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PACIFIC GAS AND ELECTRIC COMPANY

2026 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION

PREPARED TESTIMONY

PUBLIC VERSION

PACIFIC GAS AND ELECTRIC COMPANY
2026 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION
NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST
REVENUE RETURN AND RECONCILIATION
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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

INTRODUCTION AND POLICY

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
INTRODUCTION AND POLICY

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
INTRODUCTION AND POLICY

A. Introduction

This testimony supports Pacific Gas and Electric Company's (PG&E) 2026 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 2026 ERRA Forecast Application total revenue requirement of approximately $2,705 million, with a revenue requirement for rate-setting purposes of $4,015 million due to the inclusion of $1,310 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 2026 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, which PG&E has proposed to serve to the Administrative Law Judge (ALJ), Commission staff, and interested parties on October 15, 2025 (the Fall Update).[2] PG&E may also include supplemental testimony.

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

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 market prices based on 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.

PG&E's 2026 ERRA Forecast request is presented here as a base case scenario, subject to PG&E's Fall Update. PG&E requests approval of the New System Generation Charge (NSGC) forecast revenue requirement of $217 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 $27 million, and ERRA forecast revenue requirement of $2,959 million. PG&E also requests approval to credit the Public Purpose Charge Procurement (PPCP) subaccount $2.5 million, to recover approximately $41 million forecast revenue requirement for the Tree Mortality Non-Bypassable Charge (TMNBC), and to recover $11 million forecast revenue requirement for Bioenergy Market Adjusting Tariff (BioMAT). PG&E requests disposition of the recorded administration/labor costs in the Voluntary Allocation Market Offer (VAMO) Memorandum Account (VAMOMA) of $0.3 million through the PCIA rates. These forecast revenue requirements and requests are shown in Table 1-1 below.

TABLE 1-1
SUMMARY OF 2026 FORECAST ENERGY PROCUREMENT REVENUE REQUIREMENTS
(THOUSANDS OF DOLLARS)

Line No.	Description	2026 Revenue Requirement
1	CAM	$217,427
2	Ongoing CTC	(26,941)
3	PCIA	815,274
4	VAMOMA	320
5	ERRA	2,958,889
6	PPCP	(2,546)
7	TMNBC	41,412
8	BioMat	10,873
9	Revenue Requirement for Rate Setting	$4,014,709
10	Adjustments from Other Proceedings	
11	UOG-Related Costs	$(1,303,065)
12	RUBA-E	(6,517)
13	Adjustments from Other Proceedings	$(1,309,582)
14	2026 ERRA Application Revenue Requirement Request	$2,705,127

PG&E's ERRA Forecast revenue requirements also reflect necessary adjustments to certain volumes of Resource Adequacy (RA) capacity resulting from the Commission's slice-of-day (SoD) framework that took effect in 2025, described in further detail in chapters 4 and 5.

PG&E requests that the rate changes associated with Commission disposition of this Application become effective on January 1, 2026, when consolidated with other approved electric rate changes through the AET process. In addition to the 2026 revenue requirement request for forecast procurement costs, this Application also requests approval of PG&E's proposal to return GHG allowance revenue to customers. In Decision (D.) 14-10-033, 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 2026: (1) administrative and outreach (A&O) expense budget of $0.812 million pertaining to implementation of GHG revenue return; (2) customer

generation programs funded by GHG-revenues of $34.2 million; (3) net forecast revenue return amount of $579 million and PG&E's proposal to return the revenue to customers in rates in 2026; and (4) 2026 semi-annual California Climate Credit (CCC) amount of $45.09 per household and eligible small business customers. PG&E also requests that A&O set asides be updated to reflect forecast and recorded costs, and requests that the Commission find the 2024 recorded A&O expenses of $0.708 million related to the GHG revenue return to be reasonable. PG&E anticipates updating these GHG related 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 Greenhouse Gas (GHG) revenue return, will decrease by approximately 6.0 percent to 33.3 cents per kilowatt-hour (kWh) when compared to the present system average Bundled rate of 35.4 cents per kWh, effective March 1, 2025. 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 increase by approximately 3.9 percent to 21.2 cents per kWh, when compared to the present system average rate for DA and CCA customers of 20.4 cents per kWh, which was effective March 1, 2025.[3]

While PG&E currently estimates a decrease 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 and memorandum account balances. As a result, the initial 2026 rates and rate changes described in this Application may end up higher or lower than presented in the Fall Update.

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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.

Finally, PG&E requests that the Commission approve the 2026 retail sales forecast which is also subject to update in the Fall Update.

2. Considerations and Forecasting Assumptions for This Year's Proceeding

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), and PG&E's 2023 GRC as determined by D.23-11-069, as well as the pendency of open regulatory proceedings, such as the OIR to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes issued on February 20, 2025 as Rulemaking (R.) 25-02-005. Also characteristic for this proceeding are PG&E's assumptions related to balance transfers from various open proceedings.

a. 2023 GRC

The Commission issued its final decision in PG&E's 2023 GRC proceeding in November 2023. Accordingly, revenue requirements derived from D.23-11-069, plus attrition are utilized herein.

b. Rate Recovery of DCPP Costs

There are no 2026 forecast costs for DCPP in this year's Application however, there will be 2025 costs recorded to the balancing account for DCPP Unit 2 for the period January through August of 2025 that will true-up the difference between forecast and actual recorded costs in the balancing account. Any variance between forecast and recorded actuals will be amortized in 2026 rates.

c. The 2024 ERRA Forecast Proceeding

PG&E's 2024 ERRA Forecast Application (A.) 23-05-012 remains open as certain Track 2 issues are being resolved. The Track 2 Scoping Memo and Ruling is narrowly focused on issues related to the definition of and accounting for fixed generation costs. At this time, it is unclear if a proposed decision on this matter would affect the outcome of PG&E's 2026 ERRA Forecast Application.

d. PG&E's 2025 ERRA Forecast Compliance Items

In its 2025 ERRA Forecast (A.24-05-009), PG&E's proposal to allocate Common Costs[4] was approved on December 20, 2025, in OP 2 of D.24-12-038. To comply with the order, PG&E filed AL 7488-E on January 17, 2025, modifying its Common Cost allocation methodology.[5]

During the course of PG&E's ERRA Forecast proceeding, PG&E and SBUA entered into a stipulation agreeing that PG&E would, in future ERRA Forecast Applications, identify in its load forecast workpapers (WP) whether a post-regression adjustment is applied to any customer class. Following the Commission's D.24-12-038 approval of PG&E's 2025 ERRA Forecast proposal, PG&E and SBUA held a meet-and-confer on February 21, 2025. The subject of the meet-and-confer included PG&E's load forecast drivers and a demonstration of customer rate impacts by customer class when forecasted load is increased or decreased. Chapter 2 describes the meet-and-confer in more detail and supporting WPs identify any adjustments.

e. Other Pending Proceedings Following PG&E's 2025 ERRA Forecast Application

Additionally, PG&E's 2025 ERRA Forecast Application included a proposal to "pause" the Market Price Benchmark (MPB) while simultaneously undertaking an investigation to determine and resolve the underlying causes of the RA MPB's volatility. The Commission later determined that this proposal would not be included as part of the scope for the proceeding. As a result, the MPBs released in October for 2025 bundled customer generation rates were set based on a thin volume of transactions reflecting scarcity in the RA market. The Commission's 2025 ERRA Forecast Decisions noted anomalies with the MPB. Subsequently, the Commission opened a new Rulemaking earlier this year to discuss concerns with the RA MPB and explore proposals to

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4 Common Cost refers to the Electric Supply Administration Cost authorized in PG&E's GRC and forecast credit and collateral interest cost presented in this proceeding.

5 Advice Letter (AL) 7488-E was accepted by the Commission on February 16, 2025.

remedy the problems. This Rulemaking was opened on February 20, 2025 and is known as the OIR to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes (R.25-02-005). R.25-02-005 is expected to update and reform certain policies relating to the PCIA and ERRA in order to mitigate fluctuating market prices. The proceeding has been divided into two tracks: the first for immediate implementation and application to the 2026 ERRA Forecast, and the second to explore long-term solutions, which may inevitably carry over some or all of the decisions captured in Track 1. A proposed decision on Track 1 is anticipated later this month and will likely impact PG&E's Fall Update. Further, the benchmark used for 2025 may be trued-up at some point in the future based on the outcome of Track 2 of the proceeding.

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 various components and methodologies of the forecasts, including economic and regulatory variables, as well as various demand side technologies (e.g., Distributed Energy Resources). Additionally, this chapter covers how sales are reflected across various departing load types, including DA and CCA.
- Chapters 3-5: Next, PG&E details components of its 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-2002 contracted resources, including water district and Qualifying Facility agreements; (3) post-2002 contracted resources, including Renewables Portfolio Standard (RPS)-eligible generation and fossil contracts;

(4) purchased power costs; and (5) other electric procurement costs, such as hedging and short-term financing. GHG compliance costs required under the California Air Resources Board's (CARB) Cap-and-Trade Program associated with generation resources are reflected in the chapter applicable to the underlying energy procurement costs and summarized in Chapter 11.

PG&E's forecast of expected RA capacity from its supply portfolio under the SoD framework approved in D.22-06-050 is discussed in Chapter 4 and 5. A more detailed discussion of PG&E's methodology to implement the SoD framework is in Chapter 5.

- Chapter 6: Presents a forecast of 2026 procurement costs and administrative costs for PG&E functioning as the Central Procurement Entity.
- Chapters 7 through 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 Cost Allocation Mechanism (CAM). Chapter 8 presents costs associated with PCIA-eligible resources in the CPUC-mandated Common IOU Template,[6] as well as updated Energy Index MPB weighting factors pursuant to D.23-06-006. Chapter 8 also includes PG&E's Minimum Retained RPS entries, including the use of RPS instruments generated before 2019.
- 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 Public Utilities Code (Pub. Util. Code) Section 399.20.3(f)).
- Chapter 10: Presents the costs for BioMAT contracts, as part of the Public Purpose Program (PPP) rate component.

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6 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).

- Chapter 11: Presents the bundled load cost forecast for the ERRA revenue requirement.
- Chapter 12: Presents recorded and forecast balancing and memorandum account balances. Chapter 12 also contains PG&E's balancing account transfer proposals and presents PG&E's VAMOMA recorded balances proposed for disposition in rates.
- 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 2025 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 detailed illustrative rate tables consolidating all the proposed revenue changes in this application, including the ERRA revenue requirement and NBCs, as well as the GHG revenue return presented in Chapter 17.

  While final 2026 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 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, 2025. Final rates implemented in 2026 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 2026 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 14-14.
- Chapters 15 through 17: Address GHG -related matters, as ordered in D.12-12-033, D.14-10-033, D.15-01-024, and D.21-08-026. Specifically,

Chapter 15 explains the 2026 GHG cost forecast calculations, including direct and indirect GHG costs, as well as the reconciliation of 2024 GHG costs. Chapter 16 presents both the 2026 forecast and 2024 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, and the customer programs funded through GHG allowance proceeds and shows the methodology for returning revenue to eligible customers.

- Appendix A: Includes the statements of qualification 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' actual electric procurement costs, as required by Pub. Util. Code Section 454.5(d)(3). That provision, passed by the legislature in 2002, mandates that the CPUC:

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

In October 2002, the Commission issued D.02-10-062, which adopted a regulatory framework under which PG&E and the other IOUs would resume full procurement activities as of January 1, 2003. In D.02-10-062, the Commission established the ERRA as the balancing account for the IOUs to

track and recover energy procurement costs incurred under Commission-authorized procurement plans, in accordance with Section 454.5(d)(3). PG&E's ERRA balancing account is used to record PG&E's procurement-related costs and revenues, and any difference flows back to or 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.[7] 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 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 mechanism may need to be revisited in the future to ensure that it is meeting the original objectives.

The Commission implemented this statutory provision by adopting the ERRA "trigger" mechanism in D.02-10-062.[8] 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.[9] If the ERRA balance

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

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

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

reaches or exceeds 4 percent of the prior year recorded generation revenues, excluding CDWR revenues, the IOUs must file an expedited application.[10] 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.[11] PG&E's 2025 ERRA trigger amount—4 percent of the actual recorded generation revenues for the prior calendar year excluding revenues collected for the CDWR—is $206 million (4 percent ERRA Trigger). PG&E's 2025 ERRA threshold amount—5 percent of the actual recorded generation revenues for the prior calendar year excluding revenues collected for the CDWR—is $257.7 million (5 percent ERRA Threshold). These amounts are effective as of February 21, 2025.[12]

C. GHG Revenue Return and Reconciliation

CARB adopted the regulations to implement a Cap-and-Trade Program under Assembly Bill 32, the "Global Warming Solutions Act of 2006," on December 13, 2011. Pursuant to the Commission's GHG OIR 11-03-012, issued March 24, 2011, the IOUs began incurring costs to comply with the Cap-and-Trade Program in January 2013.

CARB acknowledged that the electricity sector incurs costs associated with the Cap-and-Trade Program. In order to mitigate the cost burden in the electricity bills associated with the Cap-and-Trade Program, CARB allocates allowances to the IOUs on behalf of their electric customers. CARB further determined that the IOUs will cosign these allocated allowances in quarterly auctions and distribute the proceeds as a credit, known as the California Climate

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

11 *Ibid.*

12 PG&E's compliance AL 7515-E, was submitted on February 21, 2025, pursuant to D.04-01-050 (hyperlink at: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7515-E.pdf).

Credit, to their residential, small business and eligible industrial EITE (emission-intensive and trade-exposed) customers.[13]

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

D. Fall Update

Consistent with the previous ERRA and GHG forecast proceedings, PG&E proposes to update its 2026 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 2026 rates go into effect.[15] At that time, PG&E will update certain NBC calculations according to the MPB, and will also update balancing account balances, as well as any relevant Commission decisions impactful to PG&E's request.

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

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[13] D.12-12-033, OP 1.

[14] D.14-10-033, OP 10

[15] See D.06-12-018, p. 12; FOF 5; and Conclusion of Law (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. The schedule for ERRA updates was later changed by the Commission.

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, PABA, and PUBA accounting entries prior to the Fall Update.[16] 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:[17]

1) Confidential versions of the monthly ERRA/PABA/PUBA activity reports;
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.[18]

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 this market

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16 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 California 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.

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

18 D.20-12-038, COL 11.

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.[19] 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 recorded and forecasted year-end 2025 CAM,[20] VAMOMA, PABA, MTCBA, PPCP, TMNBC, BioMAT, and ERRA balances in rates over the following calendar year, through the AET process.[21] To accomplish this, PG&E will update the forecast year end 2026 illustrative rates in its Fall Update.

G. Conclusion

The purpose of this testimony is to present PG&E's 2026 ERRA Forecast Application total revenue requirement of approximately $2,705 million. PG&E requests approval of the 2026 ERRA Forecast Application total revenue requirement of approximately $2,705 million, with a revenue requirement for rate-setting purposes of $4,015 million which includes $1,310 million of revenue requirements approved in other Commission proceedings. The component revenue requirements for rate setting purposes comprise of a NSGC forecast of $217 million, VAMOMA of $0.3 million, PCIA forecast of $815 million, Ongoing CTC forecast revenue requirement credit of $27 million, ERRA forecast revenue

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19 D.22-02-002, OP 7.

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

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

requirement of $2,959 million, PPCP subaccount forecast revenue requirement credit of $2.5 million, TMNBC forecast revenue requirement recovery of $41 million, and BioMat forecast revenue requirement of $11 million. Final revenue requirement implemented in 2026 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 forecasts for 2026: (1) A&O expense budget of $0.812 million pertaining to implementation of GHG revenue return; (2) customer generation programs funded by GHG-revenues of $34.2 million; (3) net forecast revenue return amount of $579 million and PG&E's proposal to return the revenue to customers in rates in 2025; and (4) 2025 semi-annual residential and eligible small business CCC amount of $45.09 per household. PG&E also requests that the Commission find the 2024 recorded A&O expenses of $0.708 million related to the GHG revenue return were reasonable.

PG&E requests that the Commission approve PG&E's rate proposals associated with its proposed electric procurement-related revenue requirements to be effective in rates on January 1, 2026. PG&E also asks that the Commission approve PG&E's 2026 retail sales forecast, as revised in its 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

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

A. Introduction

The purpose of this chapter is to describe Pacific Gas and Electric Company's (PG&E) 2026 sales and peak demand forecasts, and the methodology used to develop these forecasts as presented in PG&E's 2026 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.

PG&E forecasts distribution system sales to total about 77,744 gigawatt-hour (GWh) in 2026; this is an approximately 2.3 percent increase from the system forecast adopted by the California Public Utilities Commission (CPUC or Commission) in Decision (D.) 24-12-038, which adopted PG&E's 2025 ERRA Forecast Application (A.) 24-05-009. Much of this increase is due to newly forecasted data center sales. PG&E's bundled sales are forecast to be about 25,055 GWh, an approximately 4 percent decline from the bundled forecast adopted in the 2025 ERRA Forecast proceeding. The decrease is the result of a small increase in the system forecast driven by, e.g., data center expansion, but outweighed by the expected departure of load to Community Choice Aggregators (CCA), more specifically the expansion of Ava Community Energy (Ava) into unincorporated San Joaquin County.

The 2026 bundled electricity sales forecast is calculated as the residual of the total system sales forecast and forecasted departing load. There are 10 Energy Service Providers serving Direct Access (DA) and 12 CCAs currently serving load in PG&E's service territory in 2025.[1] In total, PG&E expects CCA

[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).

and DA providers to serve over 68 percent of PG&E's total system sales in 2026.

The 2026 system peak forecast is approximately 4 percent higher than the 2025 peak forecast adopted by D.24-12-038. This increase is driven in part by increased system sales, as peak forecast for a given load profile scales with energy. Other drivers include small year-over-year increases in weather demand and updated historical data. The 2026 bundled peak forecast is approximately 2 percent higher compared to the 2025 peak forecast adopted in PG&E's 2025 ERRA Forecast proceeding. 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 while leaving system sales unchanged.

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

In the first quarter of 2025, the economy in PG&E's service area showed an overall picture of slow and uneven improvement. Jobs and economic growth are expected to be positive but low. While population growth is higher than some recent forecasts, demographics remain a concern. Housing prices are climbing slowly mostly due to supply limits. The once dominant tech industry seems to have bottomed out and may be in the early uneven stages of recovery, but this has not yet shown up

in jobs data. The emerging focus on generative artificial intelligence will support some degree of growth in demand for energy in the foreseeable future. The effects of increasing tariffs on global trade do not have precedent in the historical record and introduce an additional layer of uncertainty.

PG&E continues to address intervenor concerns that previous modeling did not incorporate a “new normal” capturing changes in usage patterns 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 five 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 post-COVID-19 year to estimate the impact of post-COVID usage patterns in each year, taking care to exclude the influence of recent changes in rooftop solar and other new technologies. The five 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 2026 adjustment (decrease) for small and medium commercial sales of almost 4 percent, and an adjustment (increase) for residential sales of a little over 1 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.

In accordance with the Joint Stipulation between PG&E and Small Business Utility Advocates (SBUA) entered into the record of A.24-05-009 on October 30, 2024 concerning PG&E’s sales forecast

(Joint Stipulation),[2] PG&E conducted a Meet & Confer with a consultant for SBUA on February 21, 2025, providing historical monthly sales data by customer class in advance of the meeting and identifying post-regression adjustments. These post-regression adjustments are also identified in PG&E's workpapers in accordance with the Joint Stipulation. PG&E solicited data and analysis from SBUA to substantiate their assertions of lasting changes in small commercial load, but received none, either in advance or at the meeting. At the meeting, PG&E described its forecasting methodology and post-regression adjustments and summarized the rates calculation process showing impacts of increasing or decreasing load. SBUA reiterated its belief that long-term changes were not represented, but shared no data or analysis for PG&E to address. Because SBUA does not support its assertions with any forward-looking data or an illustrative forecast methodology, PG&E is not able to provide any additional responsive testimony addressing SBUA's concerns.[3]

TABLE 2-1
SERVICE AREA ECONOMIC INDICATORS

	2022	2023	2024	2025	2026
Real Gross Product ($ Billions)	[redacted]				
% Change					
Total Employment (Thous.)					
% Change					
Real Personal Income ($ Billions)					
% Change					

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

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2 The Joint Stipulation is available at: https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2405009/7814/544568947.pdf.

3 Joint Stipulation, Section II D.

sales per customer using various PG&E service area economic measures, price variables, and weather variables. The forecast models incorporate recorded data through November 2024,[4] with historic and forecast values for the models' economic drivers from the Moody's Analytics December 2024 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 for this exhibit. 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, new large data centers, and additional end use electrification. Details of these forecasts are described in Section B.2.

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 updated its forecast weather dataset using a smoothed average 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 update was used in both the sales and peak energy forecasts. The new forecast derives future weather from 12 localized global models (the previous forecast used only four models, which was all that was available at the time).

On a recorded basis, residential sector sales to all retail customers (including PG&E bundled, CCA, and DA) decreased 6.2 percent between 2022 and 2023 and increased 0.4 percent between 2023 and

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4 This Application schedule, recently revised, required an earlier start to PG&E's load forecast process and December 2024 data were not available to inform PG&E's sales forecast submitted as part of the Application.

2024. The Residential forecast for 2026 is 5.4 percent greater than the recorded 2024 value.

PG&E primarily attributes the gradual drop in residential sales over the past eight years 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) increased 0.6 percent from 2023 to 2024. Previously from 2022 to 2023, commercial sector sales declined by a total of 1.7 percent on a recorded basis. 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 2026 is 2.2 percent greater than the recorded 2024 value.

Industrial class sales to all retail customers (including PG&E bundled, CCA and DA) declined 0.1 percent in 2023 and by an additional 1.1 percent in 2024. The Industrial forecast for 2026 is 13.6 percent greater than the recorded 2024 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 rose by 8.4 percent. PG&E's 2026 agricultural sales are currently forecast to be about 6.6 percent above PG&E's recorded 2024 agricultural sales due to the use of historical average Palmer's Drought Severity Index (PDSI) values for the spring forecast. The midyear Agriculture forecast update described below will update PDSI values, incorporating the effect of normal-to-wet weather conditions through the first part of 2025. PG&E currently anticipates that

this will reduce the forecasted agricultural sales that PG&E will present in the Update to Prepared Testimony (Fall Update) for 2026 compared to the current forecast for agricultural sales.

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.[5] 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.[6]

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 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,[7] 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 will 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 advances the CPUC Energy Division's issuance of the market price benchmarks by a month to early October.[8] PG&E has consulted 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.

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

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

7 The drought factor is measured by the PDSI.

8 See D.22-01-023, Ordering Paragraph (OP) 1.

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 estimates of load modifiers as described in the next part of this chapter are also included. For 2026, PG&E's projected retail peak demand is shown in Table 2-3, line 41. 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 2026.

Starting with the 2024 ERRA Forecast, PG&E improved its retail peak model, mostly related to the forecast weather model for heating and CDD. As mentioned in the Sales Forecast subsection above, these improvements included replacing the existing simple linear climate change adder with forecast HDD/CDD supplied by PG&E's Climate Resilience group working with a consultant using publicly vetted earth system models published by the CEC. The new system peak forecast for 2026 is approximately 2 percent above the recorded system peak for 2024.

2. Post-Regression Forecast Adjustments

Although the regression-based forecast described in Section 1.b above remains at the core of PG&E's sales and peak demand forecast process, the regression forecast alone cannot incorporate all of the impacts of new technologies and policies. For this reason, PG&E takes an additional step to adjust its regression forecast before arriving at final sales and peak

demand forecasts. The adjustments cover BTM DG, Conservation and EE, EVs, Building Electrification, BTM Energy Storage, and – new for this year – new large 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 900,000 installations and approximately 8,800 megawatts (MW) of installed BTM DG capacity by the end of 2024. PG&E expects ongoing growth of BTM solar PV given economic and policy incentives, such as net billing tariff, the Inflation Reduction Act, and Title 24 new construction mandates.

In order to forecast load impacts from BTM solar, PG&E has developed a model which forecasts customer solar PV adoption and installed capacity, and estimates generation associated with that capacity. Forecasts of BTM PV adoption were based on a Bass technology diffusion model considering the economics of customer adoption. In addition to adoptions forecasted by the Bass model, PG&E also expects policy-driven adoptions from state solar initiatives including new houses compliant with the Title 24 solar mandate. Generation estimates for BTM PV were developed internally using customer PV system size and capacity factor inputs that vary by location. Lines 5 and 35 of Table 2-3 show BTM PV cumulative energy and peak demand forecasts.

For non-PV BTM DG resources, a simple Bass technology diffusion model informed the fuel cell adoption forecast. Market, policy, and trend analysis informed the wind and combustion technologies (including combustion turbines, microturbines, internal combustion engines) adoption forecasts. For non-PV BTM DG technologies, generation estimates were based on annual capacity factors from the 2016-2017 Self-Generation Incentive Program Impact Evaluation study prepared by ITRON in 2018, 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 Integrated Energy Policy Report (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, and it roughly aligns with the Mid scenario. Note that EE savings data from the CEC was scaled down from the PG&E transmission access charge area/planning area to PG&E's service area. Lines 3 and 33 of Table 2-3 show energy and peak demand forecasts of AAEE incremental to 2024.

c. EVs

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 scenario-based model informed by policies and market drivers to forecast EV population, energy demand, and hourly load. The forecast is informed by: (1) aggregated light-duty EV registration data available through June 2024; (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, and (5) load-shifting from vehicles participating in bidirectional charging. 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 both newly-constructed all-electric buildings compliant with applicable California building codes (e.g., Title 24) and 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 2024.

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

New as of this year, PG&E is explicitly incorporating the impacts of new large data centers expected in its service territory. PG&E collaborated with the CEC in the development of a data center forecast for the 2024 IEPR. PG&E's forecast is similar to the 2024 IEPR forecast for PG&E's service area.

PG&E's interconnection application queue serves as the main source data for forecasting future data center facilities. Requested load from applications is aggregated in each year; that time series is then multiplied by an assumed application conversion rate of 70 percent to create a forecast of data center capacity installed. This step accounts for uncertainty in project materialization due to, for example, application dropouts. Capacity utilization rate and load factor assumptions (approximately 60 percent and 80 percent, respectively, for 2026) are applied to the capacity forecast to create annual peak demand and annual sales forecasts for these data centers. Finally, assumptions around load shapes and seasonality were incorporated to make an hourly load forecast. These assumptions were developed based on internal and external analyses of existing data centers in PG&E's service area and the service areas of other electric utilities. All of these

assumptions largely align with the CEC's assumptions in its 2024 IEPR forecast.

Lines 7 and 39 of Table 2-3 show large data center energy and peak demand forecasts incremental to 2024.

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.[9] 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 California Energy Demand (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 2025, contains a forecast of energy deliveries to PG&E bundled and DA/CCA customers through 2040. 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 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,

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

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 "Additional Achievable Energy Efficiency"—EE 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 for two reasons. 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 2026 ERRA forecast relies on data through November 2024. 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 2026 sales.

B. Departing Load

1. Departing Load Sales Methodology

In this filing, PG&E reflects seven departing load (DL) types,[10] 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

[10] 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.

DL sales as a proxy for 2026 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 2026.

TABLE 2-2
2026 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)	250,876	0	Exempt	Exempt
3	Customer Generation DL (a)	14,517,011	216,849	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)	11,152,104	11,152,104	7,046,749	11,152,104
7	Continuous DA D.12-04-012 (a)	247,896	247,896	Exempt	247,896
8	Total Direct Access	11,400,000	11,400,000	7,046,749	11,400,000
9	CCA	41,288,287	41,288,287	41,288,287	41,288,287
10	**Total Departing Load**	**68,161,016**	**53,437,125**	**48,335,036**	**52,697,308**

(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. Departing Load Settlements

PG&E entered into four Settlement Agreements (SA) regarding the collection of DL charges. The SAs with: (1) the Power and Water Resources Pooling Authority;[11] (2) the Modesto Irrigation District and the Merced Irrigation District;[12] (3) the Turlock Irrigation District;[13] and (4) the Center for Accessible Technology, MCE, the Public Advocates Office, The Utility Reform Network, and Brightline Defense[14] have been completed. While these settlements specify the DL charges to be collected from the responsible parties, they do not affect the calculation of historical annual sales.

3. Departing Load Due to Direct Access

PG&E develops its sales forecast from billed customer data, which includes sales for bundled, CCA, and DA customers. In order for PG&E to develop a forecast of its 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 four-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 four-year timeframe (2010-2013). PG&E's

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[11] A.09-05-017 and D.09-08-015.

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

[13] A.02-01-012 and D.03-04-032.

[14] D.18-09-013.

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

4. Direct Access Expansion

In September 2018, SB 237[15] 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 2026 DA load forecast includes existing DA authorized under SB 695. PG&E relied on DA contract allocations in 2024 to estimate the amount of DA departed from bundled and CCA service for the 2026 forecast filing.

Pursuant to D.19-06-026, LSEs that anticipate load migration are required to meet and confer to discuss load migration forecast adjustments.[16] At the time of the preparation of its DA forecast scheduled DA departed load was very close to the annual cap and PG&E did not forecast any additional DA departures in 2026.

5. Departing Load 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;
3) CPSF;
4) PCE;
5) SVCE;
6) RCEA;
7) PIO;
8) 3CE;

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15 SB 237 (Stats. 2018, Chapter 800).

16 See D.19-06-026 OP 14 (describing requirements of meet-and-confer process concerning Energy Service Provider load forecast).

9) Ava (formerly EBCE) [17];
10) Valley Clean Energy Authority;
11) KCCP; and
12) SJCE.

This forecast reflects the 12 CCAs above that are expected to serve load in 2026. 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: Unincorporated San Joaquin County is scheduled to join Ava in 2026.

6. CCA Load Forecast Methodology

In order to forecast year-ahead DL due to CCA growth, PG&E follows a meet-and-confer process[18] with CCAs that plan to serve load in 2026. In January 2025, 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 2026 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.

The remaining 5 CCAs have forecasted new data center load growth in their areas. Recognizing this new source of load growth, PG&E continued the meet-and-confer process, comparing its own forecasts, excluding new data center load, for these 5 CCAs to the CCAs' own forecasts. For four of these CCAs, PG&E accepted the CCA's forecasts as its own before adding in the new data center load forecast. The remaining one CCA for which the difference between PG&E's forecast without new data center load and the CCA's forecast substantially differ, PG&E and the CCA will continue discussions during the summer months and the Fall 2025 meet-and-confer

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17 Name changed to Ava as of Oct. 24, 2023.

18 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).

to generate alignment. For the purpose of the initial forecast, PG&E will use its own forecast for this CCA.

PG&E also communicated with Ava on monthly non-coincident peak demand forecasts for its expansion scheduled for 2026 as part of the RA Forecast filing meet-and-confer.

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

The load forecast presented in this chapter was developed in March 2025 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 2025 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
2026 ENERGY (GWH) AND PEAK DEMAND (MW) REQUIREMENTS

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	**Energy Load (GWh)**													
2	Unmitigated Retail Sales													90,765
3	Conservation and Energy Efficiency [1]	(102)	(93)	(106)	(106)	(121)	(134)	(148)	(146)	(130)	(120)	(100)	(101)	(1,406)
4	Distributed Generation													
5	Solar	(670)	(796)	(1,215)	(1,445)	(1,639)	(1,684)	(1,710)	(1,636)	(1,415)	(1,204)	(845)	(715)	(14,973)
6	Non-PV DG	(255)	(223)	(247)	(240)	(244)	(237)	(245)	(246)	(238)	(241)	(234)	(243)	(2,891)
7	Large Data Centers	89	86	101	105	115	120	133	139	139	146	145	156	1,474
8	Storage	11	10	11	11	11	11	11	11	11	10	10	10	129
9	Electric Vehicles	333	307	347	343	361	357	376	383	378	398	392	412	4,386
10	Building Electrification	29	25	23	21	18	17	17	17	17	20	24	31	260
11	Retail Sales													77,744
12	Direct Access													
13	Direct Access	(952)	(901)	(910)	(897)	(925)	(960)	(1,034)	(1,049)	(1,007)	(985)	(897)	(883)	(11,400)
14	Community Choice Aggregation													
15	Marin Clean Energy													
16	Sonoma Clean Power													
17	Clean Power San Francisco													
18	Peninsula Clean Energy													
19	Silicon Valley Clean Energy													
20	Redwood Coast Energy Authority													
21	Pioneer Community Energy													
22	Central Coast Community Power													
23	Ava Community Energy													
24	San Jose Clean Energy													
25	Valley Clean Energy													
26	King City Community Power													
27	Community Choice Aggregation Total	(3,602)	(3,257)	(3,249)	(3,025)	(3,132)	(3,329)	(3,674)	(3,751)	(3,534)	(3,375)	(3,456)	(3,903)	(41,288)
28	UFE, Transmission & Distribution Losses													2,348
29	Total Requirement													27,403
30	Retail Sales excludes BART energy requirements.													

