. Lower Expected CAISO Revenues

a. Lower Market Electricity Prices

Average 2026 CAISO market electricity prices for PG&E's PCIA eligible resources are expected to be approximately 20 percent lower than the 2026 Energy Benchmark (brown power), resulting in a reduction of CAISO revenues of approximately $210 million. The decrease in CAISO electricity prices is primarily driven by lower than expected natural gas prices, which were approximately 55 percent lower through March compared to the 2026 PG&E Citygate forward prices adopted in D.25-12-027.

b. Less Generation From PCIA-Eligible Resources

Generation from PCIA eligible resources is forecasted to be approximately 1,700 gigawatt hours (GWh) less than the forecast adopted in D.25-12-027. The reduction is primarily driven by lower-than-expected generation from fossil and solar resources, with fossil being driven by a lower ratio between power and natural gas prices compared to the forward prices adopted in D.25-12-027. This net decrease in generation represents an approximately $75 million decrease in CAISO market revenues.

The total impact, including the lower market prices, is an approximately $285 million decrease in CAISO revenues.

3. Lower Procurement Costs

a. Lower Net RA Transaction Revenues

RA sales revenue, net of costs, is approximately $50 million lower than expected, primarily due to lower RA sales volumes.

b. Lower Natural Gas-Fired Generator Costs

Fuel costs for natural gas-fired resources in PG&E's electric portfolio are expected to be approximately $85 million lower, primarily due to lower PG&E Citygate natural gas prices and lower generation volumes from natural gas-fired resources compared to the generation forecast adopted in D.25-12-027.

4. Lower Retained RPS Value

Retained RPS value decreased by approximately $30 million primarily due to lower RPS generation, partially offset by slightly lower RPS sales volumes.

5. Higher Retained RA Value

Retained RA value increased by approximately $100 million primarily due to a decrease in RA sales volumes as compared to forecasted RA retained and sales volumes.

6. Higher Recorded Undercollections Brought Forward From 2025

Recorded PABA and ERRA[18] were more undercollected than the forecast in rates, primarily due to lower CAISO revenue recorded in PABA and customer revenue recorded in ERRA, among other things.

7. Balancing Account Interest

The forecast balancing account interest of approximately $40 million not included in 2026 rates is primarily due to PABA undercollection calculated based on the three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15.

F. 2026 Forecast Year-End ERRA

The ERRA overcollection, before the balance transfers[19] is $190 million.[20] The primary drivers of the undercollection are summarized in Table 12-4, as follows.

---

18 The impact of ERRA undercollection is recorded in PABA because the end of year ERRA balance is transferred to PABA in pursuant to D.22-01-023 and D.25-12-027.

19 The balance transfers are discussed in Section G.

20 Table 12-1, line 6, Column D.

TABLE 12-4
PRIMARY DRIVERS OF ERRA OVERCOLLECTION SUMMARY
(MILLIONS OF DOLLARS)

Line No.	Description		Approximate Impact (Over)/Under Collection
1	Lower Customer Revenues		$115
2	Lower Expected CAISO Costs		
	(a) Lower Market Electricity Prices	(290)	
	(b) Lower Bundled Load Requirement	(40)	
			(330)
3	Lower / (Higher) Procurement Costs		
	(a) Lower RA Contract Cost	(75)	
	(b) Higher Hedging Cost	20	
	(c) WSPP Purchases not in the forecast	25	
			(30)
4	Retained RPS and RA		
	(a) Lower Retained RPS Value	(30)	
	(b) Higher Retained RA Value	95	
			65
5	Balancing Account Interest		(10)
6	Other		1
7	**Forecast 2026 year-end ERRA balance, before Balance Transfers**		**($190)**

1. Lower Customer Revenues

Customer revenue is expected to be approximately $115 million undercollected primarily due to lower actual bundled load for January through March.

2. Lower Expected Net CAISO Costs

a. Lower Market Electricity Prices

The average price for procuring bundled customer load in the CAISO energy markets is approximately 20 percent lower than the forecast adopted in D.25-12-027 resulting in lower CAISO costs of approximately $290 million. The decrease in CAISO electricity prices is primarily driven by lower than expected natural gas prices, which were approximately 55 percent lower through March compared to the 2026 PG&E Citygate forward prices adopted in D.25-12-027.

b. Lower Bundled Load Requirement

Bundled CAISO load is expected to decrease by approximately 750 GWh, which reduces the CAISO procurement costs by approximately $40 million. The total impact is approximately a $330 million decrease in CAISO Energy costs.

3. Lower Procurement Costs

The decrease of $30 million in procurement costs is primarily attributable: (1) an approximately $75 million decrease in the RA contract cost in the forecast adopted in D.25-12-027, partially offset by (2) an approximately $20 million higher hedging cost due to lower market prices, and (3) an approximately $25 million bilateral short term energy purchase not in the D.25-12-027 forecast.

4. Retained RPS and RA

ERRA's Retained RPS value is approximately $30 million lower than forecast and the Retained RA value is approximately $95 million higher than forecast. This is primarily due to the corresponding drivers for Retained RPS and Retained RA discussed for the PABA balance in Section E above.

5. Balancing Account Interest

The forecast balancing account interest of approximately $10 million not included in 2026 rates is primarily due to ERRA overcollection calculated based on the three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15.

G. Balance Transfers

PG&E anticipates two balance transfers to ERRA and PABA as follows:

1. Residential Uncollectibles Balancing Account – Electric

In AL 6001-E-A, the Commission authorized PG&E's request to establish PG&E's Electric Preliminary Statement Part IM, RUBA-E with three subaccounts, to record uncollectibles recovered from residential electric customers compared to actual uncollectibles in order to create more transparency. The Commission also authorized PG&E to record the Arrearage Management Program (AMP) debt forgiveness of charges for services provided by PG&E, services provided by eligible third-party service providers participating in AMP, and third-party taxes, charges, and fees. The Generation Subaccount records uncollectibles associated with generation charges recovered from bundled residential customers compared to actual generation uncollectibles.

As of March 2026, PG&E has recorded $2.1 million in RUBA-E[21] (Generation Subaccount) and anticipates updating the amount in the Fall Update. Disposition of the balance is through the ERRA.

2. ERRA

After accounting for the RUBA-E balance transfer discussed above, the final 2026 year-end ERRA overcollection is $188 million. Pursuant to OP 4 of D.22-01-023, PG&E anticipates transferring the final $188 million overcollected 2026 forecast year-end ERRA to the PABA Vintage 2026 subaccount for recovery in the PCIA rates.[22]

H. 2026 Forecast Year End NSGBA

The NSGBA undercollection is primarily due to higher procurement costs as well as a higher undercollected balance brought forward from 2025 driven by the following:

1. Higher Procurement Costs

The updated contract procurement cost forecast is approximately $300 million higher than the forecast adopted in D.25-12-027. This is driven

---

21 See Table 12-1, line 5, Column A.

22 See Table 12-1, line 6, Column F.

primarily by higher fossil contract costs due to the forward prices adopted in D.25-12-027 being greater than the actuals for January through March as well as the updated forecast for April through December, reducing the energy settlement benefit for applicable contracts. The lower prices are driven in part by lower natural gas prices, which were approximately 5 percent lower through March compared to the 2026 PG&E Citygate forward prices adopted in D.25-12-027. There were also additional RA contracts executed after the portfolio assumptions were finalized for the 2026 forecast adopted in D.25-12-027.

2. Higher Recorded Undercollection Brought Forward From 2025

The higher undercollection of approximately 30 million is primarily driven by higher fossil contract costs.

I. VAMOMA

1. VAMO Administrative Support

Following the approval of the VAMOMA, PG&E established ten order numbers to track the development (one time) and implementation (ongoing) administration costs. The order numbers and the description of the workstreams they were designed cover are as follows:

TABLE 12-5
PG&E VAMO ORDER NUMBERS AND DESCRIPTIONS

Line No.	Order Number	Description	Workstream Description
1	8202717	VAMO Project Management Office and general activities owned by PG&E's Energy Procurement and Policy (EPP) group	Order dedicated to EPP VAMO team members only. Used to charge time related to VAMO implementation project management and other general activities, as approved.
2	8203064	VAMO Forecast and Position	Used to charge time related to developing processes specific to VAMO and for incremental work on the forecast process and developing the position.
3	8203065	VAMO RFI Process	Used to charge time related to supporting the development and implementation of the RFI process.
4	8203066	VAMO Allocation and MO (RFI/Request for Offers (RFO)) Process	Used to charge time related to supporting the VAMO processes (RFI/RFO, solicitation management, bid evaluation, etc.).
5	8203067	VAMO Back Office Support	Used to charge time for any implementation and operational activities related to VAMO Contract Administration, Settlements, and Reporting functions.
6	8203068	VAMO Compliance Support	Used to charge time for any compliance support such as the VAMO Report, support for Cost Allocation Mechanism Procurement Review Group meetings.
7	8203069	VAMO Policy and Law Support	Used to charge time for policy and Law related work that directly supports the implementation or operations of the VAMO function.
8	8203070	VAMO Market and Credit Risk Management (MCRM)	Used to charge time for VAMO-related MCRM work.
9	8203072	VAMO General Expenses	Used to charge costs for VAMO-related expenses such as Independent Evaluator, External counsel, etc.
10	8203073	VAMO Systems/Information Technology (IT)	Used to charge time for VAMO-related IT/Systems upgrades and expenses.

2. Request for Recovery

In D.25-12-027, PG&E received disposition of the VAMOMA costs that accrued from September 2024 – August 2025. The VAMOMA costs accumulated between September 2025 and March 2026 are provided by order number in Tables 12-6. The VAMOMA balance of recorded costs and accrued interest for September 2025 through March 2026 is $418,580.[23]

[23] See Table 12-1, line 5.

For the sake of clarity, not all order numbers listed above have accrued costs during the period being presented.

The accrued costs include, but are not limited to, ongoing maintenance of the VA and MO processes and related systems projects needed to properly administer VAMO. For 2025 the IT and systems workstreams were focused on ongoing maintenance as needed to ensure the implementation of the VA and MO processes.

Due to ongoing work related to the administration of the VA and MO processes including but not limited to administering contract settlements and maintaining ongoing IT and systems requirements, PG&E anticipates updating the accrued costs and including revised amounts in the Fall Update.

In addition, PG&E had accrued the authorized three-month commercial paper rate on the VAMOMA in accordance with Preliminary Statement JC. The amount accrued during the period is included in the figure above. However, in prior applications, PG&E had neglected to specify the calculation of interest accrued in VAMOMA under the approved tariff. Accordingly, there is roughly $99 thousand in unrecovered interest accrued between 2021 and August 2025, and also presented as a further adjustment in Table 12-6. PG&E hereby requests to also recover this amount in accordance with the preliminary statement.

TABLE 12-6
VAMO ADMINISTRATIVE COSTS ACCRUED BALANCE SUMMARY
(BY MONTH)

Line No.	VAMO Order Number	Order Description	2025					2026				
			Sep	Oct	Nov	Dec	2025 Total	Jan	Feb	Mar	2026 Total	Grand Total
1	8202617	VAMO Costs	$9,114.00	$8,246.00	$8,246.00	$8,029.00	$33,635.00	$9,027.92	$5,745.04	$10,259.00	$25,031.96	$58,666.96
4	8203067	VAMO Back Office Support	30,597.00	30,054.50	23,381.75	35,967.75	120,001.00	23,288.07	25,698.99	26,827.66	75,814.72	195,815.72
5	8203068	VAMO Compliance Support		383.79			383.79				0.00	383.79
6	8203073	VAMO Systems/IT	38,611.17	29,447.74	19,157.57	21,155.84	108,372.32	12,333.80	10,065.95	11,722.76	34,122.51	142,494.83
7		Incurred Expenses	$78,322.17	$68,132.03	$50,785.32	$65,152.59	$262,392.11	$44,649.79	$41,509.98	$48,809.42	$134,969.19	$397,361.30
8		Accrued Interest	3,115.60	3,229.77	3,344.91	3,539.16	13,229.44	3,360.52	2,218.04	2,410.32	7,988.88	21,218.32
9		Costs During Period	$81,437.77	$71,361.80	$54,130.23	$68,691.75	$275,621.55	$48,010.31	$43,728.02	$51,219.74	$142,958.07	$418,579.62
10		Prior Period Interest (Sep 21 - Aug 25)										98,775.08
11		Grand Total										$517,354.70

J. Conclusion

In this chapter, PG&E summarizes its 2026 year-end balance forecasts for amortization in the 2027 rates. These balances will be the subject of the Fall Update; and, except as described herein, are amortized for recovery through the 2027 AET AL process, or a subsequent electric rate change AL. Additionally, this chapter presents the costs of administering the overall VAMO process as tracked in the VAMOMA, for which PG&E is requesting cost recovery approval to dispose of these balances in rates effective January 1, 2027.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 13

RATE PROPOSAL

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 13
RATE PROPOSAL

TABLE OF CONTENTS

A. Introduction 13-1

B. Revenue Requirement 13-2

C. Revenue Allocation and Rate Design 13-4

1. Vintage PCIA Rates 13-4

a. 2026 ERRA Balance Transfer to PABA 13-4

b. Summary of Proposed 2027 Vintage PCIA Rates 13-5

c. Summary of Revenue Allocation Between Bundled Customers and PCIA-Eligible DL Customers 13-8

2. Generation 13-8

3. Ongoing CTC 13-9

4. NSGC 13-10

5. TMNBC 13-11

6. BioMAT NBC 13-12

7. PPCP Rates 13-13

8. Residential Base Fixed Charge 13-14

9. Changes to Total Rates 13-15

D. Conclusion 13-16

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 13
RATE PROPOSAL

A. Introduction

This chapter presents illustrative rates that recover the revenue requirements for: (1) Power Charge Indifference Adjustment (PCIA), (2) Energy Resource Recovery Account (ERRA), (3) Ongoing Competition Transition Charge (CTC), (4) Cost Allocation Mechanism (CAM), (5) Modified CAM, (6) Central Procurement Entity, (7) Tree Mortality Non-Bypassable Charge (TMNBC), (8) Bioenergy Market Adjusting Tariff (BioMAT) Non-Bypassable Charge (NBC), and (9) Voluntary Allocation and Market Offer. These revenue requirements have been outlined in Chapters 6 through 12.

To recover these revenue requirements, Pacific Gas and Electric Company (PG&E) intends to change: (1) vintage PCIA rates, (2) generation rates, (3) ongoing CTC rates, (4) New System Generation Charge (NSGC) rates,[1] (5) TMNBC rates, (6) BioMAT rates, and (7) Public Policy Charge Procurement (PPCP) rates with these rate changes going into effect on January 1, 2027.

In compliance with California Public Utilities Commission (CPUC or Commission) Rule 3.2, PG&E has calculated illustrative rates by applying the incremental revenue requirements requested in this 2027 ERRA Forecast Application (Application) on top of present rates effective March 1, 2026. For this Application, PG&E utilizes the revenue allocation and rate design methodology used to design the rates effective March 1, 2026, which was adopted by the CPUC by Decision (D.) 21-11-016 in Phase II of PG&E's 2020 General Rate Case (GRC).

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. As a result of the revenue requirements requested for approval in this application, the system average Bundled rate, including the impact of the Greenhouse Gas (GHG)

---

[1] The NSGC rate component collects the CAM revenue requirement.

revenue return, will increase by approximately 5.7 percent to 35.7 cents per kilowatt-hour (kWh) when compared to the present system average Bundled rate of 33.8 cents per kWh, effective March 1, 2026. The system average rate for DA and CCA customers, whose average rates exclude commodity charges that are provided by third-party service providers, would decrease by approximately 7.3 percent to 21.7 cents per kWh, when compared to the present system average rate for DA and CCA customers of 23.4 cents per kWh, which was effective March 1, 2026.[2]

B. Revenue Requirement

The 2027 Revenue Requirement recoverable through: (1) the NSGC; (2) the PCIA rate;[3] (3) the Ongoing CTC; (4) the ERRA; and (5) the Public Purpose Program (PPP) charge. The revenue requirements included in the PPP are: (1) PPCP Costs; (2) TMNBC; and (3) BioMAT NBC.

---

2 Average DA and CCA customer rates presented herein are for PG&E provided services only and exclude commodity charges that are provided by DA and CCA service providers.

3 Including the recovery of the Voluntary Allocation and Market Offer Memorandum Account (VAMOMA) balance (Table 13-1, line 5) adopted in this proceeding.

TABLE 13-1
SUMMARY OF 2027 FORECAST ENERGY PROCUREMENT REVENUE REQUIREMENTS
(THOUSANDS OF DOLLARS)

Line No.		2027 Cost With Revenue Fees and Uncollectibles(a)	2026 Year End Balance(b)	Authorized Transfers (d)	2026 Year End transfers to PABA (e)	2027 Revenue Requirements
		(A)	(B)	(C)	(D)	(E) = SUM (A..D)
1	Non-PPP					
2	CAM (NSGC)	$356,063	$302,504	$0		$658,567
3	Ongoing CTC (MTCBA)	(10,760)	(9,143)			(19,903)
4	PCIA/PABA	636,852	368,710	0	(190,478)	815,084
5	VAMOMA (c)		524			524
6	ERRA	2,914,908	(192,664)	2,186	190,478	2,914,908
7	RUBA-E		2,186	(2,186)		0
8	Non-PPP Subtotal	$3,897,063	$472,117	$0	$0	$4,369,180
9	PPP					
10	PPCP		(796)			(796)
11	TMNBC	26,874	3,213			30,087
12	BioMat	11,515	(716)			10,800
13	PPP Subtotal	$38,389	$1,701	$0	$0	$40,090
14	**Revenue Requirement for Rate Setting**	**$3,935,452**	**$473,818**	**$0**	**$0**	**$4,409,270**
15	Revenue Requirements authorized in other proceedings					
16	UOG-Related Costs	(1,229,145)				(1,229,145)
17	RUBA-E		(2,186)			(2,186)
18	CCA BioMat	(1,533)				(1,533)
19	Subtotal	($1,230,679)	($2,186)	$0	$0	($1,232,865)
20	**2027 ERRA Application Revenue Requirement Request**	**$2,704,774**	**$471,632**	**$0**	**$0**	**$3,176,405**

Notes:

(a) Costs exclude GTSR Program Costs

(b) The year-end balaning account balances recovered in rates through the AET, and/or a subsequent rate change advice letter.

(c) Pursuant to Electric Preliminary Statement Part JC, the VAMOMA blance approved by the Commission is recoverable through the PABA.

(d) The authorization of recovery of the RUBA-E is D.20-06-003 (as well as Advice 6001-E-A).

(e) Balance Transfers to PABA includes the transfer from ERRA balances as authorized in D.22-01-023.

The 2027 Revenue Requirement for ratesetting purposes of $4,409 million[4] includes the 2027 ERRA Application Revenue Requirement Request in this Application of $3,176 million.[5]

---

4 Table 13-1, line 14.

5 Table 13-1, line 19.

C. 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. The calculation methodology to determine the vintage PCIA revenue requirements was adopted in D.08-09-012 and subsequently modified by D.11-12-018, D.18-10-019, and D.21-05-030.[6] As prescribed in Ordering Paragraph (OP) 4 of D.18-10-019, the revenue allocation approved for the non-California Department of Water Resources (CDWR) cost portion of the indifference calculation is the generation revenue allocation methodology approved for ongoing CTC rates. The PCIA rate for each vintage year and customer class is developed by utilizing the same proportional ratio of the rate class average generation rate to the total system average generation rate. The proportional ratio is then multiplied by the total system average PCIA rate by vintage year to calculate the PCIA rate by vintage year and by rate class. Proportional generation ratios have been calculated using the 2027 generation rates presented in this Application, which are designed using the 2027 forecast Bundled sales by customer class. In all cases, the final PCIA rates include CDWR franchise fees. In addition to the methodology described above, PG&E will transfer the 2026 year-end ERRA balance to the most recent vintage subaccount in the Portfolio Allocation Balancing Account (PABA), as approved by OP 4 in D.22-01-023.

a. 2026 ERRA Balance Transfer to PABA

OP 4 of D.22-01-023 in the PCIA OIR adopted an ongoing process to transfer the year-end ERRA balance to the most-recent vintage subaccount of PABA each year. In compliance with this decision, and consistent with recent ERRA Forecast Applications, PG&E has transferred the forecast 2026 year-end ERRA balance to the 2026 vintage subaccount in PABA in this Application. Amortizing this balance in the 2026 vintage subaccount in PABA allows the balance to be applied to both Bundled customers and PCIA-eligible departed load (DL)

---

6 Modifications to the calculation methodology approved in D.11-12-018 were implemented, in part, in Res.E-4475.

customers that depart on or after July 1, 2026. As outlined in Chapter 12, PG&E currently forecasts an overcollection of $190 million in ERRA at the end of 2026.[7] Transferring this balance to the 2026 vintage subaccount in PABA will decrease PCIA rates for vintage 2026, as shown in Table 13-2.

TABLE 13-2
IMPACT OF AMORTIZATION OF THE FORECASTED 2026 YEAR-END ERRA BALANCE IN PABA

Line No.	PABA Vintage Subaccount	Applicable 2026 ERRA Year-end Balance ($000)	Applicable Billing Determinants (kWh)	Average PCIA Rate Impact
1	2026 Vintage	$(190,478)	24,331,386,818	$(0.00783)

b. Summary of Proposed 2027 Vintage PCIA Rates

Table 13-3 shows PCIA rates for all vintages and customer classes. For vintages prior to 2027, the change in PCIA rates ranges from an increase of 2.4 cents per kWh to a decrease of 4.3 cents per kWh, compared to 2026 PCIA rates implemented January 1, 2026. Table 13-3a shows PCIA rates presently in effect, and Table 13-3b shows the difference between present PCIA rates and those proposed in this Application.

7 See Table 12-1, Column K.

TABLE 13-3
PROPOSED 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	2022 Vintage	2023 Vintage	2024 Vintage	2025 Vintage	2026 Vintage	2027 Vintage
1	Residential	$0.01288	$0.01491	$0.01537	$0.01608	$0.01586	$0.01611	$0.01597	$0.01596	$0.01584	$0.01445	$0.01425	$0.01417	$0.01259	$0.01366	$0.01352	$0.01253	$0.01413	$0.00701	$0.00701
2	Small L&P	$0.01241	$0.01437	$0.01482	$0.01550	$0.01529	$0.01553	$0.01540	$0.01539	$0.01527	$0.01393	$0.01374	$0.01365	$0.01214	$0.01317	$0.01303	$0.01207	$0.01362	$0.00675	$0.00675
3	Medium L&P	$0.01312	$0.01520	$0.01566	$0.01639	$0.01617	$0.01642	$0.01628	$0.01627	$0.01615	$0.01472	$0.01452	$0.01444	$0.01283	$0.01392	$0.01378	$0.01276	$0.01441	$0.00714	$0.00714
4	E19	$0.01244	$0.01441	$0.01485	$0.01554	$0.01533	$0.01557	$0.01543	$0.01542	$0.01531	$0.01396	$0.01377	$0.01369	$0.01216	$0.01320	$0.01306	$0.01210	$0.01366	$0.00677	$0.00677
5	Streetlights	$0.01035	$0.01199	$0.01236	$0.01293	$0.01275	$0.01295	$0.01284	$0.01284	$0.01274	$0.01162	$0.01146	$0.01139	$0.01012	$0.01098	$0.01087	$0.01007	$0.01137	$0.00564	$0.00564
6	Standby	$0.00868	$0.01005	$0.01036	$0.01084	$0.01069	$0.01086	$0.01076	$0.01076	$0.01067	$0.00974	$0.00960	$0.00955	$0.00849	$0.00921	$0.00911	$0.00844	$0.00953	$0.00473	$0.00473
7	Agriculture	$0.01203	$0.01393	$0.01436	$0.01503	$0.01482	$0.01506	$0.01493	$0.01492	$0.01480	$0.01350	$0.01332	$0.01324	$0.01176	$0.01277	$0.01263	$0.01170	$0.01321	$0.00655	$0.00655
8	B20/E20 T (Excluding FPP)	$0.01077	$0.01248	$0.01286	$0.01346	$0.01327	$0.01348	$0.01337	$0.01336	$0.01326	$0.01209	$0.01192	$0.01185	$0.01054	$0.01143	$0.01131	$0.01048	$0.01183	$0.00587	$0.00587
9	B20/E20 P (Excluding FPP)	$0.01100	$0.01274	$0.01313	$0.01374	$0.01355	$0.01376	$0.01365	$0.01364	$0.01354	$0.01234	$0.01217	$0.01210	$0.01076	$0.01167	$0.01155	$0.01070	$0.01208	$0.00599	$0.00599
10	B20/E20 S (Excluding FPP)	$0.01160	$0.01343	$0.01384	$0.01449	$0.01429	$0.01451	$0.01439	$0.01438	$0.01427	$0.01301	$0.01284	$0.01276	$0.01134	$0.01231	$0.01218	$0.01128	$0.01273	$0.00631	$0.00631
11	BEV1	$0.01060	$0.01228	$0.01265	$0.01324	$0.01306	$0.01326	$0.01315	$0.01314	$0.01304	$0.01189	$0.01173	$0.01166	$0.01036	$0.01124	$0.01113	$0.01031	$0.01164	$0.00577	$0.00577
12	BEV2	$0.01183	$0.01370	$0.01412	$0.01477	$0.01457	$0.01480	$0.01467	$0.01467	$0.01455	$0.01327	$0.01309	$0.01301	$0.01157	$0.01255	$0.01242	$0.01151	$0.01298	$0.00644	$0.00644
13	System Average PCIA Rate by Vintage	$0.01156	$0.01319	$0.01468	$0.01504	$0.01527	$0.01579	$0.01553	$0.01551	$0.01515	$0.01414	$0.01329	$0.01372	$0.01201	$0.01298	$0.01285	$0.01208	$0.01355	$0.00676	$0.00676

TABLE 13-3A
PRESENT POWER CHARGE INDIFFERENCE ADJUSTMENT RATES BY CLASS AND VINTAGE
(WITH DWR FRANCHISE FEE) – MARCH 1, 2026

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	2022 Vintage	2023 Vintage	2024 Vintage	2025 Vintage	2026 Vintage
1	Residential	$0.02973	$0.03366	$0.03492	$0.03676	$0.03708	$0.03686	$0.03680	$0.03687	$0.03661	$0.03679	$0.03725	$0.03632	$0.05264	$0.05272	$0.05380	$0.05066	-$0.01011	-$0.01011
2	Small L&P	$0.02910	$0.03294	$0.03417	$0.03597	$0.03628	$0.03607	$0.03602	$0.03608	$0.03582	$0.03600	$0.03646	$0.03554	$0.05151	$0.05159	$0.05265	$0.04957	-$0.00990	-$0.00990
3	Medium L&P	$0.03071	$0.03476	$0.03606	$0.03796	$0.03829	$0.03807	$0.03801	$0.03807	$0.03780	$0.03799	$0.03847	$0.03751	$0.05436	$0.05444	$0.05557	$0.05232	-$0.01045	-$0.01045
4	E19	$0.02903	$0.03286	$0.03410	$0.03589	$0.03620	$0.03599	$0.03593	$0.03600	$0.03574	$0.03592	$0.03637	$0.03546	$0.05140	$0.05147	$0.05253	$0.04946	-$0.00987	-$0.00987
5	Streetlights	$0.02427	$0.02747	$0.02850	$0.03000	$0.03026	$0.03009	$0.03004	$0.03009	$0.02988	$0.03003	$0.03041	$0.02965	$0.04296	$0.04302	$0.04391	$0.04134	-$0.00824	-$0.00824
6	Standby	$0.02046	$0.02316	$0.02402	$0.02529	$0.02551	$0.02536	$0.02532	$0.02536	$0.02518	$0.02531	$0.02563	$0.02499	$0.03621	$0.03626	$0.03701	$0.03484	-$0.00694	-$0.00694
7	Agriculture	$0.02750	$0.03113	$0.03230	$0.03400	$0.03430	$0.03410	$0.03404	$0.03410	$0.03386	$0.03403	$0.03446	$0.03360	$0.04869	$0.04876	$0.04977	$0.04686	-$0.00935	-$0.00935
8	B20/E20 T (Excluding FPP)	$0.02637	$0.02985	$0.03097	$0.03260	$0.03288	$0.03269	$0.03264	$0.03270	$0.03247	$0.03263	$0.03304	$0.03221	$0.04668	$0.04675	$0.04772	$0.04493	-$0.00896	-$0.00896
9	B20/E20 P (Excluding FPP)	$0.02617	$0.02962	$0.03074	$0.03235	$0.03263	$0.03245	$0.03239	$0.03245	$0.03222	$0.03238	$0.03279	$0.03197	$0.04633	$0.04640	$0.04735	$0.04459	-$0.00889	-$0.00889
10	B20/E20 S (Excluding FPP)	$0.02717	$0.03075	$0.03190	$0.03358	$0.03387	$0.03368	$0.03362	$0.03368	$0.03344	$0.03361	$0.03403	$0.03318	$0.04809	$0.04816	$0.04915	$0.04628	-$0.00923	-$0.00923
11	BEV1	$0.02417	$0.02736	$0.02839	$0.02988	$0.03014	$0.02997	$0.02992	$0.02997	$0.02976	$0.02991	$0.03029	$0.02953	$0.04280	$0.04286	$0.04374	$0.04119	-$0.00822	-$0.00822
12	BEV2	$0.02751	$0.03114	$0.03231	$0.03401	$0.03430	$0.03411	$0.03405	$0.03411	$0.03387	$0.03404	$0.03447	$0.03361	$0.04870	$0.04878	$0.04978	$0.04687	-$0.00936	-$0.00936
13	System Average PCIA Rate by Vintage	$0.02749	$0.03093	$0.03398	$0.03507	$0.03623	$0.03639	$0.03625	$0.03624	$0.03549	$0.03632	$0.03527	$0.03551	$0.05110	$0.05064	$0.05098	$0.04767	-$0.00991	-$0.00991

TABLE 13-3B
DIFFERENTIAL BETWEEN PRESENT AND PROPOSED PCIA RATES

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	2022 Vintage	2023 Vintage	2024 Vintage	2025 Vintage	2026 Vintage
1	Residential	-$0.01732	-$0.01928	-$0.02010	-$0.02126	-$0.02179	-$0.02133	-$0.02141	-$0.02148	-$0.02133	-$0.02286	-$0.02352	-$0.02267	-$0.04050	-$0.03955	-$0.04077	-$0.03858	$0.02374	$0.01687
2	Small L&P	-$0.01598	-$0.01774	-$0.01851	-$0.01958	-$0.02012	-$0.01965	-$0.01974	-$0.01981	-$0.01968	-$0.02128	-$0.02193	-$0.02111	-$0.03868	-$0.03767	-$0.03888	-$0.03681	$0.02430	$0.01704
3	Medium L&P	-$0.01827	-$0.02035	-$0.02121	-$0.02242	-$0.02296	-$0.02250	-$0.02257	-$0.02265	-$0.02250	-$0.02403	-$0.02470	-$0.02382	-$0.04220	-$0.04124	-$0.04251	-$0.04021	$0.02410	$0.01722
4	E19	-$0.01868	-$0.02087	-$0.02174	-$0.02296	-$0.02345	-$0.02304	-$0.02309	-$0.02316	-$0.02300	-$0.02430	-$0.02492	-$0.02407	-$0.04127	-$0.04049	-$0.04166	-$0.03939	$0.02124	$0.01551
5	Streetlights	-$0.01559	-$0.01742	-$0.01815	-$0.01917	-$0.01957	-$0.01923	-$0.01928	-$0.01933	-$0.01920	-$0.02029	-$0.02080	-$0.02010	-$0.03448	-$0.03382	-$0.03480	-$0.03290	$0.01777	$0.01297
6	Standby	-$0.00842	-$0.00922	-$0.00966	-$0.01026	-$0.01068	-$0.01030	-$0.01039	-$0.01044	-$0.01038	-$0.01181	-$0.01231	-$0.01175	-$0.02444	-$0.02349	-$0.02438	-$0.02314	$0.02015	$0.01349
7	Agriculture	-$0.01673	-$0.01866	-$0.01944	-$0.02054	-$0.02102	-$0.02062	-$0.02068	-$0.02074	-$0.02060	-$0.02194	-$0.02254	-$0.02174	-$0.03815	-$0.03733	-$0.03846	-$0.03638	$0.02118	$0.01522
8	B20/E20 T (Excluding FPP)	-$0.01537	-$0.01711	-$0.01784	-$0.01886	-$0.01933	-$0.01893	-$0.01899	-$0.01906	-$0.01893	-$0.02028	-$0.02087	-$0.02011	-$0.03593	-$0.03508	-$0.03617	-$0.03423	$0.02104	$0.01495
9	B20/E20 P (Excluding FPP)	-$0.01457	-$0.01619	-$0.01689	-$0.01787	-$0.01834	-$0.01793	-$0.01800	-$0.01807	-$0.01795	-$0.01936	-$0.01995	-$0.01921	-$0.03499	-$0.03409	-$0.03518	-$0.03330	$0.02163	$0.01521
10	B20/E20 S (Excluding FPP)	-$0.01657	-$0.01848	-$0.01925	-$0.02034	-$0.02082	-$0.02042	-$0.02047	-$0.02054	-$0.02040	-$0.02172	-$0.02230	-$0.02152	-$0.03773	-$0.03692	-$0.03803	-$0.03597	$0.02087	$0.01500
11	BEV1	-$0.01235	-$0.01367	-$0.01427	-$0.01511	-$0.01557	-$0.01517	-$0.01525	-$0.01531	-$0.01521	-$0.01664	-$0.01720	-$0.01652	-$0.03123	-$0.03031	-$0.03133	-$0.02968	$0.02121	$0.01466
12	BEV2	-$0.01596	-$0.01795	-$0.01763	-$0.01897	-$0.01903	-$0.01831	-$0.01852	-$0.01860	-$0.01871	-$0.01990	-$0.02117	-$0.01989	-$0.03669	-$0.03579	-$0.03693	-$0.03480	$0.02291	$0.01611
13	System Average PCIA Rate by Vintage	-$0.02749	-$0.03093	-$0.03398	-$0.03507	-$0.03623	-$0.03639	-$0.03625	-$0.03624	-$0.03549	-$0.03632	-$0.03527	-$0.03551	-$0.05110	-$0.05064	-$0.05098	-$0.04767	$0.00991	$0.00991

c. Summary of Revenue Allocation Between Bundled Customers and PCIA-Eligible DL Customers

Table 13-4 summarizes the PCIA revenues allocated to Bundled and DA/CCA customers based on the PCIA rates presented in Table 13-3.