TABLE 2-3
2026 ENERGY (GWH) AND PEAK DEMAND (MW) REQUIREMENTS
(CONTINUED)

Line No.		2026 PEAK REQUIREMENTS (MW)											
31	**Peak Load (MW)**												
32	Unmitigated Retail Peak												
33	Conservation and Energy Efficiency [1]	(150)	(151)	(160)	(162)	(269)	(295)	(343)	(286)	(249)	(186)	(161)	(155)
34	Distributed Generation												
35	Solar	0	0	0	0	(30)	(144)	(907)	(564)	(90)	0	0	0
36	Non-PV DG	(342)	(331)	(332)	(334)	(328)	(329)	(329)	(330)	(331)	(324)	(325)	(326)
37	Electric Vehicles	302	308	332	378	351	358	340	347	353	359	392	372
38	Building Electrification	61	57	50	40	34	31	32	31	30	35	51	64
39	Large Data Centers	121	129	137	145	156	168	180	188	194	198	203	212
40	Storage	(332)	(333)	(341)	(344)	(339)	(358)	(359)	(364)	(364)	(330)	(330)	(327)
41	Retail Peak with distribution losses												
42	Direct Access with distribution losses	(1,491)	(1,616)	(1,570)	(1,595)	(1,680)	(2,010)	(2,086)	(2,081)	(1,761)	(1,838)	(1,525)	(1,440)
43	Community Choice Aggregation with dist losses	(6,881)	(7,052)	(6,622)	(6,563)	(7,458)	(8,370)	(8,685)	(8,884)	(8,689)	(7,324)	(6,887)	(7,741)
44	UFE & Transmission Losses												
45	Puget Sound Power & Light (Return)												
46	Total Requirement												
47	Retail Peak excludes BART demand requirements.												

Notes:

Distributed generation, storage, and EV impacts are cumulative, whereas energy efficiency, building electrification, and data center impacts are incremental to end-of-year 2024.

EE data represents savings from additional achievable energy efficiency programs and codes & standards incremental to 2024, 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

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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) 2026 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-2004) resources are comprised of a large fleet of hydroelectric generation plants, many 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. Unit 1's initial operating license expired at the end of 2024 while Unit 2's current operating license will expire on August 26, 2025.

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 current license period in 2024 and 2025. The Nuclear Regulatory Commission (NRC) has authorized PG&E to continue operating DCPP while its license renewal application is pending at the NRC, and a successor cost recovery mechanism is in place for DCPP. PG&E does not seek recovery for forecast DCPP costs in this Application. On March 28, 2025, PG&E submitted Application 25-03-015 to recover in customer rates 2026 DCPP extended operation costs.

2. Hydroelectric Generation (Hydro)

PG&E owns and operates numerous hydroelectric 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 2026 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), using NG as their primary fuel source, with a small amount of distillate oil as a pilot fuel. The reciprocating engines are dual-fuel capable—meaning they can operate on either NG or distillate. PG&E maintains an adequate inventory of distillate onsite in case of NG delivery limitations to the Humboldt area.

4. Solar Resources

On April 22, 2010, the California Public Utilities Commission (CPUC or Commission) adopted 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.

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 2024 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. Qualifying Facilities

These include legacy QF contracts in effect as of December 20, 1995, eligible for Ongoing CTC recovery. As of April 2026, PG&E has 38 operating legacy QFs remaining. A majority of the remaining legacy QF capacity is comprised of Crockett Cogeneration, a 260 MW NG fired cogeneration facility located in Crockett, California.

3. 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]

In total, PG&E's 2026 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;

[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.

- RFO solicitations for the Power Purchase Agreement (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 sales solicitations continue. For 2026, PG&E's portfolio includes RPS sale contracts executed through the Voluntary Allocation Market Offer (VAMO) 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 2026. [redacted]

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

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.

The fossil facilities that are expected to provide energy and capacity to PG&E during all or part of 2026 are the Panoche Energy Center (CT); and Chevron McKittrick CHP Plant. 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-hydroelectric (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 2024, PG&E executed sales of [redacted] of large hydroelectric volumes for 2025 delivery. [redacted]

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, decision D.19-11-016 from the Integrated Resource Plan 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 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 2026 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 LSE that opted out of their procurement obligations under D.19-11-016. Additionally, pursuant to OP 10, the associated costs for LSEs that go

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[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.

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

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 2026 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
- 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 Integrated Resource Plan 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 to PG&E procure an additional 777 MW of NQC with delivery starting in 2026.

PG&E anticipates that 1,690 MW of MTR battery storage capacity will be operational by the end of 2025 with an additional 688 MW coming online during 2026.

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 2026 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 2025, PG&E does not have any of the PURPA SOCs in its 2026 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

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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.

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 IOU to seek contracts for additional 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 2026. If the Commission orders any additional procurement for the summer of 2026 prior to the Fall Update, PG&E will reflect any applicable ordered procurement as part of the updated portfolio 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

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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.

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 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 2026 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.

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

[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

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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) 2026 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 2026;
- 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 2026 forecast, PG&E is using March 28, 2025 forward electricity and natural gas prices, which are presented in Table 4-1.

TABLE 4-1
2026 FORWARD ELECTRIC AND NATURAL GAS PRICES

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

Note: Forward Energy and Natural Gas Prices were derived from March 28, 2025 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 will no longer be considered as 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. There are payments PG&E makes to various entities for water used in some hydroelectric plants, as well as payments for headwater improvements made by other entities, and water rights fees to the State Water Resources Control Board. The water rights fees are based on acre-feet of storage or the theoretical annual maximum acre-feet that can be diverted depending on the type of license or permit.

Water for power costs are estimated by using historical costs and new or emerging developments for 2026. PG&E's 2026 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. PG&E also has pursued and intends to continue pursuing selling the GHG-Free attributes from its bundled service customer share of large hydroelectric resource GHG-Free attributes. [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] 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 adjusted based on more recent actual average generation. 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 simulated hourly generation by the contract-specific prices.

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

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 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 2026 ERRA Forecast application PG&E is

assuming it will not hold any additional VAMO sales offerings, consistent with Advice Letter (AL) 7105-E.[3]

Beyond VAMO, PG&E is including RPS sales executed as a result of its 2024 RPS RFO which included agreements for deliveries in 2024 and 2025. [redacted]

In the event PG&E anticipates or has already executed applicable transactions prior to the Fall Update, such transactions would be 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.[4] PG&E did not participate in its 2023 Market Offer process as a buyer. For the Market Offer, 11 RPS sales agreements were executed.[5] 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.[6]

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

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3 AL 7105-E.

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

5 AL 6894-E.

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

TABLE 4-2
FORECASTED 2026 RPS-ELIGIBLE VOLUMES
BY VINTAGE AVAILABLE TO NON-PG&E BUYERS
(MWh)

Line No.	Vintage	Voluntary Allocation	Market Offer
1	2009	533,145	689,052
2	2010	30,248	365,868
3	2011	13,565	169,327
4	2012	738,945	222,172
5	2013	559,087	135,111
6	2014	503,903	20,934
7	2015	357,794	40,920
8	2016	62,042	4,527
9	2017	103,563	19,848
10	2018	–	–
11	2019	–	–
12	2020	–	–
13	2021	24,957	32,889
14	2022	–	–
15	2023	–	–
16	UOG Legacy	240,451	155,132
17	Total	3,167,701	1,855,780

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.[7] PG&E uses its stochastic forecast of California border natural gas prices derived from March 28, 2025 broker quotes to forecast SRAC energy pricing, consistent with the market prices described above.

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

During 2006, PG&E entered into Settlement Agreements and amendments with 123 QFs.[8] Only a few of these amendments will continue to be in effect during 2026. 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 28, 2025 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.

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

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

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"[9] of the month plus the applicable Planning Reserve Margin adjustment.[10] 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 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.[11]
- Imports: The amount of qualifying capacity that can be counted in any given hour is determined by the underlying contract's delivery profile.

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9 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.

10 PG&E applies an additional internal reserve quantity.

11 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.

- 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 2 of Chapter 5. Tables 4-6 through 4-17 present PG&E's bundled 2026 portfolio SoD RA supply forecast for each month (excluding storage).

D. Conclusion

This chapter presents PG&E's forecasted 2026 generation portfolio supply volumes and costs.

TABLE 4-3
2026 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													
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													
10	QF													
11	Imports													
12	Power Charge Indifference Adjustment (PCIA)													
13	Utility-Owned Generation													
14	Nuclear	[redacted]												
15	Hydro													
16	Fossil													
17	Solar	24	39	57	63	70	68	68	65	57	50	35	31	627
18	Fuel Cell	[redacted]												
19	Energy Storage													
20	Pre-2003 Contracted Resources													
21	QF	[redacted]												
22	Post-2002 Contracted Resources													
23	RPS Eligible													
24	RPS-Eligible Contracts	706	801	1,109	1,273	1,465	1,528	1,511	1,403	1,204	1,033	796	671	13,499
25	RPS-Eligible Contracts - Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
26	RPS-Eligible Future Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0
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
2026 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 Etiwanda	0	0	0	0	0	0	0	0	0	0	0	0	0
39	Puget Sound Power & Light Contract (Net)	[redacted]												
40	QF													
41	Public Policy Charge Procurement (PPCP)													
42	QF	[redacted]												
43	Bioenergy Market Adjusting Tariff (BioMAT)													
44	Post-2002 Contracted Resources													
45	RPS Eligible													
46	RPS-Eligible Contracts	8	8	8	9	10	10	12	12	12	10	11	9	119
47	Tree Mortality Non-Bypassable Charge (TMNBC)													
48	Post-2002 Contracted Resources													
49	RPS Eligible													
50	RPS-Eligible Contracts	108	106	102	89	118	104	115	122	105	91	94	103	1,257
51	RPS-Eligible Contracts - Sales	(69)	(64)	(62)	(69)	(80)	(65)	(75)	(84)	(88)	(82)	(78)	(80)	(896)
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													
57	Energy Storage	[redacted]												

TABLE 4-3
2026 ENERGY SUPPLY
(GWH)
(CONTINUED)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
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-Owned Generation													
67	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0
68	Energy Storage													
69	**Total Supply**													

Note: Totals may not add due to rounding.

TABLE 4-4
2026 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													
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	69	65	62	67	73	75	57	53	53	57	47	55	732
16	Fossil													
17	Solar	12	19	28	31	35	34	34	33	28	25	17	16	313
18	Fuel Cell													
19	Energy Storage													
20	Pre-2003 Contracted Resources													
21	QF													
22	Post-2002 Contracted Resources													
23	RPS Eligible													
24	RPS-Eligible Contracts	860	934	1,280	1,453	1,654	1,700	1,674	1,557	1,369	1,205	954	818	15,458
25	RPS-Eligible Contracts - Sales													
26	RPS-Eligible Future Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0
27	RPS-Eligible Future Sales	(139)	(152)	(194)	(215)	(238)	(250)	(246)	(230)	(203)	(170)	(137)	(125)	(2,300)
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
2026 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													
37	MWD Etiwanda	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Puget Sound Power & Light Contract (Net)													
39	QF													
40	Public Policy Charge Procurement (PPCP)													
41	QF													
42	Bioenergy Market Adjusting Tariff (BioMAT)													
43	Post-2002 Contracted Resources													
44	RPS Eligible													
45	RPS-Eligible Contracts	10	10	10	11	12	12	13	14	14	12	12	11	141
46	Tree Mortality Non-Bypassable Charge (TMNBC)													
47	Post-2002 Contracted Resources													
48	RPS Eligible													
49	RPS-Eligible Contracts	55	55	51	43	60	54	59	62	44	37	40	44	603
50	RPS-Eligible Contracts - Sales	(34)	(31)	(31)	(34)	(40)	(32)	(38)	(42)	(44)	(43)	(36)	(38)	(442)
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													
57	Energy Resource Recovery Account (ERRA)													
58	Post-2002 Contracted Resources													
59	Other Bilateral Contracts													
60	QF													
61	Energy Storage													
62	RPS-Eligible Future Contracts													

TABLE 4-4
2026 RPS ENERGY SUPPLY
(GWH)
(CONTINUED)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
63	Utility-Owned Generation													
64	Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.4
65	Energy Storage	[redacted]												
66	**Total Supply**													

Note: Totals may not add due to rounding.

TABLE 4-5
2026 PROCUREMENT COSTS
(THOUSANDS OF DOLLARS)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	Energy Supply / Demand Procurement Costs ($)													
2	Cost Allocation Mechanism (CAM)													
3	Utility-Owned Generation													
4	Energy Storage													
5	Post-2002 Contracted Resources													
6	Other Bilateral Contracts													
7	Fossil Contracts - Non-CHP													
8	Fossil Contracts - CHP													
9	Energy Storage Contracts													
10	QF													
	Future RA Contracts													
11	Imports													
12	CPE Administrative	383	383	394	394	435	435	435	435	415	624	394	394	5,121
13	Power Charge Indifference Adjustment (PCIA)													
14	Utility-Owned Generation													
15	Nuclear													
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													
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
2026 PROCUREMENT COSTS
(THOUSANDS OF DOLLARS)
(CONTINUED)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
37	Ongoing Competition Transition Charge (CTC)													
38	Pre-2002 Contracted Resources													
39	Irrigation District & Water Agency													
40	MWD Etiwanda													
41	Puget Sound Power & Light Contract (Net)													
42	QF													
43	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-Owned 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**	**186,552**	**143,411**	**144,758**	**164,785**	**183,764**	**257,126**	**246,887**	**234,272**	**220,542**	**174,232**	**147,698**	**160,657**	**2,264,684**

TABLE 4-6
2026 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																								
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
2026 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)																								
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	2	17	32	40	44	44	41	38	26	6	0	0	0	0	0	0	0
49	DCPP Extended Operations (DCPP_NBC_CA)																								
50	Nuclear																								
51	**Total Net Supply**																								

TABLE 4-7
2026 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																								
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 4-7
2026 BUNDLED PORTFOLIO SYSTEM RA – FEBRUARY
(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																								
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	13	53	67	69	66	66	65	65	55	28	2	0	0	0	0	0	0
49	DCPP Extended Operations (DCPP_NBC_CA)																								
50	Nuclear																								
51	**Total Net Supply**																								

TABLE 4-8
2026 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																								
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
2026 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																								
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	3	33	62	67	64	65	65	60	56	51	36	9	0	0	0	0	0	0
49	DCPP Extended Operations (DCPP_NBC_CA)																								
50	Nuclear																								
51	**Total Net Supply**																								

TABLE 4-9
2026 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																								
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
2026 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																								
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	2	30	68	76	77	77	79	79	78	78	74	66	30	2	0	0	0	0	0
49	DCPP Extended Operations (DCPP_NBC_CA)																								
50	Nuclear																								
51	**Total Net Supply**																								

TABLE 4-10
2026 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																								
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
2026 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																								
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	11	52	75	81	82	82	84	84	85	84	82	75	46	7	0	0	0	0	0
49	DCPP Extended Operations (DCPP_NBC_CA)																								
50	Nuclear																								
51	**Total Net Supply**																								

TABLE 4-11
2026 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																								
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
2026 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																								
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	1	1	1	1	1	16	57	80	87	89	90	91	91	90	89	86	79	57	17	1	1	1	1	1
49	DCPP Extended Operations (DCPP_NBC_CA)																								
50	Nuclear																								
51	**Total Net Supply**																								

TABLE 4-12
2026 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																								
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 4-12
2026 BUNDLED PORTFOLIO SYSTEM RA – JULY
(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																								
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	1	1	1	1	1	8	47	76	86	88	90	90	89	88	88	83	76	52	13	1	1	1	1	1
49	DCPP Extended Operations (DCPP_NBC_CA)																								
50	Nuclear																								
51	**Total Net Supply**																								

TABLE 4-13
2026 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																								
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 4-13
2026 BUNDLED PORTFOLIO SYSTEM RA – AUGUST
(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																								
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	1	1	1	1	1	2	29	67	83	88	89	90	89	89	87	81	66	29	2	1	1	1	1	1
49	DCPP Extended Operations (DCPP_NBC_CA)																								
50	Nuclear																								
51	**Total Net Supply**																								

TABLE 4-14
2026 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																								
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 4-14
2026 BUNDLED PORTFOLIO SYSTEM RA – SEPTEMBER
(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																								
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	1	1	1	1	1	1	18	64	81	85	86	85	85	86	86	79	52	11	1	1	1	1	1	1
49	DCPP Extended Operations (DCPP_NBC_CA)																								
50	Nuclear																								
51	**Total Net Supply**																								

TABLE 4-15
2026 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																								
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 4-15
2026 BUNDLED PORTFOLIO SYSTEM RA – OCTOBER
(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																								
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	5	42	71	74	74	72	73	73	72	60	20	0	0	0	0	0	0	0
49	DCPP Extended Operations (DCPP_NBC_CA)																								
50	Nuclear																								
51	**Total Net Supply**																								

TABLE 4-16
2026 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																								
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 4-16
2026 BUNDLED PORTFOLIO SYSTEM RA – NOVEMBER
(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																								
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	17	51	61	61	59	61	61	57	35	4	0	0	0	0	0	0	0
49	DCPP Extended Operations (DCPP_NBC_CA)																								
50	Nuclear																								
51	**Total Net Supply**																								

TABLE 4-17
2026 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																								
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 4-17
2026 BUNDLED PORTFOLIO SYSTEM RA – DECEMBER
(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																								
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	3	22	38	46	49	47	45	41	23	3	0	0	0	0	0	0	0
49	DCPP Extended Operations (DCPP_NBC_CA)																								
50	Nuclear																								
51	**Total Net Supply**																								

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

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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) 2026 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

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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 2026 hedging transactions are consistent with its current Hedging Plan.

PG&E's hedging forecast is based on market conditions as of March 28, 2025. 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

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

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

5 PG&E's 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 2026 hedging transactions is presented in Table 5-1. PG&E's actual costs in 2026 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 2026 is listed in Table 5-1, line 2. The forecast for exchange and broker fees in 2026 is shown 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 it will incur in 2026 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 market conditions on March 28, 2025.

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

---

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.

a negative MtM represents a benefit. PG&E's estimate of the MtM of all the futures from the hedging program with delivery periods in 2026 in PG&E's portfolio as of March 28, 2025, is listed on line 6 in Table 5-1. The MtM value of the futures contracts with delivery periods in 2026 that have not been executed, but will be executed between March 29, 2025, and December 31, 2026, is zero.

The estimated settlement value of options with delivery periods in 2026 is best represented by the current market value of the options, which is the options' premium value on March 28, 2025. 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 2026 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
2026 FORECAST OF NATURAL GAS AND ELECTRIC HEDGE TRANSACTION COSTS
(THOUSANDS OF DOLLARS)

Line No.	Description	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Total
1	Costs Incurred at Trade Execution	[redacted]												
2	Exchange and Broker Fees													
3	Option Premiums													
4	Total Costs Incurred at Trade Execution													
5	Costs Incurred at Trade Settlement													
6	Mark-to-market of Futures as of March 28, 2025													
7	Mark-to-market of Options as of March 28, 2025													
8	Total Costs Incurred at Trade Settlement													
9	**Net Hedging Cost**													

C. Collateral Costs

PG&E separates its forecast 2026 collateral and prepayment cost estimates into two parts: (1) costs incurred for posting letters of credit and cash, and (2) net interest (if any) paid to counterparties who post collateral with PG&E. This section does not cover financial planning and strategy, but rather describes the collateral costs based upon resources available to PG&E.

1. Collateral for Physical and Financial Transactions

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

PG&E meets its transaction collateral requirements by using a combination of letters of credit and cash postings. In addition to annual fixed costs, PG&E also pays the marginal cost for letters of credit. The forecasted annual cost for posting cash ranges from approximately 476 to 602 basis points.

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.

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

Similarly, PG&E requires its counterparties to post collateral to cover market movements associated with fixed price forward gas and power transactions, any accrued receivable amounts for physical deliveries, and certain other energy-related agreements. Thus, the counterparties would

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

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 2026 FORECAST COLLATERAL COSTS
(THOUSANDS OF DOLLARS)

Line No.	Collateral Costs	Amount
1	Collateral on Physical and Financial Transactions	$7,058
2	GHG Inventory Carrying Costs	1,148
3	Net Interest Paid on Collateral Posted to PG&E	(301)
4	Total	$7,906

D. System RA Open Position and Associated Net Costs

This section presents PG&E's forecast of its 2026 slice-of-day (SoD) system RA open position volumes and associated costs, including an approach for how to translate the SoD volumes into single monthly values that are needed in order to integrate with the currently established PCIA and related cost recovery revenue requirement calculations. 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.

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 Entity's (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 2026 SoD RA requirements for its initial forecast that are based on its current bundled hourly load forecast and PG&E's 2025 SoD requirements.[11] The initial estimates will then be replaced by the 2026 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 midday 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.

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[11] Initial forecast estimates of the 2026 SoD requirements were based on PG&E's 2025 SoD requirements and adjusted based on PG&E's 2026 hourly load forecast relative to its 2025 forecast.

[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.

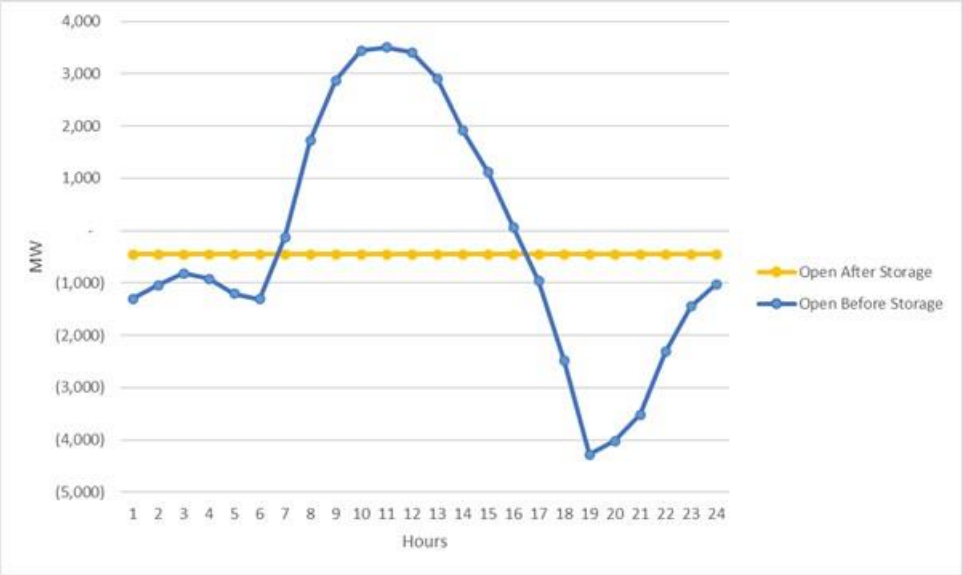
The storage heuristic and the determination of unsold capacity are outlined in more detail in the sections below.

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, and ultimately the forecasted amount of RA capacity retained by the bundled portfolio to meet its hourly requirements, 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 minimizes 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.

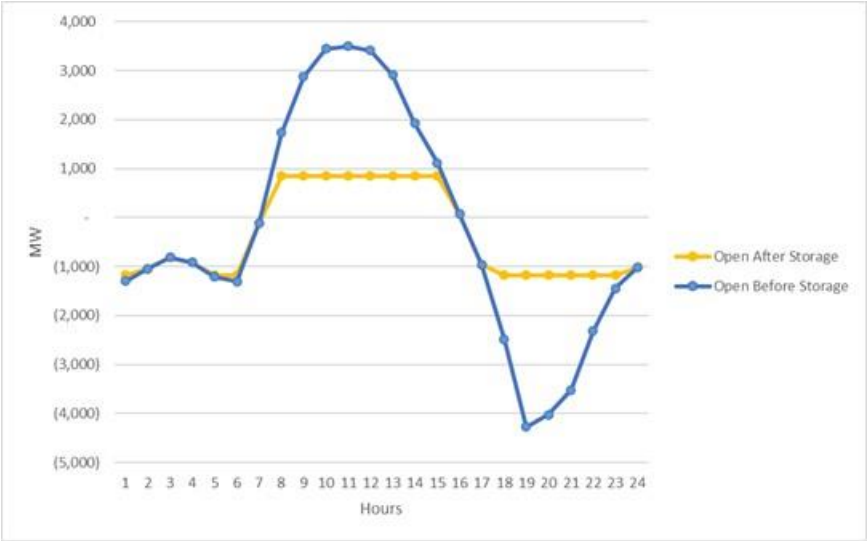
[13] Consistent with all charging sufficiency constraints.

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. In previous forecasts, PG&E used the historical relationship between actual monthly peak Unsold capacity and the bundled portfolio's minimum system RA supply to derive average quarterly "maximum unsold RA" factors. Since the SoD framework has only been in effect for a few months the requisite data to calculate hourly unsold factors are not available. Therefore, for 2026 ratesetting PG&E proposes to continue basing the Unsold RA allocation factors on historical monthly peak data until enough historical SoD position data are available for implementing SoD Unsold RA factors in setting 2027 rates. For setting 2026 rates, 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 5-3 through 5-14, 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 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 retained RA supply retained by the bundled portfolio, including forecasted Sold and Unsold RA volumes. To calculate the annual volumes to be retained at the applicable RA MPBs for ratesetting, the monthly values in each RA category are averaged across all months. When RA compliance was based on a single monthly peak, this calculation was more

straightforward. With the transition to SoD, hourly weighting factors need to be determined so that the 24 SoD positions in each month (see Tables 5-3 through 5-14) can be combined into single monthly positions required under the current cost recovery methodology for ratesetting. Algebraically, calculating single monthly values can be done by applying the hourly weights to each of the components in the SoD hourly position tables before the positions are then summed across the 24 hours. This approach effectively applies the same valuation to all RA regardless of resource type (e.g., all RA available at hour ending eighteen (HE18), including optimized storage, during March receives the same weighting).

For PG&E's 2026 ERRA Forecast, PG&E is proposing to derive the hourly weighting factors from the CEC[14] hourly system load forecast that will serve as the reference forecast used to calculate the hourly LSE SoD requirements for 2026. From the CEC's forecast, PG&E used the forecasted hourly CAISO load values corresponding to the "worst day" of the month[15] for each month to generate the monthly weights. The weights for each hour are calculated as each hour's relative load share for the applicable month.[16] Figure 5-3 shows the different monthly weighting schemes used to collapse the 24 SoD positions in each month to single monthly positions reflecting more weight being given to hours with greater demand requirements.

The resulting weighted average monthly positions are aggregated and shown in Table 5-16 while table 5-17 shows the forecasted residual excess RA sales revenue.[17]

---

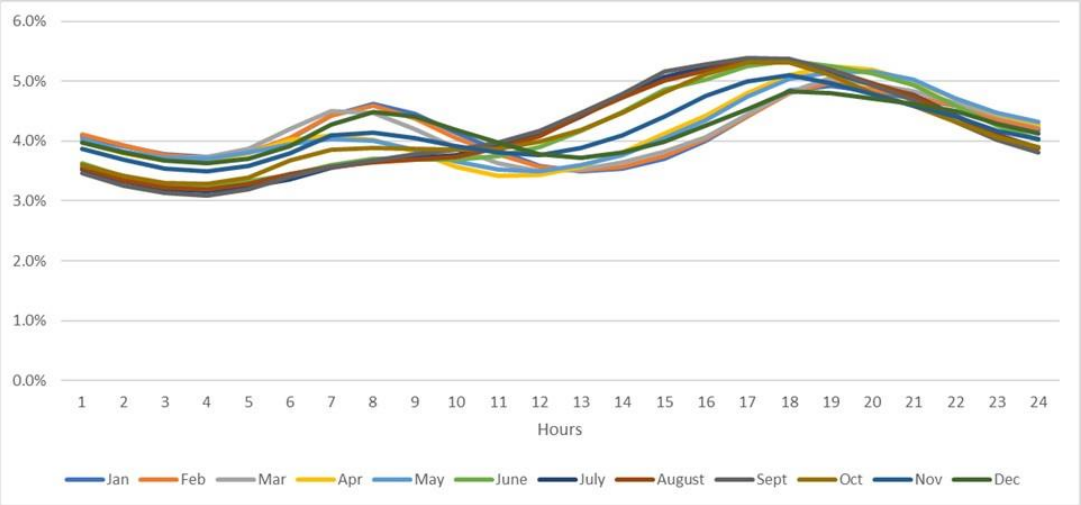
14 California Energy Demand 2024 Hourly Forecast-CAISO-Planning Scenario (Correction 3/20/2025).

15 The Commission has defined the "worst day" of the month as the day of the month with the highest hourly load.

16 Relative load shares are calculated as load in hour [x] divided by the sum of the 24-hourly loads.

17 The Forecast MPB used for calculating forecasted RA sales is based on the weighted average flexible, local, and system RA resource supply mix from PG&E's PCIA portfolio.

FIGURE 5-3
HOURLY WEIGHTING FACTORS BY MONTH



E. 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 incremental retained 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 2026 net RPS position in Table 5-15 based on the following methodology.

TABLE 5-3
2026 BUNDLED RPS OPEN POSITION

Line No.	Description	Total
1	Bundled Load (MWh) – RPS Customer	25,055,466
2	RPS Req. %	49%
3	RPS Req. (MWh)	12,359,862
4	RPS Sales (MWh)	[redacted]
5	Unsold RPS	–
6	Net RPS Generation[(a)]	[redacted]
7	Expected RPS Open Position[(b)]	

(a) Net RPS Generation is derived from PG&E's deterministic modeling.

(b) Expected RPS Open Position is derived from PG&E's RPS Stochastic model and will not tie to deterministic volumes presented above.

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. The expected RPS open position is informed by PG&E's RPS Stochastic model and incorporates solar and wind curtailment as well as a variety of simulation modeling adjustments. More information on PG&E's RPS Stochastic model can be found in PG&E's 2024 Final RPS Plan.

PG&E's executed Voluntary Allocation and Market Offer sales are described further in Chapter 4. PG&E's curtailment forecast is informed by values provided in the Electric Integrated Resource Planning and Related Procurement proceeding (R.20-05-003), as well as historical levels of solar and wind curtailment reported by the CAISO. More information on PG&E's curtailment forecast can be found in PG&E's Final 2024 RPS Plan. If applicable, Unsold RPS represents any volume that was available for sale in the Voluntary Allocation or Market Offer processes but will not be delivered as a result of the executed Voluntary Allocation or Market Offer contracts. Pursuant to D.19-10-001, any volume treated as Unsold RPS are valued at zero for the purposes of calculating retained RPS value in the PCIA until those volumes are used towards Minimum Retained RPS requirements or sold. PG&E expects to be physically short of the 2026 RPS requirement and Chapter 8 will describe PG&E's banked REC usage.

F. CAISO and Other Costs

1. CAISO Generator and Load Costs

PG&E's forecast of costs and revenues from the CAISO in 2026 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 2026 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 2026 forecast of interstate gas transportation costs is shown in Table 5-19.

G. Conclusion

In this chapter, PG&E presents its 2026 forecast for electric and natural gas hedging transaction 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
2026 SYSTEM RA OPEN POSITION (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)	[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 5-5
2026 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)	[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 5-6
2026 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)	[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 5-7
2026 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)	[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 5-8
2026 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
2026 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
2026 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)	[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 5-11
2026 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)	[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 5-12
2026 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																								
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
2026 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																								
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
2026 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)	[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 5-15
2026 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)	[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 5-16
2026 BUNDLED RPS OPEN POSITION

Line No.	Description	Total	Reference
1	Bundled Load (MWh) - RPS Customer	25,055,466	
3	RPS Req. %	49%	
4	RPS Req (MWh)	12,359,862	
5	RPS Sales (MWh)	[redacted]	Table 4-4, Row 25 & Row 27
6	Unsold RPS	-	
7	Net RPS Generation*	[redacted]	Table 4-4, Row 66
8	Expected RPS Open Position* *	[redacted]	Table 8-3

**Net RPS Generation is derived from PG&E's deterministic modeling.*

***Expected RPS Open Position is dervived from PG&E's RPS Stochastic model and will not tie to deterministic volumes presented above.*

TABLE 5-17
2026 SYSTEM RA OPEN POSITION (MW)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	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												
	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 5-18
2026 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 5-19
2026 BUNDLED MONTHLY WEIGHTED-AVERAGE SYSTEM CAPACITY (MW)

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	Capacity Supply (MW)												
2	Cost Allocation Mechanism (CAM)												
3	Utility-Owned Generation												
4	Energy Storage												
5	Post-2002 Contracted Resources												
6	Other Bilateral Contracts												
7	Fossil Contracts - Non-CHP												
8	Fossil Contracts - CHP												
9	QF												
10	Energy Storage												
11	Imports												
12	Power Charge Indifference Adjustment (PCIA)												
13	Utility-Owned Generation												
14	Nuclear												
15	Hydro												
16	Fossil												
17	Solar	18	29	30	44	49	56	56	49	48	37	27	17
18	Pre-2003 Contracted Resources												
19	QF												
20	Post-2002 Contracted Resources												
21	RPS Eligible												
22	RPS-Eligible Contracts	759	1,030	1,140	1,612	1,858	2,075	2,066	1,830	1,746	1,364	1,023	764
23	RPS-Eligible Future Contracts												
24	Other Bilateral Contracts												
25	Fossil Contracts - CHP												
26	Fossil Contracts - Non-CHP												
27	Large Hydro												
28	Energy Storage												
29	RA Contracts - Sales												
30	RA Contracts												
31	Bioenergy Market Adjusting Tariff (BioMAT)												
32	Post-2002 Contracted Resources												
33	RPS Eligible												
34	RPS-Eligible Contracts	11	11	11	10	11	11	12	12	12	11	11	12
35	Ongoing Competition Transition Charge (CTC)												
36	Pre-2002 Contracted Resources												
37	Irrigation District & Water Agency												
38	MWD Etiwanda												
39	QF												
40	Puget Sound Power & Light (Receive)												
41	Public Policy Charge Procurement (PPCP)												
42	QF												
43	Energy Resource Recovery Account (ERRA)												
44	Utility-Owned Generation												
45	Energy Storage												
46	Post-2002 Contracted Resources												
47	RA Contracts												
48	GTSR												
49	RPS-Eligible Contracts	11	21	22	32	37	44	43	39	36	27	19	13
49	DCPP Extended Operations (DCPP_NBC_CA)												
50	Nuclear												
51	Total Net Supply												

TABLE 5-20
2026 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													
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

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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) 2026 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 2026 CPE revenue requirement.