TABLE 13-4
PCIA REVENUES ALLOCATION SUMMARY
(THOUSANDS OF DOLLARS)

Line No.	Description	Forecast PCIA Revenues from Proposed PCIA Rates
1	Bundled Customers	$154,009
2	DA/CCA Customers	661,600
3	Total Revenues	$815,608

2. Generation

The generation revenue requirement for rates reflected in this chapter is shown in Table 13-1 above. The methodology applied in this filing for implementing generation rate changes between GRCs was adopted in PG&E's 2020 GRC Phase II by D.21-11-016. The approved methodology allocates incremental generation revenue using an equal percentage of functional revenues. First, the Bundled customers' current generation revenue, as determined using current rates and the sales forecast for the 2027 test year, is adjusted by subtracting non-allocated revenue to create adjusted present rate revenue. Next, the adjusted present rate revenue is compared to the total generation revenue requirement to determine the incremental generation revenue necessary to collect the generation revenue requirement proposed in this Application. This incremental generation revenue is then allocated on an equal percentage basis, i.e., each customer class and schedule receives the same percentage change based on its share of the adjusted present rate revenue. The sum of the adjusted present rate revenue, non-allocated revenue, and the incremental 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.21-11-016, 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 energy charge component for that rate schedule, or as an equal-percentage change to the generation energy rate.

Table 13-5 presents the proposed total average generation rates for Bundled customers. As required by the revenue allocation and rate design changes adopted by D.21-11-016 in PG&E's 2020 GRC Phase II proceeding, bundled generation rates do not include Bundled PCIA rates which are shown separately in PG&E's rate schedule tariffs.

TABLE 13-5
PROPOSED 2027 AVERAGE TOTAL GENERATION RATES FOR BUNDLED CUSTOMERS
($/kWh)

Line No.	Customer Class	Proposed Rate
1	Residential	$0.13191
2	Small Commercial	$0.12714
3	Medium Commercial	$0.13444
4	Large Commercial	$0.12744
5	Streetlights	$0.10600
6	Standby	$0.08878
7	Agriculture	$0.12324
8	B20/E20 T	$0.11032
9	B20/E20 P	$0.11265
10	B20/E20 S	$0.11879
11	BEV1	$0.10857
12	BEV2	$0.12117

3. Ongoing CTC

Pursuant to D.18-10-019, Ongoing CTC revenue requirements are allocated to each customer class (and voltage level of service, for

Schedule B-20/E-20) using the same generation allocation methodology used to design Bundled generation rates. As approved in PG&E's 2008 ERRA Forecast proceeding (D.08-02-018), eligible 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 B-20/E-20) by the corresponding 2027 forecast sales. Table 13-6 presents the proposed Ongoing CTC rates for Bundled, DA, CCA, and eligible DL customers.

TABLE 13-6
PROPOSED 2027 ONGOING CTC RATES
($/kWh)

Line No.	Customer Class	Proposed Rate
1	Residential	-$0.00028
2	Small Commercial	-$0.00027
3	Medium Commercial	-$0.00028
4	Large Commercial	-$0.00027
5	Streetlights	-$0.00022
6	Standby	-$0.00019
7	Agriculture	-$0.00026
8	B20/E20 T	-$0.00023
9	B20/E20 P	-$0.00024
10	B20/E20 S	-$0.00025
11	BEV1	-$0.00027
12	BEV2	-$0.00027

4. NSGC

In D.10-12-035, the Commission adopted a settlement which established an NBC 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 NBC as NSGC in AL 3896-E-B.

NSGC rates are based on the 12-month 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 allocates the proposed revenue requirement to each customer class using each customer class's contribution to 12-month coincident peak load. Proposed rates set forth herein are based on 2024 recorded data. PG&E will update this recorded data to reflect 2025 data prior to the Fall Update once the data is available. Rates for each customer class are then set by dividing the allocated revenue by each customer class's forecast usage. Proposed NSGC rates are shown in Table 13-7.

TABLE 13-7
PROPOSED 2027 NSGC RATES
($/kWh)

Line No.	Customer Class	Proposed Rate
1	Residential	$0.01252
2	Small Commercial	$0.00801
3	Medium Commercial	$0.00711
4	Large Commercial	$0.00711
5	Streetlights	$0.00697
6	Standby	$0.00567
7	Agriculture	$0.00772
8	B20/E20 T	$0.00610
9	B20/E20 P	$0.00610
10	B20/E20 S	$0.00610
11	BEV1	$0.00801
12	BEV2	$0.00711

5. TMNBC

To determine TMNBC rates, PG&E first allocates the TMNBC revenue requirement determined in Chapter 11 to each customer class using the same 12-month coincident peak allocation factors used to design NSGC rates. Rates for each customer class are then set by dividing the allocated revenue by each customer class's forecast usage. TMNBC rates are embedded in total PPP rates for billing. Proposed TMNBC rates are shown in Table 13-8 below.

TABLE 13-8
PROPOSED 2027 TREE MORTALITY NON BYPASSABLE CHARGE RATES
($/kWh)

Line No.	Customer Class	Proposed Rate
1	Residential	$0.00056
2	Small Commercial	$0.00036
3	Medium Commercial	$0.00032
4	Large Commercial	$0.00032
5	Streetlights	$0.00032
6	Standby	$0.00026
7	Agriculture	$0.00035
8	B20/E20 T	$0.00025
9	B20/E20 P	$0.00025
10	B20/E20 S	$0.00025
11	BEV1	$0.00036
12	BEV2	$0.00032

6. BioMAT NBC

To determine BioMAT NBC rates, PG&E first allocates the BioMAT NBC revenue requirement determined in Chapter 12 to each customer class using the same 12-month coincident peak allocation factors used to design NSGC rates. Rates for each customer class are then set by dividing the allocated revenue by each customer class forecast usage. Similar to the TMNBC, BioMAT NBC rates are embedded in total PPP rates for billing. Proposed BioMAT NBC rates are shown in Table 13-9 below.

TABLE 13-9
PROPOSED 2027 BIOMAT RATES
($/kWh)

Line No.	Customer Class	Proposed Rate
1	Residential	$0.00020
2	Small Commercial	$0.00013
3	Medium Commercial	$0.00012
4	Large Commercial	$0.00012
5	Streetlights	$0.00011
6	Standby	$0.00009
7	Agriculture	$0.00013
8	B20/E20 T	$0.00009
9	B20/E20 P	$0.00009
10	B20/E20 S	$0.00009
11	BEV1	$0.00013
12	BEV2	$0.00012

7. PPCP Rates

In D.22-02-002, the Commission authorized the establishment of the PPCP subaccount in the Public Policy Charge Balancing Account (PPCBA) and authorized PG&E to transfer certain public-policy procurement costs from its PABA non-vintaged subaccount to this subaccount for recovery from all customers through PPP rates.[8]

PG&E has allocated the total PPCP revenue requirement of credit of $0.8 million using the equal percent of total revenue allocation method which is consistent with the allocation methodology that applies to all other subaccounts included in the PPCBA. PPCP rates are embedded in total PPP rates for billing. Proposed PPCP rates are shown in Table 13-10 below.

8 PG&E established the PPCP subaccount through AL 6524-E, submitted March 14, 2022.

TABLE 13-10
PROPOSED 2027 PPCP RATES
($/kWh)

Line No.	Customer Class	Proposed Rate
1	Residential	-$0.00001
2	Small Commercial	-$0.00001
3	Medium Commercial	-$0.00001
4	Large Commercial	-$0.00001
5	Streetlights	-$0.00001
6	Standby	-$0.00001
7	Agriculture	-$0.00001
8	B20/E20 T	-$0.00001
9	B20/E20 P	-$0.00001
10	B20/E20 S	-$0.00001
11	BEV1	-$0.00001
12	BEV2	-$0.00001

8. Residential Base Fixed Charge

On March 1, 2026 PG&E filed Advice Letter 7846-E, which implemented an income-graduated fixed charge (Base Service Charge) for almost all residential customers, the structure of which allows for the collection of NSGC and CARE-exempt PPP rate components through the Base Service Charge (BSC).

In order to show how the NSCG rate and CARE-exempt PPP rates presented in this Application (TMNBC, BioMAT, and PPCP rates) would be paid by residential customers subject to the BSC, Table 13-11 shows proposed illustrative NSCG, TMNBC, BioMAT, and PPCP rates for residential customers calculated as daily charges ($/day).

TABLE 13-11
PROPOSED 2027 RESIDENTIAL FIXED CHARGE RATES
($/DAY)

Line No.	Customer Class	Rate Component	Proposed Rate
1	Residential	NSGC	$0.17114
2	Residential	TMNBC	$0.00782
3	Residential	BioMAT	$0.00281
4	Residential	PPCP	$(0.00021)

Because the BSC is capped at current levels, any increase in NSCG and non-CARE surcharge PPP revenue requirements may result in the CARE surcharge portion of the BSC being reduced and instead recovered through volumetric rates. For this reason, volumetric illustrative NSCG, TMNBC, BioMAT, and PPCP rates for residential customers are included in Tables 13-7 through 13-10, above.

9. Changes to Total Rates

Attachment A summarizes the illustrative proposed Bundled and DA/CCA revenues and average rates by schedule and functional rate component. Attachment A-1 presents revenues and average rates which include the GHG revenue return. Attachment A-2 presents revenues and average rates excluding the GHG revenue return. Total rates are determined by summing the current rate components that are not changing in this proceeding (e.g., nuclear decommissioning, distribution, and transmission) and the proposed rates for PCIA, Generation, Ongoing CTC, NSGC, TMNBC, BioMAT NBC, and PPCP. The TMNBC, BioMAT NBC, and PPCP rates proposed in this Application are embedded in the average PPP rate in both the Bundled and the DA/CCA customer average rate tables.

All illustrative non-ERRA rate components have been designed and maintained at present March 1, 2026 rate levels[9] and thus do not reflect the cost recovery (i.e., total 2027 revenue requirements) subject to CPUC approval through PG&E's 2027 Annual Electric True-Up (AET) for year-end balancing account adjustments. Any revenue requirement component changes approved in this proceeding will be implemented in the 2027 AET

---

9 Present 2026 rate levels are those filed in AL 7846-E, effective March 1, 2026.

and consolidated with other changes approved for implementation at that time. Therefore, the rates set forth in Attachment A are to illustrate the rate impact of this Application only.

D. Conclusion

In this chapter, PG&E presents the PCIA, Generation, Ongoing CTC, NSGC, TMNBC, BioMAT NBC, and PPCP rates by customer class based on the proposed revenue requirements summarized in Table 13-1. PG&E requests that the Commission approve the revenue requirement requests presented in this Application for implementation in rates effective January 1, 2027 concurrent with the AET, subject to updates presented in PG&E's Fall Update and 2027 AET.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 13

ATTACHMENT A

ILLUSTRATIVE TOTAL RATES BY CLASS

13-AtchA-1

Pacific Gas & Electric Company
2027 ERRA May Application
Friday, January 1, 2027
Revenue and Average Rate Summary with GHG Revenue Return

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	WFC Revenue	RB Revenue	RBC Revenue	WH Revenue	CTC Revenue	ECRA Revenue	NSGC Revenue	Residential & Small Business AB32 Credit Revenue	Climate Credit & EITE Revenue	CIA Revenue
RESIDENTIAL																				
Non-CARE	$2,431,962,096	$792,471,628	$276,478,302	$54,116,851	-$24,558,087	-$2,563,101	$763,996	$1,197,412,849	$196,313,657	-$122,933	$32,855,215	$51,081,587	-$51,081,596	$23,306,340	-$1,647,230	$132,688	$88,161,205	$0	-$122,233,200	-$414,979
CARE	$875,428,201	$524,265,420	$186,512,676	$36,507,309	-$16,566,922	-$1,729,072	$515,398	$133,463,933	$40,169,551	-$82,931	$0	$0	$0	$0	-$1,111,252	$89,514	$36,766,179	$0	-$54,245,578	-$1,532,193
TOTAL RES	$3,307,390,297	$1,316,737,048	$462,990,978	$90,624,160	-$41,125,009	-$4,292,173	$1,279,394	$1,330,876,782	$236,483,208	-$205,865	$32,855,215	$51,081,587	-$51,081,596	$23,306,340	-$2,758,482	$222,202	$124,927,384	$0	-$176,478,778	-$1,947,172
SMALL L&P																				
B-1	$670,542,841	$207,774,505	$51,436,531	$14,856,975	-$6,742,057	-$474,562	$142,136	$359,731,876	$49,153,242	-$33,749	$9,647,211	$13,989,268	-$13,989,270	$6,627,601	-$435,845	$36,427	$13,110,999	-$11,417,746	-$103,996	
B-6	$238,602,160	$75,661,174	$18,621,091	$5,374,496	-$2,438,932	-$171,672	$51,456	$125,407,300	$15,976,931	-$12,209	$3,489,638	$5,060,269	-$5,060,269	$2,397,369	-$157,667	$13,178	$4,742,891	-$2,093,551	-$33,486	
A-15	$310,345	$94,913	$23,519	$6,794	-$3,083	-$217	$65	$165,970	$22,506	-$15	$4,422	$6,413	-$6,413	$3,038	-$199	$17	$5,995	-$2,009	$0	
TC-1	$3,960,531	$1,121,622	$308,910	$89,232	-$40,493	-$2,850	$854	$2,318,088	$126,024	-$203	$58,084	$84,227	-$84,227	$39,904	-$2,618	$219	$78,746	$0	$0	
TOTAL SMALL	$913,415,878	$284,652,214	$70,390,052	$20,327,498	-$9,224,566	-$649,302	$194,510	$487,623,234	$65,278,704	-$46,176	$13,199,356	$19,140,177	-$19,140,179	$9,067,912	-$596,329	$49,840	$17,938,632	-$13,513,306	-$137,482	
MEDIUM L&P																				
B-10 T	$128,319	$61,267	$21,286	$5,397	-$2,449	-$155	$59	$28,832	$16,047	-$12	$3,513	$5,094	-$5,094	$1,332	-$167	$13	$4,229	$0	$0	
B-10 P	$6,391,683	$2,290,743	$764,898	$175,600	-$79,687	-$5,029	$2,110	$2,766,040	$518,114	-$399	$114,304	$165,751	-$165,751	$61,313	-$5,448	$431	$137,596	$0	-$13,283	
B-10 S	$685,487,825	$254,741,081	$72,883,032	$17,180,391	-$7,796,417	-$492,007	$201,399	$296,644,914	$52,504,598	-$39,027	$11,118,089	$16,122,165	-$16,122,167	$6,490,495	-$532,979	$42,124	$13,462,099	-$298,894	-$628,922	
TOTAL MEDIUM	$692,007,827	$257,093,092	$73,669,216	$17,361,388	-$7,878,553	-$497,190	$203,568	$299,439,786	$53,038,758	-$39,439	$11,235,906	$16,293,010	-$16,293,012	$6,553,139	-$538,594	$42,568	$13,603,923	-$298,894	-$642,205	
B-19 CLASS																				
B-19 FIRM T	$892,978	$752,948	$145,256	$66,931	-$30,373	-$1,917	$401	$262,970	$161,280	-$152	$43,568	$63,177	-$63,177	$16,366	-$1,968	$164	$52,445	$0	$0	
B-19 V T	$1,287,912	$676,921	$205,891	$50,169	-$22,767	-$1,437	$569	$236,074	$144,923	-$114	$32,657	$47,355	-$47,355	$12,267	-$1,475	$123	$39,311	$0	$0	
Total B-19 T	$2,180,890	$1,429,870	$351,147	$117,100	-$53,140	-$3,353	$970	$499,044	$306,204	-$266	$76,224	$110,532	-$110,532	$28,634	-$3,443	$287	$91,757	$0	$0	
B-19 FIRM P	$82,049,187	$36,616,799	$8,527,024	$2,948,179	-$1,337,876	-$84,429	$23,563	$30,531,726	$8,087,042	-$6,697	$1,919,067	$2,782,809	-$2,782,809	$863,774	-$86,692	$7,229	$2,310,115	$0	-$2,623,708	
B-19 V P	$31,502,541	$14,030,638	$3,184,974	$1,151,447	-$522,524	-$32,975	$8,801	$10,382,215	$3,187,696	-$2,616	$746,564	$1,082,581	-$1,082,581	$336,030	-$33,859	$2,823	$902,243	$0	$0	
Total B-19 P	$113,551,727	$50,647,438	$11,711,998	$4,099,626	-$1,860,400	-$117,404	$32,364	$40,913,942	$11,274,738	-$9,313	$2,665,631	$3,865,390	-$3,865,390	$1,199,804	-$120,551	$10,052	$3,212,358	$0	-$2,623,708	
B-19 FIRM S	$329,540,662	$129,582,683	$30,160,348	$8,954,218	-$4,063,401	-$256,428	$83,343	$138,268,769	$26,693,851	-$20,341	$5,828,595	$8,451,954	-$8,451,955	$2,929,199	-$263,302	$21,955	$7,016,288	$0	-$476,073	
B-19 V S	$544,695,847	$218,771,828	$44,378,046	$15,357,110	-$6,969,017	-$439,792	$122,631	$228,104,521	$43,945,079	-$34,886	$9,810,208	$14,225,628	-$14,225,629	$4,930,185	-$451,582	$37,654	$12,033,425	-$243,542	$0	
Total B-19 S	$874,236,509	$348,354,511	$74,538,394	$24,311,328	-$11,032,418	-$696,221	$205,973	$366,373,290	$70,638,930	-$55,226	$15,638,804	$22,677,582	-$22,677,584	$7,859,384	-$714,884	$59,608	$19,049,712	-$243,542	-$476,073	
B-19 T	$2,180,890	$1,429,870	$351,147	$117,100	-$53,140	-$3,353	$970	$499,044	$306,204	-$266	$76,224	$110,532	-$110,532	$28,634	-$3,443	$287	$91,757	$0	$0	
B-19 P	$113,551,727	$50,647,438	$11,711,998	$4,099,626	-$1,860,400	-$117,404	$32,364	$40,913,942	$11,274,738	-$9,313	$2,665,631	$3,865,390	-$3,865,390	$1,199,804	-$120,551	$10,052	$3,212,358	$0	-$2,623,708	
B-19 S	$874,236,509	$348,354,511	$74,538,394	$24,311,328	-$11,032,418	-$696,221	$205,973	$366,373,290	$70,638,930	-$55,226	$15,638,804	$22,677,582	-$22,677,584	$7,859,384	-$714,884	$59,608	$19,049,712	-$243,542	-$476,073	
TOTAL B-19	$989,969,126	$400,431,818	$86,601,539	$28,528,055	-$12,945,957	-$816,978	$239,308	$407,786,275	$82,219,872	-$64,805	$18,380,659	$26,653,503	-$26,653,506	$9,087,822	-$838,879	$69,947	$22,353,827	-$243,542	-$3,099,781	
STREETLIGHTS	$32,593,229	$7,792,583	$2,002,410	$667,440	-$302,883	-$18,379	$5,533	$21,147,936	$965,742	-$1,516	$434,459	$630,002	-$630,002	$280,093	-$16,325	$1,636	$512,759	$0	$0	
STANDBY																				
STANDBY T	$64,649,061	$33,164,940	$9,701,107	$3,450,458	-$1,565,809	-$102,614	$26,807	$18,973,306	$8,575,572	-$7,838	$2,246,017	$3,256,913	-$3,256,914	$775,303	-$70,685	$8,460	$2,156,616	$0	-$1,487,856	
STANDBY P	$6,468,142	$1,813,383	$482,722	$139,383	-$63,252	-$4,145	$1,334	$4,368,769	$369,014	-$317	$90,729	$131,564	-$131,564	$108,694	-$2,855	$342	$87,117	$0	-$170,713	
STANDBY S	-$1,457,640	$535,934	$121,561	$41,964	-$19,043	-$1,248	$336	$1,183,502	$120,063	-$95	$27,316	$39,610	-$39,610	$17,610	-$860	$103	$26,228	-$1,551	-$1,812,940	
TOTAL STANDBY	$69,659,563	$35,514,257	$10,305,391	$3,631,805	-$1,648,104	-$108,007	$28,477	$24,525,578	$9,064,649	-$8,250	$2,364,061	$3,428,088	-$3,428,088	$901,608	-$74,400	$8,905	$2,269,962	-$1,551	-$3,471,509	
AGRICULTURE																				
AG-A1	$80,280,665	$18,505,963	$4,398,012	$1,384,433	-$628,252	-$41,172	$12,153	$53,196,699	$4,689,856	-$3,145	$901,173	$1,306,777	-$1,306,777	$550,483	-$39,370	$3,394	$1,177,371	-$2,056,632	-$13,856	
AG-A2	$45,367,050	$13,063,249	$3,137,801	$987,736	-$448,232	-$29,374	$8,671	$25,462,552	$3,346,020	-$2,244	$642,950	$932,332	-$932,332	$392,747	-$28,089	$2,422	$840,006	-$503,610	-$3,376	
AG B	$265,453,015	$62,261,498	$12,776,937	$4,022,003	-$1,825,174	-$119,611	$35,307	$173,409,167	$15,535,156	-$9,136	$2,618,054	$3,796,399	-$3,796,399	$1,599,243	-$114,377	$9,861	$3,420,455	-$468,127	-$7,409	
AG C	$886,784,086	$272,861,798	$65,501,950	$20,619,106	-$9,356,897	-$613,195	$181,003	$470,407,847	$64,064,786	-$46,839	$13,421,655	$19,462,530	-$19,462,532	$8,198,640	-$586,362	$50,555	$17,535,225	-$379,004	-$260,518	
TOTAL AG	$1,277,884,815	$366,692,507	$85,814,700	$27,013,279	-$12,258,556	-$803,352	$237,133	$722,476,264	$87,635,818	-$61,364	$17,583,833	$25,498,038	-$25,498,040	$10,741,113	-$768,198	$66,233	$22,973,057	-$3,407,372	-$285,159	
B-20 CLASS																				
B-20 FIRM T	$162,873,065	$105,677,558	$23,687,165	$8,696,934	-$3,946,646	-$210,743	$65,455	$13,900,823	$21,461,052	-$19,756	$5,661,121	$8,209,101	-$8,209,102	$1,638,050	-$221,377	$21,324	$5,841,023	$0	-$6,006,081	
FPP T																				
TOTAL	$162,873,065	$105,677,558	$23,687,165	$8,696,934	-$3,946,646	-$210,743	$65,455	$13,900,823	$21,461,052	-$19,756	$5,661,121	$8,209,101	-$8,209,102	$1,638,050	-$221,377	$21,324	$5,841,023	$0	-$6,006,081	
B-20 FIRM P	$255,457,850	$120,224,815	$25,506,526	$9,689,405	-$4,397,027	-$234,793	$70,483	$80,674,054	$25,530,472	-$22,011	$6,307,153	$9,145,903	-$9,145,904	$2,636,082	-$251,861	$23,757	$6,507,586	$0	-$1,572,769	
FPP P																				
TOTAL	$255,457,850	$120,224,815	$25,506,526	$9,689,405	-$4,397,027	-$234,793	$70,483	$80,674,054	$25,530,472	-$22,011	$6,307,153	$9,145,903	-$9,145,904	$2,636,082	-$251,861	$23,757	$6,507,586	$0	-$1,572,769	
B-20 FIRM S	$47,721,184	$20,099,992	$4,861,834	$1,536,246	-$697,144	-$37,226	$13,435	$17,891,190	$4,065,828	-$3,490	$999,993	$1,450,074	-$1,450,074	$446,714	-$42,108	$3,767	$1,031,771	$0	-$135,880	
FPP S																				
TOTAL	$47,721,184	$20,099,992	$4,861,834	$1,536,246	-$697,144	-$37,226	$13,435	$17,891,190	$4,065,828	-$3,490	$999,993	$1,450,074	-$1,450,074	$446,714	-$42,108	$3,767	$1,031,771	$0	-$135,880	
B-20 T	$162,873,065	$105,677,558	$23,687,165	$8,696,934	-$3,946,646	-$210,743	$65,455	$13,900,823	$21,461,052	-$19,756	$5,661,121	$8,209,101	-$8,209,102	$1,638,050	-$221,377	$21,324	$5,841,023	$0	-$6,006,081	
B-20 P	$255,457,850	$120,224,815	$25,506,526	$9,689,405	-$4,397,027	-$234,793	$70,483	$80,674,054	$25,530,472	-$22,011	$6,307,153	$9,145,903	-$9,145,904	$2,636,082	-$251,861	$23,757	$6,507,586	$0	-$1,572,769	
B-20 S	$47,721,184	$20,099,992	$4,861,834	$1,536,246	-$697,144	-$37,226	$13,435	$17,891,190	$4,065,828	-$3,490	$999,993	$1,450,074	-$1,450,074	$446,714	-$42,108	$3,767	$1,031,771	$0	-$135,880	
TOTAL B-20	$466,052,098	$246,002,365	$54,055,525	$19,922,585	-$9,040,817	-$482,762	$149,373	$112,466,068	$51,057,352	-$45,257	$12,968,266	$18,805,078	-$18,805,080	$4,720,845	-$515,346	$48,848	$13,380,380	$0	-$7,714,730	
SYSTEM	**$7,748,972,835**	**$2,914,915,885**	**$845,829,811**	**$208,076,209**	**-$94,424,444**	**-$7,668,143**	**$2,337,297**	**$3,406,341,924**	**$585,744,103**	**-$472,671**	**$109,021,756**	**$161,529,483**	**-$161,529,502**	**$64,658,872**	**-$6,106,552**	**$510,179**	**$217,959,926**	**-$17,464,665**	**-$191,829,643**	**-$1,947,172**

Revenue and Average Rate Summary with GHG Revenue Return

13-AtchA-2

BDLD RESULTS Class/Schedule	PCIA Revenue	Total Proposed Revenue	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	WFC Rates	RB Rates	RBC Rates	WH 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																										
Non-CARE	$41,788,208	$2,552,261,400	5,960,717,805	$0.40800	$0.13295	$0.04638	$0.00908	-$0.00412	-$0.00043	$0.00013	$0.20088	$0.03293	-$0.00002	$0.00551	$0.00857	-$0.00857	$0.00391	-$0.00028	$0.00002	$0.01479	$0.00000	-$0.02051	-$0.00007	$0.00701	$0.42818	4.9%
CARE	$28,191,105	$911,213,138	4,021,211,547	$0.21770	$0.13037	$0.04638	$0.00908	-$0.00412	-$0.00043	$0.00013	$0.03319	$0.00999	-$0.00002	$0.00000	$0.00000	$0.00000	$0.00000	-$0.00028	$0.00002	$0.00914	$0.00000	-$0.01349	-$0.00038	$0.00701	$0.22660	4.1%
TOTAL RES	$69,979,313	$3,463,474,537	9,981,929,352	$0.33134	$0.13191	$0.04638	$0.00908	-$0.00412	-$0.00043	$0.00013	$0.13333	$0.02369	-$0.00002	$0.00329	$0.00512	-$0.00512	$0.00233	-$0.00028	$0.00002	$0.01252	$0.00000	-$0.01768	-$0.00020	$0.00701	$0.34697	4.7%
SMALL L&P																										
B-1	$11,059,290	$704,368,837	1,636,421,542	$0.40976	$0.12697	$0.03143	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.21983	$0.03004	-$0.00002	$0.00590	$0.00855	-$0.00855	$0.00405	-$0.00027	$0.00002	$0.00801	-$0.00698	-$0.00006		$0.00676	$0.43043	5.0%
B-6	$4,000,687	$250,828,694	591,973,902	$0.40306	$0.12781	$0.03146	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.21185	$0.02699	-$0.00002	$0.00589	$0.00855	-$0.00855	$0.00405	-$0.00027	$0.00002	$0.00801	-$0.00354	-$0.00006		$0.00676	$0.42372	5.1%
A-15	$5,057	$326,773	748,293	$0.41474	$0.12684	$0.03143	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.22180	$0.03008	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00406	-$0.00027	$0.00002	$0.00801	-$0.00268	$0.00000		$0.00676	$0.43669	5.3%
TC-1	$66,423	$4,161,943	9,828,512	$0.40296	$0.11412	$0.03143	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.23585	$0.01282	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00406	-$0.00027	$0.00002	$0.00801	$0.00000	$0.00000		$0.00676	$0.42346	5.1%
TOTAL SMALL	$15,131,457	$959,686,247	2,238,972,249	$0.40796	$0.12714	$0.03144	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.21779	$0.02916	-$0.00002	$0.00590	$0.00855	-$0.00855	$0.00405	-$0.00027	$0.00002	$0.00801	-$0.00604	-$0.00006		$0.00676	$0.42863	5.1%
MEDIUM L&P																										
B-10 T	$4,247	$143,439	594,451	$0.21586	$0.10307	$0.03581	$0.00908	-$0.00412	-$0.00026	$0.00010	$0.04850	$0.02699	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00224	-$0.00028	$0.00002	$0.00711	$0.00000	$0.00000		$0.00714	$0.24130	11.8%
B-10 P	$138,183	$6,865,486	19,341,510	$0.33046	$0.11844	$0.03955	$0.00908	-$0.00412	-$0.00026	$0.00011	$0.14301	$0.02679	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00317	-$0.00028	$0.00002	$0.00711	$0.00000	-$0.00069		$0.00714	$0.35496	7.4%
B-10 S	$13,519,534	$728,999,508	1,892,334,152	$0.36224	$0.13462	$0.03851	$0.00908	-$0.00412	-$0.00026	$0.00011	$0.15676	$0.02775	-$0.00002	$0.00588	$0.00852	-$0.00852	$0.00343	-$0.00028	$0.00002	$0.00711	-$0.00016	-$0.00033		$0.00714	$0.38524	6.3%
TOTAL MEDIUM	$13,661,963	$736,008,433	1,912,270,113	$0.36188	$0.13444	$0.03852	$0.00908	-$0.00412	-$0.00026	$0.00011	$0.15659	$0.02774	-$0.00002	$0.00588	$0.00852	-$0.00852	$0.00343	-$0.00028	$0.00002	$0.00711	-$0.00016	-$0.00034		$0.00714	$0.38489	6.4%
B-19 CLASS																										
B-19 FIRM T	$49,939	$1,517,860	7,372,107	$0.12113	$0.10213	$0.01970	$0.00908	-$0.00412	-$0.00026	$0.00005	$0.03567	$0.02188	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00222	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.00677	$0.20589	70.0%
B-19 V T	$37,433	$1,410,546	5,525,899	$0.23307	$0.12250	$0.03726	$0.00908	-$0.00412	-$0.00026	$0.00010	$0.04272	$0.02623	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00222	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.00677	$0.25526	9.5%
Total B-19 T	$87,372	$2,928,406	12,898,006	$0.16909	$0.11086	$0.02722	$0.00908	-$0.00412	-$0.00026	$0.00008	$0.03869	$0.02374	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00222	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.00677	$0.22704	34.3%
B-19 FIRM P	$2,199,734	$89,894,850	324,727,198	$0.25267	$0.11276	$0.02626	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.09402	$0.02490	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00266	-$0.00027	$0.00002	$0.00711	$0.00000	-$0.00808		$0.00677	$0.27683	9.6%
B-19 V P	$859,133	$34,200,592	126,826,110	$0.24839	$0.11063	$0.02511	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.08186	$0.02513	-$0.00002	$0.00589	$0.00854	-$0.00854	$0.00265	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.00677	$0.26967	8.6%
Total B-19 P	$3,058,867	$124,095,442	451,553,308	$0.25147	$0.11216	$0.02594	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.09061	$0.02497	-$0.00002	$0.00590	$0.00856	-$0.00856	$0.00266	-$0.00027	$0.00002	$0.00711	$0.00000	-$0.00581		$0.00677	$0.27482	9.3%
B-19 FIRM S	$6,681,040	$351,140,742	986,262,353	$0.33413	$0.13139	$0.03058	$0.00908	-$0.00412	-$0.00026	$0.00008	$0.14019	$0.02707	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00297	-$0.00027	$0.00002	$0.00711	$0.00000	-$0.00048		$0.00677	$0.35603	6.6%
B-19 V S	$11,458,450	$580,810,317	1,691,508,956	$0.32202	$0.12934	$0.02624	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.13485	$0.02598	-$0.00002	$0.00580	$0.00841	-$0.00841	$0.00291	-$0.00027	$0.00002	$0.00711	-$0.00014	$0.00000		$0.00677	$0.34337	6.6%
Total B-19 S	$18,139,490	$931,951,060	2,677,771,310	$0.32648	$0.13009	$0.02784	$0.00908	-$0.00412	-$0.00026	$0.00008	$0.13682	$0.02638	-$0.00002	$0.00584	$0.00847	-$0.00847	$0.00294	-$0.00027	$0.00002	$0.00711	-$0.00009	-$0.00018		$0.00677	$0.34803	6.6%
B-19 T	$87,372	$2,928,406	12,898,006	$0.16909	$0.11086	$0.02722	$0.00908	-$0.00412	-$0.00026	$0.00008	$0.03869	$0.02374	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00222	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.00677	$0.22704	34.3%
B-19 P	$3,058,867	$124,095,442	451,553,308	$0.25147	$0.11216	$0.02594	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.09061	$0.02497	-$0.00002	$0.00590	$0.00856	-$0.00856	$0.00266	-$0.00027	$0.00002	$0.00711	$0.00000	-$0.00581		$0.00677	$0.27482	9.3%
B-19 S	$18,139,490	$931,951,060	2,677,771,310	$0.32648	$0.13009	$0.02784	$0.00908	-$0.00412	-$0.00026	$0.00008	$0.13682	$0.02638	-$0.00002	$0.00584	$0.00847	-$0.00847	$0.00294	-$0.00027	$0.00002	$0.00711	-$0.00009	-$0.00018		$0.00677	$0.34803	6.6%
TOTAL B-19	$21,285,730	$1,058,974,907	3,142,222,624	$0.31505	$0.12744	$0.02756	$0.00908	-$0.00412	-$0.00026	$0.00008	$0.12978	$0.02617	-$0.00002	$0.00585	$0.00848	-$0.00848	$0.00289	-$0.00027	$0.00002	$0.00711	-$0.00008	-$0.00099		$0.00677	$0.33701	7.0%
STREETLIGHTS	$414,738	$33,886,227	73,515,226	$0.44335	$0.10600	$0.02724	$0.00908	-$0.00412	-$0.00025	$0.00008	$0.28767	$0.01314	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00381	-$0.00022	$0.00002	$0.00697	$0.00000	$0.00000		$0.00564	$0.46094	4.0%
STANDBY																										
STANDBY T	$1,798,298	$77,642,082	380,050,694	$0.17011	$0.08726	$0.02553	$0.00908	-$0.00412	-$0.00027	$0.00007	$0.04992	$0.02256	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00204	-$0.00019	$0.00002	$0.00567	$0.00000	-$0.00391		$0.00473	$0.20429	20.1%
STANDBY P	$72,643	$7,292,850	15,352,313	$0.42131	$0.11812	$0.03144	$0.00908	-$0.00412	-$0.00027	$0.00009	$0.28457	$0.02404	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00708	-$0.00019	$0.00002	$0.00567	$0.00000	-$0.01112		$0.00473	$0.47503	12.8%
STANDBY S	$21,871	$260,752	4,622,121	-$0.31536	$0.11595	$0.02630	$0.00908	-$0.00412	-$0.00027	$0.00007	$0.25605	$0.02598	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00381	-$0.00019	$0.00002	$0.00567	-$0.00034	-$0.39223		$0.00473	$0.05641	-117.9%
TOTAL STANDBY	$1,892,812	$85,195,683	400,025,127	$0.17414	$0.08878	$0.02576	$0.00908	-$0.00412	-$0.00027	$0.00007	$0.06131	$0.02266	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00225	-$0.00019	$0.00002	$0.00567	$0.00000	-$0.00868		$0.00473	$0.21298	22.3%
AGRICULTURE																										
AG-A1	$999,186	$83,036,298	152,488,397	$0.52647	$0.12136	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.34886	$0.03076	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	-$0.01349	-$0.00009		$0.00655	$0.54454	3.4%
AG-A2	$712,878	$47,582,107	108,794,221	$0.41700	$0.12007	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.23404	$0.03076	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	-$0.00463	-$0.00003		$0.00655	$0.43736	4.9%
AG B	$2,902,797	$276,046,642	443,003,493	$0.59921	$0.14054	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.39144	$0.03507	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	-$0.00106	-$0.00002		$0.00655	$0.62313	4.0%
AG C	$14,881,411	$936,481,160	2,271,091,514	$0.39047	$0.12015	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.20713	$0.02821	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	-$0.00017	-$0.00011		$0.00655	$0.41235	5.6%
TOTAL AG	$19,496,272	$1,343,146,207	2,975,377,624	$0.42949	$0.12324	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.24282	$0.02945	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	-$0.00115	-$0.00010		$0.00655	$0.45142	5.1%
B-20 CLASS																										
B-20 FIRM T	$5,622,779	$181,868,679	957,923,769	$0.17003	$0.11032	$0.02473	$0.00908	-$0.00412	-$0.00022	$0.00007	$0.01451	$0.02240	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00171	-$0.00023	$0.00002	$0.00610	$0.00000	-$0.00627		$0.00587	$0.18986	11.7%
FPP T																										
TOTAL	$5,622,779	$181,868,679	957,923,769	$0.17003	$0.11032	$0.02473	$0.00908	-$0.00412	-$0.00022	$0.00007	$0.01451	$0.02240	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00171	-$0.00023	$0.00002	$0.00610	$0.00000	-$0.00627		$0.00587	$0.18986	11.7%
B-20 FIRM P	$6,395,868	$277,087,740	1,067,239,570	$0.23936	$0.11265	$0.02390	$0.00908	-$0.00412	-$0.00022	$0.00007	$0.07559	$0.02392	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00247	-$0.00024	$0.00002	$0.00610	$0.00000	-$0.00147		$0.00599	$0.25963	8.5%
FPP P																										
TOTAL	$6,395,868	$277,087,740	1,067,239,570	$0.23936	$0.11265	$0.02390	$0.00908	-$0.00412	-$0.00022	$0.00007	$0.07559	$0.02392	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00247	-$0.00024	$0.00002	$0.00610	$0.00000	-$0.00147		$0.00599	$0.25963	8.5%
B-20 FIRM S	$1,068,926	$51,103,846	169,209,785	$0.28202	$0.11879	$0.02873	$0.00908	-$0.00412	-$0.00022	$0.00008	$0.10573	$0.02403	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00264	-$0.00025	$0.00002	$0.00610	$0.00000	-$0.00080		$0.00632	$0.30201	7.1%
FPP S																										
TOTAL	$1,068,926	$51,103,846	169,209,785	$0.28202	$0.11879	$0.02873	$0.00908	-$0.00412	-$0.00022	$0.00008	$0.10573	$0.02403	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00264	-$0.00025	$0.00002	$0.00610	$0.00000	-$0.00080		$0.00632	$0.30201	7.1%
B-20 T	$5,622,779	$181,868,679	957,923,769	$0.17003	$0.11032	$0.02473	$0.00908	-$0.00412	-$0.00022	$0.00007	$0.01451	$0.02240	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00171	-$0.00023	$0.00002	$0.00610	$0.00000	-$0.00627		$0.00587	$0.18986	11.7%
B-20 P	$6,395,868	$277,087,740	1,067,239,570	$0.23936	$0.11265	$0.02390	$0.00908	-$0.00412	-$0.00022	$0.00007	$0.07559	$0.02392	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00247	-$0.00024	$0.00002	$0.00610	$0.00000	-$0.00147		$0.00599	$0.25963	8.5%
B-20 S	$1,068,926	$51,103,846	169,209,785	$0.28202	$0.11879	$0.02873	$0.00908	-$0.00412	-$0.00022	$0.00008	$0.10573	$0.02403	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00264	-$0.00025	$0.00002	$0.00610	$0.00000	-$0.00080		$0.00632	$0.30201	7.1%
TOTAL B-20	$13,087,572	$510,060,265	2,194,373,124	$0.21239	$0.11211	$0.02463	$0.00908	-$0.00412	-$0.00022	$0.00007	$0.05125	$0.02327	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00215	-$0.00023	$0.00002	$0.00610	$0.00000	-$0.00352		$0.00596	$0.23244	9.4%
SYSTEM	**$154,949,856**	**$8,190,432,508**	**22,918,685,439**	**$0.33811**	**$0.12719**	**$0.03691**	**$0.00908**	**-$0.00412**	**-$0.00033**	**$0.00010**	**$0.14863**	**$0.02556**	**-$0.00002**	**$0.00476**	**$0.00705**	**-$0.00705**	**$0.00282**	**-$0.00027**	**$0.00002**	**$0.00951**	**-$0.00076**	**-$0.00837**	**-$0.00008**	**$0.00676**	**$0.35737**	**5.7%**