B. Central Procurement Entity 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]

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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 Request for Offers (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. Central Procurement Entity Procurement Costs

As mentioned above in Section B, in D.22-03-034 the Commission adopted PG&E's proposal to include CPE procurement costs in the Energy Resource

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

Recovery Account (ERRA) forecast 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 non-compensated self-shown local RA resources,[7] compensated self-shown local RA resources, and compensated offered local RA resources.[8] Though each of these resource categories have been procured by the CPE through its annual competitive solicitations for delivery beginning from 2023 and

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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 Per D.24-12-003, the non-compensated self-shown process has been eliminated from the CPE procurement process starting with the 2025 PG&E CPE Local RA RFO.

8 See, for example the 2024 CPE Local RA RFO Solicitation Protocol, pp. 7-10. https://www.pge.com/assets/pge/docs/about/doing-business-with-pge/2024-CPE-RFO-Solicitation-Protocol-Final.pdf.

beyond, only the compensated resource categories for 2026 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 compensation up to an administratively pre-determined price.[9] 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 2024, the CPE procured local RA capacity through the compensated self-shown resource process for the 2026 compliance year, with pricing based on the local RA premium for the local capacity area that the resource is located.[10] The total procurement costs for the Compensated Self-Shown RA Capacity procured for 2026 is 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.[11] 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

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

10 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.

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

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 2026 compliance year, with competitively offered pricing.[12] The total procurement costs for the compensated offered resources procured for 2026 are presented in Table 6-1 below.

3. 2025 CPE Procurement

On February 20, 2025, the CPE launched its 2025 CPE Local RA RFO to procure additional local RA capacity for the 2026 compliance year and beyond. The CPE seeks to procure the remaining capacity needed in each month to meet 100 percent of the local RA obligations for 2026.

Due to the uncertainty of how much 2026 RA capacity will be offered competitively for compensation, forecasted costs of any potential purchased capacity from the 2025 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 2026 in the 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 2025 procurement efforts. According to the timeline adopted in D.22-03-034, the CPE ACR will be due in mid-September of 2025.

D. Central Procurement Entity 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).[13]

PG&E has established a CPE organization within PG&E that provides the Commission, LSEs, and other market participants with reasonable assurances

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12 Specific capacity amounts procured to date by the CPE for the 2026 RA compliance year can be found on Page1 of Attachment 2 (Public Attachment A) in Advice Letter 7365-E, PG&E CPE's 2024 ACR. https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7365-E.pdf.

13 D.20-06-002, p. 96, OP 16.

as to the neutrality and transparency of the central procurement process, while 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 R.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 2026 associated with central procurement of local RA pursuant to D.20-06-002.

E. Conclusion

In this chapter, PG&E presents the 2026 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
2026 CPE-PROCUREMENT COST FORECAST FOR CAM
(THOUSANDS OF DOLLARS)

Line No.	Description	1/1/2026	2/1/2026	3/1/2026	4/1/2026	5/1/2026	6/1/2026	7/1/2026	8/1/2026	9/1/2026	10/1/2026	11/1/2026	12/1/2026	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
2026 CPE-ADMINISTRATIVE COST FORECAST FOR CAM
(THOUSANDS OF DOLLARS)

Line No.	Cost Element	2026 Cost	Description	2026 Headcount
1	Solicitation and Procurement	$1,575	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	415	Contract administration and settlements of CPE agreements.	3.5
3	Compliance	17	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	Augmented regulatory expertise to manage filings and communication related to CPE transactional volume.	0.1
5	Credit/Risk and Treasury	17	Additional expertise to perform credit calculations and monitor and maintain adequate protections and documentation for CPE transactions.	0.1
6	Information Technology (IT)	180	Personnel required to maintain systems and functionality related to CPE operations.	0.5
7	Accounting	17	Personnel required to address accounting operations for additional CPE transactions.	0.1
8	Legal	75	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	$2,413		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

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
COST ALLOCATION MECHANISM

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E) 2026 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. The LSE's customers receiving the RA benefit pay the net cost of this capacity, determined as a net of the total cost of the contract minus the energy and ancillary service revenues associated with dispatch of the contract.

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

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

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

area for the multi-year local RA program beginning with the 2023 RA compliance year.[2] 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 administrative costs incurred in serving the central procurement function shall be recoverable under the CAM.[3]

As indicated in Chapter 6, the CPE has executed certain 2026 procurement transactions and expects to include any incremental procurement for 2026 in the Fall Update.[4]

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.[5]

The Commission approved CAM cost recovery for emergency summer procurement executed pursuant to D.21-02-028, D.21-03-056 or D.21-12-015 delivering in 2026.[6]

For the 2026 ERRA Forecast, the CAM includes CHP generation authorized under the QF/CHP Settlement,[7] and energy storage Power Purchase Agreements (PPA) approved pursuant to Res.E-4949, as well as the Collateral and Interest costs presented in Chapter 5 and UOG related costs allocated to CAM, as presented in Chapter 8. The 2026 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

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

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

4 PG&E as CPE submitted these transactions to the Commission in its Annual Compliance Reports through Advice Letter (AL) 7365-E, AL 6386-E and AL 6706-E.

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

6 AL 6504-E included a firm import transaction pertinent to the 2025 CAM.

7 D.10-12-035.

articulated a calculation method to determine the market value of the resource.[8] 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."

PG&E's calculation of the forecasted 2026 CAM revenue requirement is presented in Table 7-1.

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8 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.

TABLE 7-1
2026 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	196,354
4	RF&U @ 0.01252	2,458
5	CAM Revenue Requirement	198,812

C. Conclusion

In this chapter, PG&E presents its forecast for the CAM revenue requirement which based on the forecasted net costs to be incurred in 2026, 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

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
POWER CHARGE INDIFFERENCE ADJUSTMENT AND
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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) 2026 revenue requirement forecasts for the vintaged Power Charge Indifference Adjustment (PCIA), Ongoing Competition Transition Charge (CTC) and Public Policy Charge Procurement (PPCP) Subaccount[1] component of the Public Purpose Policy (PPP) Charge. As required by state law,[2] 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

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1 The PPCP Subaccount is a two-way balancing subaccount in the Public Purpose Policy Charge Balancing Account (PPPCBA) established in Advice Letter (AL) 6524-E. In pursuant to Electric Preliminary Statement Part HM, the PPCP is established to record the recovery of the above-market costs associated with: (1) new Public Utility Regulatory Policies Act (PURPA) Standard Offer Contract approved pursuant to D.20-05-006, and (2) existing under 20 megawatts (MW) Qualifying Facility (QF) contracts pursuant to D.10-12-035 (QF Settlement).

2 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.

authorized in D.04-12-048 using a vintaged total portfolio indifference calculation.[3] The NBCs discussed in this chapter are the PCIA, Ongoing CTC, and PPCP.

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.[4] The CRS incorporates, among other elements, a California Department of Water Resources (CDWR) power charge and the Ongoing CTC.[5] 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,[6] for all power purchase contract costs included in CPUC rates as of that date.[7]

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.[8] 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

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3 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.

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

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

6 Pub. Util. Code § 369.

7 Pub. Util. Code § 367.

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

DL customers that are not exempt from the NBC associated with new generation resources, as defined in D.08-09-012.[9] 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 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.[10] 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 (VAMO), 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 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

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9 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.

10 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.

business day thereafter if October 1 is on a Saturday or Sunday.[11] 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 calculation underlying the Ongoing CTC and PCIA Revenue Requirements. In D.21-03-051, the Commission granted the Petition for Modification (PFM) 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 workpapers 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 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 PPP charge.[12] 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

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

[12] 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.

March 14, 2022, PG&E submitted AL 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.

4. Order Instituting Rulemaking to Update and Reform ERRA and PCIA Policies and Processes (OIR 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 two tracks. Track 1 addresses potential changes in the RA MPB calculation that the Energy Division expects to issue in October 2025. The scope for Track 2 has not yet been determined. Based on the adopted procedural schedule for Track 1, PG&E expects to implement a Commission decision addressing the RA MPB in the Fall update of this 2026 ERRA Forecast proceeding.

C. Total Portfolio Costs

The total portfolio indifference calculation is applied to the Revenue Requirements of the 2026 PCIA, Ongoing CTC and PPCP.[13] 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 8-8 presents the 2026 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.[14] Eligible portfolio costs of the applicable generation resources included in the total portfolio indifference

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[13] See Section B.(3). The PPCP Revenue Requirement relates to the New QF Standard Offer Contracts approved pursuant to D.20-05-006 and certain existing Standard Contract for QFs 20 MW or less pursuant to D.10-12-035.

[14] 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.

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 those authorized in PG&E's 2023 General Rate Case (GRC) D.23-11-069 or approved in other regulatory proceedings.[15] 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.

2. 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 in the total portfolio indifference calculation as described in this testimony.

D. UOG Base Revenue Requirement and Other Related Costs Authorized by the Commission

PG&E is forecasting to recover a total of $1,303 million of UOG-Related Costs authorized by the Commission as presented in Table 8-1 below.

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15 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 + 2024 to 2026 Attrition	D. 23-11-069	1,205,338
2	Cost of Capital and Debt Adjustment	Advice 5042-G/7535-E	19,893
3	Hydro Sales	Advice 5042-G/7535-E	(8,866)
4	Pension	Advice 5042-G/7535-E	30,252
5	Gain on Sale of SFGO	D.21-08-027	(21,028)
6	Purchase of Oakland General Office	D.24-08-009	77,476
7	Total		**1,303,065**

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Recovery of Authorized UOG Related Cost
(thousands of dollars)

Line No.		Total
1	PCIA	1,254,681
2	ERRA	(737)
3	CAM	49,122
4	Total	**1,303,065**

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

1. 2023 GRC Including the 2024, 2025 and 2026 Attrition

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 presented in AL 5042-G/7535-E. The Energy Supply Administration (ESA) cost is allocated between PCIA and CAM based on the methodology authorized by the Commission in D.24-12-038.

2. 2023 Cost of Capital Adjustments

Line 5 is the amount of the 2023 Cost of Capital (COC) Adjustment based on the formula authorized by the Commission in AL 4996-G/7423-E effective January 1, 2025.[16]

[16] A disposition letter dated December 4, 2024 was issued by the Commission approving AL 4996-G/7423-E.

3. AL 5042-G/7535-E (Tier 1)

The Hydro Sales in line 3 relates to the sale of PG&E's three hydro generation facilities authorized in D.22-11-002, D.19-10-011, and D.20-11-024, as presented in PG&E's AL 5042-G/7535-E Attachment 1 "Adopted Rolling Revenue Requirement Report." The Pension Revenue Requirement in line 4 is the 2025 Test Year amount shown on page 2 of AL 5042-G/7535-E, as a placeholder for 2026.

4. Gain on Sale of SFGO

Line 5 is the 2026 portion of the amortization of the gain on the sale of PG&E's San Francisco General Office authorized in D.21-08-027.

5. Purchase of OGO

Line 6 is the 2026 revenue requirement related to the purchase of the Oakland General Office headquarters (OGO) authorized in D.24-08-009.

E. 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.[17] As such, PG&E does not include a forecast of UOG-related costs currently pending before the Commission in PG&E's Prepared Testimony. However, PG&E provides updates on pending UOG-related costs potentially relevant to PG&E's 2026 PCIA rates. Upon the authorization by the Commission, any approved costs will be included in the PCIA Revenue Requirement presented in the Fall Update.

1. 2026 Cost of Capital

On March 20, 2025, PG&E filed its 2026 COC Application (A.25-03-010) with the proposed rate of return on rate base for its electric generation, electric distribution, natural gas distribution, and natural gas transmission and storage assets. Included in the 2026 COC Application was a request for approval of a Yield Spread Adjustment above the current Federal Reserve Statistical Release H.15 Commercial Paper Rate applicable to

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

under-collected and over-collected balances in PG&E's balancing and memorandum accounts to become effective January 1, 2026. The proposed Generation Revenue Requirement is $39.7 million. The Commission has not yet set a procedural schedule, but based on past COC proceedings, a Decision is expected by December 31, 2025.

2. Wildfire Mitigation and Catastrophic Events (WMCE)

On December 1, 2023, PG&E filed its 2023 WMCE application (A.23-12-001) to recover amounts recorded to various balancing and memorandum accounts in prior years and concurrently filed a Motion for interim rate relief (IRR), which requested 85 percent of the total revenue requirement request. The proposed Generation Revenue Requirement in the IRR was $7,430 thousand.

On January 9, 2024, PG&E filed a Supplemental Motion proposing modifications to the level of IRR and the amortization period. Specifically, PG&E requested the Commission authorize 55 percent IRR to be amortized over 17 months and continuing at that monthly level until 85 percent recovery is reached or superseded by a Commission decision; provided that at least 9 of the 17 months of the IRR, or the equivalent in Revenue Requirement (RRQ), are collected in 2024

On September 16, 2024, the Commission issued D.24-09-003 which authorized PG&E to recover 55 percent of the requested revenue requirement to be collected in Distribution Rates on an interim basis, subject to refund based on the amount authorized for recovery in the Final Decision in the 2023 WMCE proceeding. PG&E began collecting this interim rate recovery on October 1, 2024. A final decision in this application has not yet been issued but is expected no later than December 1, 2025.[18]

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

[18] On April 24, 2025, the Commission issued D.25-04-036 extending the statutory deadline for completion of the proceeding to December 1, 2025.

Requirement is $32.5 million.[19] 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.[20] PG&E began collecting this interim rate recovery on April 1, 2024 and will complete recovery no later than December 31, 2025. As per the current procedural schedule, a Proposed Decision was to have been issued in the first quarter of 2025 but is still pending.[21]

4. Transmission Revenue Requirement Reclassification Memorandum Account

On September 30, 2024 PG&E filed its Transmission Revenue Requirement Reclassification Memorandum Account (TRRRMA) Application (A.24-09-015) requesting recovery of $337.9 million net revenue requirement for costs recorded in the TRRRMA. Specifically TRRRMA costs include: (1) Common, General, and Intangible plant costs recorded from March 1, 2017 through December 31, 2022 that should be recovered in CPUC-jurisdictional rates consistent with the Federal Energy Regulatory Commission's (FERC) decision in PG&E's eighteenth Transmission Owner rate case proceeding (TO18); (2) 2023 California Independent System Operator (CAISO) Control Changes: $7.7 million; Assets that changed operational control designation in the CAISO Register in 2023; and (3) Distribution to Transmission Accounting Adjustment: ($42.6 million), which corrects an error for assets that were transferred from Electric Distribution FERC Plant Accounts to Electric Transmission FERC Plant Accounts in 2023. Per the current procedural schedule, a Proposed Decision is expected to be issued in the fourth quarter of 2025.

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

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

21 A.23-06-008, *Administrative Law Judge's Ruling Revising Proceeding Schedule*, dated June 11, 2024.

5. Gas Advanced Metering Infrastructure Replacement Program

PG&E filed its Gas Advanced Metering Infrastructure Replacement (GAMI Replacement) Program Application (A.24-03-011) on March 14, 2024. PG&E's Application requested funding for 2023-2026 to replace the battery-operated Gas Modules that have failed or are reaching end-of-life, and to upgrade the Gas AMI System to provide gas customers with improved functionality, including new safety features. On March 14, 2025, PG&E submitted a Motion jointly with the Public Advocated Office, The Utility Reform Network, and Small Business Utility Advocates to adopt a Settlement Agreement for an adopted revenue requirement of approximately $88.6 million for 2023-2026. As of the date of this filing, a Proposed Decision in this Application has not been issued.

F. Generation Resource Product Forecast

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

1. Resource Adequacy Capacity

Pursuant to D.18-10-019 and D.19-10-001, the Resource Adequacy (RA) of PG&E's electric generation portfolio included in this testimony is categorized as follows:

- RA that provides all three types of RA capacity is counted as local capacity;
- RA that provides both system and local capacity is counted as local capacity;
- RA that provides both system and flexible capacity is counted as flexible capacity; and
- RA that provides only system capacity is counted as system capacity.

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 weighting methodology described in Chapter 5 and are then averaged across all months to produce a single value.[22]

The final RA capacity position from PG&E's supply portfolio is presented in Table 5-18[23] and serves as the basis for PG&E's forecast of residual 2026 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.[24]

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 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 CAISO market, as described in Chapter 5.

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22 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.

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

24 As described in Section F of this testimony.

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 Renewable Energy Credit (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 2026 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 2026 RPS compliance target and described further in the following testimony.

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.[25] PG&E was ordered to record an accounting entry to reduce the PABA and increase the ERRA based on an estimate of PG&E's 2019 RPS shortfall. While D.11-12-020 established annual minimum quantities applicable to the third RPS compliance period in effect at the

[25] 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.").

time D.20-02-047 was issued, D.19-06-023 established minimum quantities for the current 2021-2024 compliance period and thereafter.[26]

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. The expected open position is derived from PG&E's RPS Stochastic model and will not tie to deterministic volumes presented in earlier chapters. RPS generation for 2025 includes both actual RPS generation as well as forecasted data. Forecasted RPS generation data for part of 2025 and all of 2026 is calculated using PG&E's RPS stochastic forecasting model.[27] More details on this model and how generation forecasts are calculated can be found below.

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.[28] 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.

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26 D.19-06-023, p. 11, OP 1 adopts RPS procurement quantity requirements for the years 2021-2024.

27 Consistent with the RPS Stochastic Model PG&E uses in the RPS Plan Proceeding.

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

With data captured annually for recorded RPS generation, Bundled Sales and RPS requirement targets, the net available RPS 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 2026 as well as the applicable years from the prior compliance period needed in order to meet a forecasted minimum retained RPS entry for 2026, if applicable.

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	12,990,684	1,322,452	-	-	1,322,452
11	2023*	26,017,569	41%	10,732,247	10,144,199	(588,048)	3,409,455	-	(3,997,503)
12	2024	28,509,270	44%	12,544,079	7,147,524	(5,396,555)	349,104	-	(5,745,659)
13	2025	25,807,535	47%	12,044,377	[redacted]		-	-	[redacted]
14	2026	25,055,466	49%	12,359,862			-	-	

** Values for delivery year 2024 will be updated during PG&E's 2026 ERRA Forecast Application Fall Update based on PG&E's final 2024 RPS Compliance Report*
(E) Net Physical RPS position is RPS generation less RPS Sales. Value is dervived from PG&E's deterministic model.
(F) Expected Net Open is dervived from PG&E's RPS Stochastic model for 2025 and 2026 and will not tie to the deterministic volumes.

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, 2024, and 2025, PG&E's accounting entries for crediting

PABA vintages are based on the methodologies the CPUC approved in D.22-12-044 and D.23-12-044. For 2026 onwards, PG&E will apply the methodology ordered by the commission in D.23-12-022, adjusted to reflect D.24-08-004 that refers to D.19-10-001 to define applicable RECs as 'RECs generated commencing January 1, 2019 and going forward.'[29] 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).

TABLE 8-3
HISTORICAL MINIMUM RETAINED RPS ENTRIES

Line No.	(A) Delivery/ Vintage Year	(B) Net Available Compliance Period RPS Generation (MWH)	(C) * Applied Prior Years Minimum RPS Entry	(D) Adjusted Net RPS Position
1	2013	1,928,480		
2	2014	3,980,017		
3	2015	4,482,478		
4	2016	5,379,425		
5	2017	3,704,274		
6	2018	4,773,405	(4,773,405)	-
7	2019	(701,826)	701,826	-
8	2020	445,318		
9	2021	5,399,732	(5,399,732)	-
10	2022	1,322,452	(1,322,452)	-
11	2023	(3,997,503)	3,997,503	-
12	2024	(5,745,659)	5,745,659	-
13	2025			
14	Total			

**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 2026, if applicable.

29 D.19-10-001, Finding of Fact 8.

3) Determination of Additional Retained RECs for 2026

As shown in Table 8-2, PG&E is initially forecasting a short RPS position in 2026 and expects to use banked RECs in order to meet the RPS compliance target.

As determined by the Commission in D.23-12-022, and subsequently modified by D.24-08-004, RECs generated and banked in and after 2019 (Post-2019 Banked RECs) are first applied to meet PG&E's minimum retained RPS requirement.[30] Once these already retained volumes have been exhausted, PG&E will then utilize RECs generated and retained before January 1, 2019 (Pre-2019 Banked RECs) to meet the compliance target. Once the Pre-2019 Banked REC volumes have been exhausted, PG&E will then look to retain previously Unsold RPS volumes, if available,[31] to meet its minimum retained RPS requirement. As ordered by the Commission in D.19-10-001, PG&E will apply the applicable current RPS Adder when crediting customers based on their PCIA vintage for any Post-2019 Banked RECs utilized towards meeting PG&E's minimum retained RPS requirement. For any utilized Pre-2019 Banked RECs, PG&E will credit applicable ERRA Forecast year vintage customers (e.g., vintage 2026 for the 2026 ERRA Forecast), regardless of delivery year, as D.19-10-001 excluded these RECs from receiving any additional ratemaking treatment associated with bundled RPS compliance.[32]

While PG&E's initial 2026 forecast does not reflect any Unsold RECs generated in 2023 and 2024 due to the Voluntary Allocation Market Offer process being needed for meeting the 2026 minimum retained RPS requirement, PG&E may attempt to sell these Unsold RECs to benefit all customers prior to its Fall Update. Executed

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30 PG&E's 2018 excess retained RPS volumes were already fully utilized to meet its minimum retained RPS requirements for 2024 and 2025 based on the CPUC's adopted methodology for each year, which was subsequently modified by D.24-08-004.

31 Unsold volumes may not be available for PG&E bundled compliance use if PG&E elects to sell those volumes or if PG&E does not retire and bank those volumes.

32 Credit and debit entries associated with the use of any Pre-2019 Banked REC volume will offset as they will be applied to the same PCIA vintage year (e.g., 2026).

transactions of applicable Unsold REC volumes, if any, will be presented in PG&E's Fall Update.

Table 8-4 presents PG&E's forecasted minimum retained RPS entry for 2026.

TABLE 8-4
2026 MINIMUM RETAINED RPS ENTRY

Line No.	(A) Delivery Year	Vintage Credited	(B) Pre-2026 Adjusted Net RPS Position	(C) Minimum 2026 Entry	(D) = (B + C) Post-2026 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		[redacted]	[redacted]	-
15	Total			-	[redacted]

PG&E will update the forecasted 2026 minimum retained RPS entry in its Fall Update based on updated portfolio forecast assumptions. The entries associated with the 2026 minimum retained RPS, if applicable, will be true-ed up through the applicable balancing accounts and presented as part of PG&E's 2026 ERRA Compliance Review Application.

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 also offered volumes

of its bundled share of Large Hydroelectric generation volumes for sale in 2024 and executed sale contracts for [redacted] GWh of 2025 deliveries. [redacted]

G. 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.[33] 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 certain revisions are under consideration in R.25-02-005. 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

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

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) Energy Index – Represents the CAISO market energy value of the vintaged portfolio;[34]

b) GHG Free Index – Represents the GHG-Free MPB, if any, for a given year;[35]

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;[36]
- 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

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34 Formally known as Brown Power MPB.

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

36 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.

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 workpapers 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 2025-2027 period in A.24-05-005, there is no need for a new line item for a 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).[37] Capacity expected to remain unsold is assigned a price of zero.[38] The RA Adder shall be calculated in a manner that reflects the three types of RA capacity: system, local, and flexible. Changes to the methodology applicable to the RA MPB are under consideration in R.25-02-005 and PG&E's Fall Update will reflect any relevant Commission directives.

3. 2026 Market Price Benchmark

The 2026 MPBs used in this testimony, and presented in Table 8-7, are calculated using data consistent with the methodology described above,

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

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

except as described below. PG&E will incorporate any change to these MPBs in the Fall Update adopted by the Commission.

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 2026 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 2026 delivery year, no new line item to its 2026 PCIA WPs identifying the output and incremental value of large hydroelectric resources is required. [redacted]

c) Green/RPS Adder

The Green/RPS Adder uses a placeholder value of $71.24 /MWh as issued by the Energy Division in its MPB Calculations 2024 REVISED publication for 2025 (MPB Publication), dated November 5, 2024.[39]

d) Capacity/RA Adders

The Capacity/RA Adders use placeholder values as authorized by the Commission in D.23-12-022 for 2025, as follows:

- System $40.31/kilowatt (kW)-month;
- PG&E Local $13.29 kW-month;
- Southern California Edison Company (SCE) Local $11.23/kW-month; [40]
- San Diego Gas & Electric Company (SDG&E) Local $9.99/kW month; and

[39] The final publication is available at 2024-market-price-benchmarks-revised-20241105.pdf.

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

- Flexible $16.97/kW-month.

H. Indifference Amount Calculation

Table 8-8 presents the costs, energy, and capacity[41] volumes, (lines 1 through 8) for the total portfolio, derived from Table 8-6. The market value of the portfolio is derived by multiplying the appropriate MPB, presented in Table 8-7, by the portfolio's generation and capacity. The cost is compared to the market value for each vintage to determine the level of indifference.[42]

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.

I. 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 8-5 below. PG&E will update these amounts in the Fall Update of this testimony.

TABLE 8-5
SUMMARY OF INDIFFERENCE AMOUNT REVENUE REQUIREMENTS
(THOUSANDS OF DOLLARS)

Line No.	Rate Component	Revenue Requirement
1	Ongoing CTC	$(36,486)
2	PPCP/PPP	(1,459)
3	PCIA	212,518
4	Total	$174,574

41 Reflects the slice-of-day weightings proposed in Chapter 5 to derive the annual supply volumes.

42 Also applies to the Ongoing CTC portfolio and PPCP.

TABLE 8-6
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	PPCP	UOG Legacy and Vintaged PCIA Portfolio																		IOU Total Portfolio
				UOG Legacy	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	
1.		$63,611	$994	$694,179	$1,256,210	$428,757	$123,203	$85,454	$12,388	($32,645)	($19,549)	($2,623)	$2,039	$62	$30,263	($28,861)	$171,026	($0)	$13,798	$339	$214	$28,861	$2,827,719
2.	CRS Eligible Non-Renewable Supply at Generation Meter (GWh)	627	0	7,669	7,346	-595	330	1,549	723	549	442	71	147	0	0	0	-501	0	0	0	0	0	18,357
3.	CRS Eligible Renewable Supply at Generation Meter (GWh)	91	16	193	2,939	3,678	996	286	194	-456	-283	-29	41	0	0	0	1,213	0	16	6	3	0	8,906
4.	CRS Eligible Total Net Qualifying Capacity (MW)																						
5.	CRS Eligible System NQC (System only, No flex or local)	87	1	173	208	76	31	44	38	2	0	0	7	0	0	0	36	0	1	0	0	0	704
6.	CRS Eligible Local NQC - PG&E (System and local, with or without flex)	99	0	790	298	39	19	43	7	4	8	2	0	0	0	0	2	0	0	0	0	0	1,312
7.	CRS Eligible Local NQC - SCE (System and local, with or without flex)	0	0	0	0	33	0	5	0	3	17	0	0	0	0	0	0	0	0	0	0	0	59
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	0	0	0	0	0	0	0	0	0	0	0
9.	CRS Eligible Flexible NQC (System and flex only, No local)	0	0	155	419	0	0	0	0	0	0	0	0	0	-12	0	4	0	0	0	0	0	567

Fn. a: UOG Hydro expense, reflecting Water for Power costs, included in Line 1 are inconsistent with Table 4-5, line 16 and will be updated during PG&E's Fall Update.

TABLE 8-7
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 2026 Calendar and NERC Holiday Schedule	56.1%
4.	Off Peak Time Weight (%)	Based on 2026 Calendar and NERC Holiday Schedule	43.9%
5.	Portfolio Weights	2022-2024 PCIA revenue less the actual average NP15	0.89
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)	2025 forecast Benchmark	$71.24
8.	Green Benchmark ($/MWh)	Line 6 + Line 7	[redacted]
9.	System RA Benchmark ($/kW-Year)	2025 forecast Benchamrk ($$40.31 kW-Month x 12)	$483.72
10.	Local RA Benchmark ($/kW-Year) - PG&E	2025 forecast Benchamrk ($$13.29 kW-Month x 12)	$159.48
11.	Local RA Benchmark ($/kW-Year) - SCE	2025 forecast Benchamrk ($$11.23 kW-Month x 12)	$134.76
12.	Local RA Benchmark ($/kW-Year) - SDG&E	2025 forecast Benchamrk ($$9.99 kW-Month x 12)	$119.88
13.	Flexible RA Benchmark ($/kW-Year)	2025 forecast Benchamrk ($$16.97 kW-Month x 12)	$203.64
14.	Revenue Fee and Uncollectible Factor	Advice 4989-G/7419-E	0.012520

TABLE 8-8
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 No.	Description	Equation	Unit	Ongoing CTC-Eligible	PPCP	UOG Legacy and Vintaged PCIA																
						UOG Legacy	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	Cost of Portfolio																							
1.	Portfolio Total Cost		$000	$63,611	$994	$694,179	$1,256,210	$428,757	$123,203	$85,454	$12,388	($32,645)	($19,549)	($2,623)	$2,039	$62	$30,263	($28,861)	$171,026	($0)	$13,798	$339	$214	$28,861
2.	CRS Eligible Non-Renewable Supply at Generation Meter		GWh	627	0	7,669	7,346	-595	330	1,549	723	549	442	71	147	0	0	0	-501	0	0	0	0	0
3.	CRS Eligible Renewable Supply at Generation Meter		GWh	91	16	193	2,939	3,678	996	286	194	-456	-283	-29	41	0	0	0	1,213	0	16	6	3	0
4.	CRS Eligible System NQC		MW	87	1	173	208	76	31	44	38	2	0	0	7	0	0	0	36	0	1	0	0	0
5.	CRS Eligible Local NQC - PG&E		MW	99	0	790	298	39	19	43	7	4	8	2	0	0	0	0	2	0	0	0	0	0
6.	CRS Eligible Local NQC - SCE		MW	0	0	0	0	33	0	5	0	3	17	0	0	0	0	0	0	0	0	0	0	0
7.	CRS Eligible Local NQC - SDG&E		MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.	CRS Eligible Flexible NQC		MW	0	0	155	419	0	0	0	0	0	0	0	0	0	-12	0	4	0	0	0	0	0
9.	**Portfolio Unit Cost**	**Line 1 / (Line 2 + Line 3)**	**$/MWh**	**$88.61**	**$62.45**	**$88.29**	**$122.14**	**$139.08**	**$92.89**	**$46.58**	**$13.50**	**($353.56)**	**($123.19)**	**($61.52)**	**$10.82**	**$0.00**	**$0.00**	**$0.00**	**$240.14**	**$0.00**	**$852.02**	**$59.37**	**$62.63**	**$0.00**
10.	**Market Value of Portfolio**																							
11.	**Market Value of Brown Portfolio**																							
12.	Non-Renewable Energy		GWh	627	0	7,669	7,346	-595	330	1,549	723	549	442	71	147	0	0	0	-501	0	0	0	0	0
13.	Weighted Average Brown Benchmark		$/MWh																					
14.	**Market Value of Brown Portfolio**	**Line 10 x Line 11**	**$000**																					
15.	**Market Value of Green Portfolio**																							
16.	Renewable Energy		GWh	91	16	193	2,939	3,678	996	286	194	-456	-283	-29	41	0	0	0	1,213	0	16	6	3	0
17.	Weighted Average Green Benchmark		$/MWh																					
18.	**Market Value of Green Portfolio**	**Line 16 x Line 17**	**$000**																					
19.	**Capacity Adder**																							
20.	Average Monthly System NQC		MW	87	1	173	208	76	31	44	38	2	0	0	7	0	0	0	36	0	1	0	0	0
21.	System RA Benchmark		$/kW-Year	$483.72	$483.72	$483.72	$483.72	$483.72	$483.72	$483.72	$483.72	$483.72	$483.72	$483.72	$483.72	$483.72	$483.72	$483.72	$483.72	$483.72	$483.72	$483.72	$483.72	$483.72
22.	Average Monthly Local Area NQC - PG&E		MW	99	0	790	298	39	19	43	7	4	8	2	0	0	0	0	2	0	0	0	0	0
23.	Local RA Benchmark - PG&E		$/kW-Year	$159.48	$159.48	$159.48	$159.48	$159.48	$159.48	$159.48	$159.48	$159.48	$159.48	$159.48	$159.48	$159.48	$159.48	$159.48	$159.48	$159.48	$159.48	$159.48	$159.48	$159.48
24.	Average Monthly Local Area NQC - SCE		MW	0	0	0	0	33	0	5	0	3	17	0	0	0	0	0	0	0	0	0	0	0
25.	Local RA Benchmark - SCE		$/kW-Year	$134.76	$134.76	$134.76	$134.76	$134.76	$134.76	$134.76	$134.76	$134.76	$134.76	$134.76	$134.76	$134.76	$134.76	$134.76	$134.76	$134.76	$134.76	$134.76	$134.76	$134.76
26.	Average Monthly Local Area NQC - SDG&E		MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27.	Local RA Benchmark - SDG&E		$/kW-Year	$119.88	$119.88	$119.88	$119.88	$119.88	$119.88	$119.88	$119.88	$119.88	$119.88	$119.88	$119.88	$119.88	$119.88	$119.88	$119.88	$119.88	$119.88	$119.88	$119.88	$119.88
28.	Average Monthly Flexible NQC		MW	0	0	155	419	0	0	0	0	0	0	0	0	0	-12	0	4	0	0	0	0	0
29.	Flexible RA Benchmark		$/kW-Year	$203.64	$203.64	$203.64	$203.64	$203.64	$203.64	$203.64	$203.64	$203.64	$203.64	$203.64	$203.64	$203.64	$203.64	$203.64	$203.64	$203.64	$203.64	$203.64	$203.64	$203.64
30.	**Market Value of Capacity**		**$000**	**$57,694**	**$514**	**$241,206**	**$233,373**	**$47,411**	**$17,825**	**$29,052**	**$19,441**	**$2,290**	**$3,546**	**$357**	**$3,429**	**$0**	**($2,452)**	**$0**	**$18,731**	**$0**	**$472**	**$133**	**$89**	**$0**
31.	**Portfolio Market Value**	**Line 14 + Line 18 + Line 30**	$000	**$99,646**	**$2,435**	**$643,694**	**$951,227**	**$461,833**	**$154,345**	**$140,105**	**$78,661**	**($25,647)**	**($8,782)**	**$426**	**$15,683**	**$0**	**($2,452)**	**$0**	**$140,380**	**$0**	**$2,427**	**$823**	**$501**	**$0**
32.	**Indifference Amount**																							
33.	**Portfolio Total Cost**	**Line 1**	$000	**$63,611**	**$994**	**$694,179**	**$1,256,210**	**$428,757**	**$123,203**	**$85,454**	**$12,388**	**($32,645)**	**($19,549)**	**($2,623)**	**$2,039**	**$62**	**$30,263**	**($28,861)**	**$171,026**	**($0)**	**$13,798**	**$339**	**$214**	**$28,861**
34.	**Portfolio Market Value**	**Line 31**	$000	**$99,646**	**$2,435**	**$643,694**	**$951,227**	**$461,833**	**$154,345**	**$140,105**	**$78,661**	**($25,647)**	**($8,782)**	**$426**	**$15,683**	**$0**	**($2,452)**	**$0**	**$140,380**	**$0**	**$2,427**	**$823**	**$501**	**$0**
35.	**Total Indifference Amount (Unadjusted)**	**Line 32 - Line 33**	$000	**($36,035)**	**($1,441)**	**$50,484**	**$304,983**	**($33,077)**	**($31,142)**	**($54,651)**	**($66,272)**	**($6,998)**	**($10,767)**	**($3,049)**	**($13,644)**	**$62**	**$32,715**	**($28,861)**	**$30,645**	**($0)**	**$11,371**	**($484)**	**($287)**	**$28,861**
36.	**Other Adjustments**		$000																					
37.	**Adjusted Indifference Amount**	**Sum (Lines 35:36)**	$000	**($36,035)**	**($1,441)**	**$50,484**	**$304,983**	**($33,077)**	**($31,142)**	**($54,651)**	**($66,272)**	**($6,998)**	**($10,767)**	**($3,049)**	**($13,644)**	**$62**	**$32,715**	**($28,861)**	**$30,645**	**($0)**	**$11,371**	**($484)**	**($287)**	**$28,861**
38.	**Revenue Franchise Fees & Uncollectibles (RF&U)**	**Advice 4989-G/7419-E**	$000	**($451)**	**($18)**	**$632**	**$3,818**	**($414)**	**($390)**	**($684)**	**($830)**	**($88)**	**($135)**	**($38)**	**($171)**	**$1**	**$410**	**($361)**	**$384**	**($0)**	**$142**	**($6)**	**($4)**	**$361**
39.	**Adjusted Indifference Amount with RF&U**	**Line 37 + Line 38**	$000	**($36,486)**	**($1,459)**	**$51,116**	**$308,801**	**($33,491)**	**($31,532)**	**($55,335)**	**($67,102)**	**($7,085)**	**($10,902)**	**($3,088)**	**($13,815)**	**$63**	**$33,125**	**($29,222)**	**$31,029**	**($0)**	**$11,514**	**($490)**	**($291)**	**$29,222**
40.	**Cummulative Adjusted Indifference Amount with RF&U**		$000	**($36,486)**	**($1,459)**	**$51,116**	**$359,918**	**$326,427**	**$294,895**	**$239,560**	**$172,458**	**$165,373**	**$154,471**	**$151,384**	**$137,569**	**$137,631**	**$170,756**	**$141,534**	**$172,563**	**$172,563**	**$184,077**	**$183,587**	**$183,296**	**$212,518**

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

TREE MORTALITY REVENUE REQUIREMENT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
TREE MORTALITY REVENUE REQUIREMENT

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
TREE MORTALITY REVENUE REQUIREMENT

A. Introduction

This chapter discusses Pacific Gas and Electric Company's (PG&E) 2026 procurement cost forecast and revenue requirement for the Tree Mortality Non-Bypassable Charge (TMNBC). The discussion will cover a background of the TMNBC, the procurement cost forecast for TMNBC contracts, and the value of energy, Resource Adequacy (RA) capacity, and Renewable Energy Credits (REC) for TMNBC contracts.

B. Program Background

On October 30, 2015, Governor Edmund G. Brown, Jr. issued a Proclamation of a State of Emergency (Proclamation) to address the tree mortality crisis in California. 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.

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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 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 2026 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. For PG&E, the executed supply contracts that are forecasted to provide deliveries to PG&E in 2026 include the following biomass facilities:

1) Burney Forest Products;
2) Wheelabrator Shasta; and
3) Woodland Biomass.

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

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

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.

As a result of its 2021 TMNBC RA solicitation, PG&E retained the RA from Woodland Biomass from the initial delivery date of January 1, 2022 through the expected delivery end date of August 31, 2026. The TMNBC RA for Burney Forest and Wheelabrator Shasta went unsold.[3] PG&E submitted a reserve price for the Woodland Biomass RA based on a need for its bundled portfolio and was the only bidder.[4]

PG&E's 2022 TMNBC Bundled RPS Energy solicitation resulted in the sales of bundled energy and associated RECs from Burney Forest Products and Wheelabrator Shasta for the terms of the underlying PPAs.[5] The energy sales were made to San Diego Community Power and East Bay Community Energy respectively.

Table 9-1 shows the 2026 TMNBC net cost revenue requirement forecast for the contract costs and the value of energy, RA sales, and REC sales.

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3 PG&E Advice 6414-E, filed November 22, 2021, p. 2.

4 Advice 6414-E, p. 6.

5 PG&E Advice 6743-E, filed October 21, 2022, pp. 1-2.

TABLE 9-1
2026 TMNBC REVENUE REQUIREMENT
(THOUSANDS OF DOLLARS)

Line No.	Description	Table Cross Reference	Revenue Requirement
1	Tree Mortality Non-Bypassable Charge (TMNBC)		
2	Post-2002 Contracted Resources		
3	RPS Eligible		
4	RPS-Eligible Contracts	Table 4-5 Line 52	[redacted]
5	RPS-Eligible Contracts - Sales	Table 4-5 Line 53	
6	RPS-Eligible Future Contracts	Table 4-5 Line 54	
7	RPS-Eligible Future Sales	Table 4-5 Line 55	
8	Resource Adequacy Sales	Table 4-5 Line 56	
9	CAISO Costs (GMCs)	Table 5-19 Line 6	
10	CAISO Revenues		
11	**Net Costs**		**32,055**
12	RF&U @ 0.01252		401
13	**Total RRQ**		**32,456**

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 2026, 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

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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) 2026 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 2025 end-of-year balancing account balance forecast is shown in Chapter 12, while the associated 2026 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 Renewable 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. In D.14-12-081, the Commission directed the IOUs to submit Tier 2 Advice Letters (AL) with the tariff, standard contract, and ancillary documents to implement the BioMAT Program.

D.14-12-081 also authorized the Commission to initiate a review process:

> …at any time after the price for any technology category reaches $197/megawatt hour (MWh) and remains at that price or increases, over two program periods.[1]

[1] D.14-12-081, discussion on p. 62, Conclusion of Law (COL) 52, and Ordering Paragraph 8.

On October 1, 2017, the offer price for Category 3 reached $199.72/MWh and remained at that price for subsequent program periods.[2] In response, on November 28, 2017, Energy Division issued a letter ordering the IOUs to set a temporary price cap for Category 3 offer prices at $199.72/MWh, except for projects that can attest to using at least 60 percent High Hazard Zone fuel, in addition to initiating a BioMAT Program review.

On October 30, 2018, the Commission released a BioMAT Program Review and Staff Proposal putting forth both observations about program performance and an initial staff proposal of recommended program modifications. One of these proposed modifications was to "allocate program costs through a non-bypassable charge (NBC) to all customers in each IOU's service territory."[3] On July 19, 2019, the Commission held a public workshop to discuss potential program changes.

On March 10, 2020, the Commission requested comments from parties on the Commission's final staff proposal.[4] The final proposal continued to endorse allocating BioMAT Program costs through an NBC to all retail customers in each respective IOU's service territory.

The final decision revising the BioMAT Program, D.20-08-043, was issued on September 1, 2020 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."[5] 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 PG&E and SCE's proposed models that are similar to the tree mortality NBC were reasonable.[6]

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2 SB 1122 mandates a separate set of procurement targets, given as MW by technology category, set out in Section 399.20(f)(2)(A); Category 3 is for byproducts of sustainable forest management required by Section 399.20(f)(2)(A)(iii) and will be determined based on the proportion of bioenergy that sustainable forest management providers derive from sustainable forest management in fire threat treatment areas, as designated by the Department of Forestry and Fire Protection.

3 BioMAT Program Review and Staff Proposal, p. 18.

4 See Administrative Law Judge's Ruling Requesting Comments on the BioMAT Staff Proposal, March 10, 2020.

5 D.20-08-043, discussion at pp. 13-14, and COL, 3.

6 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.

On October 1, 2020, PG&E submitted a proposal to establish a BioMAT Non-Bypassable Charge Balancing Account (BNBCBA) and Non-Bypassable Rate Design and Implementation Plan, which was ultimately approved.[7] 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 18-07-003.

The following section describes the derivation of the 2026 BioMAT NBC revenue requirement.

C. Derivation of BioMAT Revenue Requirement

The formula used to calculate the BioMAT revenue requirement 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.

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

D. BioMAT Contract Procurement Costs and Revenue Requirement

Table 10-1 shows the total expected BioMAT contract costs for 2026, along with the forecasted energy revenues and imputed RA and REC values associated with the BioMAT portfolio.[8]

TABLE 10-1
2026 BIOMAT ADJUSTED PROCUREMENT COSTS
(THOUSANDS OF DOLLARS)

Line No.	Description	Table Cross Reference	Revenue Requirement
1	BioMAT		
2	Post-2002 Contracted Resources		
3	RPS Eligible		
4	RPS-Eligible Contracts	Table 4-5, line 48	[redacted]
5	Grid Management Charges	Table 5-19, line 7	
6	CAISO Revenues		
7	REC Market Value		(8,499)
8	RA Capacity Market Value		(4,777)
9	Net Costs		$8,218
10	Revenue Fees and Uncollectibles @ 0.01252		103
11	Total Revenue Requirement		$8,321

E. Conclusion

In this chapter, PG&E presents its forecast for the 2026 BioMAT revenue requirement which includes a forecast of the BioMAT portfolio's 2026 contract costs, CAISO market energy value, and imputed values of the BioMAT portfolio's REC and RA attributes shown in Table 10-1. PG&E's Fall Update will include a revenue requirement and ratemaking update consistent with any Commission decisions issued in R.25-02-005 or R.18-07-003.

[8] The current forecast uses the Forecast 2025 PCIA RA and REC benchmark values. The benchmarks will be updated in the Fall Update after the initial 2026 PCIA benchmarks are made available by the Commission, including, as applicable, the 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

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 11
ENERGY RESOURCE RECOVERY ACCOUNT

A. Introduction

The purpose of this chapter is to present the 2026 revenue requirement forecast for the Energy Resource Recovery Account (ERRA). The 2026 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 2025. Given the timing for the final year-ahead requirements, PG&E's estimate of its 2026 SoD RA requirements are based on its current bundled hourly load forecast and PG&E's 2025 SoD requirements.

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 Market Price Benchmarks 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]

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[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, pp. 5-12 to 5-13.

B. Procurement and UOG-related Cost Forecast

In Chapters 4 and 5, PG&E shows the 2026 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 2026 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 Power Charge Indifference Adjustment, Ongoing Competition Transition Charge, Public Policy Charge Procurement (PPCP) Costs,[2] and Bioenergy Market Adjusting Tariff cost recovery at forecasted RA and RPS Adders.[3] The 2026 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.

---

2 In pursuant to Decision (D.) 22-02-002, Ordering Paragraph 9, PG&E established the PPCP Subaccount in Advice Letter 6524-E to record the recovery of the above-market costs associated with New Qualifying Facility (QF) Standard Offer Contracts approved: pursuant to D.20-05-006; and certain existing Standard Contracts for QFs of 20 megawatts or less, pursuant to D.10-12-035 (QF Settlement), authorized by the Commission.

3 D.18-10-019, D.19-10-001, and D.20-02-047.

D. Conclusion

Based on the procurement cost and resource market value forecast described above, the forecasted 2026 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.

TABLE 11-1
2026 ERRA REVENUE REQUIREMENT
(THOUSANDS OF DOLLARS)

Line No.	Description	Table Cross Reference	Revenue Requirement
1	Energy Resource Recovery Account (ERRA)		
2	Bundled Load Requirement	Table 5-19 Line 9	[redacted]
3	Other Load	Table 5-19 Line 10	
4	Grid Management Charges	Table 5-19 Line 4	
5	Utility-Owned Generation		
6	Energy Storage	Table 4-5 Line 63	
7	Other Bilateral Contracts		
8	Future Non-RPS-Eligible Hydro Sales	Table 4-5 Line 65	
9	QF	Table 4-5 Line 66	
10	RPS-Eligible Future Contracts	Table 4-5 Line 67	
11	RA Contracts	Table 4-5 Line 68	
12			
13	Hedging Costs	Table 5-1 Line 9	
14	Collateral & Interest Expense	See Note (a)	9,070
15	UOG-related Costs	See Note (b)	(728)
14	CAISO Revenues		[redacted]
16	Resource RA and REC Market Benchmark Value		
17	PCIA REC Value	Table 8-8 calculations	626,854
18	PCIA RA Value	Table 8-8 calculations	614,902
19	CTC REC Value	Table 8-8 calculations	6,465
20	CTC RA Value	Table 8-8 calculations	57,694
21	PPCP REC Value	Table 8-8 calculations	1,134
22	PPCP RA Value	Table 8-8 calculations	514
23	BioMAT REC Value	Table 10-1, Line 7	8,499
24	BioMAT RA Value	Table 10-1, Line 8	4,777
25	**Total Costs**		**2,922,302**
26	RF&U @ 0.01252		36,587
27	**Total RRQ**		**2,958,889**

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 12

BALANCING ACCOUNTS FORECASTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 12
BALANCING ACCOUNTS FORECASTS

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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 2025 year-end balances for inclusion in 2026 electric rates; and (2) seek approval to recover the accumulated Voluntary Allocation and Market Offer 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 PG&E's 2025 Balancing Accounts Forecast, including the accumulated VAMOMA;
- Section C – Overview of Portfolio Allocation Balancing Account (PABA) Subaccounts;
- Section D – Description of the balances recorded in the PABA;
- Section E – Description of the transactions forecast in PABA;
- Section F – Primary Drivers of the forecasted 2025 year-end PABA;
- Section G – Primary Drivers of the forecasted 2025 year-end Energy Resource Recovery Account (ERRA);
- Section H – Summary of Balance Transfers;
- Section I - Overview of the Voluntary Allocation and Market Offer (VAMO) Administrative Cost; and
- Section J – Conclusion.

B. Overview of PG&E's 2025 Balancing Accounts Forecast

1. Summary of Forecast Methodology and Amortization

Similar to previous years and as adopted by the California Public Utilities Commission (Commission), the forecasted 2025 year-end balancing account balances are based on the balances recorded through March 31, 2025, plus forecasted transactions from April 1 through December 31, 2025. 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 2026 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 Power Charge Indifference Adjustment (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 the 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 bundled customers and recovered through generation rates.

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[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

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2 See PG&E AL 6524-E, effective on March 14, 2022; 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. As noted in the Rate Proposal testimony at the time, implementation of the MCAM rate was expected to occur in mid-2027. Given the 2027 implementation, PG&E is not presenting the MCAMBA balance as part of this testimony, and anticipates making a presentation of the revenue requirement at the time of rate implementation.

f. New System Generation Balancing Account

As stated in Electric Preliminary Statement Part FS, the purpose of the New System Generation Balancing Account (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 Memorandum Account

As stated in Electric Preliminary Statement Part JC, the Voluntary Allocation and Market Offer 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 2025 Year-End Balancing Account Balances

PG&E presents a summary of the forecasted 2025 year-end balancing account balances in Table 12-1 below. Column A shows the recorded balances as of March 2025. This is added to the April through December 2025 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 $642 million that PG&E is requesting to amortize in 2026 rates in Column I is derived after adjusting for the balance transfers between Residential Uncollectibles Balancing Account-Electric (RUBA-E),[4] ERRA, and PABA

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

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 ongoing volatility in electric and gas commodity prices, and changes to the Commission-issued MPBs.

[5] Authorized in D.22-01-023, D.22-12-044, D.23-12-022, and D.24-12-038.

TABLE 12-1
2025 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 4889-G/ 7419-E 0.01252	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 2026 Rates comprises		
										Recorded/ Forecast Year End Balance with RF&U	Balance Transfers of RUBA to ERRA authorized in D. 20-06-003	Balance Transfers from ERRA to PABA
		(A)	(B)	(C)	(D)= Σ (A..C)	(E)	(F)	(G)	(H)= Σ (D..G)	(I)	(J)	(K)
1	Non-PPP											
2	NSGBA	26,819	(243,177)	234,743	18,385			230	18,615	18,615	0	
3	MTCBA	(8,205)	38,622	(20,989)	9,427			118	9,546	9,546		
4	PABA	898,634	248,509	46,434	1,193,576		(598,274)	7,453	602,756	1,208,520	0	(605,764)
5	VAMOMA	316			316			4	320	320		
6	ERRA	(222,960)	(3,321,849)	2,940,098	(604,711)	6,437	598,274	0	0	(612,282)	6,517	605,764
7	RUBA-E	6,437			6,437	(6,437)		0	0	6,517	(6,517)	
8	Subtotal (Non-PPP)	701,041	(3,277,895)	3,200,285	623,431	0	0	78,054	631,236	631,236	0	0
9	PPP											
10	PPCP	(1,738)	1,515	(851)	(1,074)			(13)	(1,087)	(1,087)		
11	TMNBCBA	13,461	(35,107)	30,492	8,846			111	8,956	8,956		
12	BNBCBA	(5,066)	2,966	4,621	2,521			32	2,552	2,552		
13	Subtotal (PPP)	6,656	(30,626)	34,262	10,292	0	0	129	10,421	10,421	0	0
14	**Total (Non-PPP and PPP)**	**707,696**	**(3,308,520)**	**3,234,547**	**633,723**	**0**	**0**	**78,182**	**641,657**	**641,657**	**0**	**0**

* Balance Transfers to PABA includes the transfer from ERRA balances as authorized in D. 22-01-023

Totals may not add due to rounding

C. PABA Subaccounts

1. Recorded and Forecast PABA Subaccount Balances

PG&E presents the 2025 forecast year-end PABA subaccount balances in Table 12-2. Line 2 shows the recorded January 1, 2025, PABA subaccount balances. Lines 3 through 10 summarize the recorded PABA subaccount balances through March 2025, 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 $1,194 million undercollection. The primary driver of the $1,194 million undercollection for PABA is discussed in Section F.

2. Balance Transfers

The balance transfers to PABA reflected in Line 30 through 32 are: (1) $605 million overcollection from ERRA and (2) $6 million undercollection from RUBA-E.[6] Details of these balance transfers are discussed in Section H.

3. 2025 Forecast Year-End PABA, After Balance Transfers

The forecasted 2025 year-end PABA subaccounts, after accounting for the balance transfers, plus an allowance for RF&U, is an under-collection of $603 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.

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6 Also shown in Table 12-1, line 6, Columns E and F.

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

TABLE 12-2
2025 FORECAST YEAR-END VINTAGED PABA BALANCES
(THOUSANDS OF DOLLARS)

Line No.		Legacy UOG Subaccount	Vintage Subaccounts																Total
			Vin 2009	Vin 2010	Vin 2011	Vin 2012	Vin 2013	Vin 2014	Vin 2015	Vin 2016	Vin 2017	Vin 2018	Vin 2019	Vin 2020	Vin 2021	Vin 2022	Vin 2023	Vin 2024	Vin 2025	
1	Recorded from January to March (a)																		
2	Recorded Beginning Balance as of January	295,082	466,462	100,052	50,688	69,475	36,501	1,130	2,298	2,256	(2,039)	(67,821)	(3,716)	(4,262)	16,243	(3,764)	(44,532)	0	0	914,052
3	PCIA Customer Revenue	(52,121)	(108,334)	(9,842)	(1,629)	1,642	4,296	1,454	604	902	4,262	37,576	23,012	796	128,580	1,888	15,977	29,397	(22,288)	56,172
4	Portfolio Costs	415,864	203,799	40,577	5,112	8,854	5,374	2,513	2,965	291	10	(53)	12,455	(219)	16,781	16	(71)	9	0	714,276
5	Energy Value	(259,660)	(37,877)	(8,838)	(4,538)	(6,548)	(2,701)	(466)	(959)	(211)	(735)	0	0	0	(289)	0	0	0	0	(322,821)
6	RPS Value	0	1,248	(9,479)	(679)	(1,447)	(1,705)	(887)	(1,554)	(251)	(505)	(26,097)	0	0	(492)	0	0	0	26,097	(15,751)
7	RA Value	(151,282)	(49,706)	(6,878)	(2,248)	(4,171)	(1,010)	(140)	(492)	(51)	(2,759)	0	(26,130)	0	(37,646)	0	(20)	0	0	(282,534)
8	One Time Adjustments	19,994	13,269	1,248	1,047	1,371	50	9	15	1	7	0	(0)	(3)	6	0	0	(210,595)	0	(173,580)
9	Interest	4,112	4,685	1,054	546	794	398	24	27	32	(27)	(760)	(15)	(38)	557	(151)	(585)	(1,833)	0	8,819
10	Recorded March Balance	271,989	493,545	107,893	48,299	69,970	41,203	3,636	2,905	2,969	(1,785)	(57,155)	5,606	(3,727)	123,741	(2,010)	(29,232)	(183,022)	3,809	898,634
11	Forecast from April to December (b)																			
12	PCIA Customer Revenue	(151,956)	(383,085)	(38,473)	(5,822)	(3,635)	20,704	2,624	3,673	226	14,912	130,189	83,789	3,216	480,995	3,738	55,762	111,581	(79,928)	248,509
13	Portfolio Costs	1,121,094	1,050,062	317,680	97,514	92,611	53,381	7,185	12,756	1,505	5,853	47	18,974	0	70,130	(0)	5,633	0	0	2,854,423
14	Energy Value	(493,558)	(421,029)	(91,912)	(40,018)	(51,282)	(28,057)	(5,011)	(8,627)	(1,149)	(5,123)	0	0	0	(504)	0	(449)	0	0	(1,146,717)
15	RPS Value	(6,761)	(192,454)	(170,612)	(54,407)	(33,183)	(46,910)	(8,151)	(13,640)	(1,890)	(8,335)	(98,746)	0	(2,864)	(19,669)	0	(858)	0	101,610	(556,871)
16	RA Value	(460,509)	(286,320)	(46,664)	(22,045)	(25,974)	(23,636)	(2,478)	(3,017)	(400)	(12,539)	0	(63,205)	0	(182,256)	0	(9,017)	0	0	(1,138,060)
17	One Time Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Interest	7,142	13,904	3,351	1,181	1,935	948	23	(46)	68	(154)	(1,081)	735	(75)	9,850	(5)	(108)	(4,147)	137	33,658
19	Forecast transactions from April to December	15,452	(218,922)	(26,629)	(23,597)	(19,528)	(23,570)	(5,809)	(8,902)	(1,639)	(5,386)	30,408	40,292	278	358,546	3,733	50,964	107,434	21,818	294,943
20	Forecast Year End Balance (c) = (a) + (b)																			
21	Recorded Beginning Balance as of January	295,082	466,462	100,052	50,688	69,475	36,501	1,130	2,298	2,256	(2,039)	(67,821)	(3,716)	(4,262)	16,243	(3,764)	(44,532)	0	0	914,052
22	PCIA Customer Revenue	(204,076)	(491,419)	(48,315)	(7,450)	(1,993)	25,000	4,077	4,277	1,128	19,174	167,765	106,801	4,012	609,575	5,626	71,739	140,977	(102,216)	304,681
23	Portfolio Costs	1,536,957	1,253,861	358,257	102,626	101,464	58,754	9,698	15,721	1,796	5,863	(6)	31,429	(219)	86,911	16	5,562	9	0	3,568,700
24	Energy Value	(753,218)	(458,907)	(100,750)	(44,556)	(57,830)	(30,757)	(5,477)	(9,586)	(1,359)	(5,857)	0	0	0	(792)	0	(449)	0	0	(1,469,538)
25	RPS Value	(6,761)	(191,206)	(180,091)	(55,086)	(34,629)	(48,615)	(9,038)	(15,194)	(2,142)	(8,840)	(124,843)	0	(2,864)	(20,161)	0	(858)	0	127,707	(572,622)
26	RA Value	(611,791)	(336,026)	(53,542)	(24,294)	(30,145)	(24,646)	(2,619)	(3,509)	(450)	(15,298)	0	(89,335)	0	(219,902)	0	(9,037)	0	0	(1,420,594)
27	One Time Adjustments	19,994	13,269	1,248	1,047	1,371	50	9	15	1	7	0	(0)	(3)	6	0	0	(210,595)	0	(173,580)
28	Interest	11,254	18,588	4,405	1,727	2,729	1,346	48	(19)	100	(181)	(1,842)	719	(113)	10,407	(156)	(693)	(5,980)	137	42,478
29	Forecast Year End Balance before Transfers	287,441	274,623	81,264	24,702	50,442	17,633	(2,173)	(5,997)	1,329	(7,171)	(26,747)	45,899	(3,449)	482,287	1,722	21,732	(75,588)	25,627	1,193,576
30	Balance Transfers from ERRA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(598,274)	(598,274)
31	Forecast Year End Balance after Balance Transfers	287,441	274,623	81,264	24,702	50,442	17,633	(2,173)	(5,997)	1,329	(7,171)	(26,747)	45,899	(3,449)	482,287	1,722	21,732	(75,588)	(572,647)	595,302
32	RF&U per Advice 4839-G/7086-E @ 0.01252	3,599	3,438	1,017	309	632	221	(27)	(75)	17	(90)	(335)	575	(43)	6,038	22	272	(946)	(7,170)	7,453
33	**Forecast Year End Balance after Balance Transfers (Including RF&U)**	**291,040**	**278,061**	**82,281**	**25,011**	**51,074**	**17,854**	**(2,200)**	**(6,073)**	**1,346**	**(7,261)**	**(27,082)**	**46,473**	**(3,492)**	**488,325**	**1,744**	**22,004**	**(76,534)**	**(579,816)**	**602,756**

Totals may not add due to rounding

D. PABA Balances Recorded Through March 2025

The PABA balances recorded through March 2025 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 2025 ERRA Compliance Review Application to be filed in February 2026 after recording all 12 months of 2025.[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, 2025, and March 1, 2025. 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.

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[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.24-12-038 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.24-12-038. 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 Commission revised authorized Final MPBs for 2025.

5. One-Time Adjustments

One-time adjustment transactions recorded in the period from January through March 31, 2025, totaling a credit of $174 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 2025, 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) 2024 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 $24.2 million credit to PABA in January 2025;[12]

2) Transfer of Land Conversation Plan Environmental Remediation Memo Account (LCPERMA) 2024 balance as authorized in PG&E's AET AL 7469-E. This resulted in a $1 thousand debit to PABA in January 2025;

3) Transfer of General Office Sale Balancing Account (GOSBA) 2024 balance as authorized by D.23-11-069, and upon approval of PG&E's AET AL 7469-E. This resulted in a $16.0 million credit to PABA in January 2025;

4) Transfer of General Office Sale Memorandum Account (GOSMA) 2024 balance as authorized by D.24-08-009, and upon approval of PG&E's AET AL 7469-E. This resulted in a $50.2 million debit to PABA;

5) Transfer of RTBA-E 2024 activity as determined in PG&E's 2020 GRC Settlement and authorized by D.20-12-005, upon approval of PG&E's AET AL 7469-E. This resulted in a $36.6 million debit to PABA in January 2025;[13]

6) Transfer of Department of Energy Litigation Balancing Account (DOELBA) 2024 balance as authorized by D.23-11-069, and upon approval of PG&E's AET AL 7469-E. This resulted in a $1.4 million credit to PABA in January 2025;

7) Transfer of year-end ERRA Balance to most recent PABA vintage as authorized by D.22-01-023. The 2024 ERRA Balance transfer resulted in a $243.8 million credit to PABA in January 2025.

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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 Includes $6.2 million credit for depreciation subaccount and $18.0 million credit related to the final return for the DCPP Employee Retention Program.

13 Includes $0.3 million that was allocated to ERRA and subsequently transferred to PABA Vintage 2024 Subaccount.

8) Transfer of 2024 balance of the PCIA Financing Subaccount in ERRA[14] as authorized in PG&E's AET AL 7469-E. This resulted in a $3 thousand credit to PABA in January 2025;
9) Transfer of 2024 balance of the PCIA Undercollection Balancing Account[15] in PABA Legacy UOG as authorized in D.24-12-038. This resulted in a $2.2 million debit in PABA in January 2025;
10) Recovery of 2024 RUBA-E balance of $32.9 million;[16]
11) Transfer of 2024 HLBA balances to PABA of $16.1 million credit, as authorized by the 2023 GRC D.23-11-069;
12) Transfer of 2024 balance of the Land Conservation Plan Implementation Account (LCPIA), as authorized by the 2020 WMCE Decision D.23-02-017. This resulted in a $11 thousand debit in PABA;
13) Authorized monthly collections of GOSMA in PABA for the first quarter as authorized in D.24-08-009. This resulted in a $5.4 million debit in PABA over the course of the first quarter of 2025; and
14) Transfer of Authorized VAMO Memorandum Account expenses as authorized in D24-12-038. This resulted in a $0.6 million debit to PABA in January 2025.

6. Balancing Account Interest

The balancing account interest (Table 12-2, line 9) is calculated based on the 3-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15.

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14 The PCIA Financing Subaccount in ERRA tracks any amounts financed by bundled customers related to revenue shortfalls associated with capped PCIA rates for eligible departing load customers established in D.18-10-019. The cap was removed in D.20-12038. Since the subaccount is no longer required, it was closed in 2024 after the final residual amount is transferred to PABA Vintage 2020.

15 The PCIA Undercollection Balancing Account to record the shortfall in revenues accruing from departing load customers when PCIA rates are capped, as authorized in D.18-10-019. The cap was removed in D.20-12038. Since the account is no longer required, it was closed in 2024 after the final residual amount is transferred to PABA Vintage Legacy UOG.

16 The 2023 RUBA-E balance was recoverable in ERRA and subsequently transferred to PABA Vintage 2023 Subaccount for recovery.

E. PABA Forecast From April Through December 2025

The components of the PABA transactions forecasted from April 1, 2025, through December 31, 2025, 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 AL 7116-E and 7191-E, effective January 1, 2025, and March 1, 2025, respectively.

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 2025 (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 2025 costs and revenues is the same as used to calculate the 2025 forecast amounts (i.e., price curve date of March 28, 2025).

b. UOG Related Cost

The UOG-related cost forecast reflects the UOG revenue requirement as authorized in the Commission's decisions, and recoverable through 2025.

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, including an updated forecast of Unsold volumes. The updated retained RPS and RA volumes are then multiplied by the D.24-12-038 authorized RPS and RA Adders to

calculate the applicable credits in PABA.[17] Additionally, PG&E will update the RPS credits in PABA associated with the Minimum Retained RPS allocation methodology authorized in D.24-12-038.

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 4.27 percent per annum.

F. 2025 Forecast Year-End PABA

By adding the PABA balance recorded as of the March 2025 accounting close,[18] and the forecast April 2025 through December 2025 forecast transactions,[19] the forecast year-end PABA is under-collected by $1,194 million.[20] The primary drivers for the undercollected balance are summarized in Table 12-3 below, which is followed by a discussion of the drivers.