Pacific Gas & Electric Company
2027 ERRA May Application
Friday, January 1, 2027
Revenue and Average Rate Summary with GHG Revenue Return

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	WFC Revenue	RB Revenue	RBC Revenue	WH Revenue	CTC Revenue	ECRA Revenue	NSGC Revenue	Residential & Small Business AB32 Credit Revenue	Climate Credit & EITE Revenue	CIA Revenue	PCIA Revenue
RESIDENTIAL																				
Non-CARE	$4,016,313,088	$593,722,084	$116,212,988	-$52,737,153	-$5,504,120	$1,640,646	$2,423,228,356	$378,726,705	-$263,992	$73,067,747	$109,649,906	-$109,649,913	$50,049,094	-$3,537,342	$284,941	$158,340,070	$0	-$223,770,111	$59,843,464	$191,179,065
CARE	$454,536,935	$159,605,661	$31,240,628	-$14,176,916	-$1,479,630	$441,037	$163,304,064	$40,532,090	-$70,967	$0	$0	$0	$0	-$950,915	$76,598	$37,096,886	$0	-$58,438,820	-$57,896,293	$46,266,077
TOTAL RES	$4,470,850,022	$753,327,745	$147,453,616	-$66,914,068	-$6,983,750	$2,081,683	$2,586,532,420	$419,258,794	-$334,959	$73,067,747	$109,649,906	-$109,649,913	$50,049,094	-$4,488,257	$361,539	$195,436,956	$0	-$282,208,931	$1,947,172	$237,445,143
SMALL L&P																				
B-1	$1,248,468,714	$120,208,742	$34,723,618	-$15,757,488	-$1,109,144	$332,175	$815,702,596	$114,871,680	-$78,879	$22,542,687	$32,688,794	-$32,688,797	$15,487,757	-$1,018,654	$85,138	$30,642,936	-$14,081,334	-$196,734		$54,890,287
B-6	$367,456,603	$36,150,419	$10,438,677	-$4,737,045	-$333,433	$99,895	$239,713,241	$31,010,102	-$23,713	$6,767,525	$9,813,481	-$9,813,482	$4,651,017	-$306,230	$25,594	$9,211,935	-$2,572,889	-$120,607		$16,404,543
A-15	$325,304	$30,478	$8,804	-$3,995	-$281	$84	$237,560	$29,165	-$20	$5,729	$8,307	-$8,307	$3,937	-$258	$22	$7,769	-$38,564	$0		$17,348
TC-1	$9,483,312	$912,026	$263,450	-$119,553	-$8,415	$2,520	$6,532,393	$372,073	-$598	$171,488	$248,672	-$248,672	$117,812	-$7,729	$646	$232,489	$0	$0		$425,738
TOTAL SMALL	$1,625,733,932	$157,301,665	$45,434,548	-$20,618,080	-$1,451,273	$434,675	$1,062,185,791	$146,283,021	-$103,210	$29,487,429	$42,759,254	-$42,759,258	$20,260,523	-$1,332,870	$111,400	$40,095,129	-$16,692,786	-$317,341		$71,737,917
MEDIUM L&P																				
B-10 T	$312,935	$48,490	$19,827	-$8,997	-$568	$134	$71,174	$58,950	-$45	$12,906	$18,715	-$18,715	$4,892	-$615	$49	$15,536	$0	$0		$29,115
B-10 P	$12,761,466	$2,102,765	$443,164	-$201,107	-$12,691	$5,806	$6,641,602	$1,302,248	-$1,007	$286,541	$415,509	-$415,509	$153,700	-$13,748	$1,087	$347,252	$0	$0		$734,012
B-10 S	$1,263,906,920	$168,737,510	$43,702,635	-$19,832,143	-$1,251,543	$466,276	$700,238,280	$133,726,162	-$99,276	$28,335,481	$41,088,832	-$41,088,836	$16,545,674	-$1,355,766	$107,153	$34,244,226	-$541,194	-$361,171		$71,277,278
TOTAL MEDIUM	$1,276,981,321	$170,888,764	$44,165,626	-$20,042,246	-$1,264,802	$472,216	$706,951,056	$135,087,360	-$100,328	$28,634,927	$41,523,055	-$41,523,059	$16,704,266	-$1,370,129	$108,288	$34,607,013	-$541,194	-$361,171		$72,040,404
B-19 CLASS																				
B-19 FIRM T	$2,538,914	$459,913	$171,091	-$77,641	-$4,900	$1,271	$582,694	$412,270	-$389	$111,369	$161,494	-$161,494	$41,835	-$5,031	$419	$134,062	$0	$0		$253,994
B-19 V T	$709,553	$139,470	$44,538	-$20,211	-$1,275	$385	$158,556	$128,656	-$101	$28,991	$42,040	-$42,040	$10,890	-$1,310	$109	$34,899	$0	$0		$62,164
Total B-19 T	$3,248,466	$599,383	$215,629	-$97,852	-$6,175	$1,656	$741,250	$540,926	-$490	$140,360	$203,534	-$203,534	$52,726	-$6,341	$529	$168,961	$0	$0		$316,158
B-19 FIRM P	$110,344,209	$14,930,121	$5,528,728	-$2,508,923	-$158,330	$41,257	$53,364,981	$15,165,652	-$12,559	$3,598,831	$5,218,609	-$5,218,609	$1,619,838	-$162,575	$13,556	$4,332,165	$0	-$736,258		$7,135,470
B-19 V P	$55,144,693	$7,610,809	$2,688,461	-$1,220,017	-$76,991	$21,031	$25,050,875	$7,461,802	-$6,107	$1,750,008	$2,537,659	-$2,537,659	$787,681	-$79,055	$6,592	$2,106,607	$0	$0		$3,959,825
Total B-19 P	$165,488,901	$22,540,930	$8,217,190	-$3,728,939	-$235,321	$62,288	$78,415,856	$22,627,453	-$18,666	$5,348,839	$7,756,268	-$7,756,268	$2,407,519	-$241,630	$20,148	$6,438,772	$0	-$736,258		$11,095,295
B-19 FIRM S	$921,246,781	$114,479,758	$32,616,462	-$14,801,266	-$934,060	$316,344	$527,238,926	$97,102,954	-$74,092	$21,180,531	$30,713,552	-$30,713,555	$10,645,867	-$959,100	$79,971	$25,557,395	$0	-$781,350		$46,684,484
B-19 V S	$1,468,232,372	$157,868,873	$64,954,121	-$29,476,011	-$1,860,137	$436,242	$783,740,936	$187,332,896	-$147,551	$42,043,666	$60,966,855	-$60,966,861	$21,119,385	-$1,910,002	$159,259	$50,896,326	-$404,118	$0		$86,757,792
Total B-19 S	$2,389,479,152	$272,348,631	$97,570,583	-$44,277,277	-$2,794,197	$752,586	$1,310,979,861	$284,435,849	-$221,643	$63,224,196	$91,680,407	-$91,680,416	$31,765,252	-$2,869,103	$239,231	$76,453,721	-$404,118	-$781,350		$133,442,276
B-19 T	$3,248,466	$599,383	$215,629	-$97,852	-$6,175	$1,656	$741,250	$540,926	-$490	$140,360	$203,534	-$203,534	$52,726	-$6,341	$529	$168,961	$0	$0		$316,158
B-19 P	$165,488,901	$22,540,930	$8,217,190	-$3,728,939	-$235,321	$62,288	$78,415,856	$22,627,453	-$18,666	$5,348,839	$7,756,268	-$7,756,268	$2,407,519	-$241,630	$20,148	$6,438,772	$0	-$736,258		$11,095,295
B-19 S	$2,389,479,152	$272,348,631	$97,570,583	-$44,277,277	-$2,794,197	$752,586	$1,310,979,861	$284,435,849	-$221,643	$63,224,196	$91,680,407	-$91,680,416	$31,765,252	-$2,869,103	$239,231	$76,453,721	-$404,118	-$781,350		$133,442,276
TOTAL B-19	$2,558,216,520	$295,488,944	$106,003,401	-$48,104,068	-$3,035,694	$816,530	$1,390,136,967	$307,604,228	-$240,800	$68,713,396	$99,640,208	-$99,640,218	$34,225,497	-$3,117,073	$259,907	$83,061,454	-$404,118	-$1,517,608		$144,853,729
STREETLIGHTS	$52,388,401	$4,430,575	$1,476,793	-$670,165	-$40,665	$12,243	$37,935,474	$2,075,982	-$3,355	$961,293	$1,393,956	-$1,393,956	$619,740	-$36,121	$3,621	$1,134,542	$0	$0		$1,981,330
STANDBY																				
STANDBY T	$18,452,125	$3,401,553	$1,383,527	-$627,841	-$41,145	$9,400	$5,163,435	$3,438,540	-$3,143	$900,584	$1,305,922	-$1,305,922	$310,873	-$28,343	$3,392	$864,737	$0	$0		$1,491,706
STANDBY P	$3,902,251	$315,984	$64,698	-$29,360	-$1,924	$873	$3,290,676	$171,287	-$147	$42,114	$61,069	-$61,069	$50,453	-$1,325	$159	$40,438	$0	-$34,183		$45,135
STANDBY S	$746,611	$62,424	$25,237	-$11,453	-$751	$172	$468,251	$72,206	-$57	$16,428	$23,821	-$23,821	$10,591	-$517	$62	$15,774	-$870	$0		$25,632
TOTAL STANDBY	$23,100,986	$3,779,961	$1,473,462	-$668,653	-$43,820	$10,445	$8,922,362	$3,682,033	-$3,347	$959,125	$1,390,812	-$1,390,812	$371,917	-$30,185	$3,613	$920,948	-$870	-$34,183		$1,562,473
AGRICULTURE																				
AG-A1	$31,458,334	$2,126,085	$669,262	-$303,709	-$19,903	$5,875	$24,050,945	$2,267,168	-$1,520	$435,645	$631,721	-$631,721	$266,114	-$19,032	$1,641	$569,164	-$468,223	-$4,647		$936,150
AG-A2	$16,048,529	$1,539,609	$484,648	-$219,932	-$14,413	$4,254	$10,496,733	$1,641,775	-$1,101	$315,473	$457,463	-$457,463	$192,707	-$13,782	$1,188	$412,162	-$93,292	-$5,257		$675,120
AG B	$72,219,821	$5,118,289	$1,611,166	-$731,143	-$47,915	$14,143	$53,520,729	$6,223,199	-$3,660	$1,048,761	$1,520,792	-$1,520,792	$640,638	-$45,818	$3,950	$1,370,194	-$88,537	-$5,965		$2,234,053
AG C	$360,484,446	$42,088,449	$13,248,861	-$6,012,299	-$394,010	$116,304	$213,395,631	$41,164,995	-$30,096	$8,624,120	$12,505,700	-$12,505,701	$5,268,058	-$376,768	$32,485	$11,267,304	-$38,676	-$595,073		$18,264,907
TOTAL AG	$480,211,130	$50,872,432	$16,013,937	-$7,267,083	-$476,241	$140,577	$301,464,038	$51,297,137	-$36,378	$10,423,999	$15,115,676	-$15,115,677	$6,367,517	-$455,401	$39,264	$13,618,824	-$688,728	-$610,942		$22,110,229
B-20 CLASS																				
B-20 FIRM T	$343,698,248	$85,467,140	$33,883,754	-$15,376,359	-$821,068	$236,173	$44,715,020	$83,613,493	-$76,971	$20,691,482	$30,004,391	-$30,004,394	$6,381,936	-$862,497	$83,079	$22,756,962	$0	-$13,538,816		$34,777,079
FPP T	$10,123,742	$0	$0	$0	$0	$0	$3,640,529	$6,469,848	-$5,956	$0	$2,474,792	-$2,474,792	$493,822	$0	$0	$0	$0	$0		$0
TOTAL	$353,821,990	$85,467,140	$33,883,754	-$15,376,359	-$821,068	$236,173	$48,355,549	$90,083,341	-$82,927	$20,691,482	$32,479,183	-$32,479,186	$6,875,757	-$862,497	$83,079	$22,756,962	$0	-$13,538,816		$34,777,079
B-20 FIRM P	$933,306,332	$137,754,219	$53,779,505	-$24,405,000	-$1,303,180	$380,659	$421,795,680	$141,702,827	-$122,167	$35,006,851	$50,762,880	-$50,762,885	$14,631,153	-$1,397,912	$131,860	$36,119,321	$0	-$3,450,214		$55,064,682
FPP P	$2,198,597	$0	$0	$0	$0	$0	$1,705,528	$468,061	-$404	$0	$167,676	-$167,676	$48,328	$0	$0	$0	$0	$0		$0
TOTAL	$935,504,929	$137,754,219	$53,779,505	-$24,405,000	-$1,303,180	$380,659	$423,501,208	$142,170,889	-$122,570	$35,006,851	$50,930,556	-$50,930,561	$14,679,481	-$1,397,912	$131,860	$36,119,321	$0	-$3,450,214		$55,064,682
B-20 FIRM S	$378,726,783	$51,758,477	$19,144,218	-$8,687,596	-$463,901	$143,025	$184,571,393	$50,667,085	-$43,488	$12,461,602	$18,070,372	-$18,070,374	$5,566,809	-$524,740	$46,939	$12,857,615	$0	-$289,221		$21,955,569
FPP S	$5,209,643	$0	$0	$0	$0	$0	$3,868,521	$1,241,044	-$1,065	$0	$442,617	-$442,617	$136,354	$0	$0	$0	$0	$0		$0
TOTAL	$383,936,426	$51,758,477	$19,144,218	-$8,687,596	-$463,901	$143,025	$188,439,914	$51,908,129	-$44,554	$12,461,602	$18,512,989	-$18,512,991	$5,703,163	-$524,740	$46,939	$12,857,615	$0	-$289,221		$21,955,569
B-20 T	$353,821,990	$85,467,140	$33,883,754	-$15,376,359	-$821,068	$236,173	$48,355,549	$90,083,341	-$82,927	$20,691,482	$32,479,183	-$32,479,186	$6,875,757	-$862,497	$83,079	$22,756,962	$0	-$13,538,816		$34,777,079
B-20 P	$935,504,929	$137,754,219	$53,779,505	-$24,405,000	-$1,303,180	$380,659	$423,501,208	$142,170,889	-$122,570	$35,006,851	$50,930,556	-$50,930,561	$14,679,481	-$1,397,912	$131,860	$36,119,321	$0	-$3,450,214		$55,064,682
B-20 S	$383,936,426	$51,758,477	$19,144,218	-$8,687,596	-$463,901	$143,025	$188,439,914	$51,908,129	-$44,554	$12,461,602	$18,512,989	-$18,512,991	$5,703,163	-$524,740	$46,939	$12,857,615	$0	-$289,221		$21,955,569
TOTAL B-20	$1,673,263,345	$274,979,835	$106,807,476	-$48,468,956	-$2,588,148	$759,857	$660,296,671	$284,162,359	-$250,051	$68,159,935	$101,922,728	-$101,922,738	$27,258,402	-$2,785,148	$261,878	$71,733,897	$0	-$17,278,251		$111,797,330
SYSTEM	**$12,160,745,658**	**$1,711,069,921**	**$468,828,860**	**-$212,753,320**	**-$15,884,392**	**$4,728,226**	**$6,754,424,778**	**$1,349,450,914**	**-$1,072,427**	**$280,407,851**	**$413,395,596**	**-$413,395,632**	**$155,856,956**	**-$13,615,185**	**$1,149,510**	**$440,608,764**	**-$18,327,696**	**-$302,328,427**	**$1,947,172**	**$663,528,555**

13-AtchA-3

Pacific Gas & Electric Company
2027 ERRA May Application
Friday, January 1, 2027
Revenue and Average Rate Summary with GHG Revenue Return

DA/CCA RESULTS

Class/Schedule	Total Proposed Revenue	Total Sales (kWh)	Revenue At Present Rates	TO Rates	TAC Rates	TRBAA Rates	T-ECRA Rates	RS Rates	Dist Rates	PPP Rates	ND Rates	WFC Rates	RB Rates	RB Credit Rates	WH 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																								
Non-CARE	$3,760,482,435	$12,800,338,582	$0.31377	$0.04638	$0.00908	-$0.00412	-$0.00043	$0.00013	$0.18931	$0.02959	-$0.00002	$0.00571	$0.00857	-$0.00857	$0.00391	-$0.00028	$0.00002	$0.01237	$0.00000	-$0.01748	$0.00468	$0.01494	$0.29378	-6.4%
CARE	$345,549,500	$3,441,011,083	$0.13209	$0.04638	$0.00908	-$0.00412	-$0.00043	$0.00013	$0.04746	$0.01178	-$0.00002	$0.00000	$0.00000	$0.00000	$0.00000	-$0.00028	$0.00002	$0.01078	$0.00000	-$0.01698	-$0.01683	$0.01345	$0.10042	-24.0%
TOTAL RES	$4,106,031,935	$16,241,349,665	$0.27528	$0.04638	$0.00908	-$0.00412	-$0.00043	$0.00013	$0.15926	$0.02581	-$0.00002	$0.00450	$0.00675	-$0.00675	$0.00308	-$0.00028	$0.00002	$0.01203	$0.00000	-$0.01738	$0.00012	$0.01462	$0.25281	-8.2%
SMALL L&P																								
B-1	$1,177,245,383	3,824,632,939	$0.32643	$0.03143	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.21328	$0.03003	-$0.00002	$0.00589	$0.00855	-$0.00855	$0.00405	-$0.00027	$0.00002	$0.00801	-$0.00368	-$0.00005		$0.01435	$0.30781	-5.7%
B-6	$346,379,033	1,149,768,119	$0.31959	$0.03144	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.20849	$0.02697	-$0.00002	$0.00589	$0.00854	-$0.00854	$0.00405	-$0.00027	$0.00002	$0.00801	-$0.00224	-$0.00010		$0.01427	$0.30126	-5.7%
A-15	$297,778	969,694	$0.33547	$0.03143	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.24498	$0.03008	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00406	-$0.00027	$0.00002	$0.00801	-$0.03977	$0.00000		$0.01789	$0.30708	-8.5%
TC-1	$8,894,340	29,017,651	$0.32681	$0.03143	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.22512	$0.01282	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00406	-$0.00027	$0.00002	$0.00801	$0.00000	$0.00000		$0.01467	$0.30651	-6.2%
TOTAL SMALL	$1,532,816,533	5,004,388,403	$0.32486	$0.03143	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.21225	$0.02923	-$0.00002	$0.00589	$0.00854	-$0.00854	$0.00405	-$0.00027	$0.00002	$0.00801	-$0.00334	-$0.00006		$0.01434	$0.30629	-5.7%
MEDIUM L&P																								
B-10 T	$250,846	2,183,805	$0.14330	$0.02220	$0.00908	-$0.00412	-$0.00026	$0.00006	$0.03259	$0.02699	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00224	-$0.00028	$0.00002	$0.00711	$0.00000	$0.00000		$0.01333	$0.11487	-19.8%
B-10 P	$11,789,623	48,812,294	$0.26144	$0.04308	$0.00908	-$0.00412	-$0.00026	$0.00012	$0.13606	$0.02668	-$0.00002	$0.00587	$0.00851	-$0.00851	$0.00315	-$0.00028	$0.00002	$0.00711	$0.00000	$0.00000		$0.01504	$0.24153	-7.6%
B-10 S	$1,173,939,577	4,813,626,823	$0.26257	$0.03505	$0.00908	-$0.00412	-$0.00026	$0.00010	$0.14547	$0.02778	-$0.00002	$0.00589	$0.00854	-$0.00854	$0.00344	-$0.00028	$0.00002	$0.00711	-$0.00011	-$0.00008		$0.01481	$0.24388	-7.1%
TOTAL MEDIUM	$1,185,980,046	4,864,622,922	$0.26250	$0.03513	$0.00908	-$0.00412	-$0.00026	$0.00010	$0.14532	$0.02777	-$0.00002	$0.00589	$0.00854	-$0.00854	$0.00343	-$0.00028	$0.00002	$0.00711	-$0.00011	-$0.00007		$0.01481	$0.24380	-7.1%
B-19 CLASS																								
B-19 FIRM T	$2,080,958	18,844,790	$0.13473	$0.02441	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.03092	$0.02188	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00222	-$0.00027	$0.00002	$0.00711	$0.00000			$0.01348	$0.11043	-18.0%
B-19 V T	$585,761	4,905,627	$0.14464	$0.02843	$0.00908	-$0.00412	-$0.00026	$0.00008	$0.03232	$0.02623	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00222	-$0.00027	$0.00002	$0.00711	$0.00000			$0.01267	$0.11941	-17.4%
Total B-19 T	$2,666,719	23,750,418	$0.13678	$0.02524	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.03121	$0.02278	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00222	-$0.00027	$0.00002	$0.00711	$0.00000			$0.01331	$0.11228	-17.9%
B-19 FIRM P	$102,151,954	608,961,804	$0.18120	$0.02452	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.08763	$0.02490	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00266	-$0.00027	$0.00002	$0.00711	$0.00000	-$0.00121		$0.01172	$0.16775	-7.4%
B-19 V P	$50,061,520	296,120,586	$0.18622	$0.02570	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.08460	$0.02520	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00266	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.01337	$0.16906	-9.2%
Total B-19 P	$152,213,474	905,082,389	$0.18284	$0.02490	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.08664	$0.02500	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00266	-$0.00027	$0.00002	$0.00711	$0.00000	-$0.00081		$0.01226	$0.16818	-8.0%
B-19 FIRM S	$858,352,819	3,592,540,254	$0.25643	$0.03187	$0.00908	-$0.00412	-$0.00026	$0.00009	$0.14676	$0.02703	-$0.00002	$0.00590	$0.00855	-$0.00855	$0.00296	-$0.00027	$0.00002	$0.00711	$0.00000	-$0.00022		$0.01299	$0.23893	-6.8%
B-19 V S	$1,361,511,670	7,154,371,703	$0.20522	$0.02207	$0.00908	-$0.00412	-$0.00026	$0.00006	$0.10955	$0.02618	-$0.00002	$0.00588	$0.00852	-$0.00852	$0.00295	-$0.00027	$0.00002	$0.00711	-$0.00006	$0.00000		$0.01213	$0.19030	-7.3%
Total B-19 S	$2,219,864,489	10,746,911,957	$0.22234	$0.02534	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.12199	$0.02647	-$0.00002	$0.00588	$0.00853	-$0.00853	$0.00296	-$0.00027	$0.00002	$0.00711	-$0.00004	-$0.00007		$0.01242	$0.20656	-7.1%
B-19 T	$2,666,719	23,750,418	$0.13678	$0.02524	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.03121	$0.02278	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00222	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.01331	$0.11228	-17.9%
B-19 P	$152,213,474	905,082,389	$0.18284	$0.02490	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.08664	$0.02500	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00266	-$0.00027	$0.00002	$0.00711	$0.00000	-$0.00081		$0.01226	$0.16818	-8.0%
B-19 S	$2,219,864,489	10,746,911,957	$0.22234	$0.02534	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.12199	$0.02647	-$0.00002	$0.00588	$0.00853	-$0.00853	$0.00296	-$0.00027	$0.00002	$0.00711	-$0.00004	-$0.00007		$0.01242	$0.20656	-7.1%
TOTAL B-19	$2,374,744,683	11,675,744,764	$0.21911	$0.02531	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.11906	$0.02635	-$0.00002	$0.00589	$0.00853	-$0.00853	$0.00293	-$0.00027	$0.00002	$0.00711	-$0.00003	-$0.00013		$0.01241	$0.20339	-7.2%
STREETLIGHTS	$49,881,288	162,661,392	$0.32207	$0.02724	$0.00908	-$0.00412	-$0.00025	$0.00008	$0.23322	$0.01276	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00381	-$0.00022	$0.00002	$0.00697	$0.00000	$0.00000		$0.01218	$0.30666	-4.8%
STANDBY																								
STANDBY T	$16,267,275	152,388,622	$0.12109	$0.02232	$0.00908	-$0.00412	-$0.00027	$0.00006	$0.03388	$0.02256	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00204	-$0.00019	$0.00002	$0.00567	$0.00000	$0.00000		$0.00979	$0.10675	-11.8%
STANDBY P	$3,954,878	7,126,171	$0.54759	$0.04434	$0.00908	-$0.00412	-$0.00027	$0.00012	$0.46177	$0.02404	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00708	-$0.00019	$0.00002	$0.00567	$0.00000	-$0.00480		$0.00633	$0.55498	1.3%
STANDBY S	$683,129	2,779,734	$0.26859	$0.02246	$0.00908	-$0.00412	-$0.00027	$0.00006	$0.16845	$0.02598	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00381	-$0.00019	$0.00002	$0.00567	-$0.00031	$0.00000		$0.00922	$0.24575	-8.5%
TOTAL STANDBY	$20,905,282	162,294,527	$0.14234	$0.02329	$0.00908	-$0.00412	-$0.00027	$0.00006	$0.05498	$0.02269	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00229	-$0.00019	$0.00002	$0.00567	-$0.00001	-$0.00021		$0.00963	$0.12881	-9.5%
AGRICULTURE																								
AG-A1	$30,511,013	73,715,858	$0.42675	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.32627	$0.03076	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	-$0.00635	-$0.00006		$0.01270	$0.41390	-3.0%
AG-A2	$15,415,892	53,381,516	$0.30064	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.19664	$0.03076	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	-$0.00175	-$0.00010		$0.01265	$0.28879	-3.9%
AG B	$70,862,085	177,461,934	$0.40696	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.30159	$0.03507	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	-$0.00050	-$0.00003		$0.01259	$0.39931	-1.9%
AG C	$346,024,190	1,459,295,785	$0.24703	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.14623	$0.02821	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	-$0.00003	-$0.00041		$0.01252	$0.23712	-4.0%
TOTAL AG	$462,813,179	$1,763,855,093	$0.27225	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.17091	$0.02908	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	-$0.00039	-$0.00035		$0.01254	$0.26239	-3.6%
B-20 CLASS																								
B-20 FIRM T	$301,930,402	3,732,126,080	$0.09209	$0.02290	$0.00908	-$0.00412	-$0.00022	$0.00006	$0.01198	$0.02240	-$0.00002	$0.00554	$0.00804	-$0.00804	$0.00171	-$0.00023	$0.00002	$0.00610	-$0.00363	-$0.00363		$0.00932	$0.08090	-12.2%
FPP T	$10,598,243	288,784,612	$0.03506	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.01261	$0.02240	-$0.00002	$0.00000	$0.00857	-$0.00857	$0.00171	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		$0.00000	$0.03670	4.7%
TOTAL	$312,528,646	4,020,910,692	$0.08800	$0.02126	$0.00843	-$0.00382	-$0.00020	$0.00006	$0.01203	$0.02240	-$0.00002	$0.00515	$0.00808	-$0.00808	$0.00171	-$0.00021	$0.00002	$0.00566	$0.00000	-$0.00337		$0.00865	$0.07773	-11.7%
B-20 FIRM P	$865,688,278	5,923,543,603	$0.15756	$0.02326	$0.00908	-$0.00412	-$0.00022	$0.00006	$0.07121	$0.02392	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00247	-$0.00024	$0.00002	$0.00610	$0.00000	-$0.00058		$0.00930	$0.14614	-7.2%
FPP P	$2,221,515	19,566,176	$0.11237	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.08717	$0.02392	-$0.00002	$0.00000	$0.00857	-$0.00857	$0.00247	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		$0.00000	$0.11354	1.0%
TOTAL	$867,909,793	5,943,109,778	$0.15741	$0.02318	$0.00905	-$0.00411	-$0.00022	$0.00006	$0.07126	$0.02392	-$0.00002	$0.00589	$0.00857	-$0.00857	$0.00247	-$0.00024	$0.00002	$0.00608	$0.00000	-$0.00058		$0.00927	$0.14604	-7.2%
B-20 FIRM S	$349,163,784	2,108,639,914	$0.17961	$0.02455	$0.00908	-$0.00412	-$0.00022	$0.00007	$0.08753	$0.02403	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00264	-$0.00025	$0.00002	$0.00610	$0.00000	-$0.00014		$0.01041	$0.16559	-7.8%
FPP S	$5,244,854	51,649,213	$0.10087	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.07490	$0.02403	-$0.00002	$0.00000	$0.00857	-$0.00857	$0.00264	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		$0.00000	$0.10155	0.7%
TOTAL	$354,408,638	2,160,289,127	$0.17772	$0.02396	$0.00886	-$0.00402	-$0.00021	$0.00007	$0.08723	$0.02403	-$0.00002	$0.00577	$0.00857	-$0.00857	$0.00264	-$0.00024	$0.00002	$0.00595	$0.00000	-$0.00013		$0.01016	$0.16406	-7.7%
B-20 T	$312,528,646	4,020,910,692	$0.08800	$0.02126	$0.00843	-$0.00382	-$0.00020	$0.00006	$0.01203	$0.02240	-$0.00002	$0.00515	$0.00808	-$0.00808	$0.00171	-$0.00021	$0.00002	$0.00566	$0.00000	-$0.00337		$0.00865	$0.07773	-11.7%
B-20 P	$867,909,793	5,943,109,778	$0.15741	$0.02318	$0.00905	-$0.00411	-$0.00022	$0.00006	$0.07126	$0.02392	-$0.00002	$0.00589	$0.00857	-$0.00857	$0.00247	-$0.00024	$0.00002	$0.00608	$0.00000	-$0.00058		$0.00927	$0.14604	-7.2%
B-20 S	$354,408,638	2,160,289,127	$0.17772	$0.02396	$0.00886	-$0.00402	-$0.00021	$0.00007	$0.08723	$0.02403	-$0.00002	$0.00577	$0.00857	-$0.00857	$0.00264	-$0.00024	$0.00002	$0.00595	$0.00000	-$0.00013		$0.01016	$0.16406	-7.7%
TOTAL B-20	$1,534,847,077	12,124,309,597	$0.13801	$0.02268	$0.00881	-$0.00400	-$0.00021	$0.00006	$0.05446	$0.02344	-$0.00002	$0.00562	$0.00841	-$0.00841	$0.00225	-$0.00023	$0.00002	$0.00592	$0.00000	-$0.00143		$0.00922	$0.12659	-8.3%
SYSTEM	**$11,268,020,023**	**51,999,226,364**	**$0.23386**	**$0.03291**	**$0.00902**	**-$0.00409**	**-$0.00031**	**$0.00009**	**$0.12989**	**$0.02595**	**-$0.00002**	**$0.00539**	**$0.00795**	**-$0.00795**	**$0.00300**	**-$0.00026**	**$0.00002**	**$0.00847**	**-$0.00035**	**-$0.00581**	**$0.00004**	**$0.01276**	**$0.21670**	**-7.3%**

13-AtchA-4

13-AtchA-5

Pacific Gas & Electric Company
2027 ERRA May Application
Friday, January 1, 2027
Revenue and Average Rate Summary without GHG Revenue Return

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	WFC Revenue
RESIDENTIAL											
Non-CARE	$2,537,902,374	$792,471,628	$276,478,302	$54,116,851	-$24,558,087	-$2,563,101	$763,996	$1,197,412,849	$196,313,657	-$122,933	$32,855,215
CARE	$922,443,183	$524,265,420	$186,512,676	$36,507,309	-$16,566,922	-$1,729,072	$515,398	$133,463,933	$40,169,551	-$82,931	$0
TOTAL RES	$3,460,345,557	$1,316,737,048	$462,990,978	$90,624,160	-$41,125,009	-$4,292,173	$1,279,394	$1,330,876,782	$236,483,208	-$205,865	$32,855,215
SMALL L&P											
B-1	$679,607,711	$207,774,505	$51,436,531	$14,856,975	-$6,742,057	-$474,562	$142,136	$359,731,876	$49,153,242	-$33,749	$9,647,211
B-6	$239,952,550	$75,661,174	$18,621,091	$5,374,496	-$2,438,932	-$171,672	$51,456	$125,407,300	$15,976,931	-$12,209	$3,489,638
A-15	$312,174	$94,913	$23,519	$6,794	-$3,083	-$217	$65	$165,970	$22,506	-$15	$4,422
TC-1	$3,960,531	$1,121,622	$308,910	$89,232	-$40,493	-$2,850	$854	$2,318,088	$126,024	-$203	$58,084
TOTAL SMALL	$923,832,965	$284,652,214	$70,390,052	$20,327,498	-$9,224,566	-$649,302	$194,510	$487,623,234	$65,278,704	-$46,176	$13,199,356
MEDIUM L&P											
B-10 T	$128,319	$61,267	$21,286	$5,397	-$2,449	-$155	$59	$28,832	$16,047	-$12	$3,513
B-10 P	$6,446,486	$2,290,743	$764,898	$175,600	-$79,687	-$5,029	$2,110	$2,766,040	$518,114	-$399	$114,304
B-10 S	$686,541,967	$254,741,081	$72,883,032	$17,180,391	-$7,796,417	-$492,007	$201,399	$296,644,914	$52,504,598	-$39,027	$11,118,089
TOTAL MEDIUM	$693,116,773	$257,093,092	$73,669,216	$17,361,388	-$7,878,553	-$497,190	$203,568	$299,439,786	$53,038,758	-$39,439	$11,235,906
B-19 CLASS											
B-19 FIRM T	$1,357,535	$752,948	$145,256	$66,931	-$30,373	-$1,917	$401	$262,970	$161,280	-$152	$43,568
B-19 V T	$1,287,912	$676,921	$205,891	$50,169	-$22,767	-$1,437	$569	$236,074	$144,923	-$114	$32,657
Total B-19 T	$2,645,446	$1,429,870	$351,147	$117,100	-$53,140	-$3,353	$970	$499,044	$306,204	-$266	$76,224
B-19 FIRM P	$85,582,865	$36,616,799	$8,527,024	$2,948,179	-$1,337,876	-$84,429	$23,563	$30,531,726	$8,087,042	-$6,697	$1,919,067
B-19 V P	$31,502,541	$14,030,638	$3,184,974	$1,151,447	-$522,524	-$32,975	$8,801	$10,382,215	$3,187,696	-$2,616	$746,564
Total B-19 P	$117,085,405	$50,647,438	$11,711,998	$4,099,626	-$1,860,400	-$117,404	$32,364	$40,913,942	$11,274,738	-$9,313	$2,665,631
B-19 FIRM S	$330,313,664	$129,582,683	$30,160,348	$8,954,218	-$4,063,401	-$256,428	$83,343	$138,268,769	$26,693,851	-$20,341	$5,828,595
B-19 V S	$544,867,876	$218,771,828	$44,378,046	$15,357,110	-$6,969,017	-$439,792	$122,631	$228,104,521	$43,945,079	-$34,886	$9,810,208
Total B-19 S	$875,181,541	$348,354,511	$74,538,394	$24,311,328	-$11,032,418	-$696,221	$205,973	$366,373,290	$70,638,930	-$55,226	$15,638,804
B-19 T	$2,645,446	$1,429,870	$351,147	$117,100	-$53,140	-$3,353	$970	$499,044	$306,204	-$266	$76,224
B-19 P	$117,085,405	$50,647,438	$11,711,998	$4,099,626	-$1,860,400	-$117,404	$32,364	$40,913,942	$11,274,738	-$9,313	$2,665,631
B-19 S	$875,181,541	$348,354,511	$74,538,394	$24,311,328	-$11,032,418	-$696,221	$205,973	$366,373,290	$70,638,930	-$55,226	$15,638,804
TOTAL B-19	$994,912,392	$400,431,818	$86,601,539	$28,528,055	-$12,945,957	-$816,978	$239,308	$407,786,275	$82,219,872	-$64,805	$18,380,659
STREETLIGHTS	$32,593,229	$7,792,583	$2,002,410	$667,440	-$302,883	-$18,379	$5,533	$21,147,936	$965,742	-$1,516	$434,459
STANDBY											
STANDBY T	$73,592,599	$33,164,940	$9,701,107	$3,450,458	-$1,565,809	-$102,614	$26,807	$18,973,306	$8,575,572	-$7,838	$2,246,017
STANDBY P	$7,297,881	$1,813,383	$482,722	$139,383	-$63,252	-$4,145	$1,334	$4,368,769	$369,014	-$317	$90,729
STANDBY S	$2,021,253	$535,934	$121,561	$41,964	-$19,043	-$1,248	$336	$1,183,502	$120,063	-$95	$27,316
TOTAL STANDBY	$82,911,733	$35,514,257	$10,305,391	$3,631,805	-$1,648,104	-$108,007	$28,477	$24,525,578	$9,064,649	-$8,250	$2,364,061
AGRICULTURE											
AG-A1	$81,858,443	$18,505,963	$4,398,012	$1,384,433	-$628,252	-$41,172	$12,153	$53,196,699	$4,689,856	-$3,145	$901,173
AG-A2	$45,758,675	$13,063,249	$3,137,801	$987,736	-$448,232	-$29,374	$8,671	$25,462,552	$3,346,020	-$2,244	$642,950
AG B	$265,736,882	$62,261,498	$12,776,937	$4,022,003	-$1,825,174	-$119,611	$35,307	$173,409,167	$15,535,156	-$9,136	$2,618,054
AG C	$887,381,025	$272,861,798	$65,501,950	$20,619,106	-$9,356,897	-$613,195	$181,003	$470,407,847	$64,064,786	-$46,839	$13,421,655
TOTAL AG	$1,280,735,024	$366,692,507	$85,814,700	$27,013,279	-$12,258,556	-$803,352	$237,133	$722,476,264	$87,635,818	-$61,364	$17,583,833
B-20 CLASS											
B-20 FIRM T	$169,032,248	$105,677,558	$23,687,165	$8,696,934	-$3,946,646	-$210,743	$65,455	$13,900,823	$21,461,052	-$19,756	$5,661,121
FPP T											
TOTAL	$169,032,248	$105,677,558	$23,687,165	$8,696,934	-$3,946,646	-$210,743	$65,455	$13,900,823	$21,461,052	-$19,756	$5,661,121
B-20 FIRM P	$258,105,094	$120,224,815	$25,506,526	$9,689,405	-$4,397,027	-$234,793	$70,483	$80,674,054	$25,530,472	-$22,011	$6,307,153
FPP P											
TOTAL	$258,105,094	$120,224,815	$25,506,526	$9,689,405	-$4,397,027	-$234,793	$70,483	$80,674,054	$25,530,472	-$22,011	$6,307,153
B-20 FIRM S	$47,937,335	$20,099,992	$4,861,834	$1,536,246	-$697,144	-$37,226	$13,435	$17,891,190	$4,065,828	-$3,490	$999,993
FPP S											
TOTAL	$47,937,335	$20,099,992	$4,861,834	$1,536,246	-$697,144	-$37,226	$13,435	$17,891,190	$4,065,828	-$3,490	$999,993
B-20 T	$169,032,248	$105,677,558	$23,687,165	$8,696,934	-$3,946,646	-$210,743	$65,455	$13,900,823	$21,461,052	-$19,756	$5,661,121
B-20 P	$258,105,094	$120,224,815	$25,506,526	$9,689,405	-$4,397,027	-$234,793	$70,483	$80,674,054	$25,530,472	-$22,011	$6,307,153
B-20 S	$47,937,335	$20,099,992	$4,861,834	$1,536,246	-$697,144	-$37,226	$13,435	$17,891,190	$4,065,828	-$3,490	$999,993
TOTAL B-20	$475,074,676	$246,002,365	$54,055,525	$19,922,585	-$9,040,817	-$482,762	$149,373	$112,466,068	$51,057,352	-$45,257	$12,968,266
SYSTEM	**$7,943,522,350**	**$2,914,915,885**	**$845,829,811**	**$208,076,209**	**-$94,424,444**	**-$7,668,143**	**$2,337,297**	**$3,406,341,924**	**$585,744,103**	**-$472,671**	**$109,021,756**

Class/Schedule	RB Revenue	RBC Revenue	WH 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											
Non-CARE	$51,081,587	-$51,081,596	$23,306,340	-$1,647,230	$132,688	$88,161,205	$0	$0	-$414,979	$41,788,208	$2,674,494,599
CARE	$0	$0	$0	-$1,111,252	$89,514	$36,766,179	$0	$0	-$1,532,193	$28,191,105	$965,458,716
TOTAL RES	$51,081,587	-$51,081,596	$23,306,340	-$2,758,482	$222,202	$124,927,384	$0	$0	-$1,947,172	$69,979,313	$3,639,953,315
SMALL L&P											
B-1	$13,989,268	-$13,989,270	$6,627,601	-$435,845	$36,427	$13,110,999	$0	$0		$11,059,290	$715,890,578
B-6	$5,060,269	-$5,060,269	$2,397,369	-$157,667	$13,178	$4,742,891	$0	$0		$4,000,687	$252,955,732
A-15	$6,413	-$6,413	$3,038	-$199	$17	$5,995	$0	$0		$5,057	$328,782
TC-1	$84,227	-$84,227	$39,904	-$2,618	$219	$78,746	$0	$0		$66,423	$4,161,943
TOTAL SMALL	$19,140,177	-$19,140,179	$9,067,912	-$596,329	$49,840	$17,938,632	$0	$0		$15,131,457	$973,337,035
MEDIUM L&P											
B-10 T	$5,094	-$5,094	$1,332	-$167	$13	$4,229	$0	$0		$4,247	$143,439
B-10 P	$165,751	-$165,751	$61,313	-$5,448	$431	$137,596	$0	$0		$138,183	$6,878,769
B-10 S	$16,122,165	-$16,122,167	$6,490,495	-$532,979	$42,124	$13,462,099	$0	$0		$13,519,534	$729,927,323
TOTAL MEDIUM	$16,293,010	-$16,293,012	$6,553,139	-$538,594	$42,568	$13,603,923	$0	$0		$13,661,963	$736,949,532
B-19 CLASS											
B-19 FIRM T	$63,177	-$63,177	$16,366	-$1,968	$164	$52,445	$0	$0		$49,939	$1,517,860
B-19 V T	$47,355	-$47,355	$12,267	-$1,475	$123	$39,311	$0	$0		$37,433	$1,410,546
Total B-19 T	$110,532	-$110,532	$28,634	-$3,443	$287	$91,757	$0	$0		$87,372	$2,928,406
B-19 FIRM P	$2,782,809	-$2,782,809	$863,774	-$86,692	$7,229	$2,310,115	$0	$0		$2,199,734	$92,518,558
B-19 V P	$1,082,581	-$1,082,581	$336,030	-$33,859	$2,823	$902,243	$0	$0		$859,133	$34,200,592
Total B-19 P	$3,865,390	-$3,865,390	$1,199,804	-$120,551	$10,052	$3,212,358	$0	$0		$3,058,867	$126,719,150
B-19 FIRM S	$8,451,954	-$8,451,955	$2,929,199	-$263,302	$21,955	$7,016,288	$0	$0		$6,681,040	$351,616,815
B-19 V S	$14,225,628	-$14,225,629	$4,930,185	-$451,582	$37,654	$12,033,425	$0	$0		$11,458,450	$581,053,859
Total B-19 S	$22,677,582	-$22,677,584	$7,859,384	-$714,884	$59,608	$19,049,712	$0	$0		$18,139,490	$932,670,674
B-19 T	$110,532	-$110,532	$28,634	-$3,443	$287	$91,757	$0	$0		$87,372	$2,928,406
B-19 P	$3,865,390	-$3,865,390	$1,199,804	-$120,551	$10,052	$3,212,358	$0	$0		$3,058,867	$126,719,150
B-19 S	$22,677,582	-$22,677,584	$7,859,384	-$714,884	$59,608	$19,049,712	$0	$0		$18,139,490	$932,670,674
TOTAL B-19	$26,653,503	-$26,653,506	$9,087,822	-$838,879	$69,947	$22,353,827	$0	$0		$21,285,730	$1,062,318,230
STREETLIGHTS	$630,002	-$630,002	$280,093	-$16,325	$1,636	$512,759	$0	$0		$414,738	$33,886,227
STANDBY											
STANDBY T	$3,256,913	-$3,256,914	$775,303	-$70,685	$8,460	$2,156,616	$0	$0		$1,798,298	$79,129,938
STANDBY P	$131,564	-$131,564	$108,694	-$2,855	$342	$87,117	$0	$0		$72,643	$7,463,562
STANDBY S	$39,610	-$39,610	$17,610	-$860	$103	$26,228	$0	$0		$21,871	$2,075,243
TOTAL STANDBY	$3,428,088	-$3,428,088	$901,608	-$74,400	$8,905	$2,269,962	$0	$0		$1,892,812	$88,668,743
AGRICULTURE											
AG-A1	$1,306,777	-$1,306,777	$550,483	-$39,370	$3,394	$1,177,371	$0	$0		$999,186	$85,106,785
AG-A2	$932,332	-$932,332	$392,747	-$28,089	$2,422	$840,006	$0	$0		$712,878	$48,089,094
AG B	$3,796,399	-$3,796,399	$1,599,243	-$114,377	$9,861	$3,420,455	$0	$0		$2,902,797	$276,522,178
AG C	$19,462,530	-$19,462,532	$8,198,640	-$586,362	$50,555	$17,535,225	$0	$0		$14,881,411	$937,120,682
TOTAL AG	$25,498,038	-$25,498,040	$10,741,113	-$768,198	$66,233	$22,973,057	$0	$0		$19,496,272	$1,346,838,738
B-20 CLASS											
B-20 FIRM T	$8,209,101	-$8,209,102	$1,638,050	-$221,377	$21,324	$5,841,023	$0	$0		$5,622,779	$187,874,760
FPP T											
TOTAL	$8,209,101	-$8,209,102	$1,638,050	-$221,377	$21,324	$5,841,023	$0	$0		$5,622,779	$187,874,760
B-20 FIRM P	$9,145,903	-$9,145,904	$2,636,082	-$251,861	$23,757	$6,507,586	$0	$0		$6,395,868	$278,660,509
FPP P											
TOTAL	$9,145,903	-$9,145,904	$2,636,082	-$251,861	$23,757	$6,507,586	$0	$0		$6,395,868	$278,660,509
B-20 FIRM S	$1,450,074	-$1,450,074	$446,714	-$42,108	$3,767	$1,031,771	$0	$0		$1,068,926	$51,239,726
FPP S											
TOTAL	$1,450,074	-$1,450,074	$446,714	-$42,108	$3,767	$1,031,771	$0	$0		$1,068,926	$51,239,726
B-20 T	$8,209,101	-$8,209,102	$1,638,050	-$221,377	$21,324	$5,841,023	$0	$0		$5,622,779	$187,874,760
B-20 P	$9,145,903	-$9,145,904	$2,636,082	-$251,861	$23,757	$6,507,586	$0	$0		$6,395,868	$278,660,509
B-20 S	$1,450,074	-$1,450,074	$446,714	-$42,108	$3,767	$1,031,771	$0	$0		$1,068,926	$51,239,726
TOTAL B-20	$18,805,078	-$18,805,080	$4,720,845	-$515,346	$48,848	$13,380,380	$0	$0		$13,087,572	$517,774,995
SYSTEM	**$161,529,483**	**-$161,529,502**	**$64,658,872**	**-$6,106,552**	**$510,179**	**$217,959,926**	**$0**	**$0**	**-$1,947,172**	**$154,949,856**	**$8,399,726,816**

Pacific Gas & Electric Company
2027 ERRA May Application
Friday, January 1, 2027
Revenue and Average Rate Summary without GHG Revenue Return

13-AtchA-6

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	WFC Rates	RB Rates	RBC Rates	WH 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																								
Non-CARE	5,960,717,805	$0.42577	$0.13295	$0.04638	$0.00908	-$0.00412	-$0.00043	$0.00013	$0.20088	$0.03293	-$0.00002	$0.00551	$0.00857	-$0.00857	$0.00391	-$0.00028	$0.00002	$0.01479	$0.00000	$0.00000	-$0.00007	$0.00701	$0.44869	5.4%
CARE	4,021,211,547	$0.22939	$0.13037	$0.04638	$0.00908	-$0.00412	-$0.00043	$0.00013	$0.03319	$0.00999	-$0.00002	$0.00000	$0.00000	$0.00000	$0.00000	-$0.00028	$0.00002	$0.00914	$0.00000	$0.00000	-$0.00038	$0.00701	$0.24009	4.7%
TOTAL RES	9,981,929,352	$0.34666	$0.13191	$0.04638	$0.00908	-$0.00412	-$0.00043	$0.00013	$0.13333	$0.02369	-$0.00002	$0.00329	$0.00512	-$0.00512	$0.00233	-$0.00028	$0.00002	$0.01252	$0.00000	$0.00000	-$0.00020	$0.00701	$0.36465	5.2%
SMALL L&P																								
B-1	1,636,421,542	$0.41530	$0.12697	$0.03143	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.21983	$0.03004	-$0.00002	$0.00590	$0.00855	-$0.00855	$0.00405	-$0.00027	$0.00002	$0.00801	$0.00000	$0.00000		$0.00676	$0.43747	5.3%
B-6	591,973,902	$0.40534	$0.12781	$0.03146	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.21185	$0.02699	-$0.00002	$0.00589	$0.00855	-$0.00855	$0.00405	-$0.00027	$0.00002	$0.00801	$0.00000	$0.00000		$0.00676	$0.42731	5.4%
A-15	748,293	$0.41718	$0.12684	$0.03143	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.22180	$0.03008	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00406	-$0.00027	$0.00002	$0.00801	$0.00000	$0.00000		$0.00676	$0.43938	5.3%
TC-1	9,828,512	$0.40296	$0.11412	$0.03143	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.23585	$0.01282	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00406	-$0.00027	$0.00002	$0.00801	$0.00000	$0.00000		$0.00676	$0.42346	5.1%
TOTAL SMALL	2,238,972,249	$0.41261	$0.12714	$0.03144	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.21779	$0.02916	-$0.00002	$0.00590	$0.00855	-$0.00855	$0.00405	-$0.00027	$0.00002	$0.00801	$0.00000	$0.00000		$0.00676	$0.43472	5.4%
MEDIUM L&P																								
B-10 T	594,451	$0.21586	$0.10307	$0.03581	$0.00908	-$0.00412	-$0.00026	$0.00010	$0.04850	$0.02699	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00224	-$0.00028	$0.00002	$0.00711	$0.00000	$0.00000		$0.00714	$0.24130	11.8%
B-10 P	19,341,510	$0.33330	$0.11844	$0.03955	$0.00908	-$0.00412	-$0.00026	$0.00011	$0.14301	$0.02679	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00317	-$0.00028	$0.00002	$0.00711	$0.00000	$0.00000		$0.00714	$0.35565	6.7%
B-10 S	1,892,334,152	$0.36280	$0.13462	$0.03851	$0.00908	-$0.00412	-$0.00026	$0.00011	$0.15676	$0.02775	-$0.00002	$0.00588	$0.00852	-$0.00852	$0.00343	-$0.00028	$0.00002	$0.00711	$0.00000	$0.00000		$0.00714	$0.38573	6.3%
TOTAL MEDIUM	1,912,270,113	$0.36246	$0.13444	$0.03852	$0.00908	-$0.00412	-$0.00026	$0.00011	$0.15659	$0.02774	-$0.00002	$0.00588	$0.00852	-$0.00852	$0.00343	-$0.00028	$0.00002	$0.00711	$0.00000	$0.00000		$0.00714	$0.38538	6.3%
B-19 CLASS																								
B-19 FIRM T	7,372,107	$0.18414	$0.10213	$0.01970	$0.00908	-$0.00412	-$0.00026	$0.00005	$0.03567	$0.02188	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00222	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.00677	$0.20589	11.8%
B-19 V T	5,525,899	$0.23307	$0.12250	$0.03726	$0.00908	-$0.00412	-$0.00026	$0.00010	$0.04272	$0.02623	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00222	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.00677	$0.25526	9.5%
Total B-19 T	12,898,006	$0.20511	$0.11086	$0.02722	$0.00908	-$0.00412	-$0.00026	$0.00008	$0.03869	$0.02374	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00222	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.00677	$0.22704	10.7%
B-19 FIRM P	324,727,198	$0.26355	$0.11276	$0.02626	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.09402	$0.02490	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00266	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.00677	$0.28491	8.1%
B-19 V P	126,826,110	$0.24839	$0.11063	$0.02511	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.08186	$0.02513	-$0.00002	$0.00589	$0.00854	-$0.00854	$0.00265	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.00677	$0.26967	8.6%
Total B-19 P	451,553,308	$0.25929	$0.11216	$0.02594	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.09061	$0.02497	-$0.00002	$0.00590	$0.00856	-$0.00856	$0.00266	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.00677	$0.28063	8.2%
B-19 FIRM S	986,262,353	$0.33491	$0.13139	$0.03058	$0.00908	-$0.00412	-$0.00026	$0.00008	$0.14019	$0.02707	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00297	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.00677	$0.35651	6.4%
B-19 V S	1,691,508,956	$0.32212	$0.12934	$0.02624	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.13485	$0.02598	-$0.00002	$0.00580	$0.00841	-$0.00841	$0.00291	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.00677	$0.34351	6.6%
Total B-19 S	2,677,771,310	$0.32683	$0.13009	$0.02784	$0.00908	-$0.00412	-$0.00026	$0.00008	$0.13682	$0.02638	-$0.00002	$0.00584	$0.00847	-$0.00847	$0.00294	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.00677	$0.34830	6.6%
B-19 T	12,898,006	$0.20511	$0.11086	$0.02722	$0.00908	-$0.00412	-$0.00026	$0.00008	$0.03869	$0.02374	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00222	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.00677	$0.22704	10.7%
B-19 P	451,553,308	$0.25929	$0.11216	$0.02594	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.09061	$0.02497	-$0.00002	$0.00590	$0.00856	-$0.00856	$0.00266	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.00677	$0.28063	8.2%
B-19 S	2,677,771,310	$0.32683	$0.13009	$0.02784	$0.00908	-$0.00412	-$0.00026	$0.00008	$0.13682	$0.02638	-$0.00002	$0.00584	$0.00847	-$0.00847	$0.00294	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.00677	$0.34830	6.6%
TOTAL B-19	3,142,222,624	$0.31663	$0.12744	$0.02756	$0.00908	-$0.00412	-$0.00026	$0.00008	$0.12978	$0.02617	-$0.00002	$0.00585	$0.00848	-$0.00848	$0.00289	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.00677	$0.33808	6.8%
STREETLIGHTS	73,515,226	$0.44335	$0.10600	$0.02724	$0.00908	-$0.00412	-$0.00025	$0.00008	$0.28767	$0.01314	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00381	-$0.00022	$0.00002	$0.00697	$0.00000	$0.00000		$0.00564	$0.46094	4.0%
STANDBY																								
STANDBY T	380,050,694	$0.19364	$0.08726	$0.02553	$0.00908	-$0.00412	-$0.00027	$0.00007	$0.04992	$0.02256	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00204	-$0.00019	$0.00002	$0.00567	$0.00000	$0.00000		$0.00473	$0.20821	7.5%
STANDBY P	15,352,313	$0.47536	$0.11812	$0.03144	$0.00908	-$0.00412	-$0.00027	$0.00009	$0.28457	$0.02404	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00708	-$0.00019	$0.00002	$0.00567	$0.00000	$0.00000		$0.00473	$0.48615	2.3%
STANDBY S	4,622,121	$0.43730	$0.11595	$0.02630	$0.00908	-$0.00412	-$0.00027	$0.00007	$0.25605	$0.02598	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00381	-$0.00019	$0.00002	$0.00567	$0.00000	$0.00000		$0.00473	$0.44898	2.7%
TOTAL STANDBY	400,025,127	$0.20727	$0.08878	$0.02576	$0.00908	-$0.00412	-$0.00027	$0.00007	$0.06131	$0.02266	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00225	-$0.00019	$0.00002	$0.00567	$0.00000	$0.00000		$0.00473	$0.22166	6.9%
AGRICULTURE																								
AG-A1	152,488,397	$0.53682	$0.12136	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.34886	$0.03076	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	$0.00000	$0.00000		$0.00655	$0.55812	4.0%
AG-A2	108,794,221	$0.42060	$0.12007	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.23404	$0.03076	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	$0.00000	$0.00000		$0.00655	$0.44202	5.1%
AG B	443,003,493	$0.59985	$0.14054	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.39144	$0.03507	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	$0.00000	$0.00000		$0.00655	$0.62420	4.1%
AG C	2,271,091,514	$0.39073	$0.12015	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.20713	$0.02821	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	$0.00000	$0.00000		$0.00655	$0.41263	5.6%
TOTAL AG	2,975,377,624	$0.43044	$0.12324	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.24282	$0.02945	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	$0.00000	$0.00000		$0.00655	$0.45266	5.2%
B-20 CLASS																								
B-20 FIRM T	957,923,769	$0.17646	$0.11032	$0.02473	$0.00908	-$0.00412	-$0.00022	$0.00007	$0.01451	$0.02240	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00171	-$0.00023	$0.00002	$0.00610	$0.00000	$0.00000		$0.00587	$0.19613	11.1%
FPP T																								
TOTAL	957,923,769	$0.17646	$0.11032	$0.02473	$0.00908	-$0.00412	-$0.00022	$0.00007	$0.01451	$0.02240	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00171	-$0.00023	$0.00002	$0.00610	$0.00000	$0.00000		$0.00587	$0.19613	11.1%
B-20 FIRM P	1,067,239,570	$0.24184	$0.11265	$0.02390	$0.00908	-$0.00412	-$0.00022	$0.00007	$0.07559	$0.02392	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00247	-$0.00024	$0.00002	$0.00610	$0.00000	$0.00000		$0.00599	$0.26110	8.0%
FPP P																								
TOTAL	1,067,239,570	$0.24184	$0.11265	$0.02390	$0.00908	-$0.00412	-$0.00022	$0.00007	$0.07559	$0.02392	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00247	-$0.00024	$0.00002	$0.00610	$0.00000	$0.00000		$0.00599	$0.26110	8.0%
B-20 FIRM S	169,209,785	$0.28330	$0.11879	$0.02873	$0.00908	-$0.00412	-$0.00022	$0.00008	$0.10573	$0.02403	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00264	-$0.00025	$0.00002	$0.00610	$0.00000	$0.00000		$0.00632	$0.30282	6.9%
FPP S																								
TOTAL	169,209,785	$0.28330	$0.11879	$0.02873	$0.00908	-$0.00412	-$0.00022	$0.00008	$0.10573	$0.02403	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00264	-$0.00025	$0.00002	$0.00610	$0.00000	$0.00000		$0.00632	$0.30282	6.9%
B-20 T	957,923,769	$0.17646	$0.11032	$0.02473	$0.00908	-$0.00412	-$0.00022	$0.00007	$0.01451	$0.02240	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00171	-$0.00023	$0.00002	$0.00610	$0.00000	$0.00000		$0.00587	$0.19613	11.1%
B-20 P	1,067,239,570	$0.24184	$0.11265	$0.02390	$0.00908	-$0.00412	-$0.00022	$0.00007	$0.07559	$0.02392	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00247	-$0.00024	$0.00002	$0.00610	$0.00000	$0.00000		$0.00599	$0.26110	8.0%
B-20 S	169,209,785	$0.28330	$0.11879	$0.02873	$0.00908	-$0.00412	-$0.00022	$0.00008	$0.10573	$0.02403	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00264	-$0.00025	$0.00002	$0.00610	$0.00000	$0.00000		$0.00632	$0.30282	6.9%
TOTAL B-20	2,194,373,124	$0.21650	$0.11211	$0.02463	$0.00908	-$0.00412	-$0.00022	$0.00007	$0.05125	$0.02327	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00215	-$0.00023	$0.00002	$0.00610	$0.00000	$0.00000		$0.00596	$0.23596	9.0%
SYSTEM	**22,918,685,439**	**$0.34660**	**$0.12719**	**$0.03691**	**$0.00908**	**-$0.00412**	**-$0.00033**	**$0.00010**	**$0.14863**	**$0.02556**	**-$0.00002**	**$0.00476**	**$0.00705**	**-$0.00705**	**$0.00282**	**-$0.00027**	**$0.00002**	**$0.00951**	**$0.00000**	**$0.00000**	**-$0.00008**	**$0.00676**	**$0.36650**	**5.7%**

13-AtchA-7

Pacific Gas & Electric Company
2027 ERRA May Application
Friday, January 1, 2027
Revenue and Average Rate Summary without GHG Revenue Return