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17 Corresponding debit entries are recorded in ERRA.

18 See Section C for details of recorded balances.

19 See Section D for details of forecast transactions.

20 See Table 15-1, line 5, Column D.

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

Line No.	Description		Approximate Impact (Over)/Under Collection
1	Lower Expected CAISO Revenues		
	(a) Lower Market Electricity Prices	80	
	(b) Less Generation From PCIA eligible Resources	210	
			290
2	Lower / Higher Procurement Costs and Revenues		
	(a) Lower Net RA Transaction Revenues	505	
	(b) Increase in Energy Storage Contract Costs	80	
	(c) Lower Nuclear Fuel Cost	(10)	
	(d) Lower Natural Gas Fired Generator Costs	(105)	
	(e) Lower Net RPS Contract Costs	(170)	
			300
3	Lower Retained RPS		190
4	Lower Retained RA		380
5	Higher/(Lower) recorded balances brought forward from 2024		
	(a) PABA	79	
	(b) ERRA	(67)	
			11
6	Lower recorded cost related to the purchase of Oakland General Office		(10)
7	Balancing Account Interest		40
8	Other		(8)
9	**Forecast 2025 year-end PABA balance, before Balance Transfers**		**$1,194**

1. Lower Expected CAISO Revenues

a. Lower Market Electricity Prices

Average 2025 CAISO market electricity prices for PG&E's PCIA eligible resources are expected to be approximately 5 percent lower than the 2025 Energy Benchmark (brown power), resulting in a reduction of CAISO revenues of approximately $80 million. The decrease in CAISO electricity prices is primarily driven by lower than expected natural gas prices through March, which have been approximately 25% lower on average than the 2025 PG&E Citygate forward prices adopted in D.24-12-038.

b. Less Generation From PCIA-Eligible Resources

Generation from PCIA eligible resources is forecasted to be approximately 4,000 gigawatt hours (GWh) less than the forecast adopted in D.24-12-038. 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.24-12-038. This net decrease in generation represents an approximately $210 million decrease in CAISO market revenues.

The total impact, including the lower market prices, is an approximately $290 million decrease in CAISO revenues.

2. Lower Procurement Costs

a. Lower Net RA Transaction Revenues

RA sales revenue, net of costs, is approximately $505 million lower than expected, primarily due to the residual RA sales revenue adopted in D.24-12-038 being based on the System RA MPB of $40.31 per kW-month.

b. Higher Energy Storage Contract Costs

The expected costs for Energy Storage contracts is higher by approximately $80 million than expected, primarily due to a reduction in forecasted net benefits related to CAISO wholesale market power prices.

c. Lower Nuclear Fuel Costs

Nuclear Fuel costs are slightly lower than forecast, by approximately $10 million and attributable to recorded actuals from January through March.

d. Lower Natural Gas-Fired Generator Costs

Fuel costs for natural gas-fired resources in PG&E's electric portfolio are expected to be approximately $105 million lower, primarily due to lower generation volumes from natural gas-fired resources compared to the generation forecast adopted in D.24-12-038.

e. Lower Net RPS Contract Costs

Net RPS contract costs are approximately $170 million lower than expected, primarily due to greater than expected revenues from RPS sales.

3. Lower Retained RPS

Retained RPS value decreased by approximately $190 million primarily due to higher RPS sales volumes and lower than expected RPS generation in 2025.

4. Lower Retained RA

Retained RA value decreased approximately $380 million primarily due to an overall reduction in retained RA volumes[21] and a slight decrease in RA sales volumes, as compared to forecasted RA retained and sales volumes.

5. Recorded One-Time Adjustments

Recorded One-Time Adjustments not forecast in the 2025 rates, and hence formed part of the PABA undercollection are discussed in Section D.5 above.

6. Balancing Account Interest

The forecast balancing account interest of approximately $40 million not included in 2025 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.

G. 2025 Forecast Year-End ERRA

The ERRA overcollection, before the balance transfers[22] is $605 million.[23] The primary drivers of the undercollection are summarized in Table 12-4, as follows.

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21 RA volumes from non-local battery storage projects in PG&E's 2025 ERRA Forecast were based on their effective flexible capacity (EFC) values while actual retained volumes are limited to their net qualifying capacity (NQC) values. PG&E has updated its approach for the 2026 ERRA Forecast to limit retained volumes for battery storage projects to their NQC values.

22 The balance transfers are discussed in Section G.

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

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

Line No.	Description	Approximate Impact (Over)/Under Collection	
1	Lower Customer Revenues		$280
2	Lower Expected CAISO Costs		
	(a) Lower Market Electricity Prices	(325)	
	(b) Lower Bundled Load Requirement	(70)	
			(395)
3	Greater Procurement Costs		115
4	Retained RPS and RA		
	(a) Lower Retained RPS	(195)	
	(b) Lower Retained RA	(400)	
			(595)
5	Balancing Account Interest		(15)
6	Other		6
7	**Forecast 2025 year-end ERRA-Main balance, before Balance Transfers**		**($605)**

1. Lower Customer Revenues

Customer revenue is expected to be approximately $280 million undercollected primarily due to lower recorded revenues for January through March compared to the forecast in rates.

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 expected, resulting in lower CAISO cost of approximately $325 million.

b. Lower Bundled Load Requirement

Bundled CAISO load is expected to decrease by approximately 1,100 GWh, which reduces the CAISO procurement costs by

approximately $70 million. The total impact is approximately a $395 million decrease in CAISO Energy costs.

3. Greater Procurement Costs

The increase of $115 million in procurement costs is primarily attributable to incremental bilateral and firm energy import contract purchases forecast for the period April to December.

4. Retained RPS and RA

ERRA's Retained RPS value is approximately $195 million lower than forecast and the Retained RA value is approximately $400 million lower 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.

5. Balancing Account Interest

The forecast balancing account interest of approximately $15 million not included in 2025 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.

H. 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 2025, PG&E has recorded $6.4 million in RUBA-E[24] (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 2025 year-end ERRA overcollection is $598 million. Pursuant to OP 4 of D.22-01-023, PG&E anticipates transferring the final $598 million overcollected 2025 forecast year-end ERRA to the PABA Vintage 2025 subaccount for recovery in the PCIA rates.[25]

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:

[24] See Table 12-1, line 5, Column A.

[25] See Table 12-1, line 6, Column F.

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

Line No.	Order Number	Description	Workstream Description
1	8202617	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 Request for Information (RFI) Process	Used to charge time related to supporting the development and implementation of the RFI process.
4	8203066	VAMO Allocation and Market Offer (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 previous Commission decisions, PG&E received disposition of the VAMOMA costs that accrued through August 2024. The VAMOMA costs accumulated between September 2024 and March 2025 are provided by order number in Table 12-5. The VAMOMA balance of recorded costs as of

September 2024 through March 2025 is $315,716.[26] Not all order numbers listed above have accrued costs during the period being presented.

The accrued costs include, but are not limited to, ongoing implementation of the VA process, workstreams for the implementation of the MO process, the second RFI process, which resulted in a proposed contract termination submitted by AL 7485-E, and IT and related systems projects needed to implement the VAMO. For 2024 the IT and systems workstreams were focused on completing the testing and the first release of Renewable Energy Credit (REC) tracking and REC allocations, contract tracking, settlement invoicing, calculations and reconciliation, and the updated interface between the REC Tracking and Settlement applications. For 2025, the IT and systems workstreams are focused on ongoing maintenance as needed to ensure the implementation of the VA and MO processes.

Due to ongoing work related to the implementation of the VA and MO processes including but not limited to contract terminations resulting from the RFI and IT and systems requirements, PG&E anticipates updating the accrued costs and including revised amounts in the Fall Update.

26 See Table 12-1, line 5.

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

Line No.	VAMO Order Number	Order Description	2024					2025					
			Sep	Oct	Nov	Dec	2024 Total	Jan	Feb	Mar	Apr	2025 Total	Grand Total
1	8202617	VAMO Costs	$8,710.24	$5,146.96	$7,522.48	$9,502.08	$30,881.76	$6,944.00	$8,246.00	$10,850.00	$2,170.00	$28,210.00	$59,091.76
2	8203065	VAMO RFI Process	2,472.28	6,178.30	3,098.72	7,967.87	19,717.17	8,493.32		2,674.66		11,167.98	30,885.15
3	8203066	VAMO Allocation and Market Offer (RFI/RFO)	580.83			8,776.76	9,357.59					0.00	9,357.59
4	8203067	VAMO Back Office Support	9,378.36	10,813.57	9,996.99	7,101.83	37,290.75	8,191.75	8,598.65	42,966.03	10,714.40	70,470.83	107,761.58
5	8203068	VAMO Compliance Support	243.60				243.60			767.58		767.58	1,011.18
6	8203073	VAMO Systems/IT	28,258.01	55,840.60	11,347.42		95,446.03	4,589.60	7,572.84			12,162.44	107,608.47
7		Grand Total	$49,643.32	$77,979.43	$31,965.61	$33,348.54	$192,936.90	$28,218.67	$24,417.49	$57,258.27	$12,884.40	$122,778.83	$315,715.73

J. Conclusion

In this chapter, PG&E summarizes its 2025 year-end balance forecasts for amortization in the 2026 rates. These balances will be the subject of the Fall Update; and, except as described herein, are amortized for recovery through the 2026 AET AL process, or a subsequent electric rate change AL. Additionally, this chapter requests Commission approval of $316 thousand of costs of administering the overall VAMO process as tracked in the VAMOMA and presented in Table 12-6 for disposition to PABA, as to be updated in PG&E's Fall Update. PG&E is requesting cost recovery approval to dispose of these balances in rates effective January 1, 2026.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 13

RATE PROPOSAL

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 13
RATE PROPOSAL

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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), including Central Procurement Entity costs, (5) Tree Mortality Non-Bypassable Charge (TMNBC), (6) Bioenergy Market Adjusting Tariff (BioMAT) Non-Bypassable Charge (NBC), and (7) Voluntary Allocation and Market Offer. These revenue requirements have been outlined in Chapters 3 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, 2026.

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 2026 ERRA Forecast Application (Application) on top of present rates effective March 1, 2025. For this Application, PG&E utilizes the revenue allocation and rate design methodology used to design the rates effective March 1, 2025, 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)

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1 The NSGC rate component collects the CAM revenue requirement.

revenue return, will decrease by approximately 6.0 percent to 33.3 cents per kilowatt-hour (kWh) when compared to the present system average Bundled rate of 35.4 cents per kWh, effective March 1, 2025. The system average rate for DA and CCA customers, whose average rates exclude commodity charges that are provided by third-party service providers, would increase by approximately 3.9 percent to 21.2 cents per kWh, when compared to the present system average rate for DA and CCA customers of 20.4 cents per kWh, which was effective March 1, 2025.[2]

B. Revenue Requirement

The 2026 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.

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[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 2026 FORECAST ENERGY PROCUREMENT REVENUE REQUIREMENTS
(THOUSANDS OF DOLLARS)

Line No.		2026 Cost With Revenue Fees and Uncollectibles[a]	2025 Year End Balance[b]	Authorized Transfers[d]	2025 Year End transfers to PABA[e]	2026 Revenue Requirements[f]
		(A)	(B)	(C)	(D)	(E) = SUM (A..D)
1	Non-PPP					
2	CAM (NSGC)	198,812	18,615	0		217,427
3	Ongoing CTC (MTCBA)	(36,486)	9,546			(26,941)
4	PCIA/PABA	212,518	1,208,520	0	(605,764)	815,274
5	VAMOMA[c]		320			320
6	ERRA	2,958,889	(612,282)	6,517	605,764	2,958,889
7	RUBA-E		6,517	(6,517)		0
8	Non-PPP Subtotal	3,333,733	631,236	0	0	3,964,969
9	PPP					
10	PPCP	(1,459)	(1,087)			(2,546)
11	TMNBC	32,456	8,956			41,412
12	BioMat	8,321	2,552			10,873
13	PPP Subtotal	39,318	10,421	0	0	49,740
14	**Revenue Requirement for Rate Setting**	**3,373,052**	**641,657**	**0**	**0**	**4,014,709**
15	Revenue Requirements authorized in other proceedings					
16	UOG-Related Costs[g]	(1,303,065)				(1,303,065)
17	RUBA-E		(6,517)			(6,517)
18	Subtotal	(1,303,065)	(6,517)	0	0	(1,309,582)
19	**2026 ERRA Application Revenue Requirement Request**	**2,069,987**	**635,140**	**0**	**0**	**2,705,127**

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 2026 Revenue Requirement for ratesetting purposes of $4,015 million[4] includes the 2026 ERRA Application Revenue Requirement Request in this application of $2,705 million.[5]

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

4 Table 13-1, line 14.

5 Table 13-1, line 19.

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 2026 generation rates presented in this Application, which are designed using the 2026 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 2025 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. 2025 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 2025 year-end ERRA balance to the 2025 vintage subaccount in PABA in this Application. Amortizing this balance in the 2025 vintage subaccount in PABA allows the balance to be applied to both Bundled customers and PCIA-eligible departed load (DL) customers that depart on or after July 1, 2025. As outlined in Chapter 12, PG&E currently forecasts an overcollection of $606 million in ERRA at the end of 2025.[7] Transferring this balance to the 2025 vintage subaccount in PABA will decrease PCIA rates for vintage 2025, as shown in Table 13-2.

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6 Modifications to the calculation methodology approved in D.11-12-018 were implemented, in part, in Res.E-4475.

7 See Table 12-1, Column K.

TABLE 13-2
IMPACT OF AMORTIZATION OF THE FORECASTED 2025 YEAR-END ERRA BALANCE IN PABA

Line No.	PABA Vintage Subaccount	Applicable 2025 ERRA Year-end Balance ($000)	Applicable Billing Determinants (kWh)	Average PCIA Rate Impact
1	2025 Vintage	$(605,764)	28,139,821,240	$(0.02153)

b. Summary of Proposed 2026 Vintage PCIA Rates

Table 13-3 shows PCIA rates for all vintages and customer classes. For vintages prior to 2026, the change in PCIA rates ranges from an increase of 5.5 cents per kWh to a decrease of 0.02 cents per kWh, compared to 2025 PCIA rates implemented January 1, 2025.

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
1	Residential	$0.01328	$0.01399	$0.01389	$0.01383	$0.01308	$0.01294	$0.01267	$0.01265	$0.01227	$0.01167	$0.01393	$0.01295	$0.03028	$0.03035	$0.03157	$0.02872	$0.00721	$0.00843
2	Small L&P	$0.01292	$0.01360	$0.01351	$0.01345	$0.01272	$0.01258	$0.01232	$0.01230	$0.01193	$0.01135	$0.01355	$0.01259	$0.02945	$0.02951	$0.03069	$0.02792	$0.00701	$0.00820
3	Medium L&P	$0.01360	$0.01432	$0.01422	$0.01415	$0.01339	$0.01325	$0.01297	$0.01294	$0.01256	$0.01195	$0.01426	$0.01325	$0.03100	$0.03106	$0.03231	$0.02939	$0.00738	$0.00863
4	E19	$0.01290	$0.01358	$0.01349	$0.01343	$0.01270	$0.01257	$0.01231	$0.01228	$0.01192	$0.01133	$0.01353	$0.01257	$0.02940	$0.02947	$0.03065	$0.02788	$0.00700	$0.00819
5	Streetlights	$0.01084	$0.01142	$0.01134	$0.01129	$0.01068	$0.01056	$0.01035	$0.01032	$0.01002	$0.00953	$0.01137	$0.01057	$0.02471	$0.02476	$0.02576	$0.02343	$0.00589	$0.00689
6	Standby	$0.00913	$0.00962	$0.00955	$0.00951	$0.00900	$0.00890	$0.00871	$0.00870	$0.00844	$0.00803	$0.00958	$0.00890	$0.02081	$0.02085	$0.02169	$0.01973	$0.00496	$0.00580
7	Agriculture	$0.01222	$0.01286	$0.01278	$0.01272	$0.01203	$0.01190	$0.01166	$0.01163	$0.01129	$0.01073	$0.01281	$0.01191	$0.02785	$0.02790	$0.02903	$0.02641	$0.00663	$0.00776
8	B20/E20 T (Excluding FPP)	$0.01137	$0.01197	$0.01189	$0.01184	$0.01120	$0.01108	$0.01085	$0.01083	$0.01051	$0.00999	$0.01193	$0.01108	$0.02592	$0.02597	$0.02702	$0.02458	$0.00618	$0.00722
9	B20/E20 P (Excluding FPP)	$0.01167	$0.01229	$0.01220	$0.01215	$0.01149	$0.01137	$0.01113	$0.01111	$0.01078	$0.01025	$0.01224	$0.01137	$0.02660	$0.02665	$0.02773	$0.02522	$0.00634	$0.00741
10	B20/E20 S (Excluding FPP)	$0.01202	$0.01266	$0.01257	$0.01251	$0.01184	$0.01171	$0.01147	$0.01145	$0.01111	$0.01056	$0.01261	$0.01172	$0.02740	$0.02746	$0.02857	$0.02599	$0.00653	$0.00763
11	BEV1	$0.01094	$0.01152	$0.01144	$0.01139	$0.01078	$0.01066	$0.01044	$0.01041	$0.01011	$0.00961	$0.01147	$0.01066	$0.02494	$0.02499	$0.02600	$0.02365	$0.00594	$0.00694
12	BEV2	$0.01228	$0.01293	$0.01284	$0.01278	$0.01209	$0.01196	$0.01171	$0.01169	$0.01134	$0.01079	$0.01288	$0.01196	$0.02799	$0.02805	$0.02917	$0.02654	$0.00667	$0.00779
13	System Average PCIA Rate by Vintage	$0.01210	$0.01266	$0.01344	$0.01309	$0.01268	$0.01273	$0.01240	$0.01233	$0.01183	$0.01147	$0.01310	$0.01258	$0.02945	$0.02887	$0.02978	$0.02646	$0.00700	$0.00807

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	$201,351
2	DA/CCA Customers	$614,242
3	Total Revenues	$815,594

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 2026 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 2026 AVERAGE TOTAL GENERATION RATES FOR BUNDLED CUSTOMERS
($/KWH)

Line No.	Customer Class	Proposed Rate
1	Residential	$0.12335
2	Small Commercial	$0.11994
3	Medium Commercial	$0.12627
4	Large Commercial	$0.11977
5	Streetlights	$0.10064
6	Standby	$0.08471
7	Agriculture	$0.11342
8	B20/E20 T	$0.10556
9	B20/E20 P	$0.10832
10	B20/E20 S	$0.11161
11	BEV1	$0.10159
12	BEV2	$0.11400

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 2026 forecast sales. Table 13-6 presents the proposed Ongoing CTC rates for Bundled, DA, CCA, and eligible DL customers.

TABLE 13-6
PROPOSED 2026 ONGOING CTC RATES
($/KWH)

Line No.	Customer Class	Proposed Rate
1	Residential	$(0.00036)
2	Small Commercial	$(0.00035)
3	Medium Commercial	$(0.00037)
4	Large Commercial	$(0.00035)
5	Streetlights	$(0.00029)
6	Standby	$(0.00025)
7	Agriculture	$(0.00033)
8	B20/E20 T	$(0.00031)
9	B20/E20 P	$(0.00031)
10	B20/E20 S	$(0.00032)
11	BEV1	$(0.00035)
12	BEV2	$(0.00035)

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 2023 recorded data. PG&E will update this recorded data to reflect 2024 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 2026 NSGC RATES
($/KWH)

Line No.	Customer Class	Proposed Rate
1	Residential	$0.00376
2	Small Commercial	$0.00258
3	Medium Commercial	$0.00233
4	Large Commercial	$0.00233
5	Streetlights	$0.00257
6	Standby	$0.00251
7	Agriculture	$0.00249
8	B20/E20 T	$0.00200
9	B20/E20 P	$0.00200
10	B20/E20 S	$0.00200
11	BEV1	$0.00258
12	BEV2	$0.00233

5. TMNBC

To determine TMNBC rates, PG&E first allocates the TMNBC revenue requirement determined in Chapter 9 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 2026 TREE MORTALITY NON BYPASSABLE CHARGE RATES
($/KWH)

Line No.	Customer Class	Proposed Rate
1	Residential	$0.00071
2	Small Commercial	$0.00049
3	Medium Commercial	$0.00044
4	Large Commercial	$0.00044
5	Streetlights	$0.00049
6	Standby	$0.00048
7	Agriculture	$0.00047
8	B20/E20 T	$0.00034
9	B20/E20 P	$0.00034
10	B20/E20 S	$0.00034
11	BEV1	$0.00049
12	BEV2	$0.00044

6. BioMAT NBC

To determine BioMAT NBC rates, PG&E first allocates the BioMAT NBC revenue requirement determined in Chapter 10 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 2026 BIOENERGY MARKET ADJUSTING TARIFF RATES
($/KWH)

Line No.	Customer Class	Proposed Rate
1	Residential	$0.00019
2	Small Commercial	$0.00013
3	Medium Commercial	$0.00012
4	Large Commercial	$0.00012
5	Streetlights	$0.00013
6	Standby	$0.00013
7	Agriculture	$0.00012
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 credit of $2.5 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

[8] PG&E established the PPCP subaccount through AL 6524-E, submitted March 14, 2022.

PPP rates for billing. Proposed PPCP rates are shown in Table 13-10 below.

TABLE 13-10
PROPOSED 2026 PPCP RATES
($/KWH)

Line No.	Customer Class	Proposed Rate
1	Residential	$(0.00004)
2	Small Commercial	$(0.00021)
3	Medium Commercial	$(0.00007)
4	Large Commercial	$(0.00007)
5	Streetlights	$(0.00657)
6	Standby	$(0.00215)
7	Agriculture	$(0.00029)
8	B20/E20 T	$(0.00009)
9	B20/E20 P	$(0.00009)
10	B20/E20 S	$(0.00009)
11	BEV1	$(0.00021)
12	BEV2	$(0.00007)

8. 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, 2025 rate levels[9] and thus do not reflect the cost recovery (i.e., total 2026 revenue requirements) subject to CPUC approval through PG&E's 2026 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 2026 AET

[9] Present 2025 rate levels are those filed in AL 7516-E, effective March 1, 2025.

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, 2026 concurrent with the AET, subject to updates presented in PG&E's Fall Update and 2026 AET.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 13

ATTACHMENT A

ILLUSTRATIVE TOTAL RATES BY CLASS

Pacific Gas & Electric Company
2026 May ERRA Application
Thursday, January 1, 2026
Attachment A1: 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	PCIA Revenue	Total Proposed Revenue
RESIDENTIAL																						
Non-CARE	$2,542,253,393	$736,944,080	$306,050,347	$46,006,666	-$28,500,233	-$89,981,869	$1,912,204	$1,236,237,342	$151,611,864	-$1,444,274	$32,893,083	$38,656,333	-$38,656,348	$28,320,987	-$2,137,649	$54,484	$22,459,493	$0	-$100,903,205	$29,143,950	$50,403,893	$2,419,071,150
CARE	$1,028,741,656	$503,907,162	$209,218,174	$31,450,481	-$19,482,960	-$61,512,240	$1,307,198	$321,996,214	$55,206,641	-$987,316	$0	$0	$0	$0	-$1,461,314	$37,246	$15,353,487	$0	-$65,613,214	-$43,038,953	$34,456,499	$980,837,105
TOTAL RES	$3,570,995,049	$1,240,851,242	$515,268,521	$77,457,147	-$47,983,194	-$151,494,108	$3,219,402	$1,558,233,557	$206,818,504	-$2,431,590	$32,893,083	$38,656,333	-$38,656,348	$28,320,987	-$3,598,962	$91,730	$37,812,980	$0	-$166,516,418	-$13,895,003	$84,860,392	$3,399,908,255
SMALL L&P																						
B-1	$663,750,245	$179,233,935	$53,397,844	$11,521,053	-$7,137,068	-$15,710,526	$333,631	$350,825,318	$36,929,608	-$361,675	$8,882,508	$9,658,801	-$9,658,800	$7,404,856	-$520,485	$13,644	$3,864,589	-$11,472,868	-$78,101		$12,274,315	$629,400,580
B-6	$259,552,188	$71,330,302	$21,122,125	$4,556,869	-$2,822,891	-$6,213,912	$131,972	$133,509,227	$12,922,479	-$143,052	$3,511,720	$3,818,630	-$3,818,629	$2,927,527	-$205,865	$5,397	$1,528,543	-$1,642,713	-$52,920		$4,854,803	$245,319,611
A-15	$240,036	$58,047	$17,288	$3,730	-$2,311	-$5,087	$108	$137,182	$11,970	-$117	$2,882	$3,134	-$3,134	$2,403	-$169	$4	$1,251	-$1,720	$0		$3,974	$229,436
TC-1	$5,047,047	$1,242,015	$409,085	$88,269	-$54,681	-$120,366	$2,556	$2,884,732	$136,019	-$2,771	$68,205	$74,166	-$74,166	$56,859	-$3,988	$105	$29,609	$0	$0		$94,040	$4,829,688
TOTAL SMALL	$928,589,515	$251,864,299	$74,946,342	$16,169,920	-$10,016,951	-$22,049,891	$468,267	$487,356,460	$50,000,076	-$507,615	$12,465,316	$13,554,731	-$13,554,730	$10,391,645	-$730,507	$19,149	$5,423,992	-$13,117,301	-$131,021		$17,227,132	$879,779,314
MEDIUM L&P																						
B-10 T	$370,385	$169,080	$54,228	$13,437	-$8,324	-$16,438	$339	$66,114	$33,781	-$422	$10,383	$11,290	-$11,290	$4,729	-$639	$16	$4,058	$0	$0		$15,067	$345,409
B-10 P	$8,071,573	$2,574,401	$982,534	$175,092	-$108,466	-$214,204	$6,131	$3,306,724	$522,417	-$5,497	$135,293	$147,117	-$147,117	$88,228	-$8,328	$207	$52,881	$0	-$53,441		$196,337	$7,650,311
B-10 S	$750,632,641	$240,041,893	$83,305,012	$14,616,945	-$9,054,912	-$17,882,028	$520,492	$307,745,514	$43,144,517	-$458,863	$11,222,247	$12,203,023	-$12,203,022	$7,997,330	-$695,207	$17,310	$4,414,556	-$247,782	-$885,279		$16,390,517	$700,192,261
TOTAL MEDIUM	$759,074,598	$242,785,374	$84,341,774	$14,805,473	-$9,171,702	-$18,112,670	$526,962	$311,118,352	$43,700,715	-$464,782	$11,367,923	$12,361,431	-$12,361,429	$8,090,287	-$704,174	$17,534	$4,471,495	-$247,782	-$938,720		$16,601,922	$708,187,980
B-19 CLASS																						
B-19 FIRM T	$1,408,526	$597,426	$178,836	$44,459	-$27,541	-$54,390	$1,117	$354,753	$101,679	-$1,396	$34,353	$37,355	-$37,355	$15,589	-$2,006	$53	$13,427	$0	$0		$47,300	$1,303,660
B-19 V T	$1,129,545	$501,663	$181,735	$36,199	-$22,424	-$44,284	$1,135	$192,684	$103,855	-$1,136	$27,971	$30,415	-$30,415	$12,693	-$1,633	$43	$10,933	$0	$0		$38,512	$1,037,943
Total B-19 T	$2,538,071	$1,099,089	$360,570	$80,657	-$49,965	-$98,674	$2,253	$547,436	$205,535	-$2,532	$62,324	$67,770	-$67,770	$28,282	-$3,639	$96	$24,360	$0	$0		$85,813	$2,341,604
B-19 FIRM P	$83,719,375	$30,598,963	$8,974,779	$2,208,106	-$1,367,878	-$2,701,345	$56,075	$29,339,854	$5,972,980	-$69,318	$1,706,199	$1,855,314	-$1,855,314	$923,390	-$99,618	$2,615	$666,884	$0	-$2,913,215		$2,349,247	$75,647,719
B-19 V P	$38,586,920	$14,525,503	$4,131,690	$1,059,017	-$656,040	-$1,295,576	$25,815	$12,660,304	$2,901,556	-$33,245	$815,641	$886,924	-$886,924	$441,422	-$47,777	$1,254	$319,840	$0	$0		$1,126,709	$35,976,112
Total B-19 P	$122,306,295	$45,124,466	$13,106,469	$3,267,123	-$2,023,919	-$3,996,921	$81,890	$42,000,158	$8,874,536	-$102,563	$2,521,840	$2,742,238	-$2,742,238	$1,364,812	-$147,395	$3,869	$986,724	$0	-$2,913,215		$3,475,956	$111,623,831
B-19 FIRM S	$311,126,177	$93,643,420	$32,842,790	$5,596,647	-$3,467,014	-$6,846,808	$205,203	$137,912,913	$16,202,220	-$175,693	$4,324,520	$4,702,464	-$4,702,464	$2,667,493	-$252,490	$6,628	$1,690,279	$0	-$617,495		$5,954,383	$289,686,996
B-19 V S	$644,656,207	$231,626,594	$52,561,535	$14,938,737	-$9,254,256	-$18,275,701	$328,406	$244,728,151	$41,576,699	-$468,965	$11,442,463	$12,442,485	-$12,442,483	$7,058,053	-$673,955	$17,691	$4,511,742	-$233,379	$0		$15,893,616	$595,777,432
Total B-19 S	$955,782,384	$325,270,013	$85,404,325	$20,535,384	-$12,721,270	-$25,122,509	$533,609	$382,641,065	$57,778,919	-$644,658	$15,766,982	$17,144,949	-$17,144,947	$9,725,546	-$926,445	$24,319	$6,202,021	-$233,379	-$617,495		$21,848,000	$885,464,428
B-19 T	$2,538,071	$1,099,089	$360,570	$80,657	-$49,965	-$98,674	$2,253	$547,436	$205,535	-$2,532	$62,324	$67,770	-$67,770	$28,282	-$3,639	$96	$24,360	$0	$0		$85,813	$2,341,604
B-19 P	$122,306,295	$45,124,466	$13,106,469	$3,267,123	-$2,023,919	-$3,996,921	$81,890	$42,000,158	$8,874,536	-$102,563	$2,521,840	$2,742,238	-$2,742,238	$1,364,812	-$147,395	$3,869	$986,724	$0	-$2,913,215		$3,475,956	$111,623,831
B-19 S	$955,782,384	$325,270,013	$85,404,325	$20,535,384	-$12,721,270	-$25,122,509	$533,609	$382,641,065	$57,778,919	-$644,658	$15,766,982	$17,144,949	-$17,144,947	$9,725,546	-$926,445	$24,319	$6,202,021	-$233,379	-$617,495		$21,848,000	$885,464,428
TOTAL B-19	$1,080,626,750	$371,493,568	$98,871,364	$23,883,164	-$14,795,155	-$29,218,104	$617,751	$425,188,659	$66,858,991	-$749,754	$18,351,146	$19,954,958	-$19,954,955	$11,118,640	-$1,077,479	$28,284	$7,213,105	-$233,379	-$3,530,710		$25,409,768	$999,429,863
STREETLIGHTS	$40,146,589	$8,695,715	$2,611,595	$665,334	-$412,161	-$768,158	$16,317	$24,788,627	$1,077,102	-$20,887	$514,102	$559,033	-$559,033	$416,482	-$25,221	$788	$222,487	$0	$0		$595,352	$38,377,474
STANDBY																						
STANDBY T	$101,957,948	$50,420,424	$19,237,439	$4,625,969	-$2,865,698	-$5,815,504	$120,196	$15,787,465	$11,466,538	-$145,221	$3,574,478	$3,886,873	-$3,886,872	$1,483,915	-$147,605	$5,478	$1,510,449	$0	-$9,023,747		$3,488,233	$93,722,811
STANDBY P	$9,392,431	$1,285,942	$659,309	$78,628	-$48,709	-$98,847	$4,119	$6,879,095	$284,628	-$2,468	$60,756	$66,066	-$66,066	$87,002	-$2,509	$93	$25,673	$0	-$472,164		$59,290	$8,799,839
STANDBY S	-$163,242	-$125,239	$3,642	-$15,924	$9,865	$20,019	$23	$73,710	-$211,962	$500	-$12,305	-$13,380	$13,380	-$9,265	$508	-$19	-$5,200	$0	$0		-$12,008	-$283,654
TOTAL STANDBY	$111,187,138	$51,581,127	$19,900,391	$4,688,674	-$2,904,542	-$5,894,332	$124,338	$22,740,270	$11,539,204	-$147,189	$3,622,930	$3,939,558	-$3,939,558	$1,561,652	-$149,606	$5,553	$1,530,922	$0	-$9,495,911		$3,535,516	$102,238,996
AGRICULTURE																						
AG-A1	$93,673,533	$19,156,475	$5,379,411	$1,287,861	-$797,805	-$1,582,229	$33,611	$61,155,892	$4,193,295	-$40,429	$995,128	$1,082,098	-$1,082,098	$732,575	-$55,018	$1,525	$415,647	-$2,058,464	-$16,272		$1,297,844	$90,099,047
AG-A2	$49,994,651	$12,896,851	$3,665,237	$877,478	-$543,580	-$1,078,044	$22,901	$26,916,414	$2,857,082	-$27,546	$678,026	$737,282	-$737,282	$499,137	-$37,486	$1,039	$283,199	-$480,356	-$4,349		$884,280	$47,410,280
AG B	$332,381,635	$71,863,869	$17,744,650	$4,248,167	-$2,631,657	-$5,219,177	$110,869	$204,493,944	$15,145,100	-$133,361	$3,282,552	$3,569,433	-$3,569,432	$2,416,490	-$181,485	$5,031	$1,371,064	-$417,971	-$10,108		$4,281,100	$316,369,078
AG C	$1,020,161,969	$299,988,731	$87,752,869	$21,008,522	-$13,014,370	-$25,810,470	$548,283	$473,273,457	$61,693,649	-$659,511	$16,233,249	$17,651,965	-$17,651,963	$11,950,302	-$897,499	$24,880	$6,780,343	-$300,547	-$284,821		$21,171,382	$959,458,451
TOTAL AG	$1,496,211,787	$403,905,926	$114,542,166	$27,422,029	-$16,987,413	-$33,689,921	$715,663	$765,839,706	$83,889,126	-$860,848	$21,188,954	$23,040,778	-$23,040,775	$15,598,505	-$1,171,488	$32,475	$8,850,254	-$3,257,338	-$315,550		$27,634,607	$1,413,336,856
B-20 CLASS																						
B-20 FIRM T	$349,650,588	$185,308,642	$52,560,271	$13,517,800	-$8,374,014	-$13,833,800	$328,398	$24,853,987	$31,759,848	-$424,358	$10,445,180	$11,358,044	-$11,358,043	$3,739,339	-$537,469	$16,009	$3,507,622	$0	-$6,618,832		$12,683,590	$308,932,214
FPP T																						
TOTAL	$349,650,588	$185,308,642	$52,560,271	$13,517,800	-$8,374,014	-$13,833,800	$328,398	$24,853,987	$31,759,848	-$424,358	$10,445,180	$11,358,044	-$11,358,043	$3,739,339	-$537,469	$16,009	$3,507,622	$0	-$6,618,832		$12,683,590	$308,932,214
B-20 FIRM P	$437,168,058	$171,230,779	$46,468,108	$12,171,917	-$7,540,265	-$12,456,455	$290,334	$135,249,849	$30,024,549	-$382,108	$9,405,219	$10,227,195	-$10,227,194	$4,821,344	-$496,637	$14,415	$3,158,390	$0	-$2,510,065		$11,718,296	$401,167,669
FPP P																						
TOTAL	$437,168,058	$171,230,779	$46,468,108	$12,171,917	-$7,540,265	-$12,456,455	$290,334	$135,249,849	$30,024,549	-$382,108	$9,405,219	$10,227,195	-$10,227,194	$4,821,344	-$496,637	$14,415	$3,158,390	$0	-$2,510,065		$11,718,296	$401,167,669
B-20 FIRM S	$87,082,604	$31,097,723	$9,424,076	$2,145,445	-$1,329,062	-$2,195,599	$58,882	$30,866,791	$5,318,391	-$67,351	$1,657,782	$1,802,665	-$1,802,665	$913,904	-$90,196	$2,541	$556,704	$0	-$188,540		$2,127,842	$80,299,333
FPP S																						
TOTAL	$87,082,604	$31,097,723	$9,424,076	$2,145,445	-$1,329,062	-$2,195,599	$58,882	$30,866,791	$5,318,391	-$67,351	$1,657,782	$1,802,665	-$1,802,665	$913,904	-$90,196	$2,541	$556,704	$0	-$188,540		$2,127,842	$80,299,333
B-20 T	$349,650,588	$185,308,642	$52,560,271	$13,517,800	-$8,374,014	-$13,833,800	$328,398	$24,853,987	$31,759,848	-$424,358	$10,445,180	$11,358,044	-$11,358,043	$3,739,339	-$537,469	$16,009	$3,507,622	$0	-$6,618,832		$12,683,590	$308,932,214
B-20 P	$437,168,058	$171,230,779	$46,468,108	$12,171,917	-$7,540,265	-$12,456,455	$290,334	$135,249,849	$30,024,549	-$382,108	$9,405,219	$10,227,195	-$10,227,194	$4,821,344	-$496,637	$14,415	$3,158,390	$0	-$2,510,065		$11,718,296	$401,167,669
B-20 S	$87,082,604	$31,097,723	$9,424,076	$2,145,445	-$1,329,062	-$2,195,599	$58,882	$30,866,791	$5,318,391	-$67,351	$1,657,782	$1,802,665	-$1,802,665	$913,904	-$90,196	$2,541	$556,704	$0	-$188,540		$2,127,842	$80,299,333
TOTAL B-20	$873,901,250	$387,637,143	$108,452,455	$27,835,162	-$17,243,341	-$28,485,854	$677,614	$190,970,627	$67,102,788	-$873,817	$21,508,181	$23,387,904	-$23,387,902	$9,474,587	-$1,124,302	$32,964	$7,222,715	$0	-$9,317,437		$26,529,727	$790,399,216
SYSTEM	**$8,860,732,676**	**$2,958,814,393**	**$1,018,934,608**	**$192,926,902**	**-$119,514,458**	**-$289,713,039**	**$6,366,315**	**$3,786,236,258**	**$530,986,506**	**-$6,056,480**	**$121,911,635**	**$135,454,725**	**-$135,454,730**	**$84,972,784**	**-$8,581,739**	**$228,476**	**$72,747,950**	**-$16,855,800**	**-$190,245,766**	**-$13,895,003**	**$202,394,416**	**$8,331,657,954**