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	WFC Revenue	RB Revenue	RBC Revenue	WH Revenue	CTC Revenue	ECRA Revenue	NSGC Revenue	Residential & Small Business AB32 Credit Revenue	Climate Credit & EITE Revenue	CIA Revenue	PCIA Revenue
RESIDENTIAL																				
Non-CARE	$4,210,256,041	$593,722,084	$116,212,988	-$52,737,153	-$5,504,120	$1,640,646	$2,423,228,356	$378,726,705	-$263,992	$73,067,747	$109,649,906	-$109,649,913	$50,049,094	-$3,537,342	$284,941	$158,340,070	$0	$0	$59,843,464	$191,179,065
CARE	$505,186,225	$159,605,661	$31,240,628	-$14,176,916	-$1,479,630	$441,037	$163,304,064	$40,532,090	-$70,967	$0	$0	$0	$0	-$950,915	$76,598	$37,096,886	$0	$0	-$57,896,293	$46,266,077
TOTAL RES	$4,715,442,266	$753,327,745	$147,453,616	-$66,914,068	-$6,983,750	$2,081,683	$2,586,532,420	$419,258,794	-$334,959	$73,067,747	$109,649,906	-$109,649,913	$50,049,094	-$4,488,257	$361,539	$195,436,956	$0	$0	$1,947,172	$237,445,143
SMALL L&P																				
B-1	$1,259,699,188	$120,208,742	$34,723,618	-$15,757,488	-$1,109,144	$332,175	$815,702,596	$114,871,680	-$78,879	$22,542,687	$32,688,794	-$32,688,797	$15,487,757	-$1,018,654	$85,138	$30,642,936	$0	$0		$54,890,287
B-6	$369,241,509	$36,150,419	$10,438,677	-$4,737,045	-$333,433	$99,895	$239,713,241	$31,010,102	-$23,713	$6,767,525	$9,813,481	-$9,813,482	$4,651,017	-$306,230	$25,594	$9,211,935	$0	$0		$16,404,543
A-15	$360,398	$30,478	$8,804	-$3,995	-$281	$84	$237,560	$29,165	-$20	$5,729	$8,307	-$8,307	$3,937	-$258	$22	$7,769	$0	$0		$17,348
TC-1	$9,483,312	$912,026	$263,450	-$119,553	-$8,415	$2,520	$6,532,393	$372,073	-$598	$171,488	$248,672	-$248,672	$117,812	-$7,729	$646	$232,489	$0	$0		$425,738
TOTAL SMALL	$1,638,784,407	$157,301,665	$45,434,548	-$20,618,080	-$1,451,273	$434,675	$1,062,185,791	$146,283,021	-$103,210	$29,487,429	$42,759,254	-$42,759,258	$20,260,523	-$1,332,870	$111,400	$40,095,129	$0	$0		$71,737,917
MEDIUM L&P																				
B-10 T	$312,935	$48,490	$19,827	-$8,997	-$568	$134	$71,174	$58,950	-$45	$12,906	$18,715	-$18,715	$4,892	-$615	$49	$15,536	$0	$0		$29,115
B-10 P	$12,761,466	$2,102,765	$443,164	-$201,107	-$12,691	$5,806	$6,641,602	$1,302,248	-$1,007	$286,541	$415,509	-$415,509	$153,700	-$13,748	$1,087	$347,252	$0	$0		$734,012
B-10 S	$1,264,748,618	$168,737,510	$43,702,635	-$19,832,143	-$1,251,543	$466,276	$700,238,280	$133,726,162	-$99,276	$28,335,481	$41,088,832	-$41,088,836	$16,545,674	-$1,355,766	$107,153	$34,244,226	$0	$0		$71,277,278
TOTAL MEDIUM	$1,277,823,019	$170,888,764	$44,165,626	-$20,042,246	-$1,264,802	$472,216	$706,951,056	$135,087,360	-$100,328	$28,634,927	$41,523,055	-$41,523,059	$16,704,266	-$1,370,129	$108,288	$34,607,013	$0	$0		$72,040,404
B-19 CLASS																				
B-19 FIRM T	$2,538,914	$459,913	$171,091	-$77,641	-$4,900	$1,271	$582,694	$412,270	-$389	$111,369	$161,494	-$161,494	$41,835	-$5,031	$419	$134,062	$0	$0		$253,994
B-19 V T	$709,553	$139,470	$44,538	-$20,211	-$1,275	$385	$158,556	$128,656	-$101	$28,991	$42,040	-$42,040	$10,890	-$1,310	$109	$34,899	$0	$0		$62,164
Total B-19 T	$3,248,466	$599,383	$215,629	-$97,852	-$6,175	$1,656	$741,250	$540,926	-$490	$140,360	$203,534	-$203,534	$52,726	-$6,341	$529	$168,961	$0	$0		$316,158
B-19 FIRM P	$111,335,820	$14,930,121	$5,528,728	-$2,508,923	-$158,330	$41,257	$53,364,981	$15,165,652	-$12,559	$3,598,831	$5,218,609	-$5,218,609	$1,619,838	-$162,575	$13,556	$4,332,165	$0	$0		$7,135,470
B-19 V P	$55,144,693	$7,610,809	$2,688,461	-$1,220,017	-$76,991	$21,031	$25,050,875	$7,461,802	-$6,107	$1,750,008	$2,537,659	-$2,537,659	$787,681	-$79,055	$6,592	$2,106,607	$0	$0		$3,959,825
Total B-19 P	$166,480,513	$22,540,930	$8,217,190	-$3,728,939	-$235,321	$62,288	$78,415,856	$22,627,453	-$18,666	$5,348,839	$7,756,268	-$7,756,268	$2,407,519	-$241,630	$20,148	$6,438,772	$0	$0		$11,095,295
B-19 FIRM S	$922,515,464	$114,479,758	$32,616,462	-$14,801,266	-$934,060	$316,344	$527,238,926	$97,102,954	-$74,092	$21,180,531	$30,713,552	-$30,713,555	$10,645,867	-$959,100	$79,971	$25,557,395	$0	$0		$46,684,484
B-19 V S	$1,468,517,827	$157,868,873	$64,954,121	-$29,476,011	-$1,860,137	$436,242	$783,740,936	$187,332,896	-$147,551	$42,043,666	$60,966,855	-$60,966,861	$21,119,385	-$1,910,002	$159,259	$50,896,326	$0	$0		$86,757,792
Total B-19 S	$2,391,033,291	$272,348,631	$97,570,583	-$44,277,277	-$2,794,197	$752,586	$1,310,979,861	$284,435,849	-$221,643	$63,224,196	$91,680,407	-$91,680,416	$31,765,252	-$2,869,103	$239,231	$76,453,721	$0	$0		$133,442,276
B-19 T	$3,248,466	$599,383	$215,629	-$97,852	-$6,175	$1,656	$741,250	$540,926	-$490	$140,360	$203,534	-$203,534	$52,726	-$6,341	$529	$168,961	$0	$0		$316,158
B-19 P	$166,480,513	$22,540,930	$8,217,190	-$3,728,939	-$235,321	$62,288	$78,415,856	$22,627,453	-$18,666	$5,348,839	$7,756,268	-$7,756,268	$2,407,519	-$241,630	$20,148	$6,438,772	$0	$0		$11,095,295
B-19 S	$2,391,033,291	$272,348,631	$97,570,583	-$44,277,277	-$2,794,197	$752,586	$1,310,979,861	$284,435,849	-$221,643	$63,224,196	$91,680,407	-$91,680,416	$31,765,252	-$2,869,103	$239,231	$76,453,721	$0	$0		$133,442,276
TOTAL B-19	$2,560,762,270	$295,488,944	$106,003,401	-$48,104,068	-$3,035,694	$816,530	$1,390,136,967	$307,604,228	-$240,800	$68,713,396	$99,640,208	-$99,640,218	$34,225,497	-$3,117,073	$259,907	$83,061,454	$0	$0		$144,853,729
STREETLIGHTS	$52,388,401	$4,430,575	$1,476,793	-$670,165	-$40,665	$12,243	$37,935,474	$2,075,982	-$3,355	$961,293	$1,393,956	-$1,393,956	$619,740	-$36,121	$3,621	$1,134,542	$0	$0		$1,981,330
STANDBY																				
STANDBY T	$18,452,125	$3,401,553	$1,383,527	-$627,841	-$41,145	$9,400	$5,163,435	$3,438,540	-$3,143	$900,584	$1,305,922	-$1,305,922	$310,873	-$28,343	$3,392	$864,737	$0	$0		$1,491,706
STANDBY P	$4,068,395	$315,984	$64,698	-$29,360	-$1,924	$873	$3,290,676	$171,287	-$147	$42,114	$61,069	-$61,069	$50,453	-$1,325	$159	$40,438	$0	$0		$45,135
STANDBY S	$747,355	$62,424	$25,237	-$11,453	-$751	$172	$468,251	$72,206	-$57	$16,428	$23,821	-$23,821	$10,591	-$517	$62	$15,774	$0	$0		$25,632
TOTAL STANDBY	$23,267,875	$3,779,961	$1,473,462	-$668,653	-$43,820	$10,445	$8,922,362	$3,682,033	-$3,347	$959,125	$1,390,812	-$1,390,812	$371,917	-$30,185	$3,613	$920,948	$0	$0		$1,562,473
AGRICULTURE																				
AG-A1	$31,819,330	$2,126,085	$669,262	-$303,709	-$19,903	$5,875	$24,050,945	$2,267,168	-$1,520	$435,645	$631,721	-$631,721	$266,114	-$19,032	$1,641	$569,164	$0	$0		$936,150
AG-A2	$16,127,153	$1,539,609	$484,648	-$219,932	-$14,413	$4,254	$10,496,733	$1,641,775	-$1,101	$315,473	$457,463	-$457,463	$192,707	-$13,782	$1,188	$412,162	$0	$0		$675,120
AG B	$72,278,426	$5,118,289	$1,611,166	-$731,143	-$47,915	$14,143	$53,520,729	$6,223,199	-$3,660	$1,048,761	$1,520,792	-$1,520,792	$640,638	-$45,818	$3,950	$1,370,194	$0	$0		$2,234,053
AG C	$361,269,059	$42,088,449	$13,248,861	-$6,012,299	-$394,010	$116,304	$213,395,631	$41,164,995	-$30,096	$8,624,120	$12,505,700	-$12,505,701	$5,268,058	-$376,768	$32,485	$11,267,304	$0	$0		$18,264,907
TOTAL AG	$481,493,968	$50,872,432	$16,013,937	-$7,267,083	-$476,241	$140,577	$301,464,038	$51,297,137	-$36,378	$10,423,999	$15,115,676	-$15,115,677	$6,367,517	-$455,401	$39,264	$13,618,824	$0	$0		$22,110,229
B-20 CLASS																				
B-20 FIRM T	$357,582,184	$85,467,140	$33,883,754	-$15,376,359	-$821,068	$236,173	$44,715,020	$83,613,493	-$76,971	$20,691,482	$30,004,391	-$30,004,394	$6,381,936	-$862,497	$83,079	$22,756,962	$0	$0		$34,777,079
FPP T	$10,123,742	$0	$0	$0	$0	$0	$3,640,529	$6,469,848	-$5,956	$0	$2,474,792	-$2,474,792	$493,822	$0	$0	$0	$0	$0		$0
TOTAL	$367,705,926	$85,467,140	$33,883,754	-$15,376,359	-$821,068	$236,173	$48,355,549	$90,083,341	-$82,927	$20,691,482	$32,479,183	-$32,479,186	$6,875,757	-$862,497	$83,079	$22,756,962	$0	$0		$34,777,079
B-20 FIRM P	$939,113,643	$137,754,219	$53,779,505	-$24,405,000	-$1,303,180	$380,659	$421,795,680	$141,702,827	-$122,167	$35,006,851	$50,762,880	-$50,762,885	$14,631,153	-$1,397,912	$131,860	$36,119,321	$0	$0		$55,064,682
FPP P	$2,198,597	$0	$0	$0	$0	$0	$1,705,528	$468,061	-$404	$0	$167,676	-$167,676	$48,328	$0	$0	$0	$0	$0		$0
TOTAL	$941,312,240	$137,754,219	$53,779,505	-$24,405,000	-$1,303,180	$380,659	$423,501,208	$142,170,889	-$122,570	$35,006,851	$50,930,556	-$50,930,561	$14,679,481	-$1,397,912	$131,860	$36,119,321	$0	$0		$55,064,682
B-20 FIRM S	$379,186,861	$51,758,477	$19,144,218	-$8,687,596	-$463,901	$143,025	$184,571,393	$50,667,085	-$43,488	$12,461,602	$18,070,372	-$18,070,374	$5,566,809	-$524,740	$46,939	$12,857,615	$0	$0		$21,955,569
FPP S	$5,209,643	$0	$0	$0	$0	$0	$3,868,521	$1,241,044	-$1,065	$0	$442,617	-$442,617	$136,354	$0	$0	$0	$0	$0		$0
TOTAL	$384,396,503	$51,758,477	$19,144,218	-$8,687,596	-$463,901	$143,025	$188,439,914	$51,908,129	-$44,554	$12,461,602	$18,512,989	-$18,512,991	$5,703,163	-$524,740	$46,939	$12,857,615	$0	$0		$21,955,569
B-20 T	$367,705,926	$85,467,140	$33,883,754	-$15,376,359	-$821,068	$236,173	$48,355,549	$90,083,341	-$82,927	$20,691,482	$32,479,183	-$32,479,186	$6,875,757	-$862,497	$83,079	$22,756,962	$0	$0		$34,777,079
B-20 P	$941,312,240	$137,754,219	$53,779,505	-$24,405,000	-$1,303,180	$380,659	$423,501,208	$142,170,889	-$122,570	$35,006,851	$50,930,556	-$50,930,561	$14,679,481	-$1,397,912	$131,860	$36,119,321	$0	$0		$55,064,682
B-20 S	$384,396,503	$51,758,477	$19,144,218	-$8,687,596	-$463,901	$143,025	$188,439,914	$51,908,129	-$44,554	$12,461,602	$18,512,989	-$18,512,991	$5,703,163	-$524,740	$46,939	$12,857,615	$0	$0		$21,955,569
TOTAL B-20	$1,693,414,670	$274,979,835	$106,807,476	-$48,468,956	-$2,588,148	$759,857	$660,296,671	$284,162,359	-$250,051	$68,159,935	$101,922,728	-$101,922,738	$27,258,402	-$2,785,148	$261,878	$71,733,897	$0	$0		$111,797,330
SYSTEM	**$12,443,376,875**	**$1,711,069,921**	**$468,828,860**	**-$212,753,320**	**-$15,884,392**	**$4,728,226**	**$6,754,424,778**	**$1,349,450,914**	**-$1,072,427**	**$280,407,851**	**$413,395,596**	**-$413,395,632**	**$155,856,956**	**-$13,615,185**	**$1,149,510**	**$440,608,764**	**$0**	**$0**	**$1,947,172**	**$663,528,555**

Pacific Gas & Electric Company
2027 ERRA May Application
Friday, January 1, 2027
Revenue and Average Rate Summary without GHG Revenue Return

DA/CCA RESULTS

Class/Schedule	Total Proposed Revenue	Total Sales (kWh)	Revenue At Present Rates	TO Rates	TAC Rates	TRBAA Rates	T-ECRA Rates	RS Rates	Dist Rates	PPP Rates	ND Rates	WFC Rates	RB Rates	RB Credit Rates	WH 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																								
Non-CARE	$3,984,252,546	$12,800,338,582	$0.32892	$0.04638	$0.00908	-$0.00412	-$0.00043	$0.00013	$0.18931	$0.02959	-$0.00002	$0.00571	$0.00857	-$0.00857	$0.00391	-$0.00028	$0.00002	$0.01237	$0.00000	$0.00000	$0.00468	$0.01494	$0.31126	-5.4%
CARE	$403,988,320	$3,441,011,083	$0.14681	$0.04638	$0.00908	-$0.00412	-$0.00043	$0.00013	$0.04746	$0.01178	-$0.00002	$0.00000	$0.00000	$0.00000	$0.00000	-$0.00028	$0.00002	$0.01078	$0.00000	$0.00000	-$0.01683	$0.01345	$0.11740	-20.0%
TOTAL RES	$4,388,240,866	$16,241,349,665	$0.29034	$0.04638	$0.00908	-$0.00412	-$0.00043	$0.00013	$0.15926	$0.02581	-$0.00002	$0.00450	$0.00675	-$0.00675	$0.00308	-$0.00028	$0.00002	$0.01203	$0.00000	$0.00000	$0.00012	$0.01462	$0.27019	-6.9%
SMALL L&P																								
B-1	$1,191,523,450	3,824,632,939	$0.32936	$0.03143	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.21328	$0.03003	-$0.00002	$0.00589	$0.00855	-$0.00855	$0.00405	-$0.00027	$0.00002	$0.00801	$0.00000	$0.00000		$0.01435	$0.31154	-5.4%
B-6	$349,072,529	1,149,768,119	$0.32114	$0.03144	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.20849	$0.02697	-$0.00002	$0.00589	$0.00854	-$0.00854	$0.00405	-$0.00027	$0.00002	$0.00801	$0.00000	$0.00000		$0.01427	$0.30360	-5.5%
A-15	$336,342	969,694	$0.37166	$0.03143	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.24498	$0.03008	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00406	-$0.00027	$0.00002	$0.00801	$0.00000	$0.00000		$0.01789	$0.34685	-6.7%
TC-1	$8,894,340	29,017,651	$0.32681	$0.03143	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.22512	$0.01282	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00406	-$0.00027	$0.00002	$0.00801	$0.00000	$0.00000		$0.01467	$0.30651	-6.2%
TOTAL SMALL	$1,549,826,660	5,004,388,403	$0.32747	$0.03143	$0.00908	-$0.00412	-$0.00029	$0.00009	$0.21225	$0.02923	-$0.00002	$0.00589	$0.00854	-$0.00854	$0.00405	-$0.00027	$0.00002	$0.00801	$0.00000	$0.00000		$0.01434	$0.30969	-5.4%
MEDIUM L&P																								
B-10 T	$250,846	2,183,805	$0.14330	$0.02220	$0.00908	-$0.00412	-$0.00026	$0.00006	$0.03259	$0.02699	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00224	-$0.00028	$0.00002	$0.00711	$0.00000	$0.00000		$0.01333	$0.11487	-19.8%
B-10 P	$11,789,623	48,812,294	$0.26144	$0.04308	$0.00908	-$0.00412	-$0.00026	$0.00012	$0.13606	$0.02668	-$0.00002	$0.00587	$0.00851	-$0.00851	$0.00315	-$0.00028	$0.00002	$0.00711	$0.00000	$0.00000		$0.01504	$0.24153	-7.6%
B-10 S	$1,174,841,943	4,813,626,823	$0.26274	$0.03505	$0.00908	-$0.00412	-$0.00026	$0.00010	$0.14547	$0.02778	-$0.00002	$0.00589	$0.00854	-$0.00854	$0.00344	-$0.00028	$0.00002	$0.00711	$0.00000	$0.00000		$0.01481	$0.24407	-7.1%
TOTAL MEDIUM	$1,186,882,412	4,864,622,922	$0.26268	$0.03513	$0.00908	-$0.00412	-$0.00026	$0.00010	$0.14532	$0.02777	-$0.00002	$0.00589	$0.00854	-$0.00854	$0.00343	-$0.00028	$0.00002	$0.00711	$0.00000	$0.00000		$0.01481	$0.24398	-7.1%
B-19 CLASS																								
B-19 FIRM T	$2,080,958	18,844,790	$0.13473	$0.02441	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.03092	$0.02188	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00222	-$0.00027	$0.00002	$0.00711	$0.00000			$0.01348	$0.11043	-18.0%
B-19 V T	$585,761	4,905,627	$0.14464	$0.02843	$0.00908	-$0.00412	-$0.00026	$0.00008	$0.03232	$0.02623	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00222	-$0.00027	$0.00002	$0.00711	$0.00000			$0.01267	$0.11941	-17.4%
Total B-19 T	$2,666,719	23,750,418	$0.13678	$0.02524	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.03121	$0.02278	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00222	-$0.00027	$0.00002	$0.00711	$0.00000			$0.01331	$0.11228	-17.9%
B-19 FIRM P	$102,888,213	608,961,804	$0.18283	$0.02452	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.08763	$0.02490	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00266	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.01172	$0.16896	-7.6%
B-19 V P	$50,061,520	296,120,586	$0.18622	$0.02570	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.08460	$0.02520	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00266	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.01337	$0.16906	-9.2%
Total B-19 P	$152,949,732	905,082,389	$0.18394	$0.02490	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.08664	$0.02500	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00266	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.01226	$0.16899	-8.1%
B-19 FIRM S	$859,134,169	3,592,540,254	$0.25679	$0.03187	$0.00908	-$0.00412	-$0.00026	$0.00009	$0.14676	$0.02703	-$0.00002	$0.00590	$0.00855	-$0.00855	$0.00296	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.01299	$0.23914	-6.9%
B-19 V S	$1,361,915,788	7,154,371,703	$0.20526	$0.02207	$0.00908	-$0.00412	-$0.00026	$0.00006	$0.10955	$0.02618	-$0.00002	$0.00588	$0.00852	-$0.00852	$0.00295	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.01213	$0.19036	-7.3%
Total B-19 S	$2,221,049,958	10,746,911,957	$0.22249	$0.02534	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.12199	$0.02647	-$0.00002	$0.00588	$0.00853	-$0.00853	$0.00296	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.01242	$0.20667	-7.1%
B-19 T	$2,666,719	23,750,418	$0.13678	$0.02524	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.03121	$0.02278	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00222	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.01331	$0.11228	-17.9%
B-19 P	$152,949,732	905,082,389	$0.18394	$0.02490	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.08664	$0.02500	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00266	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.01226	$0.16899	-8.1%
B-19 S	$2,221,049,958	10,746,911,957	$0.22249	$0.02534	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.12199	$0.02647	-$0.00002	$0.00588	$0.00853	-$0.00853	$0.00296	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.01242	$0.20667	-7.1%
TOTAL B-19	$2,376,666,409	11,675,744,764	$0.21932	$0.02531	$0.00908	-$0.00412	-$0.00026	$0.00007	$0.11906	$0.02635	-$0.00002	$0.00589	$0.00853	-$0.00853	$0.00293	-$0.00027	$0.00002	$0.00711	$0.00000	$0.00000		$0.01241	$0.20356	-7.2%
STREETLIGHTS	$49,881,288	162,661,392	$0.32207	$0.02724	$0.00908	-$0.00412	-$0.00025	$0.00008	$0.23322	$0.01276	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00381	-$0.00022	$0.00002	$0.00697	$0.00000	$0.00000		$0.01218	$0.30666	-4.8%
STANDBY																								
STANDBY T	$16,267,275	152,388,622	$0.12109	$0.02232	$0.00908	-$0.00412	-$0.00027	$0.00006	$0.03388	$0.02256	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00204	-$0.00019	$0.00002	$0.00567	$0.00000	$0.00000		$0.00979	$0.10675	-11.8%
STANDBY P	$3,989,061	7,126,171	$0.57091	$0.04434	$0.00908	-$0.00412	-$0.00027	$0.00012	$0.46177	$0.02404	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00708	-$0.00019	$0.00002	$0.00567	$0.00000	$0.00000		$0.00633	$0.55978	-2.0%
STANDBY S	$683,999	2,779,734	$0.26886	$0.02246	$0.00908	-$0.00412	-$0.00027	$0.00006	$0.16845	$0.02598	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00381	-$0.00019	$0.00002	$0.00567	$0.00000	$0.00000		$0.00922	$0.24607	-8.5%
TOTAL STANDBY	$20,940,335	162,294,527	$0.14337	$0.02329	$0.00908	-$0.00412	-$0.00027	$0.00006	$0.05498	$0.02269	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00229	-$0.00019	$0.00002	$0.00567	$0.00000	$0.00000		$0.00963	$0.12903	-10.0%
AGRICULTURE																								
AG-A1	$30,983,883	73,715,858	$0.43165	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.32627	$0.03076	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	$0.00000	$0.00000		$0.01270	$0.42032	-2.6%
AG-A2	$15,514,442	53,381,516	$0.30211	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.19664	$0.03076	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	$0.00000	$0.00000		$0.01265	$0.29063	-3.8%
AG B	$70,956,587	177,461,934	$0.40729	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.30159	$0.03507	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	$0.00000	$0.00000		$0.01259	$0.39984	-1.8%
AG C	$346,657,939	1,459,295,785	$0.24756	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.14623	$0.02821	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	$0.00000	$0.00000		$0.01252	$0.23755	-4.0%
TOTAL AG	$464,112,850	$1,763,855,093	$0.27298	$0.02884	$0.00908	-$0.00412	-$0.00027	$0.00008	$0.17091	$0.02908	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00361	-$0.00026	$0.00002	$0.00772	$0.00000	$0.00000		$0.01254	$0.26312	-3.6%
B-20 CLASS																								
B-20 FIRM T	$315,469,218	3,732,126,080	$0.09581	$0.02290	$0.00908	-$0.00412	-$0.00022	$0.00006	$0.01198	$0.02240	-$0.00002	$0.00554	$0.00804	-$0.00804	$0.00171	-$0.00023	$0.00002	$0.00610	$0.00000	$0.00000		$0.00932	$0.08453	-11.8%
FPP T	$10,598,243	288,784,612	$0.03506	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.01261	$0.02240	-$0.00002	$0.00000	$0.00857	-$0.00857	$0.00171	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		$0.00000	$0.03670	4.7%
TOTAL	$326,067,461	4,020,910,692	$0.09145	$0.02126	$0.00843	-$0.00382	-$0.00020	$0.00006	$0.01203	$0.02240	-$0.00002	$0.00515	$0.00808	-$0.00808	$0.00171	-$0.00021	$0.00002	$0.00566	$0.00000	$0.00000		$0.00865	$0.08109	-11.3%
B-20 FIRM P	$869,138,493	5,923,543,603	$0.15854	$0.02326	$0.00908	-$0.00412	-$0.00022	$0.00006	$0.07121	$0.02392	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00247	-$0.00024	$0.00002	$0.00610	$0.00000	$0.00000		$0.00930	$0.14673	-7.5%
FPP P	$2,221,515	19,566,176	$0.11237	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.08717	$0.02392	-$0.00002	$0.00000	$0.00857	-$0.00857	$0.00247	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		$0.00000	$0.11354	1.0%
TOTAL	$871,360,007	5,943,109,778	$0.15839	$0.02318	$0.00905	-$0.00411	-$0.00022	$0.00006	$0.07126	$0.02392	-$0.00002	$0.00589	$0.00857	-$0.00857	$0.00247	-$0.00024	$0.00002	$0.00608	$0.00000	$0.00000		$0.00927	$0.14662	-7.4%
B-20 FIRM S	$349,453,005	2,108,639,914	$0.17983	$0.02455	$0.00908	-$0.00412	-$0.00022	$0.00007	$0.08753	$0.02403	-$0.00002	$0.00591	$0.00857	-$0.00857	$0.00264	-$0.00025	$0.00002	$0.00610	$0.00000	$0.00000		$0.01041	$0.16572	-7.8%
FPP S	$5,244,854	51,649,213	$0.10087	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.07490	$0.02403	-$0.00002	$0.00000	$0.00857	-$0.00857	$0.00264	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		$0.00000	$0.10155	0.7%
TOTAL	$354,697,859	2,160,289,127	$0.17794	$0.02396	$0.00886	-$0.00402	-$0.00021	$0.00007	$0.08723	$0.02403	-$0.00002	$0.00577	$0.00857	-$0.00857	$0.00264	-$0.00024	$0.00002	$0.00595	$0.00000	$0.00000		$0.01016	$0.16419	-7.7%
B-20 T	$326,067,461	4,020,910,692	$0.09145	$0.02126	$0.00843	-$0.00382	-$0.00020	$0.00006	$0.01203	$0.02240	-$0.00002	$0.00515	$0.00808	-$0.00808	$0.00171	-$0.00021	$0.00002	$0.00566	$0.00000	$0.00000		$0.00865	$0.08109	-11.3%
B-20 P	$871,360,007	5,943,109,778	$0.15839	$0.02318	$0.00905	-$0.00411	-$0.00022	$0.00006	$0.07126	$0.02392	-$0.00002	$0.00589	$0.00857	-$0.00857	$0.00247	-$0.00024	$0.00002	$0.00608	$0.00000	$0.00000		$0.00927	$0.14662	-7.4%
B-20 S	$354,697,859	2,160,289,127	$0.17794	$0.02396	$0.00886	-$0.00402	-$0.00021	$0.00007	$0.08723	$0.02403	-$0.00002	$0.00577	$0.00857	-$0.00857	$0.00264	-$0.00024	$0.00002	$0.00595	$0.00000	$0.00000		$0.01016	$0.16419	-7.7%
TOTAL B-20	$1,552,125,327	12,124,309,597	$0.13967	$0.02268	$0.00881	-$0.00400	-$0.00021	$0.00006	$0.05446	$0.02344	-$0.00002	$0.00562	$0.00841	-$0.00841	$0.00225	-$0.00023	$0.00002	$0.00592	$0.00000	$0.00000		$0.00922	$0.12802	-8.3%
SYSTEM	**$11,588,676,147**	**51,999,226,364**	**$0.23930**	**$0.03291**	**$0.00902**	**-$0.00409**	**-$0.00031**	**$0.00009**	**$0.12989**	**$0.02595**	**-$0.00002**	**$0.00539**	**$0.00795**	**-$0.00795**	**$0.00300**	**-$0.00026**	**$0.00002**	**$0.00847**	**$0.00000**	**$0.00000**	**$0.00004**	**$0.01276**	**$0.22286**	**-6.9%**

13-AtchA-8

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 14

GREEN TARIFF SHARED RENEWABLES

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 14
GREEN TARIFF SHARED RENEWABLES

TABLE OF CONTENTS

A. Introduction 14-1

B. Background 14-1

C. Green Access Program Review Applications 14-2

D. GTSR Load Forecast 14-4

E. 2027 Rate Forecast for GTSR Program 14-5

F. Conclusion 14-8

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 14
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) 2027 rate proposal for bill charges and credits associated with PG&E's Green Tariff Shared Renewables (GTSR) Program. PG&E has one electric rate schedule associated with the GTSR Program: electric rate schedule Green Tariff (E-GT).[1] This request is consistent with Decision (D.) 15-01-051, which states that the renewable power rate and other components of GTSR rates should be updated annually.[2] Per D.24-05-065, issued June 7, 2024, the Enhanced Community Renewable (ECR) component of the GTSR Program was eliminated. Accordingly, 2026 was the first forecast year that did not include an ECR rate.

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 (A.) 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 program includes one GTSR electric rate schedule: Schedule E-GT (Green Tariff Program). Under E-GT, customers purchase energy supplies via a portfolio of new solar photovoltaic generation facilities sized 0.5 to 20 megawatts

---

1 PG&E's GTSR Program electric rate schedule E-GT is marketed as the Solar Choice Program and the E-GT tariff can be found here: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-GT.pdf.

2 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 letter, 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 Energy Resource Recovery Account (ERRA) Forecast proceeding, PG&E consolidates the GTSR rate request with the Annual ERRA Forecast proceeding.

(MW) located within PG&E's service area and under contract with PG&E. Consistent with the legislative requirement that non-participating customers remain indifferent to the GTSR Program, the Commission determined that each investor-owned utility (IOU) is required to establish a balancing account to track the costs and revenues of the program.[3]

PG&E's 2026 GTSR Forecast, approved in the 2026 ERRA Forecast D.25-12-027, was consolidated with other electric rate changes in PG&E's Advice Letter (AL) 7797-E, the Annual Electric True-Up (AET) on December 30, 2025, for rates effective January 1, 2026.

C. Green Access Program Review Applications

On May 31, 2022, PG&E filed an application and testimony to review the Green Access Program (GAP), which initially was to review the Disadvantaged Community Green Tariff (DAC-GT) and Community Solar Green Tariff (CSGT) Programs as required by D.18-06-027.[4] In accordance with the direction of D.21-12-036 and the September 2021 recommendation by Energy Division, PG&E also included testimony reviewing the GTSR program.[5] PG&E's A.22-05-022 was consolidated with San Diego Gas & Electric Company (SDG&E) filed A.22-05-023 and Southern California Edison Company (SCE) filed A.22-05-024 GAP Review applications pursuant to an August 10, 2023, Administrative Law Judge (ALJ) Ruling.

On December 2, 2022, the Assigned Commissioner issued a Scoping Memo and Ruling for the consolidated applications and the schedule included an opportunity for parties to submit supplemental testimony that would consider the passage of recent legislation, Assembly Bill (AB) 2316 (2022). The passage of AB 2316 gave the Commission authority to modify the existing legislatively mandated GAP programs—together, the DAC-GT, CSGT, GTSR Programs—to meet stated policy goals in AB 2316. Specifically, AB 2316 required the Commission to evaluate each customer renewable energy subscription program to determine if the program meets specific goals and authorizes the termination

---

3 D.15-01-051, p. 129; Finding of Fact 145 ("A balancing account will allow the IOU to track revenue under and over collection of GTSR costs using balancing account ratemaking standards.").

4 PG&E's May 31, 2022, GAP Review A.22-05-022, Chapter 1.

5 *Ibid*., Chapter 2.

or modification of a program that does not meet the goals, and to determine whether it would be beneficial to establish a community renewable program.

PG&E, SDG&E, SCE, and other parties submitted Supplemental Testimony on January 20, 2023 that proposed modifications to the GAP programs and addressed the ALJ's specific set of questions outlined in the Scoping Memo about how the Supplemental Testimony proposals met AB 2316 goals to ensure updated programs: (a) efficiently serves distinct customer groups; (b) minimizes duplicative offerings; and (c) promotes robust participation by low-income customers. Opening Briefs were filed on May 17, 2023, and Reply Briefs were filed on May 30, 2023.

On June 7, 2024, the Commission issued D.24-05-065 in the consolidated Applications A.22-05-022, A.22-05-023, and A.22-05-024 evaluating the utilities' DAC-GT Program and the GTSR Program tariffs. The decision presents the culmination of an evaluation of current customer renewable energy subscription programs, also known as GAP tariffs, and the consideration of adoption of a community renewable energy program.

With respect to the previous GTSR Program's tariff options—Green Tariff (Solar Choice) rate schedule and E-ECR—D.24-05-065 adopted PG&E's proposed GTSR Successor Program, with modifications for Solar Choice, which is referred to as the Modified Green Tariff (Modified GT). The decision also discontinued the ECR program.

The Modified GT Program, which is based on PG&E's GTSR Successor Program proposal, allows customers to remain on their otherwise applicable tariff and customer usage above the Renewable Portfolio Standard compliance target would be "topped off" with incremental green energy to achieve 100 percent clean energy. The modifications to the Green Tariff (PG&E's Solar Choice Program) are articulated in Ordering Paragraph 5 of the decision, which include, among other things:

1) Eligibility is aimed at market rate customers and all costs shall be recovered by participating customer subscribers.
2) Customer subscriptions are capped at 40 MW per customer. PG&E, SDG&E, and SCE may request to increase these caps through a Tier 2 Advice Letter.

3) The "topped-off" approach is adopted, whereby customers subscribed to the tariff remain on their otherwise applicable tariff and are "topped off" to achieve 100 percent clean energy.

4) Voluntary inclusion of storage is permitted.

5) A sunset is adopted whereby when the remaining enrolled capacity for the modified tariff falls below 500 kilowatts or there has been no participation by developers in two consecutive solicitations, a utility shall submit a Tier 1 Advice Letter informing the Commission that solicitations have been suspended.

A second proposed decision with more granular implementation details was issued on April 7, 2026. Once a final decision is approved, PG&E expects it will be required to file a compliance advice letter that will lay out an implementation timeline to transition to the Modified GT program. It is expected that full implementation of the Modified GT would not be complete for some time as PG&E's multi-year Billing System Modernization Initiative will limit PG&E's ability to implement structural rate changes to PG&E's billing system. The existing Green Tariff will remain in place as PG&E develops implementation plans to transition existing GT customers to the Modified GT program.

As such, this testimony presents a 2027 rate forecast for PG&E's existing GTSR Solar Choice Program. PG&E anticipates the existing Solar Choice Program will be relevant to 2027 ratemaking and will continue to be relevant through 2027 until an implementation plan and timeline for the Modified GT Successor program is approved by the Commission.

D. GTSR Load Forecast

The number of participating customers and amount of participating load in PG&E Solar Choice Program (E-GT) continued to have attrition in 2025 and ended the year at approximately 66.4 MW, approximately 23 MW lower than the beginning of the year. The majority of PG&E's current Solar Choice load is comprised of non-residential customers who enrolled in 2021.

The 2026 Solar Choice rates remain a premium above the otherwise applicable tariffs for all rate classes relative to the otherwise applicable tariff. PG&E expects continued attrition of customers during 2026 given the increase in rates for most schedules. However, at the time of filing, PG&E has only billed usage data through March 2026, which makes it difficult to accurately project the customer attrition in 2026. At this time, PG&E's 2027 forecast load does not reflect attrition of its Solar Choice customers in 2027 compared to the 2026 forecast approved last year. PG&E will update this forecast during its Fall Update which will have more data-based trends on customer retention for 2026 with actuals at least through August.

PG&E's initial projection for its GTSR Solar Choice load forecast for the balance of 2026 and 2027 is shown in Table 14-1 below, which includes load forecasts for PG&E's Solar Choice Program (E-GT).

TABLE 14-1
GTSR PROGRAM RECORDED AND FORECAST SALES

Line No.	Description	Actuals			Forecast	
1	Fiscal Year	2023	2024	2025	2026	2027
2	Program Year (PY)	PY 7	PY 8	PY 9	PY 10	PY 11
3	E-GT Sales (megawatt-hour (MWh)/yr)	375,231	316,358	188,762	152,005	134,246

In 2027, PG&E will be supplementing the dedicated resource pool with interim pool resources, which was approved in D.21-12-036. Pursuant to D.21-12-036, PG&E submitted Compliance AL 6451-E, which provided the Commission a specific list of interim pool resources PG&E planned to use to support the GTSR subscription level and received approval by the Commission through Resolution E-5218.[6]

E. 2027 Rate Forecast for GTSR Program

PG&E's request is to update the GTSR Program rate components for rates effective January 1, 2027. The GTSR Program bill credit and charges that make up the E-GT rates are: (1) Solar Rate (E-GT rate schedule only); (2) PCIA Program Charge; (3) Other Program Charge components: (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

6 AL 6451-E, filed December 28, 2021.

Marketing Costs and (4) Class Average Generation Rate credit. The Table 14-2 below summarizes the GTSR Program's rate components.

TABLE 14-2
GTSR PROGRAM CHARGES AND CREDITS

GTSR Program Rate Components	Charges	Credits
SOLAR CHARGE (E-GT Only)		
- Solar Choiice Interim Pool Resources	✓	
- Solar Choice Dedicated Resources	✓	
PROGRAM CHARGES (E-GT and E-ECR)		
Program Charge - Power Charge Indifference Adjustment (PCIA)		
- Vintage PCIA	✓	
Program Charge - Other		
Generation-related Program Charges		
- Renewable Integration	✓	
- Resource Adequacy	✓	
- Grid Management Charges	✓	
- WREGIS Fees	✓	
Solar Valule Adjustments		
- Time of Delivery	✓	
- Resource Adequacy from Dedicated Resources		✓
Administration and Market Program Charge		
- E-GT or E-ECR Marketing	✓	
- Administration Charge	✓	
CLASS AVERAGE GENERATION RATE CREDIT		✓

All the rate components have been reviewed and updated as appropriate in this request for 2027 except for the RIC, which will remain unchanged for 2027.

The GTSR rate component forecast for 2027 starts with the solar rate, which is based on the forecast deliveries and costs for dedicated GTSR Program resources supplemented by interim pool resources up to the forecast subscription level.

The PCIA and the RA charge presented in this testimony are consistent with PG&E's 2027 ERRA Forecast values, to be updated through the Fall Update. In Chapter 13, the PCIA rates are presented by customer class, and are an input into the GTSR Program rates presented in this chapter.

The current RA charge is calculated using the RA Market Price Benchmarks (MPB) issued by Energy Division in November 2024 for use in PG&E's 2025 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 update the 2027 MPB when the Energy Division issues the final 2026 and forecast 2027 MPBs in the fall.

The costs for CAISO GMC have been updated and are based on a 3-year rolling average of recorded data as presented in Federal Energy Regulatory Commission 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.

PG&E is not forecasting a 2026 end of year balance in the GTSR balancing account at this time. PG&E will update this forecast in its Fall Update, which will also include a true-up of the RA charge using the final RA MPB value issued by Energy Division for 2026 and a true-up of the weighted average costs of the interim pool resource mix to final actuals.

As required by D.15-01-051, PG&E will present a summary of the GTSR Program's balancing account entries, including the true-up of costs and revenues against charges and credits, in its annual ERRA Compliance Review Application.[7] PG&E submitted its 2025 ERRA Compliance Review to the Commission in February 2026 (A. 26-02-019), reviewing balancing account activity for the 2025 record period.

Tables 14-3 and 14-4 below summarize the 2027 GTSR Program charges and credits for Solar Choice Program for a 2027 vintage customer and for a 2025 vintage customer, respectively. One thing to note is that active enrollment is currently suspended at this time due to the supply imbalance however, customers interested in enrolling in the program are being put on a waitlist.

Tables 14-5 through 14-15 summarize the 2027 GTSR Program charges and credits for customers currently being served under the Solar Choice Program, which includes vintage customers 2015 through 2025. The Solar Choice rate results in Table 14-3, and Tables 14-5 through 14-15, show a mix of

[7] D.15-01-051, COL 59.

increases and decrease in the GTSR net rate results compared to the 2026 net rate results with all schedules showing a net premium compared to the otherwise applicable tariff. These increases and decreases to the Solar Choice net result are attributable to multiple factors including a lower solar charge and lower RA charge credit paired with decreases in the PCIA rate and a higher generation rate credit.

F. Conclusion

PG&E requests that the Commission approve PG&E's GTSR Program rates for Schedule E-GT, subject to those updates set forth in PG&E's Fall Update.

TABLE 14-3
GTSR PROGRAM – VINTAGE 2027
E-GT OPTION

Line No.		E1 cents/kwh	B1 cents/kwh	B6 cents/kwh	B10 cents/kwh	B19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	B20 T cents/kwh	B20 P cents/kwh	B20 S cents/kwh	BEV1 cents/kwh	BEV2 cents/kwh
	Charges												
1	**Solar Generation Price**	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576
2	PCIA	0.701	0.675	0.675	0.714	0.677	0.564	0.655	0.587	0.599	0.631	0.577	0.644
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979
5	Resource Adequacy	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845
6	CAISO Charges	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132
7	WREGIS Fees	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
8	**Sub Total**	**13.234**	**13.208**	**13.208**	**13.247**	**13.210**	**13.097**	**13.188**	**13.120**	**13.132**	**13.164**	**13.110**	**13.177**
9	**Credits**												
10	**Class Average Generation Rate**	13.892	13.389	13.389	14.159	13.421	11.164	12.979	11.619	11.864	12.510	13.389	13.421
11	Solar Value Adjustment												
12	TOD	(4.654)	(4.097)	(4.097)	(3.441)	(3.436)	(3.249)	(1.843)	(2.858)	(2.919)	(3.078)	(4.097)	(3.436)
13	RA	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	10.234	10.288	10.288	11.714	10.981	8.911	12.132	9.757	9.941	10.428	10.288	10.981
16	**2027 Premium (cents/kwh)**	**3.000**	**2.920**	**2.920**	**1.533**	**2.229**	**4.186**	**1.056**	**3.363**	**3.191**	**2.736**	**2.822**	**2.196**

TABLE 14-4
GTSR PROGRAM – VINTAGE 2026
E-GT OPTION

Line No.		E1 cents/kwh	B1 cents/kwh	B6 cents/kwh	B10 cents/kwh	B19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	B20 T cents/kwh	B20 P cents/kwh	B20 S cents/kwh	BEV1 cents/kwh	BEV2 cents/kwh
	Charges												
1	**Solar Generation Price**	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576
2	PCIA	0.701	0.675	0.675	0.714	0.677	0.564	0.655	0.587	0.599	0.631	0.577	0.644
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979
5	Resource Adequacy	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845
6	CAISO Charges	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132
7	WREGIS Fees	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
8	**Sub Total**	**13.234**	**13.208**	**13.208**	**13.247**	**13.210**	**13.097**	**13.188**	**13.120**	**13.132**	**13.164**	**13.110**	**13.177**
9	**Credits**												
10	**Class Average Generation Rate**	13.892	13.389	13.389	14.159	13.421	11.164	12.979	11.619	11.864	12.510	13.389	13.421
11	Solar Value Adjustment												
12	TOD	(4.654)	(4.097)	(4.097)	(3.441)	(3.436)	(3.249)	(1.843)	(2.858)	(2.919)	(3.078)	(4.097)	(3.436)
13	RA	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	10.234	10.288	10.288	11.714	10.981	8.911	12.132	9.757	9.941	10.428	10.288	10.981
16	**2027 Premium (cents/kwh)**	**3.000**	**2.920**	**2.920**	**1.533**	**2.229**	**4.186**	**1.056**	**3.363**	**3.191**	**2.736**	**2.822**	**2.196**

TABLE 14-5
GTSR PROGRAM – VINTAGE 2025
E-GT OPTION

Line No.		E1 cents/kwh	B1 cents/kwh	B6 cents/kwh	B10 cents/kwh	B19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	B20 T cents/kwh	B20 P cents/kwh	B20 S cents/kwh	BEV1 cents/kwh	BEV2 cents/kwh
	Charges												
1	**Solar Generation Price**	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576
2	PCIA	1.413	1.362	1.362	1.441	1.366	1.137	1.321	1.183	1.208	1.273	1.164	1.298
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979
5	Resource Adequacy	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845
6	CAISO Charges	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132
7	WREGIS Fees	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
8	**Sub Total**	**13.946**	**13.895**	**13.895**	**13.974**	**13.899**	**13.670**	**13.854**	**13.716**	**13.741**	**13.806**	**13.697**	**13.831**
9	**Credits**												
10	**Class Average Generation Rate**	13.892	13.389	13.389	14.159	13.421	11.164	12.979	11.619	11.864	12.510	13.389	13.421
11	Solar Value Adjustment												
12	TOD	(4.654)	(4.097)	(4.097)	(3.441)	(3.436)	(3.249)	(1.843)	(2.858)	(2.919)	(3.078)	(4.097)	(3.436)
13	RA	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	10.234	10.288	10.288	11.714	10.981	8.911	12.132	9.757	9.941	10.428	10.288	10.981
16	**2027 Premium (cents/kwh)**	**3.712**	**3.607**	**3.607**	**2.260**	**2.918**	**4.759**	**1.722**	**3.959**	**3.800**	**3.378**	**3.409**	**2.850**

TABLE 14-6
GTSR PROGRAM – VINTAGE 2024
E-GT OPTION

Line No.		E1 cents/kwh	B1 cents/kwh	B6 cents/kwh	B10 cents/kwh	B19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	B20 T cents/kwh	B20 P cents/kwh	B20 S cents/kwh	BEV1 cents/kwh	BEV2 cents/kwh
	Charges												
1	**Solar Generation Price**	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576
2	PCIA	1.253	1.207	1.207	1.276	1.210	1.007	1.170	1.048	1.070	1.128	1.031	1.151
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979
5	Resource Adequacy	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845
6	CAISO Charges	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132
7	WREGIS Fees	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
8	**Sub Total**	**13.786**	**13.740**	**13.740**	**13.809**	**13.743**	**13.540**	**13.703**	**13.581**	**13.603**	**13.661**	**13.564**	**13.684**
9	**Credits**												
10	**Class Average Generation Rate**	13.892	13.389	13.389	14.159	13.421	11.164	12.979	11.619	11.864	12.510	13.389	13.421
11	Solar Value Adjustment												
12	TOD	(4.654)	(4.097)	(4.097)	(3.441)	(3.436)	(3.249)	(1.843)	(2.858)	(2.919)	(3.078)	(4.097)	(3.436)
13	RA	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	10.234	10.288	10.288	11.714	10.981	8.911	12.132	9.757	9.941	10.428	10.288	10.981
16	**2027 Premium (cents/kwh)**	**3.552**	**3.452**	**3.452**	**2.095**	**2.762**	**4.629**	**1.571**	**3.824**	**3.662**	**3.233**	**3.276**	**2.703**

TABLE 14-7
GTSR PROGRAM – VINTAGE 2023
E-GT OPTION

Line No.		E1 cents/kwh	B1 cents/kwh	B6 cents/kwh	B10 cents/kwh	B19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	B20 T cents/kwh	B20 P cents/kwh	B20 S cents/kwh	BEV1 cents/kwh	BEV2 cents/kwh
	Charges												
1	**Solar Generation Price**	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576
2	PCIA	1.352	1.303	1.303	1.378	1.306	1.087	1.263	1.131	1.155	1.218	1.113	1.242
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979
5	Resource Adequacy	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845
6	CAISO Charges	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132
7	WREGIS Fees	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
8	**Sub Total**	**13.885**	**13.836**	**13.836**	**13.911**	**13.839**	**13.620**	**13.796**	**13.664**	**13.688**	**13.751**	**13.646**	**13.775**
9	**Credits**												
10	**Class Average Generation Rate**	13.892	13.389	13.389	14.159	13.421	11.164	12.979	11.619	11.864	12.510	13.389	13.421
11	Solar Value Adjustment												
12	TOD	(4.654)	(4.097)	(4.097)	(3.441)	(3.436)	(3.249)	(1.843)	(2.858)	(2.919)	(3.078)	(4.097)	(3.436)
13	RA	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	10.234	10.288	10.288	11.714	10.981	8.911	12.132	9.757	9.941	10.428	10.288	10.981
16	**2027 Premium (cents/kwh)**	**3.651**	**3.548**	**3.548**	**2.197**	**2.858**	**4.709**	**1.664**	**3.907**	**3.747**	**3.323**	**3.358**	**2.794**

TABLE 14-8
GTSR PROGRAM – VINTAGE 2022
E-GT OPTION

Line No.		E1 cents/kwh	B1 cents/kwh	B6 cents/kwh	B10 cents/kwh	B19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	B20 T cents/kwh	B20 P cents/kwh	B20 S cents/kwh	BEV1 cents/kwh	BEV2 cents/kwh
	Charges												
1	**Solar Generation Price**	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576
2	PCIA	1.366	1.317	1.317	1.392	1.320	1.098	1.277	1.143	1.167	1.231	1.124	1.255
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979
5	Resource Adequacy	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845
6	CAISO Charges	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132
7	WREGIS Fees	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
8	**Sub Total**	**13.899**	**13.850**	**13.850**	**13.925**	**13.853**	**13.631**	**13.810**	**13.676**	**13.700**	**13.764**	**13.657**	**13.788**
9	**Credits**												
10	**Class Average Generation Rate**	13.892	13.389	13.389	14.159	13.421	11.164	12.979	11.619	11.864	12.510	13.389	13.421
11	Solar Value Adjustment												
12	TOD	(4.654)	(4.097)	(4.097)	(3.441)	(3.436)	(3.249)	(1.843)	(2.858)	(2.919)	(3.078)	(4.097)	(3.436)
13	RA	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	10.234	10.288	10.288	11.714	10.981	8.911	12.132	9.757	9.941	10.428	10.288	10.981
16	**2027 Premium (cents/kwh)**	**3.665**	**3.562**	**3.562**	**2.211**	**2.872**	**4.720**	**1.678**	**3.919**	**3.759**	**3.336**	**3.369**	**2.807**

TABLE 14-9
GTSR PROGRAM – VINTAGE 2021
E-GT OPTION

Line No.		E1 cents/kwh	B1 cents/kwh	B6 cents/kwh	B10 cents/kwh	B19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	B20 T cents/kwh	B20 P cents/kwh	B20 S cents/kwh	BEV1 cents/kwh	BEV2 cents/kwh
	Charges												
1	**Solar Generation Price**	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576
2	PCIA	1.259	1.214	1.214	1.283	1.216	1.012	1.176	1.054	1.076	1.134	1.036	1.157
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979
5	Resource Adequacy	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845
6	CAISO Charges	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132
7	WREGIS Fees	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
8	**Sub Total**	**13.792**	**13.747**	**13.747**	**13.816**	**13.749**	**13.545**	**13.709**	**13.587**	**13.609**	**13.667**	**13.569**	**13.690**
9	**Credits**												
10	**Class Average Generation Rate**	13.892	13.389	13.389	14.159	13.421	11.164	12.979	11.619	11.864	12.510	13.389	13.421
11	Solar Value Adjustment												
12	TOD	(4.654)	(4.097)	(4.097)	(3.441)	(3.436)	(3.249)	(1.843)	(2.858)	(2.919)	(3.078)	(4.097)	(3.436)
13	RA	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	10.234	10.288	10.288	11.714	10.981	8.911	12.132	9.757	9.941	10.428	10.288	10.981
16	**2027 Premium (cents/kwh)**	**3.558**	**3.459**	**3.459**	**2.102**	**2.768**	**4.634**	**1.577**	**3.830**	**3.668**	**3.239**	**3.281**	**2.709**

TABLE 14-10
GTSR PROGRAM – VINTAGE 2020
E-GT OPTION

Line No.		E1 cents/kwh	B1 cents/kwh	B6 cents/kwh	B10 cents/kwh	B19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	B20 T cents/kwh	B20 P cents/kwh	B20 S cents/kwh	BEV1 cents/kwh	BEV2 cents/kwh
	Charges												
1	**Solar Generation Price**	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576
2	PCIA	1.417	1.365	1.365	1.444	1.369	1.139	1.324	1.185	1.210	1.276	1.166	1.301
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979
5	Resource Adequacy	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845
6	CAISO Charges	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132
7	WREGIS Fees	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
8	**Sub Total**	**13.950**	**13.898**	**13.898**	**13.977**	**13.902**	**13.672**	**13.857**	**13.718**	**13.743**	**13.809**	**13.699**	**13.834**
9	**Credits**												
10	**Class Average Generation Rate**	13.892	13.389	13.389	14.159	13.421	11.164	12.979	11.619	11.864	12.510	13.389	13.421
11	Solar Value Adjustment												
12	TOD	(4.654)	(4.097)	(4.097)	(3.441)	(3.436)	(3.249)	(1.843)	(2.858)	(2.919)	(3.078)	(4.097)	(3.436)
13	RA	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	10.234	10.288	10.288	11.714	10.981	8.911	12.132	9.757	9.941	10.428	10.288	10.981
16	**2027 Premium (cents/kwh)**	**3.716**	**3.610**	**3.610**	**2.263**	**2.921**	**4.761**	**1.725**	**3.961**	**3.802**	**3.381**	**3.411**	**2.853**

TABLE 14-11
GTSR PROGRAM – VINTAGE 2019
E-GT OPTION

Line No.		E1 cents/kwh	B1 cents/kwh	B6 cents/kwh	B10 cents/kwh	B19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	B20 T cents/kwh	B20 P cents/kwh	B20 S cents/kwh	BEV1 cents/kwh	BEV2 cents/kwh
	Charges												
1	**Solar Generation Price**	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576
2	PCIA	1.425	1.374	1.374	1.452	1.377	1.146	1.332	1.192	1.217	1.284	1.173	1.309
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979
5	Resource Adequacy	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845
6	CAISO Charges	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132
7	WREGIS Fees	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
8	**Sub Total**	**13.958**	**13.907**	**13.907**	**13.985**	**13.910**	**13.679**	**13.865**	**13.725**	**13.750**	**13.817**	**13.706**	**13.842**
9	**Credits**												
10	**Class Average Generation Rate**	13.892	13.389	13.389	14.159	13.421	11.164	12.979	11.619	11.864	12.510	13.389	13.421
11	Solar Value Adjustment												
12	TOD	(4.654)	(4.097)	(4.097)	(3.441)	(3.436)	(3.249)	(1.843)	(2.858)	(2.919)	(3.078)	(4.097)	(3.436)
13	RA	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	10.234	10.288	10.288	11.714	10.981	8.911	12.132	9.757	9.941	10.428	10.288	10.981
16	**2027 Premium (cents/kwh)**	**3.724**	**3.619**	**3.619**	**2.271**	**2.929**	**4.768**	**1.733**	**3.968**	**3.809**	**3.389**	**3.418**	**2.861**

TABLE 14-12
GTSR PROGRAM – VINTAGE 2018
E-GT OPTION

Line No.		E1 cents/kwh	B1 cents/kwh	B6 cents/kwh	B10 cents/kwh	B19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	B20 T cents/kwh	B20 P cents/kwh	B20 S cents/kwh	BEV1 cents/kwh	BEV2 cents/kwh
	Charges												
1	**Solar Generation Price**	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576
2	PCIA	1.445	1.393	1.393	1.472	1.396	1.162	1.350	1.209	1.234	1.301	1.189	1.327
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979
5	Resource Adequacy	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845
6	CAISO Charges	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132
7	WREGIS Fees	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
8	**Sub Total**	**13.978**	**13.926**	**13.926**	**14.005**	**13.929**	**13.695**	**13.883**	**13.742**	**13.767**	**13.834**	**13.722**	**13.860**
9	**Credits**												
10	**Class Average Generation Rate**	13.892	13.389	13.389	14.159	13.421	11.164	12.979	11.619	11.864	12.510	13.389	13.421
11	Solar Value Adjustment												
12	TOD	(4.654)	(4.097)	(4.097)	(3.441)	(3.436)	(3.249)	(1.843)	(2.858)	(2.919)	(3.078)	(4.097)	(3.436)
13	RA	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	10.234	10.288	10.288	11.714	10.981	8.911	12.132	9.757	9.941	10.428	10.288	10.981
16	**2027 Premium (cents/kwh)**	**3.744**	**3.638**	**3.638**	**2.291**	**2.948**	**4.784**	**1.751**	**3.985**	**3.826**	**3.406**	**3.434**	**2.879**

TABLE 14-13
GTSR PROGRAM – VINTAGE 2017
E-GT OPTION

Line No.		E1 cents/kwh	B1 cents/kwh	B6 cents/kwh	B10 cents/kwh	B19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	B20 T cents/kwh	B20 P cents/kwh	B20 S cents/kwh	BEV1 cents/kwh	BEV2 cents/kwh
	Charges												
1	**Solar Generation Price**	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576
2	PCIA	1.584	1.527	1.527	1.615	1.531	1.274	1.480	1.326	1.354	1.427	1.304	1.455
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979
5	Resource Adequacy	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845
6	CAISO Charges	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132
7	WREGIS Fees	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
8	**Sub Total**	**14.117**	**14.060**	**14.060**	**14.148**	**14.064**	**13.807**	**14.013**	**13.859**	**13.887**	**13.960**	**13.837**	**13.988**
9	**Credits**												
10	**Class Average Generation Rate**	13.892	13.389	13.389	14.159	13.421	11.164	12.979	11.619	11.864	12.510	13.389	13.421
11	Solar Value Adjustment												
12	TOD	(4.654)	(4.097)	(4.097)	(3.441)	(3.436)	(3.249)	(1.843)	(2.858)	(2.919)	(3.078)	(4.097)	(3.436)
13	RA	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	10.234	10.288	10.288	11.714	10.981	8.911	12.132	9.757	9.941	10.428	10.288	10.981
16	**2027 Premium (cents/kwh)**	**3.883**	**3.772**	**3.772**	**2.434**	**3.083**	**4.896**	**1.881**	**4.102**	**3.946**	**3.532**	**3.549**	**3.007**

TABLE 14-14
GTSR PROGRAM – VINTAGE 2016
E-GT OPTION

Line No.		E1 cents/kwh	B1 cents/kwh	B6 cents/kwh	B10 cents/kwh	B19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	B20 T cents/kwh	B20 P cents/kwh	B20 S cents/kwh	BEV1 cents/kwh	BEV2 cents/kwh
	Charges												
1	**Solar Generation Price**	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576
2	PCIA	1.596	1.539	1.539	1.627	1.542	1.284	1.492	1.336	1.364	1.438	1.314	1.467
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979
5	Resource Adequacy	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845
6	CAISO Charges	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132
7	WREGIS Fees	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
8	**Sub Total**	**14.129**	**14.072**	**14.072**	**14.160**	**14.075**	**13.817**	**14.025**	**13.869**	**13.897**	**13.971**	**13.847**	**14.000**
9	**Credits**												
10	**Class Average Generation Rate**	13.892	13.389	13.389	14.159	13.421	11.164	12.979	11.619	11.864	12.510	13.389	13.421
11	Solar Value Adjustment												
12	TOD	(4.654)	(4.097)	(4.097)	(3.441)	(3.436)	(3.249)	(1.843)	(2.858)	(2.919)	(3.078)	(4.097)	(3.436)
13	RA	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	10.234	10.288	10.288	11.714	10.981	8.911	12.132	9.757	9.941	10.428	10.288	10.981
16	**2027 Premium (cents/kwh)**	**3.895**	**3.784**	**3.784**	**2.446**	**3.094**	**4.906**	**1.893**	**4.112**	**3.956**	**3.543**	**3.559**	**3.019**

TABLE 14-15
GTSR PROGRAM – VINTAGE 2015
E-GT OPTION

Line No.		E1 cents/kwh	B1 cents/kwh	B6 cents/kwh	B10 cents/kwh	B19 cents/kwh	LS-3 cents/kwh	AG cents/kwh	B20 T cents/kwh	B20 P cents/kwh	B20 S cents/kwh	BEV1 cents/kwh	BEV2 cents/kwh
	Charges												
1	**Solar Generation Price**	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576	7.576
2	PCIA	1.597	1.540	1.540	1.628	1.543	1.284	1.493	1.337	1.365	1.439	1.315	1.467
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979	0.979
5	Resource Adequacy	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845	3.845
6	CAISO Charges	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132	0.132
7	WREGIS Fees	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
8	**Sub Total**	**14.130**	**14.073**	**14.073**	**14.161**	**14.076**	**13.817**	**14.026**	**13.870**	**13.898**	**13.972**	**13.848**	**14.000**
9	**Credits**												
10	**Class Average Generation Rate**	13.892	13.389	13.389	14.159	13.421	11.164	12.979	11.619	11.864	12.510	13.389	13.421
11	Solar Value Adjustment												
12	TOD	(4.654)	(4.097)	(4.097)	(3.441)	(3.436)	(3.249)	(1.843)	(2.858)	(2.919)	(3.078)	(4.097)	(3.436)
13	RA	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996	0.996
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	10.234	10.288	10.288	11.714	10.981	8.911	12.132	9.757	9.941	10.428	10.288	10.981
16	**2027 Premium (cents/kwh)**	**3.896**	**3.785**	**3.785**	**2.447**	**3.095**	**4.906**	**1.894**	**4.113**	**3.957**	**3.544**	**3.560**	**3.019**

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

TABLE OF CONTENTS

A. Introduction 15-1

B. Background 15-1

C. Calculation of Forecast GHG Costs 15-2

  1. Forecast Direct GHG Costs 15-2

D. Reconciliation of Forecast GHG Costs 15-2

  1. Recorded Direct GHG Costs 15-2

    a. Calculation of GHG Compliance Instrument Expense Recorded 15-3

E. Conclusion 15-5

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) presents the reconciliation mandated by the California Public Utilities Commission (Commission or CPUC) 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 (FR&R) application, separate from the corresponding Energy Resource Recovery Account (ERRA) Forecast application, but 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.

To develop this chapter, PG&E relies on its forecast of the direct GHG emissions compliance expenses PG&E expects to incur and record to its balancing accounts in 2027.[1] This chapter:

1) Adds that amount to the estimate of direct GHG emissions compliance expenses that PG&E anticipates will be recorded in 2027, which is included in the cost forecasts presented in Chapters 3 through 6 of this testimony, to derive a forecast of the total amount of direct GHG emissions compliance expenses that PG&E anticipates will be recorded in 2026; and
2) Presents a reconciliation of the 2025 GHG cost forecast that was included in PG&E's 2025 (ERRA) Forecast proceeding, Application (A.) 24-05-009.

B. Background

The CPUC adopted D.21-08-026, which made revisions to CPUC methodologies and processes to ensure compliance with current statute and California Air Resources Board (CARB) regulation, and to streamline existing processes. Pursuant to Ordering Paragraph (OP) 12 of that Decision, the Energy Division facilitated a workshop on August 30, 2021, to discuss updates needed for existing CPUC-approved templates. In compliance with OP 13 of the

---

[1] The CARB Cap-and-Trade Program results in direct GHG Compliance costs which are reflected in this chapter.

same Decision, the Joint IOUs submitted several Advice Letters (AL)[2] proposing changes to Appendix D of D.14-10-033. In its disposition of Advice 6326-E, Energy Division staff approved, as relevant here: (1) Template D-2 and associated notes pages, and (2) the removal of Templates D-4 and D-5. This Prepared Testimony is consistent with Staff's non-standard disposition, and PG&E has henceforth omitted Templates D-4 and D-5.

The remainder of this chapter is organized as follows:

- Section C – Calculation of Forecast GHG Costs;
- Section D – Reconciliation of Forecast GHG Costs; and[3]
- Section E – Conclusion.

C. 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 3 through 5.

D. Reconciliation of Forecast GHG Costs

PG&E is also including with this Application a reconciliation of GHG procurement costs previously forecasted for 2025 in Portfolio Allocation Balancing Account (PABA) with recorded direct GHG costs. The 2026 GHG cost forecast will be fully-reconciled in PG&E's 2028 ERRA Forecast Application.

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 Combined Heat and Power 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

---

2 Southern California Edison Company (SCE) submitted Advice 4587-E on September 14, 2021 on behalf of the Join IOUs recommending changes to Templates D-2, D-4, and D-5. On October 1, 2021 SCE submitted AL 4587-E-A (identical to PG&E's AL 6326-E-A) replacing the original AL in its entirety.

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.

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.[4]

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 from its inventory to meet PG&E's GHG emissions compliance obligation in a given year. PG&E uses the 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 uses to record, each month, 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 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, 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

---

4 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, 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.ac. for bilateral contracts.

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.[5]

PG&E's current methodology for calculating the WAC is consistent with D.19-04-016 adopting the Petition for Modification to D.15-01-024 (Petition).[6] 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 ($/MT of carbon dioxide equivalent (mtCO_2e)) multiplied by emissions volumes ($/mt$CO_2$e).

Table 15-3 shows the WAC calculation and direct emissions expense recorded to the PABA in 2025, as ordered in D.14-10-033,

---

5 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.

6 The Petition clarified the calculation of the WAC and makes the calculation consistent for PG&E, SCE, and San Diego Gas & Electric Company. It does not change the calculation methodology for PG&E.

Appendix C, corrected and replaced Attachment C in its entirety in D.15-01-024.

E. Conclusion

In this chapter, PG&E presents its requirements ordered by CPUC D.12-12-033 and D.14-10-033, including a reconciliation of the 2025 GHG cost forecast, and a detailed report of the monthly WAC and direct GHG emissions quantities for 2025 used to calculate 2025 recorded direct GHG costs.

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

Line No.	Description	2025 Forecast	2025 Recorded	2025 Final	2026 Forecast	2026 Recorded	2026 Final	2027 Forecast	2027 Recorded	2027 Final
1	Direct GHG Emissions (MT CO2e)									
2	Utility Owned Generation (UOG)	[redacted]								
3	Tolling Agreements									
4	Energy Imports (Specified)									
5	Energy imports (Unspecified)									
6	Qualifying Facility (QF) Contracts									
7	Contracts with Financial Settlement									
8	Subtotal									
9	**Total Emissions (MT CO2e)**	**2,179,565**	**2,220,181**	**2,327,659**	**1,950,513**	**1,950,513**	**-**	**2,076,730**	**-**	**-**
10	Proxy GHG Price ($/MT) (a)	37.58	29.52	29.89	30.58	30.58	-	31.02	-	-
11	GHG Costs ($)	[redacted]								
12	Direct GHG Costs (b)									
13	Direct GHG Costs - Financial Settlement									
14	Previous Year's Forecast Reconciliation (Line 21)	N/A	N/A		(19,031,446)	(19,031,446)		5,139,896	-	
15	**Total Costs ($)**	**80,084,942**	**61,053,496**	**66,193,392**	**40,615,237**	**40,615,237**		**67,932,363**	**-**	
16	Forecast Variance ($)	N/A	(19,031,446)	5,139,896	N/A	-		N/A	-	

(a) The difference between PG&E's confidential forecast GHG price and the 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	2025 Forecast	2025 Recorded	2025 Final	2026 Forecast	2026 Recorded	2026 Final	2027 Forecast	2027 Recorded	2027 Final
1	Direct GHG Emissions (MT CO2e)									
2	Utility Owned Generation (UOG)	[redacted]								
3	Tolling Agreements									
4	Energy Imports (Specified)									
5	Energy imports (Unspecified)									
6	Qualifying Facility (QF) Contracts									
7	Contracts with Financial Settlement									
8	Subtotal									
9	**Total Emissions (MT CO2e)**	**2,179,565**	**2,220,181**	**2,327,659**	**1,950,513**	**1,950,513**	**-**	**2,076,730**	**-**	**-**
10	Proxy GHG Price ($/MT) (a)	37.58	29.52	29.89	30.58	30.58		31.02	-	-
11	GHG Costs ($)	[redacted]								
12	Direct GHG Costs (b)									
13	Direct GHG Costs - Financial Settlement									
14	Previous Year's Forecast Reconciliation (Line 21)	N/A	N/A		(19,031,446)	(19,031,446)		5,139,896	-	
15	**Total Costs ($)**	**80,084,942**	**61,053,496**	**66,193,392**	**40,615,237**	**40,615,237**		**69,560,071**	**-**	
16	Forecast Variance ($)	N/A	(19,031,446)	5,139,896	N/A	-		N/A	-	

(a) The difference between PG&E's confidential forecast GHG price and the 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 WAC OF COMPLIANCE INSTRUMENTS AND DIRECT COSTS
(TEMPLATE C-1 OF REVISED ATTACHMENT C OF D.19-04-016)

Compliance Period 5[(a)]

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

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

	Direct GHG Costs				True-Ups (d)	Monthly BA Entry (e)
Month	Direct Monthly Emissions (MT) (c)		WAC Pricing ($/MT)	WAC x Direct Emissions Qty ($)	True-Up Value +/- ($)	Monthly Balancing Account Entries ($)
Jan-25	[redacted]					
Feb-25	[redacted]					
Mar-25	[redacted]					
Apr-25	[redacted]					
May-25	[redacted]					
Jun-25	[redacted]					
Jul-25	[redacted]					
Aug-25	[redacted]					
Sep-25	[redacted]					
Oct-25	[redacted]					
Nov-25	[redacted]					
Dec-25	[redacted]					

Transaction Type Definition:

Purchase	Purchase of compliance instruments
Retirement	Compliance instruments retired to CARB or transferred to a third-party
Transfer	Transfer of compliance instruments procured for Compressor Station Obligations to GHG Compressor Station Portfolio
Carryforward	Transfer of compliance instruments procured during previous Compliance Period carried forward into the current Compliance Period inventory
Wacog Adjustment	Premium paid to a third-party relating to the purchase of compliance instruments.