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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	5,974,903,185	$0.42549	$0.12334	$0.05122	$0.00770	-$0.00477	-$0.01506	$0.00032	$0.20690	$0.02537	-$0.00024	$0.00551	$0.00647	-$0.00647	$0.00474	-$0.00036	$0.00001	$0.00376	$0.00000	-$0.01689	$0.00488	$0.00844	$0.40487	-4.8%
CARE	4,084,490,973	$0.25187	$0.12337	$0.05122	$0.00770	-$0.00477	-$0.01506	$0.00032	$0.07883	$0.01352	-$0.00024	$0.00000	$0.00000	$0.00000	$0.00000	-$0.00036	$0.00001	$0.00376	$0.00000	-$0.01606	-$0.01054	$0.00844	$0.24014	-4.7%
TOTAL RES	10,059,394,158	$0.35499	$0.12335	$0.05122	$0.00770	-$0.00477	-$0.01506	$0.00032	$0.15490	$0.02056	-$0.00024	$0.00327	$0.00384	-$0.00384	$0.00282	-$0.00036	$0.00001	$0.00376	$0.00000	-$0.01655	-$0.00138	$0.00844	$0.33798	-4.8%
SMALL L&P																								
B-1	1,496,240,596	$0.44361	$0.11979	$0.03569	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.23447	$0.02468	-$0.00024	$0.00594	$0.00646	-$0.00646	$0.00495	-$0.00035	$0.00001	$0.00258	-$0.00767	-$0.00005		$0.00820	$0.42065	-5.2%
B-6	591,801,148	$0.43858	$0.12053	$0.03569	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.22560	$0.02184	-$0.00024	$0.00593	$0.00645	-$0.00645	$0.00495	-$0.00035	$0.00001	$0.00258	-$0.00278	-$0.00009		$0.00820	$0.41453	-5.5%
A-15	484,440	$0.49549	$0.11982	$0.03569	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.28318	$0.02471	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00496	-$0.00035	$0.00001	$0.00258	-$0.00355	$0.00000		$0.00820	$0.47361	-4.4%
TC-1	11,463,462	$0.44027	$0.10835	$0.03569	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.25165	$0.01187	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00496	-$0.00035	$0.00001	$0.00258	$0.00000	$0.00000		$0.00820	$0.42131	-4.3%
TOTAL SMALL	2,099,989,646	$0.44219	$0.11994	$0.03569	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.23208	$0.02381	-$0.00024	$0.00594	$0.00645	-$0.00645	$0.00495	-$0.00035	$0.00001	$0.00258	-$0.00625	-$0.00006		$0.00820	$0.41894	-5.3%
MEDIUM L&P																								
B-10 T	1,745,037	$0.21225	$0.09689	$0.03108	$0.00770	-$0.00477	-$0.00942	$0.00019	$0.03789	$0.01936	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00271	-$0.00037	$0.00001	$0.00233	$0.00000	$0.00000		$0.00863	$0.19794	-6.7%
B-10 P	22,739,226	$0.35496	$0.11321	$0.04321	$0.00770	-$0.00477	-$0.00942	$0.00027	$0.14542	$0.02297	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00388	-$0.00037	$0.00001	$0.00233	$0.00000	-$0.00235		$0.00863	$0.33644	-5.2%
B-10 S	1,898,304,490	$0.39542	$0.12645	$0.04388	$0.00770	-$0.00477	-$0.00942	$0.00027	$0.16212	$0.02273	-$0.00024	$0.00591	$0.00643	-$0.00643	$0.00421	-$0.00037	$0.00001	$0.00233	-$0.00013	-$0.00047		$0.00863	$0.36885	-6.7%
TOTAL MEDIUM	1,922,788,752	$0.39478	$0.12627	$0.04386	$0.00770	-$0.00477	-$0.00942	$0.00027	$0.16181	$0.02273	-$0.00024	$0.00591	$0.00643	-$0.00643	$0.00421	-$0.00037	$0.00001	$0.00233	-$0.00013	-$0.00049		$0.00863	$0.36831	-6.7%
B-19 CLASS																								
B-19 FIRM T	5,773,842	$0.24395	$0.10347	$0.03097	$0.00770	-$0.00477	-$0.00942	$0.00019	$0.06144	$0.01761	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00270	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00819	$0.22579	-7.4%
B-19 V T	4,701,105	$0.24027	$0.10671	$0.03866	$0.00770	-$0.00477	-$0.00942	$0.00024	$0.04099	$0.02209	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00270	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00819	$0.22079	-8.1%
Total B-19 T	10,474,947	$0.24230	$0.10493	$0.03442	$0.00770	-$0.00477	-$0.00942	$0.00022	$0.05226	$0.01962	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00270	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00819	$0.22354	-7.7%
B-19 FIRM P	286,766,974	$0.29194	$0.10670	$0.03130	$0.00770	-$0.00477	-$0.00942	$0.00020	$0.10231	$0.02083	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00322	-$0.00035	$0.00001	$0.00233	$0.00000	-$0.01016		$0.00819	$0.26380	-9.6%
B-19 V P	137,534,658	$0.28056	$0.10561	$0.03004	$0.00770	-$0.00477	-$0.00942	$0.00019	$0.09205	$0.02110	-$0.00024	$0.00593	$0.00645	-$0.00645	$0.00321	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00819	$0.26158	-6.8%
Total B-19 P	424,301,632	$0.28825	$0.10635	$0.03089	$0.00770	-$0.00477	-$0.00942	$0.00019	$0.09899	$0.02092	-$0.00024	$0.00594	$0.00646	-$0.00646	$0.00322	-$0.00035	$0.00001	$0.00233	$0.00000	-$0.00687		$0.00819	$0.26308	-8.7%
B-19 FIRM S	726,837,334	$0.42805	$0.12884	$0.04519	$0.00770	-$0.00477	-$0.00942	$0.00028	$0.18974	$0.02229	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00367	-$0.00035	$0.00001	$0.00233	$0.00000	-$0.00085		$0.00819	$0.39856	-6.9%
B-19 V S	1,940,095,675	$0.33228	$0.11939	$0.02709	$0.00770	-$0.00477	-$0.00942	$0.00017	$0.12614	$0.02143	-$0.00024	$0.00590	$0.00641	-$0.00641	$0.00364	-$0.00035	$0.00001	$0.00233	-$0.00012	$0.00000		$0.00819	$0.30709	-7.6%
Total B-19 S	2,666,933,009	$0.35838	$0.12196	$0.03202	$0.00770	-$0.00477	-$0.00942	$0.00020	$0.14348	$0.02166	-$0.00024	$0.00591	$0.00643	-$0.00643	$0.00365	-$0.00035	$0.00001	$0.00233	-$0.00009	-$0.00023		$0.00819	$0.33202	-7.4%
B-19 T	10,474,947	$0.24230	$0.10493	$0.03442	$0.00770	-$0.00477	-$0.00942	$0.00022	$0.05226	$0.01962	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00270	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00819	$0.22354	-7.7%
B-19 P	424,301,632	$0.28825	$0.10635	$0.03089	$0.00770	-$0.00477	-$0.00942	$0.00019	$0.09899	$0.02092	-$0.00024	$0.00594	$0.00646	-$0.00646	$0.00322	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00687		$0.00819	$0.26308	-8.7%
B-19 S	2,666,933,009	$0.35838	$0.12196	$0.03202	$0.00770	-$0.00477	-$0.00942	$0.00020	$0.14348	$0.02166	-$0.00024	$0.00591	$0.00643	-$0.00643	$0.00365	-$0.00035	$0.00001	$0.00233	-$0.00009	-$0.00023		$0.00819	$0.33202	-7.4%
TOTAL B-19	3,101,709,588	$0.34840	$0.11977	$0.03188	$0.00770	-$0.00477	-$0.00942	$0.00020	$0.13708	$0.02156	-$0.00024	$0.00592	$0.00643	-$0.00643	$0.00358	-$0.00035	$0.00001	$0.00233	-$0.00008	-$0.00114		$0.00819	$0.32222	-7.5%
STREETLIGHTS	86,406,990	$0.46462	$0.10064	$0.03022	$0.00770	-$0.00477	-$0.00889	$0.00019	$0.28688	$0.01247	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00482	-$0.00029	$0.00001	$0.00257	$0.00000	$0.00000		$0.00689	$0.44415	-4.4%
STANDBY																								
STANDBY T	600,775,235	$0.16971	$0.08393	$0.03202	$0.00770	-$0.00477	-$0.00968	$0.00020	$0.02628	$0.01909	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00247	-$0.00025	$0.00001	$0.00251	$0.00000	-$0.01502		$0.00581	$0.15600	-8.1%
STANDBY P	10,211,492	$0.91979	$0.12593	$0.06457	$0.00770	-$0.00477	-$0.00968	$0.00040	$0.67366	$0.02787	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00852	-$0.00025	$0.00001	$0.00251	$0.00000	-$0.04624		$0.00581	$0.86176	-6.3%
STANDBY S	-2,068,090	$0.07893	$0.06056	-$0.00176	$0.00770	-$0.00477	-$0.00968	-$0.00001	-$0.03564	$0.10249	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00448	-$0.00025	$0.00001	$0.00251	$0.00000	$0.00000		$0.00581	$0.13716	73.8%
TOTAL STANDBY	608,918,637	$0.18260	$0.08471	$0.03268	$0.00770	-$0.00477	-$0.00968	$0.00020	$0.03735	$0.01895	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00256	-$0.00025	$0.00001	$0.00251	$0.00000	-$0.01559		$0.00581	$0.16790	-8.0%
AGRICULTURE																								
AG-A1	167,254,643	$0.56007	$0.11453	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.36565	$0.02507	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	-$0.01231	-$0.00010		$0.00776	$0.53869	-3.8%
AG-A2	113,958,172	$0.43871	$0.11317	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.23620	$0.02507	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	-$0.00422	-$0.00004		$0.00776	$0.41603	-5.2%
AG B	551,710,063	$0.60246	$0.13026	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.37065	$0.02745	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	-$0.00076	-$0.00002		$0.00776	$0.57343	-4.8%
AG C	2,728,379,538	$0.37391	$0.10995	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.17346	$0.02261	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	-$0.00011	-$0.00010		$0.00776	$0.35166	-6.0%
TOTAL AG	3,561,302,416	$0.42013	$0.11342	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.21504	$0.02356	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	-$0.00091	-$0.00009		$0.00776	$0.39686	-5.5%
B-20 CLASS																								
B-20 FIRM T	1,755,558,428	$0.19917	$0.10556	$0.02994	$0.00770	-$0.00477	-$0.00788	$0.00019	$0.01416	$0.01809	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00213	-$0.00031	$0.00001	$0.00200	$0.00000	-$0.00377		$0.00722	$0.17597	-11.6%
FPP T																								
TOTAL	1,755,558,428	$0.19917	$0.10556	$0.02994	$0.00770	-$0.00477	-$0.00788	$0.00019	$0.01416	$0.01809	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00213	-$0.00031	$0.00001	$0.00200	$0.00000	-$0.00377		$0.00722	$0.17597	-11.6%
B-20 FIRM P	1,580,768,432	$0.27655	$0.10832	$0.02940	$0.00770	-$0.00477	-$0.00788	$0.00018	$0.08556	$0.01899	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00305	-$0.00031	$0.00001	$0.00200	$0.00000	-$0.00159		$0.00741	$0.25378	-8.2%
FPP P																								
TOTAL	1,580,768,432	$0.27655	$0.10832	$0.02940	$0.00770	-$0.00477	-$0.00788	$0.00018	$0.08556	$0.01899	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00305	-$0.00031	$0.00001	$0.00200	$0.00000	-$0.00159		$0.00741	$0.25378	-8.2%
B-20 FIRM S	278,629,256	$0.31254	$0.11161	$0.03382	$0.00770	-$0.00477	-$0.00788	$0.00021	$0.11078	$0.01909	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00328	-$0.00032	$0.00001	$0.00200	$0.00000	-$0.00068		$0.00764	$0.28819	-7.8%
FPP S																								
TOTAL	278,629,256	$0.31254	$0.11161	$0.03382	$0.00770	-$0.00477	-$0.00788	$0.00021	$0.11078	$0.01909	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00328	-$0.00032	$0.00001	$0.00200	$0.00000	-$0.00068		$0.00764	$0.28819	-7.8%
B-20 T	1,755,558,428	$0.19917	$0.10556	$0.02994	$0.00770	-$0.00477	-$0.00788	$0.00019	$0.01416	$0.01809	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00213	-$0.00031	$0.00001	$0.00200	$0.00000	-$0.00377		$0.00722	$0.17597	-11.6%
B-20 P	1,580,768,432	$0.27655	$0.10832	$0.02940	$0.00770	-$0.00477	-$0.00788	$0.00018	$0.08556	$0.01899	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00305	-$0.00031	$0.00001	$0.00200	$0.00000	-$0.00159		$0.00741	$0.25378	-8.2%
B-20 S	278,629,256	$0.31254	$0.11161	$0.03382	$0.00770	-$0.00477	-$0.00788	$0.00021	$0.11078	$0.01909	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00328	-$0.00032	$0.00001	$0.00200	$0.00000	-$0.00068		$0.00764	$0.28819	-7.8%
TOTAL B-20	3,614,956,116	$0.24175	$0.10723	$0.03000	$0.00770	-$0.00477	-$0.00788	$0.00019	$0.05283	$0.01856	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00262	-$0.00031	$0.00001	$0.00200	$0.00000	-$0.00258		$0.00734	$0.21865	-9.6%
SYSTEM	**25,055,466,305**	**$0.35364**	**$0.11809**	**$0.04067**	**$0.00770**	**-$0.00477**	**-$0.01156**	**$0.00025**	**$0.15111**	**$0.02119**	**-$0.00024**	**$0.00487**	**$0.00541**	**-$0.00541**	**$0.00339**	**-$0.00034**	**$0.00001**	**$0.00290**	**-$0.00067**	**-$0.00759**	**-$0.00055**	**$0.00808**	**$0.33253**	**-6.0%**

13-AtchA-2

Pacific Gas & Electric Company
2026 May ERRA Application
Thursday, January 1, 2026

Attachment A1: 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	Total Proposed Revenue
RESIDENTIAL																					
Non-CARE	$3,755,738,025	$709,701,024	$106,684,989	-$66,089,272	-$208,659,212	$4,434,241	$2,818,589,567	$351,572,740	-$3,349,124	$79,379,984	$89,602,296	-$89,602,267	$65,673,617	-$4,957,016	$126,343	$52,081,555	$0	-$273,596,350	$108,301,960	$184,020,748	$3,923,915,822
CARE	$290,292,731	$158,370,868	$23,806,918	-$14,747,922	-$46,562,622	$989,510	$303,194,168	$41,789,409	-$747,360	$0	$0	$0	$0	-$1,106,168	$28,194	$11,622,102	$0	-$60,359,362	-$94,406,958	$40,688,279	$362,559,054
TOTAL RES	$4,046,030,756	$868,071,892	$130,491,907	-$80,837,195	-$255,221,834	$5,423,750	$3,121,783,734	$393,362,148	-$4,096,485	$79,379,984	$89,602,296	-$89,602,267	$65,673,617	-$6,063,184	$154,537	$63,703,657	$0	-$333,955,711	$13,895,002	$224,709,026	$4,286,474,877
SMALL L&P																					
B-1	$1,215,846,401	$145,481,469	$31,390,563	-$19,445,842	-$42,805,313	$908,973	$938,630,236	$100,605,458	-$985,430	$24,192,873	$26,307,227	-$26,307,224	$20,169,643	-$1,418,128	$37,175	$10,529,561	-$14,149,315	-$147,747		$51,560,282	$1,244,554,460
B-6	$339,701,737	$41,588,798	$8,968,866	-$5,556,038	-$12,230,272	$259,848	$261,640,764	$25,417,269	-$281,556	$6,899,817	$7,502,832	-$7,502,831	$5,754,931	-$405,185	$10,621	$3,008,491	-$2,018,827	-$190,602		$14,714,896	$347,581,822
A-15	$342,726	$28,487	$6,147	-$3,808	-$8,382	$178	$347,748	$19,724	-$193	$4,742	$5,156	-$5,156	$3,959	-$278	$7	$2,062	-$33,023	$0		$10,436	$377,807
TC-1	$8,382,211	$983,644	$212,242	-$131,480	-$289,420	$6,146	$6,700,747	$327,058	-$6,663	$163,999	$178,332	-$178,332	$136,717	-$9,588	$251	$71,194	$0	$0		$365,062	$8,529,907
TOTAL SMALL	$1,564,273,075	$188,082,399	$40,577,818	-$25,137,168	-$55,333,388	$1,175,144	$1,207,319,495	$126,369,508	-$1,273,841	$31,261,431	$33,993,547	-$33,993,543	$26,065,250	-$1,833,180	$48,055	$13,611,308	-$16,201,165	-$338,349		$66,650,675	$1,601,043,997
MEDIUM L&P																					
B-10 T	$242,428	$103,816	$21,234	-$13,154	-$25,977	$649	$103,595	$53,384	-$667	$16,408	$17,841	-$17,841	$7,473	-$1,010	$25	$6,413	$0	$0		$75,262	$347,451
B-10 P	$9,534,677	$1,894,522	$334,542	-$207,242	-$409,271	$11,837	$6,144,096	$994,265	-$10,502	$256,545	$278,965	-$278,965	$167,299	-$15,911	$396	$101,037	$0	$0		$569,220	$9,830,834
B-10 S	$1,159,150,458	$196,877,553	$38,605,467	-$23,915,335	-$47,229,026	$1,230,097	$785,356,112	$114,155,523	-$1,211,924	$29,739,584	$32,338,696	-$32,338,693	$21,195,263	-$1,836,143	$45,719	$11,659,481	-$448,648	-$508,390		$64,701,721	$1,188,417,056
TOTAL MEDIUM	$1,168,927,563	$198,875,891	$38,961,243	-$24,135,731	-$47,664,274	$1,242,583	$791,603,804	$115,203,172	-$1,223,093	$30,012,536	$32,635,503	-$32,635,500	$21,370,035	-$1,853,065	$46,140	$11,766,931	-$448,648	-$508,390		$65,346,203	$1,198,595,341
B-19 CLASS																					
B-19 FIRM T	$2,157,727	$689,821	$203,067	-$125,796	-$248,428	$4,310	$796,624	$464,427	-$6,375	$156,910	$170,623	-$170,623	$71,205	-$9,161	$240	$61,330	$0	$0		$413,509	$2,471,684
B-19 V T	$1,178,290	$493,361	$59,180	-$36,661	-$72,400	$3,083	$436,587	$169,792	-$1,858	$45,729	$49,725	-$49,725	$20,752	-$2,670	$70	$17,873	$0	$0		$105,070	$1,237,908
Total B-19 T	$3,336,017	$1,183,182	$262,248	-$162,457	-$320,828	$7,393	$1,233,211	$634,219	-$8,233	$202,638	$220,348	-$220,348	$91,957	-$11,831	$311	$79,203	$0	$0		$518,579	$3,709,592
B-19 FIRM P	$81,983,012	$15,132,049	$3,717,583	-$2,302,970	-$4,548,004	$94,545	$51,820,227	$10,056,152	-$116,704	$2,872,570	$3,123,620	-$3,123,619	$1,554,625	-$167,717	$4,403	$1,122,771	$0	-$817,499		$4,575,927	$82,997,958
B-19 V P	$49,476,981	$8,980,171	$3,080,494	-$1,908,306	-$3,768,605	$56,108	$27,984,457	$8,455,539	-$96,705	$2,380,293	$2,588,320	-$2,588,320	$1,288,207	-$138,975	$3,648	$930,360	$0	$0		$5,063,973	$52,310,659
Total B-19 P	$131,459,993	$24,112,220	$6,798,077	-$4,211,276	-$8,316,608	$150,654	$79,804,684	$18,511,691	-$213,409	$5,252,862	$5,711,940	-$5,711,939	$2,842,832	-$306,692	$8,051	$2,053,130	$0	-$817,499		$9,639,900	$135,308,617
B-19 FIRM S	$649,869,101	$105,159,584	$22,889,756	-$14,179,758	-$28,002,792	$657,040	$449,137,859	$66,168,901	-$718,568	$17,633,853	$19,174,977	-$19,174,975	$10,879,885	-$1,032,662	$27,107	$6,913,080	$0	-$1,013,458		$37,027,732	$671,547,562
B-19 V S	$1,356,675,108	$193,521,021	$59,095,961	-$36,608,797	-$72,296,617	$1,209,125	$908,800,454	$164,735,075	-$1,855,173	$45,394,376	$49,361,650	-$49,361,644	$28,002,049	-$2,666,090	$69,985	$17,847,945	-$387,255	$0		$82,623,780	$1,387,485,845
Total B-19 S	$2,006,544,209	$298,680,605	$81,985,717	-$50,788,554	-$100,299,409	$1,866,165	$1,357,938,313	$230,903,976	-$2,573,741	$63,028,229	$68,536,627	-$68,536,619	$38,881,935	-$3,698,752	$97,092	$24,761,025	-$387,255	-$1,013,458		$119,651,512	$2,059,033,408
B-19 T	$3,336,017	$1,183,182	$262,248	-$162,457	-$320,828	$7,393	$1,233,211	$634,219	-$8,233	$202,638	$220,348	-$220,348	$91,957	-$11,831	$311	$79,203	$0	$0		$518,579	$3,709,592
B-19 P	$131,459,993	$24,112,220	$6,798,077	-$4,211,276	-$8,316,608	$150,654	$79,804,684	$18,511,691	-$213,409	$5,252,862	$5,711,940	-$5,711,939	$2,842,832	-$306,692	$8,051	$2,053,130	$0	-$817,499		$9,639,900	$135,308,617
B-19 S	$2,006,544,209	$298,680,605	$81,985,717	-$50,788,554	-$100,299,409	$1,866,165	$1,357,938,313	$230,903,976	-$2,573,741	$63,028,229	$68,536,627	-$68,536,619	$38,881,935	-$3,698,752	$97,092	$24,761,025	-$387,255	-$1,013,458		$119,651,512	$2,059,033,408
TOTAL B-19	$2,141,340,220	$323,976,007	$89,046,041	-$55,162,288	-$108,936,845	$2,024,212	$1,438,976,208	$250,049,886	-$2,795,383	$68,483,730	$74,468,915	-$74,468,906	$41,816,724	-$4,017,276	$105,454	$26,893,358	-$387,255	-$1,830,957		$129,809,991	$2,198,051,616
STREETLIGHTS	$46,699,865	$4,660,180	$1,187,235	-$735,469	-$1,370,716	$29,117	$37,961,495	$1,886,338	-$37,270	$917,374	$997,549	-$997,549	$743,178	-$45,005	$1,406	$397,009	$0	$0		$1,686,262	$47,281,133
STANDBY																					
STANDBY T	$12,914,153	$4,069,797	$926,173	-$573,746	-$1,164,332	$25,428	$5,200,783	$2,295,734	-$29,075	$715,652	$778,197	-$778,197	$297,097	-$29,552	$1,097	$302,409	$0	$0		$1,002,624	$13,040,090
STANDBY P	$3,924,432	$330,936	$39,605	-$24,534	-$49,789	$2,068	$3,443,315	$143,365	-$1,243	$30,602	$33,277	-$33,277	$43,822	-$1,264	$47	$12,932	$0	-$94,544		$26,156	$3,901,473
STANDBY S	$741,437	$72,962	$19,923	-$12,342	-$25,046	$456	$589,984	$265,183	-$625	$15,394	$16,740	-$16,740	$11,591	-$636	$24	$6,505	$0	$0		$30,671	$974,044
TOTAL STANDBY	$17,580,022	$4,473,696	$985,700	-$610,622	-$1,239,166	$27,952	$9,234,082	$2,704,282	-$30,944	$761,649	$828,214	-$828,214	$352,511	-$31,452	$1,167	$321,846	$0	-$94,544		$1,059,452	$17,915,608
AGRICULTURE																					
AG-A1	$29,502,353	$2,337,703	$559,659	-$346,698	-$687,581	$14,606	$25,360,745	$1,822,259	-$17,569	$432,448	$470,242	-$470,242	$318,351	-$23,909	$663	$180,626	-$468,640	-$5,457		$779,222	$30,256,426
AG-A2	$12,852,523	$1,508,554	$361,156	-$223,729	-$443,706	$9,425	$9,938,163	$1,175,930	-$11,338	$279,065	$303,454	-$303,454	$205,437	-$15,429	$428	$116,560	-$88,985	-$6,771		$505,368	$13,310,128
AG B	$83,417,018	$7,247,104	$1,734,997	-$1,074,797	-$2,131,567	$45,280	$68,837,084	$6,185,420	-$54,466	$1,340,629	$1,457,794	-$1,457,794	$986,920	-$74,120	$2,055	$559,957	-$79,051	-$8,138		$2,353,539	$85,870,846
AG C	$311,523,607	$47,182,513	$11,295,755	-$6,997,500	-$13,877,642	$294,798	$220,567,119	$33,171,125	-$354,603	$8,728,210	$9,491,018	-$9,491,017	$6,425,377	-$482,562	$13,377	$3,645,620	-$30,670	-$650,585		$15,780,562	$324,710,897
TOTAL AG	$437,295,501	$58,275,874	$13,951,567	-$8,642,724	-$17,140,496	$364,109	$324,703,111	$42,354,734	-$437,975	$10,780,351	$11,722,508	-$11,722,506	$7,936,086	-$596,021	$16,522	$4,502,763	-$667,346	-$670,952		$19,418,692	$454,148,297
B-20 CLASS																					
B-20 FIRM T	$253,807,300	$108,297,384	$29,675,472	-$18,383,377	-$30,369,184	$676,645	$51,534,148	$69,722,032	-$931,589	$19,852,411	$21,587,426	-$21,587,424	$8,208,929	-$1,179,899	$35,143	$7,700,242	$0	-$14,920,070		$32,330,778	$262,249,067
FPP T	$9,319,367	$0	$0	$0	$0	$0	$3,223,690	$5,247,384	-$70,113	$0	$1,876,584	-$1,876,584	$617,816	$0	$0	$0	$0	$0		$0	$9,018,778
TOTAL	$263,126,667	$108,297,384	$29,675,472	-$18,383,377	-$30,369,184	$676,645	$54,757,839	$74,969,416	-$1,001,702	$19,852,411	$23,464,010	-$23,464,008	$8,826,745	-$1,179,899	$35,143	$7,700,242	$0	-$14,920,070		$32,330,778	$271,267,845
B-20 FIRM P	$798,847,208	$161,292,182	$45,287,948	-$28,055,001	-$46,346,627	$1,007,758	$467,897,527	$111,712,084	-$1,421,704	$34,993,918	$38,052,237	-$38,052,232	$17,938,732	-$1,847,835	$53,633	$11,751,393	$0	-$5,506,379		$54,119,900	$822,877,534
FPP P	$2,464,348	$0	$0	$0	$0	$0	$2,021,602	$360,709	-$4,591	$0	$122,868	-$122,868	$57,923	$0	$0	$0	$0	$0		$0	$2,435,643
TOTAL	$801,311,556	$161,292,182	$45,287,948	-$28,055,001	-$46,346,627	$1,007,758	$469,919,129	$112,072,793	-$1,426,295	$34,993,918	$38,175,104	-$38,175,100	$17,996,655	-$1,847,835	$53,633	$11,751,393	$0	-$5,506,379		$54,119,900	$825,313,177
B-20 FIRM S	$318,885,020	$58,829,878	$15,534,150	-$9,623,103	-$15,897,286	$367,571	$199,549,663	$38,507,943	-$487,657	$12,003,211	$13,052,240	-$13,052,239	$6,617,144	-$653,065	$18,396	$4,030,828	$0	-$401,308		$21,099,809	$329,496,177
FPP S	$6,305,280	$0	$0	$0	$0	$0	$5,087,230	$972,602	-$12,317	$0	$329,663	-$329,663	$167,130	$0	$0	$0	$0	$0		$0	$6,214,645
TOTAL	$325,190,300	$58,829,878	$15,534,150	-$9,623,103	-$15,897,286	$367,571	$204,636,893	$39,480,545	-$499,973	$12,003,211	$13,381,903	-$13,381,901	$6,784,275	-$653,065	$18,396	$4,030,828	$0	-$401,308		$21,099,809	$335,710,822
B-20 T	$263,126,667	$108,297,384	$29,675,472	-$18,383,377	-$30,369,184	$676,645	$54,757,839	$74,969,416	-$1,001,702	$19,852,411	$23,464,010	-$23,464,008	$8,826,745	-$1,179,899	$35,143	$7,700,242	$0	-$14,920,070		$32,330,778	$271,267,845
B-20 P	$801,311,556	$161,292,182	$45,287,948	-$28,055,001	-$46,346,627	$1,007,758	$469,919,129	$112,072,793	-$1,426,295	$34,993,918	$38,175,104	-$38,175,100	$17,996,655	-$1,847,835	$53,633	$11,751,393	$0	-$5,506,379		$54,119,900	$825,313,177
B-20 S	$325,190,300	$58,829,878	$15,534,150	-$9,623,103	-$15,897,286	$367,571	$204,636,893	$39,480,545	-$499,973	$12,003,211	$13,381,903	-$13,381,901	$6,784,275	-$653,065	$18,396	$4,030,828	$0	-$401,308		$21,099,809	$335,710,822
TOTAL B-20	$1,389,628,523	$328,419,444	$90,497,569	-$56,061,481	-$92,613,097	$2,051,975	$729,313,861	$226,522,754	-$2,927,970	$66,849,539	$75,021,017	-$75,021,009	$33,607,675	-$3,680,798	$107,173	$23,482,462	$0	-$20,827,757		$107,550,487	$1,432,291,845
SYSTEM	**$10,811,775,525**	**$1,974,835,382**	**$405,699,080**	**-$251,322,677**	**-$579,519,817**	**$12,338,842**	**$7,660,895,790**	**$1,158,452,822**	**-$12,822,961**	**$288,446,595**	**$319,269,548**	**-$319,269,493**	**$197,565,076**	**-$18,119,980**	**$480,454**	**$144,679,336**	**-$17,704,414**	**-$358,226,660**	**$13,895,002**	**$616,230,788**	**$11,235,802,714**