Notes:

(a) PG&E tracks WAC by Compliance Period. This template includes the WAC calculation for compliance instruments procured for the purposes of complying with its ARB obligation for Compliance Periods 2 through 5.

(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

TABLE OF CONTENTS

A. Introduction 16-1

B. GHG Administrative Recorded and Forecast Expenses 16-2

   1. Recorded Administrative Expenses 16-2

   2. Forecast Administrative Expenses 16-2

C. GHG Customer Outreach Recorded and Forecast Expenses 16-4

   1. Recorded Outreach Expenses 16-4

      a. CCC/SMB/EITE 16-5

      b. Labor 16-5

   2. Forecast Outreach Expenses 16-6

      a. Residential Climate Credit 16-6

      b. SMB Credit 16-7

      c. EITE Credit 16-7

      d. Labor 16-8

D. Conclusion 16-8

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 2025 recorded and 2027 forecasted greenhouse gas (GHG) administrative and outreach (A&O) expenses for review of reasonableness by the California Public Utilities Commission (CPUC or Commission), consistent with the direction provided in Decision (D.) 12-12-033,[1] D.14-10-033,[2] D.14-12-037,[3] D.16-06-041,[4] and D.21-08-026,[5] and Resolution (Res.) E-4611[6] and Res.E-4716.[7]

As part of the Commission's framework for administering the GHG Revenue Return for Emissions-Intensive and Trade-Exposed (EITE) entities, also referred to as the "California Industry Assistance" or the "EITE Credit," D.21-08-026[8] establishes the conditions under which large-EITE credits are administered and the circumstances under which that administration may change. D.21-08-026 explains that the Commission-administered EITE credit for large EITE facilities is based on California Air Resources Board's (CARB) existing regulatory framework and acknowledges that this administration could change if CARB modifies that framework. The decision further establishes a transition process to facilitate a potential shift in responsibility should CARB adopt and implement amendments to the Cap-and-Invest Regulation that directly allocate or administer large-EITE assistance. CARB's proposed amendments to the

---

1 Ordering Paragraphs (OP) 23 and 24.

2 OPs 9, 10, and 11.

3 OPs 6, 9 and 10.

4 OP 4.

5 OPs 7 and 8.

6 OP 5.

7 Finding of Facts 7 and 13.

8 See D.21-08-026, Section 4.4.1 (Large EITE Facilities).

Cap-and-Invest Regulation have not yet been finalized as of the date of this filing.[9] Accordingly, PG&E's 2027 administrative and outreach forecast reflects Commission direction and program requirements currently in effect. PG&E will update its forecast, as appropriate, to reflect adopted CARB regulations once finalized and implemented.

B. GHG Administrative Recorded and Forecast Expenses

1. Recorded Administrative Expenses

In 2025, PG&E incurred approximately $0.720 million to implement and administer the GHG allowance revenue return to customers. GHG allowance revenue return includes the twice-annual electric California Climate Credit (CCC) for residential households and eligible small businesses (SMB), and the annual facility-specific California Industry Assistance Credits for EITE customers. A breakdown of the total can be found in Table 16-1.

TABLE 16-1
2025 RECORDED ADMIN EXPENSES
(MILLIONS OF DOLLARS)

Line No.	Admin	Expenses
1	Program Management	$0.275
2	Information Technology (IT) Billing	0.246
3	Call Center	0.199
4	Total	$0.720

2. Forecast Administrative Expenses

In 2027, PG&E expects to incur approximately $0.837 million to administer the GHG allowance revenue return for the following activities: General Program Management, IT Billing System Maintenance, and Customer Inquiry Support (call center) costs. A breakdown of the total can be found in Table 16-2.

---

9 See CARB, Proposed 2026 Cap-and-Invest Regulation Amendments, available at: https://ww2.arb.ca.gov/our-work/programs/cap-and-invest-program/cap-and-invest-regulation.

TABLE 16-2
2027 FORECAST ADMIN EXPENSES
(MILLIONS OF DOLLARS)

Line No.	Admin	Expenses
1	Program Management	$0.389
2	IT Billing	0.053
3	Call Center	0.395
4	Total	$0.837

The Program Management expense is forecasted to be approximately $0.389 million. This includes $0.369 million to administer the GHG revenue return and $0.020 million to host and maintain the EITE attestation website.[10] The program management function is responsible for ensuring credits are accurately and timely returned to customers, identifying and reviewing billing system exceptions, managing and reconciling revenue reporting, developing the necessary guidance and training for call center/billing operations staff and account representatives, responding to customer inquiries, and other related work.

Consistent with D.21-08-026,[11] the scope and duration of administrative activities related to large EITEs subject to CARB's Mandatory Reporting Regulation (MRR) are contingent on CARB's regulatory framework. If CARB directly administers large-EITE assistance for the 2027 compliance year, certain large-EITE attestation-related, billing, and outreach activities reflected in this forecast would no longer be required on a forward basis. PG&E would continue to administer California Industry Assistance for qualifying small EITE facilities not subject to MRR requirements. PG&E will update its forecast, as appropriate, in its Fall Update to reflect adopted and implemented CARB regulations. Due to the complexities associated with matching the CARB's reporting entities with PG&E's customer accounts, dedicated resources are required to accurately verify and identify facility information in PG&E's billing systems. This process is manual and requires extensive customer outreach to resolve billing inquiries and discrepancies.

---

10 Res.E-4716, OP 2.

11 OP 2.

The IT/billing system forecast expense is approximately $0.053 million. This expense is required to accurately administer GHG revenue return to eligible residential, SMB and EITE customers.

The customer inquiry support forecast expense is approximately $0.395 million and includes call center operations support for CCC and SMB customers and assigned account representatives for EITE customers. While PG&E's current 2027 customer inquiry support forecast reflects current information and assumptions, PG&E will update the forecast, as appropriate, following completion of the August and September CCC distributions,[12] when it has improved visibility into CCC-related customer inquiry volumes.

PG&E notes that the Commission opened a Rulemaking[13] in July 2025 to evaluate potential improvements to the structure, timing, eligibility, and distribution of the GHG allowance revenue return to better support customer affordability. At this time, PG&E understands that changes to the structure and eligibility of the CCC will not occur in 2027, and accordingly, PG&E does not forecast significant changes to its requirement in this 2027 ERRA Forecast Application.

C. GHG Customer Outreach Recorded and Forecast Expenses

1. Recorded Outreach Expenses

The 2025 total recorded outreach expense of $0.148 million was required to plan, execute, and manage CCC, SMB and EITE outreach efforts. A breakdown of the total can be found in Table 16-3.

---

[12] Pursuant to D.26-04-036, adopted April 30, 2026, PG&E is directed to distribute the residential electric California Climate Credit in August and September 2027.

[13] *Rulemaking (R.) 25-07-013 (Order Instituting Rulemaking to Improve the California Climate Credit).*

TABLE 16-3
2025 RECORDED OUTREACH EXPENSES
(MILLIONS OF DOLLARS)

Line No.	Outreach	Expenses
1	Marketing Materials	$0.103
2	Labor	0.045
3	Total	$0.148

a. CCC/SMB/EITE

Pursuant to Res.E-4611,[14] D.16-06-041,[15] D.21-08-026,[16] and Res.E-5339,[17] PG&E distributed the Energy Division staff's approved messaging to customers through bill inserts and emails. GHG allowance revenue return related resources were also updated on PG&E's website and distributed to call center support staff.

Of the total 2025 expenditure of $0.148 million, PG&E incurred $0.103 million to notify eligible customers of the CCC, SMB and EITE credits through various outreach efforts as outlined below.

PG&E informed customers about the CCC and SMB credit distributions through a 1-panel bill insert that was included in the customer's bill package. Customers who are electronically billed by PG&E were sent an email regarding their credit. PG&E sent direct mail letters to master-meter customers regarding their responsibility to pass along the credit to tenants and to post the notification in a conspicuous place on their premises.

EITE customers were notified of their on-bill or check credit via email or direct mail letter with guidance on how to "cash out" any remaining credit amount that exceeded their total bill amount.

b. Labor

PG&E incurred labor costs of approximately $0.045 million to administer these outreach efforts.

---

14 Addressed Education and Outreach plans for GHG allowance revenue return.

15 OP 1 and 2.

16 OP 7.

17 OP 4 and 6.

2. Forecast Outreach Expenses

For 2027, PG&E estimates approximately $0.261 million to administer CCC, SMB, EITE credit outreach. A breakdown of the total can be found in Table 16-4.

TABLE 16-4
2027 FORECAST OUTREACH EXPENSES
(MILLIONS OF DOLLARS)

Line No.	Outreach	Forecast
1	CCC Marketing Materials	$0.172
2	SMB Marketing Materials	0.022
3	EITE Marketing Materials	0.002
4	Labor	0.065
5	Total	$0.261

PG&E developed the following forecasts based on the regulatory approvals and authorizations that are current as of this filing. 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.[18]

a. Residential Climate Credit

PG&E forecasts approximately $0.172 million to administer the CCC outreach efforts for residential customers. PG&E plans to inform residential customers of the twice-annual credit distribution by means of a 1-panel bill insert and an email to electronically-billed customers during August and September. The content of these communications is provided by the Energy Division staff, and similar content is expected to be authorized for use in 2027. PG&E plans to use the following outreach methods to notify residential customers of the CCC during August and September.

1) A 1-panel bill insert in August and September bill packages to approximately 2.5 million electric customers each month;

---

18 Fn. 9.

2) An e-mail notification to PG&E's electronically billed residential customers in August and September;

3) A letter to approximately 60,000 master-meter customers sent during each August and September deployment informing such customers of their requirement to pass the credits to tenants, and to post the notification of the credit in a conspicuous place on their premises; and

4) Inclusion in PG&E's residential eNewsletter to leverage a cost-efficient communication channel and direct customers to learn more at CPUC's CCC website.

b. SMB Credit

PG&E forecasts costs of approximately $0.022 million for outreach[19] to SMB customers. This outreach includes:

1) A one-panel bill insert distributed in April and October to approximately 1.0 million eligible customers in total, with roughly 0.5 million customers reached per distribution;

2) An email message to eligible SMB customers who are electronically billed through PG&E; and

3) An email notification to impacted SMB entities exceeding the 100+ account cap, informing them of their change in eligibility to receive the credit for the current year.[20]

c. EITE Credit

PG&E forecasts that it will incur expenses of approximately $0.002 million for outreach to EITE customers in 2027. This outreach will include:

1) E-mail notification to eligible customers; and

2) A letter to customers who request their EITE credit in the form of a check, rather than an on-bill credit.

---

[19] D.21-08-026, OP 7.

[20] Fn. 12.

d. Labor

PG&E estimates labor expenses of $0.065 million for EITE, CCC and SMB outreach efforts. The forecasted cost includes planning, execution, monitoring and managing the outreach plans and calendars, regulatory forecasting and reconciliations, and coordination with the CPUC staff and other investor-owned utilities.

D. Conclusion

In this chapter, PG&E describes its 2025 recorded and 2027 forecast GHG A&O expenses, as presented in Table 16-5 below. PG&E requests that the Commission review and approve the following as reasonable:

1) 2025 recorded A&O expenses of $0.867 million; and
2) 2027 forecast A&O expenses of $1.1 million.

TABLE 16-5
DETAIL OF A&O EXPENSES 2025-2027
(TEMPLATE D-3)
(THOUSANDS OF DOLLARS)

Template D-3: Detail of Outreach and Administrative Expenses (In $'000)

		2025		2026		2027	
Line	Description	Forecast	Recorded	Forecast	Recorded*	Forecast	Recorded
1	**Utility Administrative**						
2	General Program Management	360	275	359	49	389	
3	IT/Billing System Enhancements	215	246	103	22	53	
4	Customer Inquiry Support Cost	180	199	230	12	395	
5	**Subtotal Administrative**	754	720	692	83	837	
6	**Utility Outreach**						**Information not yet available**
7	Marketing - Internal						
8	Marketing - Contract/Consultant						
9	Targetbase						
10	Customer Outreach & Education	193	148	233	38	261	
11	**Subtotal Outreach**	193	148	233	38	261	
12	**Utility Outreach and Administrative Expenses (Line 5 + Line 11)**	947	867	925	121	1,098	
13	**Additional (Non-Utility) Statewide Outreach**			-		-	
14	**Total Outreach and Administrative Expenses (Line 12 + Line 13)****	947	867	925	121	1,098	

*Recorded Expense reflect latest available data and includes actuals from January through March.
**Totals may not add up due to rounding.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 17

GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION – REVENUE CALCULATIONS

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

TABLE OF CONTENTS

A. Introduction 17-1

1. Background 17-1

2. Order Instituting Rulemaking to Update the California Climate Credit R.25-07-013 17-4

3. Organization of this Chapter 17-5

B. Forecast 2027 Net Available GHG Allowance Proceeds 17-5

1. GHG Allowance Revenue Proceeds 17-5

2. GHG A&O Expenses 17-6

3. Clean Energy and Energy Efficiency (CEEE) Programs 17-7

C. Low-Income and Disadvantaged Community Solar Programs Previously Funded in Whole or in Part From the GHG Allowance Revenues 17-8

1. Introduction 17-8

2. SOMAH Program 17-9

3. DAC-SASH Program 17-11

4. DAC-GT Program 17-12

5. CCAs’ DAC-GT Budget Requests 17-14

6. PPP Funding for CEEE Programs 17-15

7. GHG Funds Remaining for CEEE Programs 17-16

D. Amortization of the 2026 Year-End Forecast Balance 17-17

E. 2027 GHG Allowance Return Revenue Requirement 17-18

F. Distribution of 2027 GHG Allowance Revenue Return 17-18

1. Methodology for the Distribution of GHG Allowance Revenue Return ... 17-18

a. EITE Revenue Return 17-18

b. Semi-Annual CCC Payment 17-20

TABLE OF CONTENTS
(CONTINUED)

G. Conclusion 17-21

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

A. Introduction

This chapter addresses Pacific Gas and Electric Company's (PG&E or the Utility) 2027 Greenhouse Gas (GHG) Allowance Return Revenue Requirement and its distribution to the customers in PG&E's territory in pursuant to Decisions (D.) 12-12-033, D.14-10-033, and D.21-08-026 authorized by the California Public Utilities Commission (CPUC or Commission). In this chapter, PG&E presents its: (1) forecasted 2027 GHG allowance return revenue requirement; and (2) 2026 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 CPUC requirements as ordered in D.12-12-033, D.14-10-033, D.15-01-024, and D.21-08-026.

1. Background

D.12-12-033 established the framework for investor-owned utilities (IOU) to manage and return California cap-and-trade greenhouse gas (GHG) allowance proceeds for the benefit of customers. Among other requirements, it allows IOUs to set aside reasonable GHG administrative and customer outreach (A&O) costs from allowance proceeds before returning net proceeds. It further directs IOUs to provide customer benefits through structured bill credits (including the California Climate Credit), supported by appropriate accounting, reporting, and reconciliation of GHG revenues and related costs. In D.14-10-033, the Commission adopted standard procedures for IOUs to present their GHG forecast revenue and reconciliation requests and provided associated reporting templates.[1] Separately, California law historically authorized limited use of a portion of

[1] The templates were subsequently updated in later Commission decisions (including D.14-10-055, D.15-01-024, and D.21-08-026).

GHG allowance revenues for certain clean energy and energy efficiency (CEEE) purposes, subject to statutory conditions (former Pub. Util. Code § 748.5), and the Commission's reporting templates have included lines to reflect those amounts where applicable. D.21-08-026 subsequently directed revisions to the applicable reporting templates through a workshop and advice letter process.

Ordering Paragraph (OP) 1 of D.15-01-024 requires PG&E and the other IOUs to file a Template D-1 to reflect the "Annual Allowance Revenue Receipts and Customer Returns" in their respective Energy Resource Recovery Account (ERRA) Forecast proceedings. The Template D-1 as required by D.15-01-024 as subsequently modified pursuant to D.21-08-026 is presented as Table 17-1 in this testimony. In its Fall Update, PG&E will use the updated Template D-1, as directed in a recent decision adopted by the Commission on April 30, 2026, as discussed further below.

TABLE 17-1
(TEMPLATE D-1)
ANNUAL ALLOWANCE REVENUE RECEIPTS AND CUSTOMER RETURNS
(THOUSANDS OF DOLLARS)

		2025		2026		2027	
Line	Description	Forecast [1]	Recorded	Forecast [1]	Recorded [2]	Forecast	Recorded
1	**Proxy GHG Price ($/MT)**	$37.58	N/A	$30.58	N/A	$31.02	
2	**Allocated Allowances ('000 MT) [3]**	21,426	21,070	23,023	22,677	16,165	
3	**Revenues**						
4	Prior Balance (From Line 31 of previous year)	53,324	28,767	199,666	167,955	(28,519)	
5	Allowance Revenue	(805,193)	(591,119)	(704,047)	(705,697)	(501,431)	
6	Interest		3,443		4,251		
7	Revenue Franchise Fees and Uncollectibles (RF&U)	(8,016)	(8,613)	(5,877)	(5,285)	(7,115)	
8	**Subtotal Revenues**	(759,885)	(567,521)	(510,258)	(538,777)	(537,065)	
9	**Expenses**						
10	Outreach and Administrative Expenses	817	674	934	750	1,202	
11	RF&U						
12	Interest	(144)		(183)		(212)	
13	**Subtotal Expenses**	674	674	750	750	990	
14	**Allowance Revenue Approved for Clean Energy or Energy Efficiency Programs**	38,303	38,303	34,232	34,232	5,939	Information not yet available
	(a) SOMAH including true-ups	34,626	34,626	15,196	15,196	1,867	
	(b) DAC-SASH	4,370	4,370	4,370	4,370	4,370	
	(c) DAC-GT and CS-GT including true-ups	5,664	5,664	18,219	18,219	25,271	
	(d) CCAs' DAC-GT and CS-GT including true-ups	9,667	9,667	13,206	13,206	10,436	
	(e) CCA Disbursement Reconciliation to PG&E	34	34	(715)	(715)	386	
	(f) Funding from Public Purpose Program (PPP)	(16,059)	(16,059)	(16,046)	(16,046)	(36,392)	
15	**Net GHG Revenues (Line 8 + Line 13 + Line 14)**	(720,909)	(528,545)	(475,276)	(503,795)	(530,137)	
16	**GHG Revenues to be Distributed in Future Years**						
17	**Net GHG Revenues Available for Customers in Forecast Year(Line 15 + Line 16)**	(720,909)	(528,545)	(475,276)	(503,795)	(530,137)	
18	**GHG Revenue Returned to Eligible Customers**						
19	EITE Customer Return	42,978	52,307	51,257	51,257	35,566	
20	Small Business Volumetric Return	0	0	0	0	0	
21	Residential Volumetric Return	0	0	0	0	0	
22	**Subtotal EITE + Volumetric Returns**	42,978	52,307	51,257	51,257	35,566	
23	**Semi-Annual Climate Credit [4]**						
24	Number of Households Eligible for the California Climate Credit						
25	Number of Eligible Residential Bundled Households	1,868,362	1,769,816	1,878,608	1,878,608	2,113,953	
26	Number of Eligible Residential Unbundled Households	3,559,652	3,356,460	3,602,410	3,602,410	3,380,443	
27	Number of Eligible Small Business Customers	393,473	405,493	379,232	379,232	429,829	
28	**Total Customers Eligible for Climate Credit (Sum 24..27)**	5,821,487	5,531,770	5,860,251	5,860,251	5,924,225	
29	**Per - Customer Semi-Annual Climate Credit (0.5 x (Line 17 + 22) ÷ Line 28)**	(58.23)	(58.23)	(36.18)	(36.18)	(41.74)	
30	**Total Revenue Distributed for the Climate Credit (2 x Line 28 x Line 29)**	(677,931)	(644,193)	(424,019)	(424,019)	(494,571)	
31	**Revenue Balance (Line 17 + Line 22 - Line 30)**	0	167,955	0	(28,519)	0	

-

Note 1 "Forecast" are derived from corresponding tables authorized by the Commission in prior ERRA Forecast

Note 2 "Recorded" includes January through March recorded, plus forecast through the rest of the year.

Note 3 Forecast based on latest published allocation by CARB

Note 4 "Recorded" columns for Lines 24 through 27 are calculated by dividing the recorded amounts distributed to Residential Bundled and Unbundled, as well as Small Business Customers over the authorized Per-Customers Semi-Annual Climate Credit (Line 29) as determined by the formula in the Template D-1, authorized in D. 15-01-024.

Note: PG&E has not included a Treasury remittance forecast in this table due to the limited time between the Commission's clarification of the applicable reporting requirements and the filing of this Application. PG&E will update its GHG reporting and Template D-1 to reflect the Commission's April 30, 2026 decision (D.26-04-036) in its Fall Update.

2. Order Instituting Rulemaking to Update the California Climate Credit R.25-07-013

The Commission has initiated Rulemaking (R.) 25-07-013 to consider changes to the California Climate Credit (CCC) pursuant to Assembly Bill (AB) 1207. AB 1207 amended Public Utilities Code § 748.5, including eliminating the use of GHG allowance revenue proceeds to fund CEEE programs and requiring that five percent of such revenues be remitted to the State Treasury. The Commission's open rulemaking addresses, among other matters, both interim and long-term changes to the CCC, the allocation and disposition of GHG allowance revenues, and the remittance of a portion of such revenues to the State Treasury, consistent with statutory direction.

The Commission recently adopted two Decisions under this Rulemaking, and further decisions are expected. In D.26-03-013, the Commission paused the distribution of the residential electric credit pending further decisions. On April 30, 2026, the Commission adopted D.26-04-036, which directs the distribution of the residential electric credit in August and September 2027. As relevant here, that Decision also specified that large IOUs, including PG&E, should include forecasts of their Treasury remittances in their ERRA Forecast Applications. This was a change from the Proposed Decision, which proposed that large IOUs should include this information in their ERRA *compliance* proceedings. D.26-04-036 also included a revised Template D-1.

Given the timing of the Commission's updated final Decision, PG&E did not have time to prepare an updated Template D-1 reflecting the revisions included D.26-04-036 and the accompanying template. Accordingly, the forecasts, methodologies, and amounts presented in this chapter do not include any adjustment or forecast related to potential Treasury remittance requirements. Although PG&E has not forecasted or included any Treasury remittance amounts in the GHG allowance revenue requirement, Template D-1, or related tables presented in this chapter, PG&E will include in its Fall Update revised GHG allowance revenue forecasts, CCC calculations, reporting treatment, and Treasury remittance amounts to reflect D.26-04-036 and the accompanying template.

3. Organization of this Chapter

The remainder of this chapter further describes the items reflected in the forecast 2027 column of Table 17-1.

- Section B – Forecast 2027 Net Available GHG Allowance Proceeds;
- Section C – Low-Income and Disadvantaged Community Solar Programs Previously Funded in Whole or in Part from the GHG Allowance Revenues;
- Section D – Amortization of the 2026 Year-End Forecast Balance;
- Section E – Forecast 2027 GHG Allowance Return Revenue Requirement;
- Section F – Distribution of 2027 GHG Allowance Revenue Return; and
- Section G – Conclusion.

B. Forecast 2027 Net Available GHG Allowance Proceeds

Pursuant to D.12-12-033 and D.14-10-033, PG&E's forecast 2027 net available GHG allowance revenue proceeds for distribution to eligible customers is calculated after setting aside GHG A&O expenses. Effective July 1, 2026, GHG allowance proceeds are no longer permitted to fund CEEE programs in California.

Below are details of the calculation of the forecast 2027 GHG allowance return.

1. GHG Allowance Revenue Proceeds

The California Air Resources Board (CARB) allocates GHG allowances to the IOUs on behalf of its customers. D.14-10-033 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.[2]

[2] D.14-10-033, p. 5.

PG&E's forecast of 2027 GHG allowance allocation is approximately 16.2 million allowances, based on 2027 allowances allocated to PG&E as reflected in the "Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation" produced by CARB (the Cap-and-Invest Regulation).[3] Using the proxy price of $31.02/MT, shown in Table 17-1, line 1, PG&E's forecasted 2027 GHG allowance revenue proceeds are $466.5 million, as shown in Table 17-1, line 5. As is typical, PG&E will provide an updated forecast in its Fall Update to Prepared Testimony (Fall Update) that incorporates any regulatory or market changes to the 2027 allowance allocation and proxy price. PG&E notes that it is using the best information available at the time of this Application, but given the uncertainty about CARB's updates to the Cap-and-Invest program, PG&E's forecast is especially uncertain.

2. GHG A&O Expenses

In D.12-12-033, OP 1, the Commission allowed the IOUs to set aside their respective utility GHG A&O expenses from the GHG allowance revenues prior to returning the net revenues to customers. PG&E is requesting in this application to set aside $1 million to pay for the 2027 forecast GHG A&O expenses, as shown in Table 17-2, line 16, Column E below.

Since inception, the Commission had authorized PG&E to set aside a total of $13.3 million to pay for its GHG A&O expenses (See Table 17-2, line 16, Column A). Recorded and Forecast GHG A&O expenses is $14.5 million, as shown in Table 17-2, line 16, Column B, resulting in a shortfall of $1.2 million, as shown in Table 17-2, line 16, Column C.[4] After deducting the $0.2 million recorded accumulated balancing account interest

---

3 See Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation and Appendix B.

4 Recorded A&O Expenses as of December 2025 is $12.5 million. Forecast GHG A&O Expenses refer to 2026 Forecast GHG A&O authorized Expenses of $0.9 million and 2027 Forecast GHG A&O Expenses of $1.1 million requested in Chapter 16 of this Testimony.

as of December 2025[5] (see Table 17-2, line 16, Column D), the cumulative set aside amount required by PG&E to pay for its 2027 GHG A&O Expenses is $1 million as shown in Table 17-2, line 16, Column E. These amounts will be updated in the Fall Update of this application.

TABLE 17-2
GHG A&O EXPENSES SET ASIDE
(THOUSANDS OF DOLLARS)

Line No.	Year	Authorization/ Application Request	Authorized Amount Set Aside	Recorded and Forecast GHG A&O Expenses [1]	GHG A&O Expenses Excess/ (Shortage)	Recorded Balancing Account Interest [2]	Total Excess/ (Shortage) including interest
			(A)	(B)	(C) = (A) +(B)	(D)	(E) = (C) + (D)
1	2013	D.13-12-041	3,520	(1,360)	2,160	0	2,160
2	2014	D.13-12-041	4,156	(2,695)	1,461	1	1,463
3	2015	D.14-12-054	1,380	(1,083)	298	6	303
4	2016	D.15-12-022	NIL	(1,022)	(1,022)	17	(1,005)
5	2017	D.16-12-038	NIL	(1,052)	(1,052)	23	(1,029)
6	2018	D.18-01-009	NIL	(901)	(901)	29	(873)
7	2019	D.19-02-023	NIL	(426)	(426)	18	(408)
8	2020	D.20-02-047	1,206	(598)	608	8	616
9	2021	D.20-12-038	189	(560)	(371)	1	(371)
10	2022	D. 22-02-002	285	(717)	(432)	10	(422)
11	2023	D. 22-12-044	482	(528)	(46)	31	(15)
12	2024	D. 23-12-022	695	(708)	(13)	40	27
13	2025	D. 24-12-038	674	(867)	(193)	29	(165)
14	2026	D.25-12-027	750	(925)	(175)		(175)
15	2027	A. 26-05-XXX		(1,098)	(1,098)		(1,098)
16	**Total**		**13,338**	**(14,540)**	**(1,202)**	**212**	**(990)**

Note 1. *Recorded through 2025 is $12.5 million and Forecast 2026 and 2027 is $2.0 million, comprising of $0.925 million authroized in D.25-12-027 and $1.1 million PG&E's forecast budget for 2027 as presented in Chapter 16.*

Note 2. *A full year of 2026 recorded Balancing Account interest is not yet available*

3. Clean Energy and Energy Efficiency (CEEE) Programs

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. In 2025, the legislature passed AB 1207, which amends that provision so that it "shall become inoperative on July 1, 2026."[6]

---

5 Consistent with recorded GHG A&O expenses, recorded balancing account interest of partial test year 2026 is not included in the table.

6 Pub. Util. Code 748.5(c).

As discussed below in Section C, the total amount PG&E is proposing to set-aside from GHG funds for CEEE projects is $5.9 million. PG&E notes that this is not a request for *new* GHG funding, but a request to remedy a prior duplicative return to the GHGRBA account. All other CEEE program requests, including GHG related true ups from prior years, are included in the $36.4 million request for PPP, as presented in Table 17-1, line 14.[7] These amounts are subject to further review of forecasts.

C. Low-Income and Disadvantaged Community Solar Programs Previously Funded in Whole or in Part From the GHG Allowance Revenues

1. Introduction

PG&E currently has three active Clean Energy and Energy Efficiency (CEEE) programs that in the past have been funded in whole or in part from the sales of GHG allowances: (1) Solar on Multi-Family Affordable Housing (SOMAH); (2) Disadvantaged Community Single-Family Affordable Solar Housing (DAC-SASH); and (3) Disadvantaged Community Green Tariff (DAC-GT). Through 2024, the Community Solar – Green Tariff (CS-GT) program was also funded in part by the sale of GHG allowances. However, D.24-05-065 issued on May 30, 2024, discontinued the CS-GT program. PG&E formally closed this program in 2025. Additionally, PG&E also funds the DAC-GT programs offered by CCAs, as applicable. In this section, PG&E uses rounded amounts in the narrative description, however, actual requested dollar amounts are reflected in the accompanying tables.

Ordering Paragraph (OP) 8 of D.18-06-027 states that "if such [GHG allowance] funds are exhausted, the DAC-SASH program will be funded through public purpose program funds through the conclusion of the program in 2030." The applicability of this paragraph in light of AB 1207's passage was confirmed via the ALJ correction filed on April 4, 2026.[8] PG&E received additional guidance from Energy Division staff on April 23, 2026, that DAC-GT funding in 2027 should also come from public purpose

[7] See also Table 17-8, line 14.

[8] "Administrative Law Judge's Ruling Correcting Error in Staff Proposal Redlined Handbook Included with January 26, 2026 Administrative Law Judge Ruling." Filed April 2, 2026 in Rulemaking 25-01-005.

funds (PPP), per OP 14 of D.18-06-027. As such, PG&E requests allocations for 2027 budget for the DAC-SASH and DAC-GT programs from PPP funds only. In addition, PG&E requests $5.9 million from the Greenhouse Gas Revenue Balancing Account (GHGRBA) to correct a duplicative return to the GHGRBA in 2026. Further detail is provided in the DAC-GT section below. Lastly, per D.20-04-012, no new funds for the SOMAH program are requested in 2027. The only SOMAH request is for a true-up from 2025.

2. SOMAH Program

In 2015, the Legislature enacted Assembly Bill 693 establishing the SOMAH Program,[9] directing the CPUC to use 10 percent of GHG allowance funding for the program, up to a statewide total of $100 million annually. The SOMAH Program was established by the CPUC in December 2017 with D.17-12-022 to provide incentives for solar on multi-family housing. The five IOUs[10] were directed to create balancing accounts to track the authorized funding for SOMAH. In D.20-02-047 and D.20-12-038, the Commission directed PG&E to transfer set aside amounts on a quarterly basis.[11]

D.20-04-012 stipulates that, through its ERRA Forecast proceeding, PG&E should propose funding for the SOMAH Program until June 30, 2026.[12] As such, no additional new funds are requested for the SOMAH program, and the only SOMAH request is a true-up from 2025.

D.20-04-012 and D.22-09-009 directed the IOUs to submit a joint advice letter to true-up the final three months of each year. If the recorded GHG proceeds from all five IOUs exceed $1 billion, PG&E will perform the SOMAH true-up based on its proportionate share of allowance sale proceeds over the previous four quarters.[13] The total recorded GHG revenues from the IOUs in 2025 exceeded $1 billion. Therefore, in

---

9 This bill added Pub. Util. Code Section 2870.

10 IOUs include PG&E, Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Liberty Utilities (CalPeco Electric), PacifiCorp d/b/a Pacific Power (PacifiCorp).

11 D.20-02-047, pp. 21-22.

12 D.20-04-012, OP6.

13 D.17-12-022, OP 7, pp. 69-70.

AL 7854-E[14] PG&E presented its 2025 SOMAH true-up amount of $1.87 million. As SOMAH does not request any additional funding, and the 15 percent CEEE allowance is no longer in effect, as stated in AL 7854-E, PG&E includes this request in Table 17-5 Forecasted PPP Funding for CEEE Programs.