13-AtchA-3

Pacific Gas & Electric Company
2026 May ERRA Application
Thursday, January 1, 2026
Revenue and Average Rate Summary with GHG Revenue Return

DA/CCA RESULTS

Class/Schedule	Total Sales (kWh)	Revenue At Present Rates	TO Rates	TAC Rates	TRBAA Rates	T-ECRA Rates	RS Rates	Dist Rates	PPP Rates	ND Rates	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	$13,855,265,928	$0.27107	$0.05122	$0.00770	-$0.00477	-$0.01506	$0.00032	$0.20343	$0.02537	-$0.00024	$0.00573	$0.00647	-$0.00647	$0.00474	-$0.00036	$0.00001	$0.00376	$0.00000	-$0.01975	$0.00782	$0.01328	$0.28321	4.5%
CARE	$3,091,829,928	$0.09389	$0.05122	$0.00770	-$0.00477	-$0.01506	$0.00032	$0.09806	$0.01352	-$0.00024	$0.00000	$0.00000	$0.00000	$0.00000	-$0.00036	$0.00001	$0.00376	$0.00000	-$0.01952	-$0.03053	$0.01316	$0.11726	24.9%
TOTAL RES	$16,947,095,856	$0.23874	$0.05122	$0.00770	-$0.00477	-$0.01506	$0.00032	$0.18421	$0.02321	-$0.00024	$0.00468	$0.00529	-$0.00529	$0.00388	-$0.00036	$0.00001	$0.00376	$0.00000	-$0.01971	$0.00082	$0.01326	$0.25293	5.9%
SMALL L&P																							
B-1	4,076,696,475	$0.29824	$0.03569	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.23024	$0.02468	-$0.00024	$0.00593	$0.00645	-$0.00645	$0.00495	-$0.00035	$0.00001	$0.00258	-$0.00347	-$0.00004		$0.01265	$0.30529	2.4%
B-6	1,164,787,855	$0.29164	$0.03571	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.22463	$0.02182	-$0.00024	$0.00592	$0.00644	-$0.00644	$0.00494	-$0.00035	$0.00001	$0.00258	-$0.00173	-$0.00016		$0.01263	$0.29841	2.3%
A-15	798,281	$0.42933	$0.03569	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.43562	$0.02471	-$0.00024	$0.00594	$0.00646	-$0.00646	$0.00496	-$0.00035	$0.00001	$0.00258	-$0.04137	$0.00000		$0.01307	$0.47328	10.2%
TC-1	27,563,854	$0.30410	$0.03569	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.24310	$0.01187	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00496	-$0.00035	$0.00001	$0.00258	$0.00000	$0.00000		$0.01324	$0.30946	1.8%
TOTAL SMALL	5,269,846,466	$0.29683	$0.03569	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.22910	$0.02398	-$0.00024	$0.00593	$0.00645	-$0.00645	$0.00495	-$0.00035	$0.00001	$0.00258	-$0.00307	-$0.00006		$0.01265	$0.30381	2.4%
MEDIUM L&P																							
B-10 T	2,757,672	$0.08791	$0.03765	$0.00770	-$0.00477	-$0.00942	$0.00024	$0.03757	$0.01936	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00271	-$0.00037	$0.00001	$0.00233	$0.00000	$0.00000		$0.02729	$0.12599	43.3%
B-10 P	43,446,997	$0.21946	$0.04361	$0.00770	-$0.00477	-$0.00942	$0.00027	$0.14142	$0.02288	-$0.00024	$0.00590	$0.00642	-$0.00642	$0.00385	-$0.00037	$0.00001	$0.00233	$0.00000	$0.00000		$0.01310	$0.22627	3.1%
B-10 S	5,013,697,012	$0.23120	$0.03927	$0.00770	-$0.00477	-$0.00942	$0.00025	$0.15664	$0.02277	-$0.00024	$0.00593	$0.00645	-$0.00645	$0.00423	-$0.00037	$0.00001	$0.00233	-$0.00009	-$0.00010		$0.01290	$0.23703	2.5%
TOTAL MEDIUM	5,059,901,682	$0.23102	$0.03930	$0.00770	-$0.00477	-$0.00942	$0.00025	$0.15645	$0.02277	-$0.00024	$0.00593	$0.00645	-$0.00645	$0.00422	-$0.00037	$0.00001	$0.00233	-$0.00009	-$0.00010		$0.01291	$0.23688	2.5%
B-19 CLASS																							
B-19 FIRM T	26,372,400	$0.08182	$0.02616	$0.00770	-$0.00477	-$0.00942	$0.00016	$0.03021	$0.01761	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00270	-$0.00035	$0.00001	$0.00233	$0.00000			$0.01568	$0.09372	14.6%
B-19 V T	7,685,769	$0.15331	$0.06419	$0.00770	-$0.00477	-$0.00942	$0.00040	$0.05680	$0.02209	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00270	-$0.00035	$0.00001	$0.00233	$0.00000			$0.01367	$0.16106	5.1%
Total B-19 T	34,058,169	$0.09795	$0.03474	$0.00770	-$0.00477	-$0.00942	$0.00022	$0.03621	$0.01862	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00270	-$0.00035	$0.00001	$0.00233	$0.00000			$0.01523	$0.10892	11.2%
B-19 FIRM P	482,802,923	$0.16981	$0.03134	$0.00770	-$0.00477	-$0.00942	$0.00020	$0.10733	$0.02083	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00322	-$0.00035	$0.00001	$0.00233	$0.00000	-$0.00169		$0.00948	$0.17191	1.2%
B-19 V P	400,064,209	$0.12367	$0.02245	$0.00770	-$0.00477	-$0.00942	$0.00014	$0.06995	$0.02114	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00322	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.01266	$0.13076	5.7%
Total B-19 P	882,867,132	$0.14890	$0.02731	$0.00770	-$0.00477	-$0.00942	$0.00017	$0.09039	$0.02097	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00322	-$0.00035	$0.00001	$0.00233	$0.00000	-$0.00093		$0.01092	$0.15326	2.9%
B-19 FIRM S	2,972,695,521	$0.21861	$0.03538	$0.00770	-$0.00477	-$0.00942	$0.00022	$0.15109	$0.02226	-$0.00024	$0.00593	$0.00645	-$0.00645	$0.00366	-$0.00035	$0.00001	$0.00233	$0.00000	-$0.00034		$0.01246	$0.22591	3.3%
B-19 V S	7,674,800,129	$0.17677	$0.02522	$0.00770	-$0.00477	-$0.00942	$0.00016	$0.11841	$0.02146	-$0.00024	$0.00591	$0.00643	-$0.00643	$0.00365	-$0.00035	$0.00001	$0.00233	-$0.00005	$0.00000		$0.01077	$0.18078	2.3%
Total B-19 S	10,647,495,650	$0.18845	$0.02805	$0.00770	-$0.00477	-$0.00942	$0.00018	$0.12754	$0.02169	-$0.00024	$0.00592	$0.00644	-$0.00644	$0.00365	-$0.00035	$0.00001	$0.00233	-$0.00004	-$0.00010		$0.01124	$0.19338	2.6%
B-19 T	34,058,169	$0.09795	$0.03474	$0.00770	-$0.00477	-$0.00942	$0.00022	$0.03621	$0.01862	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00270	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.01523	$0.10892	11.2%
B-19 P	882,867,132	$0.14890	$0.02731	$0.00770	-$0.00477	-$0.00942	$0.00017	$0.09039	$0.02097	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00322	-$0.00035	$0.00001	$0.00233	$0.00000	-$0.00093		$0.01092	$0.15326	2.9%
B-19 S	10,647,495,650	$0.18845	$0.02805	$0.00770	-$0.00477	-$0.00942	$0.00018	$0.12754	$0.02169	-$0.00024	$0.00592	$0.00644	-$0.00644	$0.00365	-$0.00035	$0.00001	$0.00233	-$0.00004	-$0.00010		$0.01124	$0.19338	2.6%
TOTAL B-19	11,564,420,950	$0.18517	$0.02801	$0.00770	-$0.00477	-$0.00942	$0.00018	$0.12443	$0.02162	-$0.00024	$0.00592	$0.00644	-$0.00644	$0.00362	-$0.00035	$0.00001	$0.00233	-$0.00003	-$0.00016		$0.01122	$0.19007	2.6%
STREETLIGHTS	154,186,308	$0.30288	$0.03022	$0.00770	-$0.00477	-$0.00889	$0.00019	$0.24621	$0.01223	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00482	-$0.00029	$0.00001	$0.00257	$0.00000	$0.00000		$0.01094	$0.30665	1.2%
STANDBY																							
STANDBY T	120,282,187	$0.10737	$0.03384	$0.00770	-$0.00477	-$0.00968	$0.00021	$0.04324	$0.01909	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00247	-$0.00025	$0.00001	$0.00251	$0.00000	$0.00000		$0.00834	$0.10841	1.0%
STANDBY P	5,143,455	$0.76300	$0.06434	$0.00770	-$0.00477	-$0.00968	$0.00040	$0.66946	$0.02787	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00852	-$0.00025	$0.00001	$0.00251	$0.00000	-$0.01838		$0.00509	$0.75853	-0.6%
STANDBY S	2,587,363	$0.28656	$0.02820	$0.00770	-$0.00477	-$0.00968	$0.00018	$0.22803	$0.10249	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00448	-$0.00025	$0.00001	$0.00251	$0.00000	$0.00000		$0.01185	$0.37646	31.4%
TOTAL STANDBY	128,013,005	$0.13733	$0.03495	$0.00770	-$0.00477	-$0.00968	$0.00022	$0.07213	$0.02113	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00275	-$0.00025	$0.00001	$0.00251	$0.00000	-$0.00074		$0.00828	$0.13995	1.9%
AGRICULTURE																							
AG-A1	72,682,990	$0.40590	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.34892	$0.02507	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	-$0.00645	-$0.00008		$0.01072	$0.41628	2.6%
AG-A2	46,903,389	$0.27402	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.21189	$0.02507	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	-$0.00190	-$0.00014		$0.01077	$0.28378	3.6%
AG B	225,324,257	$0.37021	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.30550	$0.02745	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	-$0.00035	-$0.00004		$0.01045	$0.38110	2.9%
AG C	1,466,981,143	$0.21236	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.15035	$0.02261	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	-$0.00002	-$0.00044		$0.01076	$0.22135	4.2%
TOTAL AG	$1,811,891,779	$0.24135	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.17921	$0.02338	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	-$0.00037	-$0.00037		$0.01072	$0.25065	3.9%
B-20 CLASS																							
B-20 FIRM T	3,853,957,342	$0.06586	$0.02810	$0.00770	-$0.00477	-$0.00788	$0.00018	$0.01337	$0.01809	-$0.00024	$0.00515	$0.00560	-$0.00560	$0.00213	-$0.00031	$0.00001	$0.00200	-$0.00387	-$0.00387		$0.00839	$0.06805	3.3%
FPP T	290,054,572	$0.03213	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.01111	$0.01809	-$0.00024	$0.00000	$0.00647	-$0.00647	$0.00213	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		$0.00000	$0.03109	-3.2%
TOTAL	4,144,011,914	$0.06350	$0.02613	$0.00716	-$0.00444	-$0.00733	$0.00016	$0.01321	$0.01809	-$0.00024	$0.00479	$0.00566	-$0.00566	$0.00213	-$0.00028	$0.00001	$0.00186	$0.00000	-$0.00360		$0.00780	$0.06546	3.1%
B-20 FIRM P	5,881,551,631	$0.13582	$0.02742	$0.00770	-$0.00477	-$0.00788	$0.00017	$0.07955	$0.01899	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00305	-$0.00031	$0.00001	$0.00200	$0.00000	-$0.00094		$0.00920	$0.13991	3.0%
FPP P	18,991,044	$0.12976	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.10645	$0.01899	-$0.00024	$0.00000	$0.00647	-$0.00647	$0.00305	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		$0.00000	$0.12825	-1.2%
TOTAL	5,900,542,675	$0.13580	$0.02734	$0.00768	-$0.00475	-$0.00785	$0.00017	$0.07964	$0.01899	-$0.00024	$0.00593	$0.00647	-$0.00647	$0.00305	-$0.00031	$0.00001	$0.00199	$0.00000	-$0.00093		$0.00917	$0.13987	3.0%
B-20 FIRM S	2,017,422,102	$0.15807	$0.02916	$0.00770	-$0.00477	-$0.00788	$0.00018	$0.09891	$0.01909	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00328	-$0.00032	$0.00001	$0.00200	$0.00000	-$0.00020		$0.01046	$0.16333	3.3%
FPP S	50,954,384	$0.12374	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.09984	$0.01909	-$0.00024	$0.00000	$0.00647	-$0.00647	$0.00328	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		$0.00000	$0.12196	-1.4%
TOTAL	2,068,376,487	$0.15722	$0.02844	$0.00751	-$0.00465	-$0.00769	$0.00018	$0.09894	$0.01909	-$0.00024	$0.00580	$0.00647	-$0.00647	$0.00328	-$0.00032	$0.00001	$0.00195	$0.00000	-$0.00019		$0.01020	$0.16231	3.2%
B-20 T	4,144,011,914	$0.06350	$0.02613	$0.00716	-$0.00444	-$0.00733	$0.00016	$0.01321	$0.01809	-$0.00024	$0.00479	$0.00566	-$0.00566	$0.00213	-$0.00028	$0.00001	$0.00186	$0.00000	-$0.00360		$0.00780	$0.06546	3.1%
B-20 P	5,900,542,675	$0.13580	$0.02734	$0.00768	-$0.00475	-$0.00785	$0.00017	$0.07964	$0.01899	-$0.00024	$0.00593	$0.00647	-$0.00647	$0.00305	-$0.00031	$0.00001	$0.00199	$0.00000	-$0.00093		$0.00917	$0.13987	3.0%
B-20 S	2,068,376,487	$0.15722	$0.02844	$0.00751	-$0.00465	-$0.00769	$0.00018	$0.09894	$0.01909	-$0.00024	$0.00580	$0.00647	-$0.00647	$0.00328	-$0.00032	$0.00001	$0.00195	$0.00000	-$0.00019		$0.01020	$0.16231	3.2%
TOTAL B-20	12,112,931,076	$0.11472	$0.02711	$0.00747	-$0.00463	-$0.00765	$0.00017	$0.06021	$0.01870	-$0.00024	$0.00552	$0.00619	-$0.00619	$0.00277	-$0.00030	$0.00001	$0.00194	$0.00000	-$0.00172		$0.00888	$0.11824	3.1%
SYSTEM	**53,048,287,121**	**$0.20381**	**$0.03723**	**$0.00765**	**-$0.00474**	**-$0.01092**	**$0.00023**	**$0.14441**	**$0.02184**	**-$0.00024**	**$0.00544**	**$0.00602**	**-$0.00602**	**$0.00372**	**-$0.00034**	**$0.00001**	**$0.00273**	**-$0.00033**	**-$0.00675**	**$0.00026**	**$0.01162**	**$0.21180**	**3.9%**

13-AtchA-4

Pacific Gas & Electric Company
2026 May ERRA Application
Thursday, January 1, 2026

Attachment A2: 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	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	$2,670,771,065	$736,944,080	$306,050,347	$46,006,666	-$28,500,233	-$89,981,869	$1,912,204	$1,236,237,342	$151,611,864	-$1,444,274	$32,893,083	$38,656,333	-$38,656,348	$28,320,987	-$2,137,649	$54,484	$22,459,493	$0	$0	$29,143,950	$50,403,893	$2,519,974,354
CARE	$1,112,311,424	$503,907,162	$209,218,174	$31,450,481	-$19,482,960	-$61,512,240	$1,307,198	$321,996,214	$55,206,641	-$987,316	$0	$0	$0	$0	-$1,461,314	$37,246	$15,353,487	$0	$0	-$43,038,953	$34,456,499	$1,046,450,319
TOTAL RES	$3,783,082,490	$1,240,851,242	$515,268,521	$77,457,147	-$47,983,194	-$151,494,108	$3,219,402	$1,558,233,557	$206,818,504	-$2,431,590	$32,893,083	$38,656,333	-$38,656,348	$28,320,987	-$3,598,962	$91,730	$37,812,980	$0	$0	-$13,895,003	$84,860,392	$3,566,424,673
SMALL L&P																						
B-1	$678,390,619	$179,233,935	$53,397,844	$11,521,053	-$7,137,068	-$15,710,526	$333,631	$350,825,318	$36,929,608	-$361,675	$8,882,508	$9,658,801	-$9,658,800	$7,404,856	-$520,485	$13,644	$3,864,589	$0	$0		$12,274,315	$640,951,549
B-6	$261,757,086	$71,330,302	$21,122,125	$4,556,869	-$2,822,891	-$6,213,912	$131,972	$133,509,227	$12,922,479	-$143,052	$3,511,720	$3,818,630	-$3,818,629	$2,927,527	-$205,865	$5,397	$1,528,543	$0	$0		$4,854,803	$247,015,244
A-15	$243,288	$58,047	$17,288	$3,730	-$2,311	-$5,087	$108	$137,182	$11,970	-$117	$2,882	$3,134	-$3,134	$2,403	-$169	$4	$1,251	$0	$0		$3,974	$231,157
TC-1	$5,047,047	$1,242,015	$409,085	$88,269	-$54,681	-$120,366	$2,556	$2,884,732	$136,019	-$2,771	$68,205	$74,166	-$74,166	$56,859	-$3,988	$105	$29,609	$0	$0		$94,040	$4,829,688
TOTAL SMALL	$945,438,039	$251,864,299	$74,946,342	$16,169,920	-$10,016,951	-$22,049,891	$468,267	$487,356,460	$50,000,076	-$507,615	$12,465,316	$13,554,731	-$13,554,730	$10,391,645	-$730,507	$19,149	$5,423,992	$0	$0		$17,227,132	$893,027,637
MEDIUM L&P																						
B-10 T	$370,385	$169,080	$54,228	$13,437	-$8,324	-$16,438	$339	$66,114	$33,781	-$422	$10,383	$11,290	-$11,290	$4,729	-$639	$16	$4,058	$0	$0		$15,067	$345,409
B-10 P	$8,152,096	$2,574,401	$982,534	$175,092	-$108,466	-$214,204	$6,131	$3,306,724	$522,417	-$5,497	$135,293	$147,117	-$147,117	$88,228	-$8,328	$207	$52,881	$0	$0		$196,337	$7,703,752
B-10 S	$751,242,912	$240,041,893	$83,305,012	$14,616,945	-$9,054,912	-$17,882,028	$520,492	$307,745,514	$43,144,517	-$458,863	$11,222,247	$12,203,023	-$12,203,022	$7,997,330	-$695,207	$17,310	$4,414,556	$0	$0		$16,390,517	$701,325,322
TOTAL MEDIUM	$759,765,393	$242,785,374	$84,341,774	$14,805,473	-$9,171,702	-$18,112,670	$526,962	$311,118,352	$43,700,715	-$464,782	$11,367,923	$12,361,431	-$12,361,429	$8,090,287	-$704,174	$17,534	$4,471,495	$0	$0		$16,601,922	$709,374,482
B-19 CLASS																						
B-19 FIRM T	$1,408,526	$597,426	$178,836	$44,459	-$27,541	-$54,390	$1,117	$354,753	$101,679	-$1,396	$34,353	$37,355	-$37,355	$15,589	-$2,006	$53	$13,427	$0	$0		$47,300	$1,303,660
B-19 V T	$1,129,545	$501,663	$181,735	$36,199	-$22,424	-$44,284	$1,135	$192,684	$103,855	-$1,136	$27,971	$30,415	-$30,415	$12,693	-$1,633	$43	$10,933	$0	$0		$38,512	$1,037,943
Total B-19 T	$2,538,071	$1,099,089	$360,570	$80,657	-$49,965	-$98,674	$2,253	$547,436	$205,535	-$2,532	$62,324	$67,770	-$67,770	$28,282	-$3,639	$96	$24,360	$0	$0		$85,813	$2,341,604
B-19 FIRM P	$84,153,479	$30,598,963	$8,974,779	$2,208,106	-$1,367,878	-$2,701,345	$56,075	$29,339,854	$5,972,980	-$69,318	$1,706,199	$1,855,314	-$1,855,314	$923,390	-$99,618	$2,615	$666,884	$0	$0		$2,349,247	$78,560,933
B-19 V P	$38,586,920	$14,525,503	$4,131,690	$1,059,017	-$656,040	-$1,295,576	$25,815	$12,660,304	$2,901,556	-$33,245	$815,641	$886,924	-$886,924	$441,422	-$47,777	$1,254	$319,840	$0	$0		$1,126,709	$35,976,112
Total B-19 P	$122,740,399	$45,124,466	$13,106,469	$3,267,123	-$2,023,919	-$3,996,921	$81,890	$42,000,158	$8,874,536	-$102,563	$2,521,840	$2,742,238	-$2,742,238	$1,364,812	-$147,395	$3,869	$986,724	$0	$0		$3,475,956	$114,537,045
B-19 FIRM S	$311,746,511	$93,643,420	$32,842,790	$5,596,647	-$3,467,014	-$6,846,808	$205,203	$137,912,913	$16,202,220	-$175,693	$4,324,520	$4,702,464	-$4,702,464	$2,667,493	-$252,490	$6,628	$1,690,279	$0	$0		$5,954,383	$290,304,492
B-19 V S	$644,958,942	$231,626,594	$52,561,535	$14,938,737	-$9,254,256	-$18,275,701	$328,406	$244,728,151	$41,576,699	-$468,965	$11,442,463	$12,442,485	-$12,442,483	$7,058,053	-$673,955	$17,691	$4,511,742	$0	$0		$15,893,616	$596,010,811
Total B-19 S	$956,705,453	$325,270,013	$85,404,325	$20,535,384	-$12,721,270	-$25,122,509	$533,609	$382,641,065	$57,778,919	-$644,658	$15,766,982	$17,144,949	-$17,144,947	$9,725,546	-$926,445	$24,319	$6,202,021	$0	$0		$21,848,000	$886,315,303
B-19 T	$2,538,071	$1,099,089	$360,570	$80,657	-$49,965	-$98,674	$2,253	$547,436	$205,535	-$2,532	$62,324	$67,770	-$67,770	$28,282	-$3,639	$96	$24,360	$0	$0		$85,813	$2,341,604
B-19 P	$122,740,399	$45,124,466	$13,106,469	$3,267,123	-$2,023,919	-$3,996,921	$81,890	$42,000,158	$8,874,536	-$102,563	$2,521,840	$2,742,238	-$2,742,238	$1,364,812	-$147,395	$3,869	$986,724	$0	$0		$3,475,956	$114,537,045
B-19 S	$956,705,453	$325,270,013	$85,404,325	$20,535,384	-$12,721,270	-$25,122,509	$533,609	$382,641,065	$57,778,919	-$644,658	$15,766,982	$17,144,949	-$17,144,947	$9,725,546	-$926,445	$24,319	$6,202,021	$0	$0		$21,848,000	$886,315,303
TOTAL B-19	$1,081,983,922	$371,493,568	$98,871,364	$23,883,164	-$14,795,155	-$29,218,104	$617,751	$425,188,659	$66,858,991	-$749,754	$18,351,146	$19,954,958	-$19,954,955	$11,118,640	-$1,077,479	$28,284	$7,213,105	$0	$0		$25,409,768	$1,003,193,951
STREETLIGHTS	$40,146,589	$8,695,715	$2,611,595	$665,334	-$412,161	-$768,158	$16,317	$24,788,627	$1,077,102	-$20,887	$514,102	$559,033	-$559,033	$416,482	-$25,221	$788	$222,487	$0	$0		$595,352	$38,377,474
STANDBY																						
STANDBY T	$114,343,249	$50,420,424	$19,237,439	$4,625,969	-$2,865,698	-$5,815,504	$120,196	$15,787,465	$11,466,538	-$145,221	$3,574,478	$3,886,873	-$3,886,872	$1,483,915	-$147,605	$5,478	$1,510,449	$0	$0		$3,488,233	$102,746,557
STANDBY P	$9,616,828	$1,285,942	$659,309	$78,628	-$48,709	-$98,847	$4,119	$6,879,095	$284,628	-$2,468	$60,756	$66,066	-$66,066	$87,002	-$2,509	$93	$25,673	$0	$0		$59,290	$9,272,003
STANDBY S	-$163,242	-$125,239	$3,642	-$15,924	$9,865	$20,019	$23	$73,710	-$211,962	$500	-$12,305	-$13,380	$13,380	-$9,265	$508	-$19	-$5,200	$0	$0		-$12,008	-$283,654
TOTAL STANDBY	$123,796,835	$51,581,127	$19,900,391	$4,688,674	-$2,904,542	-$5,894,332	$124,338	$22,740,270	$11,539,204	-$147,189	$3,622,930	$3,939,558	-$3,939,558	$1,561,652	-$149,606	$5,553	$1,530,922	$0	$0		$3,535,516	$111,734,907
AGRICULTURE																						
AG-A1	$96,076,284	$19,156,475	$5,379,411	$1,287,861	-$797,805	-$1,582,229	$33,611	$61,155,892	$4,193,295	-$40,429	$995,128	$1,082,098	-$1,082,098	$732,575	-$55,018	$1,525	$415,647	$0	$0		$1,297,844	$92,173,783
AG-A2	$50,577,517	$12,896,851	$3,665,237	$877,478	-$543,580	-$1,078,044	$22,901	$26,916,414	$2,857,082	-$27,546	$678,026	$737,282	-$737,282	$499,137	-$37,486	$1,039	$283,199	$0	$0		$884,280	$47,894,985
AG B	$332,858,370	$71,863,869	$17,744,650	$4,248,167	-$2,631,657	-$5,219,177	$110,869	$204,493,944	$15,145,100	-$133,361	$3,282,552	$3,569,433	-$3,569,432	$2,416,490	-$181,485	$5,031	$1,371,064	$0	$0		$4,281,100	$316,797,156
AG C	$1,020,739,111	$299,988,731	$87,752,869	$21,008,522	-$13,014,370	-$25,810,470	$548,283	$473,273,457	$61,693,649	-$659,511	$16,233,249	$17,651,965	-$17,651,963	$11,950,302	-$897,499	$24,880	$6,780,343	$0	$0		$21,171,382	$960,043,818
TOTAL AG	$1,500,251,282	$403,905,926	$114,542,166	$27,422,029	-$16,987,413	-$33,689,921	$715,663	$765,839,706	$83,889,126	-$860,848	$21,188,954	$23,040,778	-$23,040,775	$15,598,505	-$1,171,488	$32,475	$8,850,254	$0	$0		$27,634,607	$1,416,909,743
B-20 CLASS																						
B-20 FIRM T	$355,912,015	$185,308,642	$52,560,271	$13,517,800	-$8,374,014	-$13,833,800	$328,398	$24,853,987	$31,759,848	-$424,358	$10,445,180	$11,358,044	-$11,358,043	$3,739,339	-$537,469	$16,009	$3,507,622	$0	$0		$12,683,590	$315,551,046
FPP T																						
TOTAL	$355,912,015	$185,308,642	$52,560,271	$13,517,800	-$8,374,014	-$13,833,800	$328,398	$24,853,987	$31,759,848	-$424,358	$10,445,180	$11,358,044	-$11,358,043	$3,739,339	-$537,469	$16,009	$3,507,622	$0	$0		$12,683,590	$315,551,046
B-20 FIRM P	$440,647,727	$171,230,779	$46,468,108	$12,171,917	-$7,540,265	-$12,456,455	$290,334	$135,249,849	$30,024,549	-$382,108	$9,405,219	$10,227,195	-$10,227,194	$4,821,344	-$496,637	$14,415	$3,158,390	$0	$0		$11,718,296	$403,677,734
FPP P																						
TOTAL	$440,647,727	$171,230,779	$46,468,108	$12,171,917	-$7,540,265	-$12,456,455	$290,334	$135,249,849	$30,024,549	-$382,108	$9,405,219	$10,227,195	-$10,227,194	$4,821,344	-$496,637	$14,415	$3,158,390	$0	$0		$11,718,296	$403,677,734
B-20 FIRM S	$87,200,402	$31,097,723	$9,424,076	$2,145,445	-$1,329,062	-$2,195,599	$58,882	$30,866,791	$5,318,391	-$67,351	$1,657,782	$1,802,665	-$1,802,665	$913,904	-$90,196	$2,541	$556,704	$0	$0		$2,127,842	$80,487,873
FPP S																						
TOTAL	$87,200,402	$31,097,723	$9,424,076	$2,145,445	-$1,329,062	-$2,195,599	$58,882	$30,866,791	$5,318,391	-$67,351	$1,657,782	$1,802,665	-$1,802,665	$913,904	-$90,196	$2,541	$556,704	$0	$0		$2,127,842	$80,487,873
B-20 T	$355,912,015	$185,308,642	$52,560,271	$13,517,800	-$8,374,014	-$13,833,800	$328,398	$24,853,987	$31,759,848	-$424,358	$10,445,180	$11,358,044	-$11,358,043	$3,739,339	-$537,469	$16,009	$3,507,622	$0	$0		$12,683,590	$315,551,046
B-20 P	$440,647,727	$171,230,779	$46,468,108	$12,171,917	-$7,540,265	-$12,456,455	$290,334	$135,249,849	$30,024,549	-$382,108	$9,405,219	$10,227,195	-$10,227,194	$4,821,344	-$496,637	$14,415	$3,158,390	$0	$0		$11,718,296	$403,677,734
B-20 S	$87,200,402	$31,097,723	$9,424,076	$2,145,445	-$1,329,062	-$2,195,599	$58,882	$30,866,791	$5,318,391	-$67,351	$1,657,782	$1,802,665	-$1,802,665	$913,904	-$90,196	$2,541	$556,704	$0	$0		$2,127,842	$80,487,873
TOTAL B-20	$883,760,144	$387,637,143	$108,452,455	$27,835,162	-$17,243,341	-$28,485,854	$677,614	$190,970,627	$67,102,788	-$873,817	$21,508,181	$23,387,904	-$23,387,902	$9,474,587	-$1,124,302	$32,964	$7,222,715	$0	$0		$26,529,727	$799,716,653
SYSTEM	**$9,118,224,694**	**$2,958,814,393**	**$1,018,934,608**	**$192,926,902**	**-$119,514,458**	**-$289,713,039**	**$6,366,315**	**$3,786,236,258**	**$530,986,506**	**-$6,056,480**	**$121,911,635**	**$135,454,725**	**-$135,454,730**	**$84,972,784**	**-$8,581,739**	**$228,476**	**$72,747,950**	**$0**	**$0**	**-$13,895,003**	**$202,394,416**	**$8,538,759,520**

13-AtchA-5

Pacific Gas & Electric Company
2026 May ERRA Application
Thursday, January 1, 2026
Attachment A2: Revenue and Average Rate Summary without GHG Revenue Return