Pursuant to D.20-04-012, Table 17-3 below shows a true-up of the prior years' authorized SOMAH set aside amounts compared to actual auction revenues, presented in the same format as the untitled table in D.20-02-047 at page 20.[15] Collections for all prior years are under the 15 percent allowance for the respective year each collection would have occurred.

14 See, PG&E AL 7521-E-B, available at: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7521-E-B.pdf.

15 D.20-04-012, Table 1: Recorded and Forecasted GHG Revenues, p. 3.

TABLE 17-3
SOMAH SET ASIDE AMOUNTS

Line No.	Year	Recorded GHG Allowance Revenues	Set Aside Based on 10% of Recorded GHG Revenue or $100 million limit	Actual Set Aside[(a)]	Difference (Actual Set Aside – 10% Set Aside or $100 million limit)
1	2016[(b)]	$301,670,155	$15,083,508	$15,083,508	$0
2	2017	345,513,934	34,551,393	34,551,393	0
3	2018	348,098,763	34,809,876	34,809,876	0
4	2019	389,040,958	38,904,096	38,904,096	0
5	2020	385,893,957	38,589,396	38,589,396	0
6	2021	384,773,215	34,518,517	34,518,517	0
7	2022	486,243,930	34,816,563	34,816,563	0
8	2023	544,616,174	34,626,367	34,626,367	0
9	2024	576,556,216	39,757,379	39,757,379	0
10	2025[(c)]	591,119,328	41,624,590	39,757,379	(1,867,211)
11	Total	$4,353,526,631	$347,281,685	$345,414,474	$(1,867,211)

(a) Years 2016 through 2025 include already-executed true ups: Years 2016-2019 include true-ups for previous under-collections, which were collected in 2020 ($30.7 million) per D.20-02-047 and 2021 ($4.45 million) per D.20-12-038. Year 2020 includes the true-up ($187 thousand over-collected) which was netted in 2022 per D.22-02-002. Year 2021 includes the true-up ($2.91 million under-collected), which was netted in 2023 per D.22-12-044. Year 2022 includes the true-up ($11.59 million over-collected), which was netted in 2024 per D.23-12-022. Year 2023 includes the true-up ($5.13 million over-collected), which was netted in 2025 per D.24-12-038. Year 2024 includes the true-up ($4.68 million over-collected), which was netted in 2026 per D.25-05-011.

(b) AB 693 implemented SOMAH mid-way through 2016; therefore, GHG Revenue and set aside amounts are pro-rated 50 percent and totals reflect the pro-rated amounts.

(c) Year 2025 is the only year with a pending true-up ($1.87 under-collected), which PG&E proposes to collect from PPP funds per AL 7854-E.

3. DAC-SASH Program

In D.18-06-027, to implement a legislative directive,[16] the Commission created the DAC-SASH Program. That program is designed to incentivize the installation of solar generation on low-income single-family homes in disadvantaged communities. GRID Alternatives was selected to administer

16 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).)

the DAC-SASH Program. The annual budget is $10 million statewide, apportioned among the IOUs. PG&E's share is $4.37 million annually.[17]

As discussed above, D.18-06-027 directed the IOUs to fund the DAC-SASH Program first from GHG revenues, and then through Public Purpose Program (PPP) funds if the GHG revenues were exhausted. As GHG revenues are no longer available for this program in 2027, PG&E requests all program funds in 2027 from PPP as shown in line 13 of Table 17-5, Forecasted PPP Funding for CEEE Programs.

Pursuant to D.18-06-027, DAC-SASH expenses are reviewed annually in the ERRA Compliance Review proceeding.[18] PG&E has presented the costs recorded to the DAC-SASH subaccount in the Public Policy Charge Balancing Account (referred as the DAC-SASH balancing account) and the DAC-SASH memorandum account for the years 2019-2023.[19] The 2025 ERRA Compliance Review proceeding (A.26-02-019) is in progress.

4. DAC-GT Program

In D.18-06-027, to effectuate legislative direction,[20] the Commission created the DAC-GT and CS-GT Programs. DAC-GT is designed to overcome barriers to solar adoption for low-income customers within Disadvantaged Communities (DAC). The DAC-GT Program is available to low-income residential customers in DACs and participants receive 100 percent renewable energy and a 20 percent bill discount, compared to their otherwise applicable tariff.[21]

D.18-06-027 set no budget for the DAC-GT Program, but—as with DAC-SASH—instructed IOUs to fund it first through available GHG allowance proceeds, then through PPP funds if the GHG revenues were exhausted. As described in PG&E AL 6308-E,[22] the CARB prohibits using

---

17 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.

18 D.18-06-027, OP 8, pp. 102-103.

19 Applications (A.) 20-02-009, A.21-03-008, A.22-02-015, A.23-02-018, A. 24-02-012.

20 See Pub. Util. Code § 2827.1(b)(1).

21 D.18-06-027, pp. 50-53.

22 See PG&E AL 6308-E, available at: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6308-E.pdf.

GHG funds to deliver volumetric discounts. Beginning with its 2022 ERRA Forecast filing, generation costs were funded from GHG proceeds and all other costs were funded from PPP for both PG&E and the CCAs' DAC-GT Program. As a result of AB 1207 rendering funding for CEEE programs "inoperative" after July 1, 2026, PG&E requests the 2027 DAC-GT budget from PPP funding only. As in prior years, PG&E will put into rates the budget requests from PPP funds in the Annual Electric True-Up (AET), subsequent to approval of PG&E's DAC-GT Budget AL.

PG&E requested a DAC-GT budget for Program Year (PY) 2027 and a true-up for prior years and 2025 in AL 7877-E, as shown in Table 17-4 below. PG&E intends to request $19.3 million for the PG&E DAC-GT program, which includes PG&E's previous year true-ups, from PPP funds in the AET. Note that Table 17-4 is updated this year to include CCA DAC-GT funding requests, previously in Table 17-6, as discussed in the next section.

In addition to PG&E's request for PPP funds for the 2027 budget, PG&E requests $5.9 million from the GHGRBA to correct a prior error. D.24-05-065 discontinued the CS-GT program and PG&E formally closed the program in 2025. To close the CS-GT balancing account, PG&E sent the remaining balance of $9 million from that account as follows: (1) $3.3 million of unspent PPP funding transferred to the DAC-GT balancing account, and (2) $5.8 million of unspent GHG auction proceeds returned to the GHGRBA. PG&E verified the $5.8 million of unspent GHG funds had been returned to the GHGRBA in the 2026 ERRA Forecast testimony, but the accompanying table mistakenly reflected these funds as an additional $5.9[23] million true-down. This error in the tables was included in the approved final Decision, which resulted in PG&E returning a second $5.9 million from the DAC-GT balancing account to the GHGRBA in April 2026. To correct this mistaken double return to the GHGRBA, PG&E requests this second returned amount be sent back to the DAC-GT balancing account in this filing as detailed in Table 17-6, line 5.

[23] Please note the 2026 return amount was slightly more than the 2025 return amount because it included $120,000 in delay damages paid by a CS-GT dedicated resource developer in 2024 when a project was late to come online. These numbers were detailed in PG&E's 2024 ERRA Compliance DAC-GT CS-GT Confidential workpapers.

TABLE 17-4
FUNDING REQUESTS FOR PG&E'S DAC-GT AND CS-GT PROGRAMS

		PPP		GHG		
Line No.	CCA	2025 True-Up[(a)]	2027 Funding[(b)]	2025 True-Up[(a) (c)]	2027 Set Aside	Total
1	MCE	$(2,847,329)	$2,852,801	–	–	$5,472
2	Ava	290,755	7,063,513	–	–	7,354,268
3	SJCE[(d)]	(150,342)	415,455	$(393,869)	–	108,296
4	PCE	102,084	2,314,520	636,440	–	3,053,044
5	CPSF[(e)]	(529,835)	444,906	–	–	(84,929)
6	PG&E	(5,695,435)	21,306,775	3,721,358	$5,938,644[(f)]	25,271,342
7	Total	$(8,830,102)	$34,397,970	$4,200,981	–	$35,707,493

(a) PG&E's true-up amounts reflect the true-up for 2025 and true-up amounts from previous years, as detailed in AL 7877-E.

(b) PG&E's total does not include the CCA Disbursement Reconciliation which is captured as a separate line item in table 17-5.

(c) PG&E and PCE recorded their GHG true-ups separated in this column with the understanding the amounts would be made whole though PPP funding.

(d) SJCE expects to use $156,817 of their GHG true-up surplus in 2027 and the remaining $237,052 in subsequent years. SJCE requests $108,296 in PPP funds for the portion of their 2027 budget that is not eligible to be covered by GHG funding and is beyond their $(150,342) 2025 surplus in PPP funds.

(e) PG&E is working with CPSF to better understand CPSF's negative request and how it impacts total funding. PG&E anticipates this will be resolved in the Fall Update.

(f) PG&E requests these funds to correct a duplicative return from the DAC-GT balancing account to the Greenhouse Gas Revenue balancing account, as detailed in Section C.4.

Pursuant to D.18-06-027, DAC-GT expenses are reviewed annually in the ERRA Compliance proceeding,[24] in which PG&E has presented the costs recorded to the DAC-GT subaccount in the Public Policy Charge Balancing Account for years 2019-2023.[25] The 2025 ERRA Compliance Review proceeding (A.26-02-019) is in progress. Review of the DAC-GT balancing account is expected in late May 2026, after this application is filed.

5. CCAs' DAC-GT Budget Requests

Under D.18-06-027, CCAs may choose to offer their own version of the DAC-GT and CSGT Programs. In PG&E territory, the five CCAs that typically submit budget ALs for DAC-GT with program budgets for the subsequent year and carryover from the prior Program Year are:

24 D.18-06-027, OP 10, p. 103.

25 A.20-02-009, A.21-03-008, A.22-02-015, A.23-02-018, and A.24-02-012.

- Marin Clean Energy (MCE);
- Ava Community Energy (Ava);
- San Jose Clean Energy (SJCE);
- Peninsula Clean Energy (PCE); and
- CleanPower SF (CPSF).

In accordance with D. 24-05-065, the CCAs have also discontinued their CS-GT Programs. Table 17-4 above presents the funding requests in accordance with each of the CCA's 2027 budget advice letters submitted on April 1, 2026. This table details the 2027 funding requests and the 2025 true-ups for the CCAs' DAC-GT programs.

In total, as shown in Table 17-5 below, PG&E and the CCAs are requesting $30 million in PPP funding for DAC-GT, including $19.3 million for PG&E, $10 million for the five CCA programs, and $386 thousand for a 2025 CCA Disbursement Reconciliation to PG&E. These amounts will be validated and updated, as necessary, upon the approval of these budget advice letters in PG&E's Fall Update.

6. PPP Funding for CEEE Programs

As mentioned above, PG&E's 2027 CEEE program budget request will be entirely from PPP funds. Table 17-5 below reflects the forecasted funding for CEEE programs to be recovered through PPP which include all costs for the DAC-SASH program, SOMAH's 2025 true up, and the DAC-GT programs for PG&E and the CCAs. Any updates which may need to occur between the timing of this ERRA Forecast May filing and the approval of the DAC-GT budget ALs for PG&E and the CCAs will be included in PG&E's Fall Update.

TABLE 17-5
FORECASTED PPP FUNDING FOR CEEE PROGRAMS

Line No.	CEEE Program PPP Funding Request	2026	2027
1	PG&E's DAC-GT funding request	$12,312,335	$21,306,775
2	PG&E's DAC-GT Previous Years GHG True-Up[a]	–	1,067,858
3	PG&E's DAC-GT Previous Years PPP True-Up[a]	–	(564,987)
4	PG&E's DAC-GT 2025 GHG True-Up	–	2,653,501
5	PG&E's DAC-GT 2025 PPP True-Up	–	(5,130,447)
6	PG&E's DAC-GT 2024 PPP True-Up	(1,663,347)	–
7	CCAs' DAC-GT funding request	6,349,010	13,091,195
8	CCAs' DAC-GT 2025 PPP True-Up	–	(3,134,667)
9	CCA's DAC-GT 2025 GHG True-up[b]	–	479,623
10	CCAs' DAC-GT 2024 PPP True-Up	(237,976)	–
11	2024 CCA Disbursement Reconciliation to PG&E	(714,507)	–
12	2025 CCA Disbursement Reconciliation to PG&E[c]	–	386,401
13	DAC-SASH 2027 funding request	–	4,370,000
14	SOMAH 2025 GHG True Up	–	1,867,211
15	Total PPP Funds	$16,045,515	$36,392,463

(a) PG&E true-up amounts from years prior to 2025. These amounts are included in columns C and E in Table 17-4.

(b) This is the sum of PCE's $636,440 in GHG true-ups and SJCE's -$156,817 in GHG true-ups they intend to apply to their 2027 budget, as recorded in Table 17-4.

(c) This is the amount undercollected by PG&E in 2025 compared to what was distributed to the CCAs. This amount was not included in Table 17-4.

7. GHG Funds Remaining for CEEE Programs

Table 17-6 below lists the program-by-program previous year true-ups and 2027 set aside amounts from GHG funding. GHG funds are being requested only to recall the $5.9 million duplicative return to the GHGRBA, as described above in Section C.4.

TABLE 17-6
FORECASTED GHG FUNDING FOR CEEE PROGRAMS

Line No.	CEEE Program GHG Set Aside[(a)]	2026	2027
1	SOMAH	$19,878,689	–
2	SOMAH 2024 True-Up	(4,682,558)	–
3	DAC-SASH	4,370,000	–
4	PG&E's DAC-GT annual budget	11,334,222	–
5	PG&E duplicative return to GHGRBA[(a)]	–	$5,938,644
6	CCAs' DAC-GT	6,917,262	–
7	CCAs' DAC-GT and CS-GT 2024 True-Up	178,162	–
8	Total GHG Funds	$37,995,778	$5,938,644

(a) PG&E requests these funds to correct a duplicative return from the DAC-GT balancing account to the Greenhouse Gas Revenue balancing account, as detailed in Section C.4.

The GHG Allowance for CEEE Programs table which had been used to calculate the GHG allowance for CEEE programs based on forecasted GHG revenue is removed from this filing as it is no longer relevant.

D. Amortization of the 2026 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 2025 year-end recorded balance of the subaccount was $168 million under-collected. A comparison between the recorded and forecasted 2025 transactions is shown in Table 17-1, lines 3 through 31. The primary reason for the undercollection is due to lower-than-forecast recorded GHG allowance revenue proceeds as a result of the lower-than-forecast CARB GHG settled prices.

Based on recorded transactions from January through March 2026, and forecast amounts from April 2026 through December 2026, the GHG Revenue Subaccount is forecast to be $28.5 million over-collected by year end 2026, as presented in Table 171, line 31. PG&E will update the year-end 2027 balance in the Fall Update and will amortize any remaining balance in the 2027 AET process, or subsequent electric rate change authorized by the Commission.

E. 2027 GHG Allowance Return Revenue Requirement

As shown in Table 17-1, line 17, PG&E's 2027 GHG allowance return revenue requirement to be included in its 2027 electric rates is $530.1 million, comprised of the following components:

- Forecast 2027 GHG allowance revenue, after setting aside the GHG Expenses and CEEE Funds is $494.5 million, as discussed in Sections B and C;
- Less – The forecast 2026 GHG Revenues Subaccount *under*-collected balance within the GHGRBA of $28.5 million, as discussed in Section D; and
- Plus – An allowance of Revenue Fees and Uncollectibles (RF&U) of $7.1 million (see Table 17-1, line 7).[26]

The forecast 2027 GHG allowance revenue requirement will be updated in the Fall Update, and effective on or after January 1, 2027, through the AET process, or subsequent electric rate change.

F. Distribution of 2027 GHG Allowance Revenue Return

This section describes the methodology that PG&E will use to allocate GHG allowance revenue to its customers. Table 17-1, lines 19-21 and 30, shows how the total allowance revenue return is divided between the three types of allowance return. The approach described below is consistent with Commission D.12-12-033, D.14-12-037, and D.21-08-026.

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) or a semi-annual basis (for the CCC) for residential households and eligible small business customers).[27]

a. EITE Revenue Return

D.12-12-033 requires that IOUs administer the return of GHG allowance revenues to eligible EITE entities to cover all or a portion of

[26] Calculated based on the RF&U Factor authorized by the Commission in Tier 1 AL 4889-G/7419-E.

[27] D.12-12-033, OP 1.

their indirect GHG compliance costs, in the form of a yearly on-bill credit or rebate check.[28] Customers that are either subject to direct reporting requirements to CARB, or have gone through the attestation and verification process—as prescribed in D.14-12-037 and Resolution E-4716—are eligible to receive the EITE Revenue Return, also referred to as the “California Industry Assistance” or the “EITE Credit.”

CARB has indicated its intent—upon adoption and implementation of Cap-and-Invest amendments—to directly allocate allowances to, and assume responsibility for crediting, EITE entities subject to CARB’s direct reporting requirements.[29] IOUs will continue to administer EITE credits for small EITE customers within their service territories.[30] However, pursuant to D.21-08-026, and until such amendments are adopted by CARB and authorized for implementation by the Commission, PG&E will continue to administer and distribute EITE credits consistent with Commission direction.

To forecast the EITE credit, the 2027 forecasted return is set to be based on the recorded 2026 return for each rate schedule and adjusted for forecasted sales changes between 2026 and 2027. The Commission’s Phase 1A Decision (D.26-04-036, adopted April 2026) proposes changes to the EITE program that may apply in future years. To the extent those changes are adopted and affect authorized EITE treatment for 2027, actual EITE returns may differ from the forecast presented herein. Forecasted EITE returns reflected in Table 17-1, line 19 will be implemented consistent with final Commission direction, with any necessary updates reflected in PG&E’s Fall Update.[31]

---

28 *Id*., OP 25.

29 See California Air Resources Board, Proposed 2026 Cap-and-Invest Regulation Amendments, available at: https://ww2.arb.ca.gov/our-work/programs/cap-and-invest-program/cap-and-invest-regulation.

30 D.14-12-037 and Resolution E-4716, establish facility-level eligibility, CPUC calculation authority, and utility administrative responsibilities for small EITE customers.

31 See Phase 1A D.26-04-036 of R.25-07-013, addressing initial residential California Climate Credit issues. The forecasted 2027 EITE revenue return reflects existing practice and may be updated, as appropriate, to conform to the Commission’s final decision and any implementing guidance.

b. Semi-Annual CCC Payment

As the Commission directed in D.12-12-003 (and as updated in D.26-04-036, adopted April 30, 2026), all residential electric customers receive a CCC distributed as a separate on-bill line item credit twice a year.[32] D.21-08-026 also adds eligible small business customers to receive the same credit.

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 and small business customers based on service accounts, including master-meter (MM) sub-accounts.[33] In equation form, this calculation is as follows:

FIGURE 17-1
CCC CALCULATION EQUATION

$$\frac{1}{2} \times \frac{\text{Total Annual Climate Credit Revenue}}{\text{Eligible Single Meter Residential \& Small Business Accounts} + (\text{MM Sub-accounts} - \text{MM Host Accounts})}$$

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.[34] Total revenue for the biannual CCC Payment is given in Table 17-1, line 30.

---

32 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.

33 Since the master-meter aggregated—or “host”—account does not represent a true household, these accounts will be subtracted from the total.

34 See D.12-12-033, p. 180 (Finding of Fact (FOF) 112: “via a delivery rate component”), and p. 182 (FOF 122: “against electricity purchases”).

In D.15-12-022, the Commission directed PG&E to use the public proxy price and formulas to determine the biannual CCC Payment.[35] Therefore, the biannual 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 2027 GHG allowance revenue return requirement of $530.1 million, which includes a forecast of the end of year 2026 balance;
2) Approve the GHG A&O expense set-aside of $1 million;
3) Approve correcting the duplicative accounting error related to CEEE programs of $5.9 million;
4) Approve its revenue distribution proposals; and
5) Adopt the semi-annual residential CCC of $41.74 per household.
6) Approve $36.4 million in PPP funding for customer programs formerly funded by GHG auction revenues.

The forecast amounts presented in this testimony will be updated in the Fall Update, and be effective on January 1, 2027, through the AET process, or subsequent electric rate change.

---

35 D.15-12-022, pp. 12-13, and Conclusion of Law 2.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENT(S) OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF AVERY ARJO

Q 1 Please state your name and business address.

A 1 My name is Avery Arjo, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Manager in the Energy Policy and Procurement Department. I am responsible for managing the financial position of PG&E's electric portfolio, among other things.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Science degree in Economics from the University of Kansas in 2014 and a Master of Arts degree in Economics from California State University, East Bay in 2017. From 2016 to present, I have been employed by PG&E in various positions including Electric Settlement Analyst, Portfolio Management Analyst, and Manager of Energy Transactions.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2027 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 5, "Bundled Portfolio Open Positions and Other Costs":
  - Section B.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF GEORGE P. CLAVIER

Q 1 Please state your name and business address.

A 1 My name is George P. Clavier, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at 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 2027 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 3, "Electric Generation Portfolio Background";
- Chapter 4, "Generation Supply Portfolio Costs and Volumes":
  - All Sections except Sections B.6.b;
- Chapter 5, "Bundled Portfolio Open Positions and Other Costs":
  - Sections A, D, F, and G;

- Chapter 15, “Greenhouse Gas Forecast Revenue and Reconciliation – Cost Calculations”:
  - Sections A and B; and
  - Tables 15-1 and 15-2.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MARK COUGHLAN

Q 1 Please state your name and business address.

A 1 My name is Mark Coughlan, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 My current position at PG&E is Expert Analyst of Electric Rates within the Regulatory Affairs organization. In this capacity, I am responsible for 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 Arts degree in History from the University of Notre Dame in May 2005 and a Master of Science degree in Civil & Environmental Engineering from Stanford University in September 2007. From 2008 to 2021, I worked as a consulting professional engineer and have held various positions in the financial services and technology sectors, where my work focused on operations and regulatory compliance and analytics. I joined PG&E in March 2021 as an Expert Rate Analyst in the Rates Department within Regulatory Affairs. My work has primarily focused on the design of electric generation rates, and I have assisted with the preparation of PG&E rate design proposals in various proceedings including the Energy Resource Recovery Account Forecast proceeding and the General Rate Case.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E’s 2027 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 13, “Rate Proposal”; and
- Chapter 13, 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 CHRISTA HOFFMAN

Q 1 Please state your name and business address.

A 1 My name is Christa Hoffman, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Manager 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 Science in Environmental Science and Management and a Bachelor of Arts in Economics in 2019 from University of California, Davis.

I joined PG&E in 2020 as an analyst in my current department, Portfolio and Resource Forecasting. During my time on this team, I have worked on various energy procurement, Renewable Portfolio Standard position, and carbon emissions forecasts 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 2027 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 3, "Electric Generation Portfolio Background":
  - Sections D.2, D.3b;
- Chapter 4, "Generation Supply Portfolio Costs and Volumes":
  - Sections B.3.a, B.6.b through B.6.c;
- Chapter 5, "Bundled Portfolio Open Positions and Other Costs":
  - Section E; and
- Chapter 8, "Power Charge Indifference Adjustment and Ongoing Competition Transition Charge":
  - Sections F.3 through F.4.

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 (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Principal Data Scientist in our System Planning organization with responsibility for load forecasting and certain aspects of system 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 25 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 Quantitative Analyst and then as a Manager in Market and Credit Risk, as a Manager in Rates, and currently as a Principal Data Scientist in System Planning.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2027 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 and B.1.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF NICHOLAS R. MANUEL

Q 1 Please state your name and business address.

A 1 My name is Nicholas R. Manuel, and my business address is Pacific Gas and Electric Company (PG&E or the Company), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Senior Manager 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.).

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 2027 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 5, "Bundled Portfolio Open Positions and Other Costs":
  - Section C; and
  - Table 5-2.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF NICHOLAS J. MARKEVICH

Q 1 Please state your name and business address.

A 1 My name is Nicholas J. Markevich, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Senior Consultant Project Engineer (Civil, Water Rights) in the Water Management Group within the Power Generation organization at PG&E. I perform a variety of regulatory compliance, contract management, planning, and analytical work primarily in support of the operation of PG&E's Hydro facilities, as well as providing support for PG&E's Hydro regulatory filings, contract negotiations, and divestiture proceedings. Currently my primary responsibilities are in the areas of water rights, water contracts, headwater benefits, and Federal Energy Regulatory Commission (FERC) fees.

Q 3 Please summarize your educational and professional background.

A 3 I graduated with a Bachelor of Science degree in Civil Engineering in 1978 and a Master of Science degree in Civil Engineering in 1980, both from the University of California, Berkeley.

I joined PG&E in 1985 as a Design Engineer in the Civil Engineering Department, where I worked on various energy infrastructure projects, seismic safety improvements, and dam safety evaluations in support of PG&E's Hydro and Fossil facilities. In 1987, I was promoted to Civil Engineer and worked on flood hydrology, dam stability, and spillway design projects for PG&E's Hydro facilities, as well as supporting various business practices related to PG&E's Hydro and Fossil facilities. In 1993, I transferred to the Hydro Generation Department as a Senior License Coordinator and worked in support of regulatory compliance for PG&E's Hydro facilities, including the coordination of agency inspections, meetings, filings, fee payments, and various tasks in support of relicensing PG&E's FERC-licensed Hydro projects. In 2006, I transferred to the Water Management Group in Power Generation as a Senior Hydro Scheduler and worked on forecasting water availability and optimizing the dispatch of

PG&E's Hydro facilities. In 2015, I was promoted to Senior Project Engineer and assumed responsibility for maintaining PG&E's water rights, as well as supporting PG&E's Hydro facilities and operations in the areas of FERC fees, water contracts, headwater benefits, and divestiture proceedings. In 2023, I was promoted to Senior Consultant Project Engineer with the same responsibilities.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2027 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 4, "Generation Supply Portfolio Costs and Volumes":
  - Section B.3.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF AKSHAY MEHMI

Q 1 Please state your name and business address.

A 1 My name is Akshay Mehmi, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Senior Electric Rates Analyst for the Electric Rates team under the Rates Department within the Regulatory Proceedings and Rates department. My responsibilities within Electric Rates include rate change implementation, rate design and analysis, analysis for Transmission related rates, and other regulatory support for Regulatory Proceedings and Rates.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mechanical Engineering from the University of California, Davis. In 2019, I was hired by the California Department of Transportation as a Mechanical Engineering Intern for the Office of Assets and Equipment under the Division of Rail and Mass Transportation. In 2021, I was hired by PG&E as an Associate Electric Rates Analyst for the Rates Department. I have since remained within the Rates Department, now serving as a Senior Electric Rates Analyst. I have served as a Witness Assistant and Witness in multiple PG&E Transmission Owner rate cases.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2027 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 14, "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 JORGE MERAZ

Q 1 Please state your name and business address.

A 1 My name is Jorge Meraz, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Principal Quantitative Analyst in the System Planning Department in PG&E's Strategy and Innovation organization. I work on the system peak, departing load, and behind-the-meter distributed generation forecasts.

Q 3 Please summarize your educational and professional background.

A 3 I hold a Bachelor of Science degree in Environmental Science from Loyola University Chicago, and a Master of Science and PhD degree in Civil and Environmental Engineering from Stanford University.

I joined PG&E in January 2023 as an analyst where my primary responsibilities include developing various forecasts that inform PG&E's sales and peak demand, in addition to supporting various regulatory proceedings.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2027 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.1.c, A.2.a, A.2.e, and B.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF DANIEL NELLI

Q 1 Please state your name and business address.

A 1 My name is Daniel Nelli, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Principal Quantitative Analyst in the System Planning Department in PG&E's Strategy organization. I work on various load modifier forecasts including electric vehicles, energy efficiency, building electrification, and data centers.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Science degree in Biophysics and a Master of Science in Civil and Environmental Engineering from Stanford University. I started my career at PG&E in February 2021 as an analyst on my current team—Electric Load Forecasting—where my primary responsibilities include developing energy impact forecasts of multiple emerging demand-side technologies.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2027 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.2.b, A.2.c, A.2.d, and A.2.f.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MEHUL PATEL

Q 1 Please state your name and business address.

A 1 My name is Mehul Patel, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 As Director of Central Procurement Entity (CPE) Transactions, I oversee the CPE department which focuses on Local Resource Adequacy procurement processes for PG&E's role as the CPE for PG&E's distribution service area.

Q 3 Please summarize your educational and professional background.

A 3 I graduated with a Bachelor of Science degree in Facilities Engineering in 2002 from the California Maritime Academy. I also hold a Master of Business Administration degree, earned in 2022, from California State University, Monterey Bay. I have worked in the energy industry for over 20 years, 13 of which have been for PG&E where I have held several leadership positions within the Energy Policy and Procurement organization, including positions within Short-Term Electric Supply and my currently held position of Director, CPE Transactions.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2027 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 6, "Central Procurement Entity Procurement Cost and Revenue Requirement."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MICHELLE PATRICK

Q 1 Please state your name and business address.

A 1 My name is Michelle Patrick, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Manager of PG&E's Distributed Generation Programs team in the Resiliency and Distributed Generation Solutions organization. In this role, I oversee the development and management of PG&E's customer facing solar incentive and renewable energy programs (Solar on Multifamily Affordable Housing, Disadvantaged Community-Single-Family Affordable Solar Homes, Green Tariff Shared Renewables, Disadvantaged Community-Green Tariff), large rates related to storage, and PG&E's Meter Socket Adapter program.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Economics/Mathematics with a minor in English from the University of California at Santa Barbara with honors and a Master's in Business Administration from the University of North Carolina, Kenan-Flagler Business School with honors. In my nine years at PG&E I have worked in customer service strategy, corporate sustainability, and wildfire mitigation prior to joining this current team. This work has included strategic planning, program management, data analyses and regulatory compliance. Outside of PG&E, I have worked in economic consulting, real estate finance and as an adjunct professor of macroeconomics at Cuesta College. Additionally, I have also served on the boards of Global Glimpse, Heal the Brain with Jane, and HumanKind Fairtrade nonprofits over the last 12 years in various roles including as a Director, Treasurer, Vice Chair, and Chairperson.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2027 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 RYAN A. STANLEY

Q 1 Please state your name and business address.

A 1 My name is Ryan A. Stanley, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Senior Manager in the Energy Accounting Department within the Corporate and Capital 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 and Portfolio Allocation 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 19 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 sponsoring the following testimony in PG&E's 2027 Energy Resource Recovery Account and Generation Non Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 12, "Balancing Accounts Forecasts":
  - Sections A, C, and I; and
- Chapter 15, "Greenhouse Gas Forecast Revenue and Reconciliation – Cost Calculations."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF CHRISTINA SYRIANI

Q 1 Please state your name and business address.

A 1 My name is Christina Syriani, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Principal Case Manager on PG&E's Regulatory Proceedings and Rates team within Corporate Affairs. I am responsible for managing regulatory proceedings filed at the California Public Utilities Commission on matters related to generation and energy procurement. I took this position in May 2023 and have managed PG&E's Energy Resource Recovery Account (ERRA) Forecast proceedings for prompt years 2024 through the current application.

Q 3 Please summarize your educational and professional background.

A 3 I completed my Bachelor of Arts with a focus in English at the University of California, Santa Barbara, a Paralegal Certification at California State University of the East Bay, and a master's in public policy from Pepperdine University. I spent three years working in civil litigation, and nearly eight years in telecommunications project management before transitioning to the energy industry in 2019. I began with a temporary assignment at Calpine Energy and then worked as a Regulatory Analyst IV with the California Public Advocates Office in their Wildfire Safety division before eventually moving to PG&E as an Expert Projects Lead in Electric Operations in August 2020. I later moved to PG&E's Corporate Affairs to work in Regulatory Rates and Proceedings, managing cases with the California Public Utilities Commission. Today, these proceedings include: (1) post-ruling matters relating to the Power Charge Indifference Adjustment (PCIA); (2) the Order Instituting New Rulemaking (R.) Updating and Reforming PCIA and ERRA Processes and Policies (R.25-02-005); and (3) the annual ERRA Forecast proceedings.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2027 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 ANGELIA VEGA

Q 1 Please state your name and business address.

A 1 My name is Angelia Vega, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Strategic Analyst, Expert in the Bundled Portfolio Planning and Analysis 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 2027 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 7, "Cost Allocation Mechanism";
- Chapter 8, "Power Charge Indifference Adjustment and Ongoing Competition Transition Charge":
  - Sections A through E, F.1, F.2, and G through I;

- Chapter 9, “Tree Mortality Revenue Requirement”;
- Chapter 10, “Bioenergy Market Adjustment Tariff Revenue Requirement”;
- Chapter 11, “Energy Resource Recovery Account”;
- Chapter 12, “Balancing Accounts Forecasts”:
  - Sections A, B, D through H and J;
- Chapter 13, “Rate Proposal”:
  - Section B; and
- Chapter 17, “Greenhouse Gas Forecast Revenue and Reconciliation – Revenue Calculations”:
  - Sections A, B, D, E and G.

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 (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Product Manager in the Pricing Products group within the Customer Experience organization. I am responsible for the administration of the greenhouse gas allowance revenue return to commercial customers.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Marketing from the San Francisco State University, and a Certification in Project Management from the 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 2027 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
STATEMENT OF QUALIFICATIONS OF THOMAS YU

Q 1 Please state your name and business address.

A 1 My name is Thomas Yu, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 My current position at PG&E is Rate Analyst, Principle within the Regulatory Affairs organization. In this capacity, I manage the commercial and industrial (C&I) rates, both as a subject matter expert in retail C&I rates, and as an expert in modeling and analysis.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Decision Science and Public Policy and Management from Carnegie Mellon University in May 2010, after which I received a Master of Science in Engineering and Public Policy from Carnegie Mellon University in May 2011. From 2011 to 2013, I was a financial analyst at DAI Management Consultants, boutique consulting firm specializing in powerplant valuation. There, I analyzed wholesale markets, forecasted project financials, and wrote valuation reports for transaction and tax credit support. From 2013 to 2015, I worked at PG&E in the Electric Rates department, where I executed rate changes, analyzed customer bill distributions, and documented C&I rate making practice. From 2015 through 2024, I worked at energy storage companies, predominantly managing assets and measuring performance of behind-the-meter batteries at Advanced Microgrid Solutions and Stem Inc. I rejoined PG&E in 2024 again in Electric Rates to develop models and serve as witness in the 2023 General Rate Case Phase II and ERRA and as an expert on NEM policy.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2027 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.