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	5,974,903,185	$0.44700	$0.12334	$0.05122	$0.00770	-$0.00477	-$0.01506	$0.00032	$0.20690	$0.02537	-$0.00024	$0.00551	$0.00647	-$0.00647	$0.00474	-$0.00036	$0.00001	$0.00376	$0.00000	$0.00000	$0.00488	$0.00844	$0.42176	-5.6%
CARE	4,084,490,973	$0.27233	$0.12337	$0.05122	$0.00770	-$0.00477	-$0.01506	$0.00032	$0.07883	$0.01352	-$0.00024	$0.00000	$0.00000	$0.00000	$0.00000	-$0.00036	$0.00001	$0.00376	$0.00000	$0.00000	-$0.01054	$0.00844	$0.25620	-5.9%
TOTAL RES	10,059,394,158	$0.37607	$0.12335	$0.05122	$0.00770	-$0.00477	-$0.01506	$0.00032	$0.15490	$0.02056	-$0.00024	$0.00327	$0.00384	-$0.00384	$0.00282	-$0.00036	$0.00001	$0.00376	$0.00000	$0.00000	-$0.00138	$0.00844	$0.35454	-5.7%
SMALL L&P																								
B-1	1,496,240,596	$0.45340	$0.11979	$0.03569	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.23447	$0.02468	-$0.00024	$0.00594	$0.00646	-$0.00646	$0.00495	-$0.00035	$0.00001	$0.00258	$0.00000	$0.00000		$0.00820	$0.42837	-5.5%
B-6	591,801,148	$0.44231	$0.12053	$0.03569	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.22560	$0.02184	-$0.00024	$0.00593	$0.00645	-$0.00645	$0.00495	-$0.00035	$0.00001	$0.00258	$0.00000	$0.00000		$0.00820	$0.41740	-5.6%
A-15	484,440	$0.50220	$0.11982	$0.03569	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.28318	$0.02471	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00496	-$0.00035	$0.00001	$0.00258	$0.00000	$0.00000		$0.00820	$0.47716	-5.0%
TC-1	11,463,462	$0.44027	$0.10835	$0.03569	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.25165	$0.01187	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00496	-$0.00035	$0.00001	$0.00258	$0.00000	$0.00000		$0.00820	$0.42131	-4.3%
TOTAL SMALL	2,099,989,646	$0.45021	$0.11994	$0.03569	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.23208	$0.02381	-$0.00024	$0.00594	$0.00645	-$0.00645	$0.00495	-$0.00035	$0.00001	$0.00258	$0.00000	$0.00000		$0.00820	$0.42525	-5.5%
MEDIUM L&P																								
B-10 T	1,745,037	$0.21225	$0.09689	$0.03108	$0.00770	-$0.00477	-$0.00942	$0.00019	$0.03789	$0.01936	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00271	-$0.00037	$0.00001	$0.00233	$0.00000	$0.00000		$0.00863	$0.19794	-6.7%
B-10 P	22,739,226	$0.35850	$0.11321	$0.04321	$0.00770	-$0.00477	-$0.00942	$0.00027	$0.14542	$0.02297	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00388	-$0.00037	$0.00001	$0.00233	$0.00000	$0.00000		$0.00863	$0.33879	-5.5%
B-10 S	1,898,304,490	$0.39574	$0.12645	$0.04388	$0.00770	-$0.00477	-$0.00942	$0.00027	$0.16212	$0.02273	-$0.00024	$0.00591	$0.00643	-$0.00643	$0.00421	-$0.00037	$0.00001	$0.00233	$0.00000	$0.00000		$0.00863	$0.36945	-6.6%
TOTAL MEDIUM	1,922,788,752	$0.39514	$0.12627	$0.04386	$0.00770	-$0.00477	-$0.00942	$0.00027	$0.16181	$0.02273	-$0.00024	$0.00591	$0.00643	-$0.00643	$0.00421	-$0.00037	$0.00001	$0.00233	$0.00000	$0.00000		$0.00863	$0.36893	-6.6%
B-19 CLASS																								
B-19 FIRM T	5,773,842	$0.24395	$0.10347	$0.03097	$0.00770	-$0.00477	-$0.00942	$0.00019	$0.06144	$0.01761	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00270	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00819	$0.22579	-7.4%
B-19 V T	4,701,105	$0.24027	$0.10671	$0.03866	$0.00770	-$0.00477	-$0.00942	$0.00024	$0.04099	$0.02209	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00270	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00819	$0.22079	-8.1%
Total B-19 T	10,474,947	$0.24230	$0.10493	$0.03442	$0.00770	-$0.00477	-$0.00942	$0.00022	$0.05226	$0.01962	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00270	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00819	$0.22354	-7.7%
B-19 FIRM P	286,766,974	$0.29346	$0.10670	$0.03130	$0.00770	-$0.00477	-$0.00942	$0.00020	$0.10231	$0.02083	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00322	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00819	$0.27395	-6.6%
B-19 V P	137,534,658	$0.28056	$0.10561	$0.03004	$0.00770	-$0.00477	-$0.00942	$0.00019	$0.09205	$0.02110	-$0.00024	$0.00593	$0.00645	-$0.00645	$0.00321	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00819	$0.26158	-6.8%
Total B-19 P	424,301,632	$0.28928	$0.10635	$0.03089	$0.00770	-$0.00477	-$0.00942	$0.00019	$0.09899	$0.02092	-$0.00024	$0.00594	$0.00646	-$0.00646	$0.00322	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00819	$0.26994	-6.7%
B-19 FIRM S	726,837,334	$0.42891	$0.12884	$0.04519	$0.00770	-$0.00477	-$0.00942	$0.00028	$0.18974	$0.02229	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00367	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00819	$0.39941	-6.9%
B-19 V S	1,940,095,675	$0.33244	$0.11939	$0.02709	$0.00770	-$0.00477	-$0.00942	$0.00017	$0.12614	$0.02143	-$0.00024	$0.00590	$0.00641	-$0.00641	$0.00364	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00819	$0.30721	-7.6%
Total B-19 S	2,666,933,009	$0.35873	$0.12196	$0.03202	$0.00770	-$0.00477	-$0.00942	$0.00020	$0.14348	$0.02166	-$0.00024	$0.00591	$0.00643	-$0.00643	$0.00365	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00819	$0.33234	-7.4%
B-19 T	10,474,947	$0.24230	$0.10493	$0.03442	$0.00770	-$0.00477	-$0.00942	$0.00022	$0.05226	$0.01962	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00270	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00819	$0.22354	-7.7%
B-19 P	424,301,632	$0.28928	$0.10635	$0.03089	$0.00770	-$0.00477	-$0.00942	$0.00019	$0.09899	$0.02092	-$0.00024	$0.00594	$0.00646	-$0.00646	$0.00322	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00819	$0.26994	-6.7%
B-19 S	2,666,933,009	$0.35873	$0.12196	$0.03202	$0.00770	-$0.00477	-$0.00942	$0.00020	$0.14348	$0.02166	-$0.00024	$0.00591	$0.00643	-$0.00643	$0.00365	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00819	$0.33234	-7.4%
TOTAL B-19	3,101,709,588	$0.34883	$0.11977	$0.03188	$0.00770	-$0.00477	-$0.00942	$0.00020	$0.13708	$0.02156	-$0.00024	$0.00592	$0.00643	-$0.00643	$0.00358	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00819	$0.32343	-7.3%
STREETLIGHTS	86,406,990	$0.46462	$0.10064	$0.03022	$0.00770	-$0.00477	-$0.00889	$0.00019	$0.28688	$0.01247	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00482	-$0.00029	$0.00001	$0.00257	$0.00000	$0.00000		$0.00689	$0.44415	-4.4%
STANDBY																								
STANDBY T	600,775,235	$0.19033	$0.08393	$0.03202	$0.00770	-$0.00477	-$0.00968	$0.00020	$0.02628	$0.01909	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00247	-$0.00025	$0.00001	$0.00251	$0.00000	$0.00000		$0.00581	$0.17102	-10.1%
STANDBY P	10,211,492	$0.94177	$0.12593	$0.06457	$0.00770	-$0.00477	-$0.00968	$0.00040	$0.67366	$0.02787	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00852	-$0.00025	$0.00001	$0.00251	$0.00000	$0.00000		$0.00581	$0.90800	-3.6%
STANDBY S	-2,068,090	$0.07893	$0.06056	-$0.00176	$0.00770	-$0.00477	-$0.00968	-$0.00001	-$0.03564	$0.10249	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00448	-$0.00025	$0.00001	$0.00251	$0.00000	$0.00000		$0.00581	$0.13716	73.8%
TOTAL STANDBY	608,918,637	$0.20331	$0.08471	$0.03268	$0.00770	-$0.00477	-$0.00968	$0.00020	$0.03735	$0.01895	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00256	-$0.00025	$0.00001	$0.00251	$0.00000	$0.00000		$0.00581	$0.18350	-9.7%
AGRICULTURE																								
AG-A1	167,254,643	$0.57443	$0.11453	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.36565	$0.02507	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	$0.00000	$0.00000		$0.00776	$0.55110	-4.1%
AG-A2	113,958,172	$0.44383	$0.11317	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.23620	$0.02507	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	$0.00000	$0.00000		$0.00776	$0.42029	-5.3%
AG B	551,710,063	$0.60332	$0.13026	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.37065	$0.02745	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	$0.00000	$0.00000		$0.00776	$0.57421	-4.8%
AG C	2,728,379,538	$0.37412	$0.10995	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.17346	$0.02261	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	$0.00000	$0.00000		$0.00776	$0.35187	-5.9%
TOTAL AG	3,561,302,416	$0.42126	$0.11342	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.21504	$0.02356	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	$0.00000	$0.00000		$0.00776	$0.39786	-5.6%
B-20 CLASS																								
B-20 FIRM T	1,755,558,428	$0.20273	$0.10556	$0.02994	$0.00770	-$0.00477	-$0.00788	$0.00019	$0.01416	$0.01809	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00213	-$0.00031	$0.00001	$0.00200	$0.00000	$0.00000		$0.00722	$0.17974	-11.3%
FPP T																								
TOTAL	1,755,558,428	$0.20273	$0.10556	$0.02994	$0.00770	-$0.00477	-$0.00788	$0.00019	$0.01416	$0.01809	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00213	-$0.00031	$0.00001	$0.00200	$0.00000	$0.00000		$0.00722	$0.17974	-11.3%
B-20 FIRM P	1,580,768,432	$0.27876	$0.10832	$0.02940	$0.00770	-$0.00477	-$0.00788	$0.00018	$0.08556	$0.01899	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00305	-$0.00031	$0.00001	$0.00200	$0.00000	$0.00000		$0.00741	$0.25537	-8.4%
FPP P																								
TOTAL	1,580,768,432	$0.27876	$0.10832	$0.02940	$0.00770	-$0.00477	-$0.00788	$0.00018	$0.08556	$0.01899	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00305	-$0.00031	$0.00001	$0.00200	$0.00000	$0.00000		$0.00741	$0.25537	-8.4%
B-20 FIRM S	278,629,256	$0.31296	$0.11161	$0.03382	$0.00770	-$0.00477	-$0.00788	$0.00021	$0.11078	$0.01909	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00328	-$0.00032	$0.00001	$0.00200	$0.00000	$0.00000		$0.00764	$0.28887	-7.7%
FPP S																								
TOTAL	278,629,256	$0.31296	$0.11161	$0.03382	$0.00770	-$0.00477	-$0.00788	$0.00021	$0.11078	$0.01909	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00328	-$0.00032	$0.00001	$0.00200	$0.00000	$0.00000		$0.00764	$0.28887	-7.7%
B-20 T	1,755,558,428	$0.20273	$0.10556	$0.02994	$0.00770	-$0.00477	-$0.00788	$0.00019	$0.01416	$0.01809	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00213	-$0.00031	$0.00001	$0.00200	$0.00000	$0.00000		$0.00722	$0.17974	-11.3%
B-20 P	1,580,768,432	$0.27876	$0.10832	$0.02940	$0.00770	-$0.00477	-$0.00788	$0.00018	$0.08556	$0.01899	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00305	-$0.00031	$0.00001	$0.00200	$0.00000	$0.00000		$0.00741	$0.25537	-8.4%
B-20 S	278,629,256	$0.31296	$0.11161	$0.03382	$0.00770	-$0.00477	-$0.00788	$0.00021	$0.11078	$0.01909	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00328	-$0.00032	$0.00001	$0.00200	$0.00000	$0.00000		$0.00764	$0.28887	-7.7%
TOTAL B-20	3,614,956,116	$0.24447	$0.10723	$0.03000	$0.00770	-$0.00477	-$0.00788	$0.00019	$0.05283	$0.01856	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00262	-$0.00031	$0.00001	$0.00200	$0.00000	$0.00000		$0.00734	$0.22122	-9.5%
SYSTEM	**25,055,466,305**	**$0.36392**	**$0.11809**	**$0.04067**	**$0.00770**	**-$0.00477**	**-$0.01156**	**$0.00025**	**$0.15111**	**$0.02119**	**-$0.00024**	**$0.00487**	**$0.00541**	**-$0.00541**	**$0.00339**	**-$0.00034**	**$0.00001**	**$0.00290**	**$0.00000**	**$0.00000**	**-$0.00055**	**$0.00808**	**$0.34079**	**-6.4%**

13-AtchA-6

Pacific Gas & Electric Company
2026 May ERRA Application
Thursday, January 1, 2026
Attachment A2: 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	Total Proposed Revenue
RESIDENTIAL																					
Non-CARE	$4,104,210,267	$709,701,024	$106,684,989	-$66,089,272	-$208,659,212	$4,434,241	$2,818,589,567	$351,572,740	-$3,349,124	$79,379,984	$89,602,296	-$89,602,267	$65,673,617	-$4,957,016	$126,343	$52,081,555	$0	$0	$108,301,960	$184,020,748	$4,197,512,172
CARE	$367,170,811	$158,370,868	$23,806,918	-$14,747,922	-$46,562,622	$989,510	$303,194,168	$41,789,409	-$747,360	$0	$0	$0	$0	-$1,106,168	$28,194	$11,622,102	$0	$0	-$94,406,958	$40,688,279	$422,918,416
TOTAL RES	$4,471,381,077	$868,071,892	$130,491,907	-$80,837,195	-$255,221,834	$5,423,750	$3,121,783,734	$393,362,148	-$4,096,485	$79,379,984	$89,602,296	-$89,602,267	$65,673,617	-$6,063,184	$154,537	$63,703,657	$0	$0	$13,895,002	$224,709,026	$4,620,430,588
SMALL L&P																					
B-1	$1,233,965,019	$145,481,469	$31,390,563	-$19,445,842	-$42,805,313	$908,973	$938,630,236	$100,605,458	-$985,430	$24,192,873	$26,307,227	-$26,307,224	$20,169,643	-$1,418,128	$37,175	$10,529,561	$0	$0		$51,560,282	$1,258,851,522
B-6	$342,466,403	$41,588,798	$8,968,866	-$5,556,038	-$12,230,272	$259,848	$261,640,764	$25,417,269	-$281,556	$6,899,817	$7,502,832	-$7,502,831	$5,754,931	-$405,185	$10,621	$3,008,491	$0	$0		$14,714,896	$349,791,251
A-15	$405,141	$28,487	$6,147	-$3,808	-$8,382	$178	$347,748	$19,724	-$193	$4,742	$5,156	-$5,156	$3,959	-$278	$7	$2,062	$0	$0		$10,436	$410,831
TC-1	$8,382,211	$983,644	$212,242	-$131,480	-$289,420	$6,146	$6,700,747	$327,058	-$6,663	$163,999	$178,332	-$178,332	$136,717	-$9,588	$251	$71,194	$0	$0		$365,062	$8,529,907
TOTAL SMALL	$1,585,218,774	$188,082,399	$40,577,818	-$25,137,168	-$55,333,388	$1,175,144	$1,207,319,495	$126,369,508	-$1,273,841	$31,261,431	$33,993,547	-$33,993,543	$26,065,250	-$1,833,180	$48,055	$13,611,308	$0	$0		$66,650,675	$1,617,583,511
MEDIUM L&P																					
B-10 T	$242,428	$103,816	$21,234	-$13,154	-$25,977	$649	$103,595	$53,384	-$667	$16,408	$17,841	-$17,841	$7,473	-$1,010	$25	$6,413	$0	$0		$75,262	$347,451
B-10 P	$9,534,677	$1,894,522	$334,542	-$207,242	-$409,271	$11,837	$6,144,096	$994,265	-$10,502	$256,545	$278,965	-$278,965	$167,299	-$15,911	$396	$101,037	$0	$0		$569,220	$9,830,834
B-10 S	$1,159,917,956	$196,877,553	$38,605,467	-$23,915,335	-$47,229,026	$1,230,097	$785,356,112	$114,155,523	-$1,211,924	$29,739,584	$32,338,696	-$32,338,693	$21,195,263	-$1,836,143	$45,719	$11,659,481	$0	$0		$64,701,721	$1,189,374,095
TOTAL MEDIUM	$1,169,695,061	$198,875,891	$38,961,243	-$24,135,731	-$47,664,274	$1,242,583	$791,603,804	$115,203,172	-$1,223,093	$30,012,536	$32,635,503	-$32,635,500	$21,370,035	-$1,853,065	$46,140	$11,766,931	$0	$0		$65,346,203	$1,199,552,379
B-19 CLASS																					
B-19 FIRM T	$2,157,727	$689,821	$203,067	-$125,796	-$248,428	$4,310	$796,624	$464,427	-$6,375	$156,910	$170,623	-$170,623	$71,205	-$9,161	$240	$61,330	$0	$0		$413,509	$2,471,684
B-19 V T	$1,178,290	$493,361	$59,180	-$36,661	-$72,400	$3,083	$436,587	$169,792	-$1,858	$45,729	$49,725	-$49,725	$20,752	-$2,670	$70	$17,873	$0	$0		$105,070	$1,237,908
Total B-19 T	$3,336,017	$1,183,182	$262,248	-$162,457	-$320,828	$7,393	$1,233,211	$634,219	-$8,233	$202,638	$220,348	-$220,348	$91,957	-$11,831	$311	$79,203	$0	$0		$518,579	$3,709,592
B-19 FIRM P	$82,104,829	$15,132,049	$3,717,583	-$2,302,970	-$4,548,004	$94,545	$51,820,227	$10,056,152	-$116,704	$2,872,570	$3,123,620	-$3,123,619	$1,554,625	-$167,717	$4,403	$1,122,771	$0	$0		$4,575,927	$83,815,456
B-19 V P	$49,476,981	$8,980,171	$3,080,494	-$1,908,306	-$3,768,605	$56,108	$27,984,457	$8,455,539	-$96,705	$2,380,293	$2,588,320	-$2,588,320	$1,288,207	-$138,975	$3,648	$930,360	$0	$0		$5,063,973	$52,310,659
Total B-19 P	$131,581,810	$24,112,220	$6,798,077	-$4,211,276	-$8,316,608	$150,654	$79,804,684	$18,511,691	-$213,409	$5,252,862	$5,711,940	-$5,711,939	$2,842,832	-$306,692	$8,051	$2,053,130	$0	$0		$9,639,900	$136,126,115
B-19 FIRM S	$650,887,219	$105,159,584	$22,889,756	-$14,179,758	-$28,002,792	$657,040	$449,137,859	$66,168,901	-$718,568	$17,633,853	$19,174,977	-$19,174,975	$10,879,885	-$1,032,662	$27,107	$6,913,080	$0	$0		$37,027,732	$672,561,021
B-19 V S	$1,357,177,446	$193,521,021	$59,095,961	-$36,608,797	-$72,296,617	$1,209,125	$908,800,454	$164,735,075	-$1,855,173	$45,394,376	$49,361,650	-$49,361,644	$28,002,049	-$2,666,090	$69,985	$17,847,945	$0	$0		$82,623,780	$1,387,873,100
Total B-19 S	$2,008,064,665	$298,680,605	$81,985,717	-$50,788,554	-$100,299,409	$1,866,165	$1,357,938,313	$230,903,976	-$2,573,741	$63,028,229	$68,536,627	-$68,536,619	$38,881,935	-$3,698,752	$97,092	$24,761,025	$0	$0		$119,651,512	$2,060,434,121
B-19 T	$3,336,017	$1,183,182	$262,248	-$162,457	-$320,828	$7,393	$1,233,211	$634,219	-$8,233	$202,638	$220,348	-$220,348	$91,957	-$11,831	$311	$79,203	$0	$0		$518,579	$3,709,592
B-19 P	$131,581,810	$24,112,220	$6,798,077	-$4,211,276	-$8,316,608	$150,654	$79,804,684	$18,511,691	-$213,409	$5,252,862	$5,711,940	-$5,711,939	$2,842,832	-$306,692	$8,051	$2,053,130	$0	$0		$9,639,900	$136,126,115
B-19 S	$2,008,064,665	$298,680,605	$81,985,717	-$50,788,554	-$100,299,409	$1,866,165	$1,357,938,313	$230,903,976	-$2,573,741	$63,028,229	$68,536,627	-$68,536,619	$38,881,935	-$3,698,752	$97,092	$24,761,025	$0	$0		$119,651,512	$2,060,434,121
TOTAL B-19	$2,142,982,493	$323,976,007	$89,046,041	-$55,162,288	-$108,936,845	$2,024,212	$1,438,976,208	$250,049,886	-$2,795,383	$68,483,730	$74,468,915	-$74,468,906	$41,816,724	-$4,017,276	$105,454	$26,893,358	$0	$0		$129,809,991	$2,200,269,828
STREETLIGHTS	$46,699,865	$4,660,180	$1,187,235	-$735,469	-$1,370,716	$29,117	$37,961,495	$1,886,338	-$37,270	$917,374	$997,549	-$997,549	$743,178	-$45,005	$1,406	$397,009	$0	$0		$1,686,262	$47,281,133
STANDBY																					
STANDBY T	$12,914,153	$4,069,797	$926,173	-$573,746	-$1,164,332	$25,428	$5,200,783	$2,295,734	-$29,075	$715,652	$778,197	-$778,197	$297,097	-$29,552	$1,097	$302,409	$0	$0		$1,002,624	$13,040,090
STANDBY P	$3,969,364	$330,936	$39,605	-$24,534	-$49,789	$2,068	$3,443,315	$143,365	-$1,243	$30,602	$33,277	-$33,277	$43,822	-$1,264	$47	$12,932	$0	$0		$26,156	$3,996,018
STANDBY S	$741,437	$72,962	$19,923	-$12,342	-$25,046	$456	$589,984	$265,183	-$625	$15,394	$16,740	-$16,740	$11,591	-$636	$24	$6,505	$0	$0		$30,671	$974,044
TOTAL STANDBY	$17,624,955	$4,473,696	$985,700	-$610,622	-$1,239,166	$27,952	$9,234,082	$2,704,282	-$30,944	$761,649	$828,214	-$828,214	$352,511	-$31,452	$1,167	$321,846	$0	$0		$1,059,452	$18,010,152
AGRICULTURE																					
AG-A1	$30,050,466	$2,337,703	$559,659	-$346,698	-$687,581	$14,606	$25,360,745	$1,822,259	-$17,569	$432,448	$470,242	-$470,242	$318,351	-$23,909	$663	$180,626	$0	$0		$779,222	$30,730,524
AG-A2	$12,962,663	$1,508,554	$361,156	-$223,729	-$443,706	$9,425	$9,938,163	$1,175,930	-$11,338	$279,065	$303,454	-$303,454	$205,437	-$15,429	$428	$116,560	$0	$0		$505,368	$13,405,885
AG B	$83,508,030	$7,247,104	$1,734,997	-$1,074,797	-$2,131,567	$45,280	$68,837,084	$6,185,420	-$54,466	$1,340,629	$1,457,794	-$1,457,794	$986,920	-$74,120	$2,055	$559,957	$0	$0		$2,353,539	$85,958,034
AG C	$311,904,157	$47,182,513	$11,295,755	-$6,997,500	-$13,877,642	$294,798	$220,567,119	$33,171,125	-$354,603	$8,728,210	$9,491,018	-$9,491,017	$6,425,377	-$482,562	$13,377	$3,645,620	$0	$0		$15,780,562	$325,392,152
TOTAL AG	$438,425,315	$58,275,874	$13,951,567	-$8,642,724	-$17,140,496	$364,109	$324,703,111	$42,354,734	-$437,975	$10,780,351	$11,722,508	-$11,722,506	$7,936,086	-$596,021	$16,522	$4,502,763	$0	$0		$19,418,692	$455,486,595
B-20 CLASS																					
B-20 FIRM T	$267,921,712	$108,297,384	$29,675,472	-$18,383,377	-$30,369,184	$676,645	$51,534,148	$69,722,032	-$931,589	$19,852,411	$21,587,426	-$21,587,424	$8,208,929	-$1,179,899	$35,143	$7,700,242	$0	$0		$32,330,778	$277,169,137
FPP T	$9,319,367	$0	$0	$0	$0	$0	$3,223,690	$5,247,384	-$70,113	$0	$1,876,584	-$1,876,584	$617,816	$0	$0	$0	$0	$0		$0	$9,018,778
TOTAL	$277,241,079	$108,297,384	$29,675,472	-$18,383,377	-$30,369,184	$676,645	$54,757,839	$74,969,416	-$1,001,702	$19,852,411	$23,464,010	-$23,464,008	$8,826,745	-$1,179,899	$35,143	$7,700,242	$0	$0		$32,330,778	$286,187,915
B-20 FIRM P	$806,480,628	$161,292,182	$45,287,948	-$28,055,001	-$46,346,627	$1,007,758	$467,897,527	$111,712,084	-$1,421,704	$34,993,918	$38,052,237	-$38,052,232	$17,938,732	-$1,847,835	$53,633	$11,751,393	$0	$0		$54,119,900	$828,383,913
FPP P	$2,464,348	$0	$0	$0	$0	$0	$2,021,602	$360,709	-$4,591	$0	$122,868	-$122,868	$57,923	$0	$0	$0	$0	$0		$0	$2,435,643
TOTAL	$808,944,976	$161,292,182	$45,287,948	-$28,055,001	-$46,346,627	$1,007,758	$469,919,129	$112,072,793	-$1,426,295	$34,993,918	$38,175,104	-$38,175,100	$17,996,655	-$1,847,835	$53,633	$11,751,393	$0	$0		$54,119,900	$830,819,556
B-20 FIRM S	$319,135,753	$58,829,878	$15,534,150	-$9,623,103	-$15,897,286	$367,571	$199,549,663	$38,507,943	-$487,657	$12,003,211	$13,052,240	-$13,052,239	$6,617,144	-$653,065	$18,396	$4,030,828	$0	$0		$21,099,809	$329,897,485
FPP S	$6,305,280	$0	$0	$0	$0	$0	$5,087,230	$972,602	-$12,317	$0	$329,663	-$329,663	$167,130	$0	$0	$0	$0	$0		$0	$6,214,645
TOTAL	$325,441,032	$58,829,878	$15,534,150	-$9,623,103	-$15,897,286	$367,571	$204,636,893	$39,480,545	-$499,973	$12,003,211	$13,381,903	-$13,381,901	$6,784,275	-$653,065	$18,396	$4,030,828	$0	$0		$21,099,809	$336,112,130
B-20 T	$277,241,079	$108,297,384	$29,675,472	-$18,383,377	-$30,369,184	$676,645	$54,757,839	$74,969,416	-$1,001,702	$19,852,411	$23,464,010	-$23,464,008	$8,826,745	-$1,179,899	$35,143	$7,700,242	$0	$0		$32,330,778	$286,187,915
B-20 P	$808,944,976	$161,292,182	$45,287,948	-$28,055,001	-$46,346,627	$1,007,758	$469,919,129	$112,072,793	-$1,426,295	$34,993,918	$38,175,104	-$38,175,100	$17,996,655	-$1,847,835	$53,633	$11,751,393	$0	$0		$54,119,900	$830,819,556
B-20 S	$325,441,032	$58,829,878	$15,534,150	-$9,623,103	-$15,897,286	$367,571	$204,636,893	$39,480,545	-$499,973	$12,003,211	$13,381,903	-$13,381,901	$6,784,275	-$653,065	$18,396	$4,030,828	$0	$0		$21,099,809	$336,112,130
TOTAL B-20	$1,411,627,087	$328,419,444	$90,497,569	-$56,061,481	-$92,613,097	$2,051,975	$729,313,861	$226,522,754	-$2,927,970	$66,849,539	$75,021,017	-$75,021,009	$33,607,675	-$3,680,798	$107,173	$23,482,462	$0	$0		$107,550,487	$1,453,119,601
SYSTEM	**$11,283,654,628**	**$1,974,835,382**	**$405,699,080**	**-$251,322,677**	**-$579,519,817**	**$12,338,842**	**$7,660,895,790**	**$1,158,452,822**	**-$12,822,961**	**$288,446,595**	**$319,269,548**	**-$319,269,493**	**$197,565,076**	**-$18,119,980**	**$480,454**	**$144,679,336**	**$0**	**$0**	**$13,895,002**	**$616,230,788**	**$11,611,733,788**

13-AtchA-7

Pacific Gas & Electric Company
2026 May ERRA Application
Thursday, January 1, 2026
Attachment A2: Revenue and Average Rate Summary without GHG Revenue Return

DA/CCA RESULTS

Class/Schedule	Total Sales (kWh)	Revenue At Present Rates	TO Rates	TAC Rates	TRBAA Rates	T-ECRA Rates	RS Rates	Dist Rates	PPP Rates	ND Rates	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	$13,855,265,928	$0.29622	$0.05122	$0.00770	-$0.00477	-$0.01506	$0.00032	$0.20343	$0.02537	-$0.00024	$0.00573	$0.00647	-$0.00647	$0.00474	-$0.00036	$0.00001	$0.00376	$0.00000	$0.00000	$0.00782	$0.01328	$0.30295	2.3%
CARE	$3,091,829,928	$0.11876	$0.05122	$0.00770	-$0.00477	-$0.01506	$0.00032	$0.09806	$0.01352	-$0.00024	$0.00000	$0.00000	$0.00000	$0.00000	-$0.00036	$0.00001	$0.00376	$0.00000	$0.00000	-$0.03053	$0.01316	$0.13679	15.2%
TOTAL RES	$16,947,095,856	$0.26384	$0.05122	$0.00770	-$0.00477	-$0.01506	$0.00032	$0.18421	$0.02321	-$0.00024	$0.00468	$0.00529	-$0.00529	$0.00388	-$0.00036	$0.00001	$0.00376	$0.00000	$0.00000	$0.00082	$0.01326	$0.27264	3.3%
SMALL L&P																							
B-1	4,076,696,475	$0.30269	$0.03569	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.23024	$0.02468	-$0.00024	$0.00593	$0.00645	-$0.00645	$0.00495	-$0.00035	$0.00001	$0.00258	$0.00000	$0.00000		$0.01265	$0.30879	2.0%
B-6	1,164,787,855	$0.29402	$0.03571	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.22463	$0.02182	-$0.00024	$0.00592	$0.00644	-$0.00644	$0.00494	-$0.00035	$0.00001	$0.00258	$0.00000	$0.00000		$0.01263	$0.30030	2.1%
A-15	798,281	$0.50752	$0.03569	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.43562	$0.02471	-$0.00024	$0.00594	$0.00646	-$0.00646	$0.00496	-$0.00035	$0.00001	$0.00258	$0.00000	$0.00000		$0.01307	$0.51464	1.4%
TC-1	27,563,854	$0.30410	$0.03569	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.24310	$0.01187	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00496	-$0.00035	$0.00001	$0.00258	$0.00000	$0.00000		$0.01324	$0.30946	1.8%
TOTAL SMALL	5,269,846,466	$0.30081	$0.03569	$0.00770	-$0.00477	-$0.01050	$0.00022	$0.22910	$0.02398	-$0.00024	$0.00593	$0.00645	-$0.00645	$0.00495	-$0.00035	$0.00001	$0.00258	$0.00000	$0.00000		$0.01265	$0.30695	2.0%
MEDIUM L&P																							
B-10 T	2,757,672	$0.08791	$0.03765	$0.00770	-$0.00477	-$0.00942	$0.00024	$0.03757	$0.01936	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00271	-$0.00037	$0.00001	$0.00233	$0.00000	$0.00000		$0.02729	$0.12599	43.3%
B-10 P	43,446,997	$0.21946	$0.04361	$0.00770	-$0.00477	-$0.00942	$0.00027	$0.14142	$0.02288	-$0.00024	$0.00590	$0.00642	-$0.00642	$0.00385	-$0.00037	$0.00001	$0.00233	$0.00000	$0.00000		$0.01310	$0.22627	3.1%
B-10 S	5,013,697,012	$0.23135	$0.03927	$0.00770	-$0.00477	-$0.00942	$0.00025	$0.15664	$0.02277	-$0.00024	$0.00593	$0.00645	-$0.00645	$0.00423	-$0.00037	$0.00001	$0.00233	$0.00000	$0.00000		$0.01290	$0.23722	2.5%
TOTAL MEDIUM	5,059,901,682	$0.23117	$0.03930	$0.00770	-$0.00477	-$0.00942	$0.00025	$0.15645	$0.02277	-$0.00024	$0.00593	$0.00645	-$0.00645	$0.00422	-$0.00037	$0.00001	$0.00233	$0.00000	$0.00000		$0.01291	$0.23707	2.6%
B-19 CLASS																							
B-19 FIRM T	26,372,400	$0.08182	$0.02616	$0.00770	-$0.00477	-$0.00942	$0.00016	$0.03021	$0.01761	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00270	-$0.00035	$0.00001	$0.00233	$0.00000			$0.01568	$0.09372	14.6%
B-19 V T	7,685,769	$0.15331	$0.06419	$0.00770	-$0.00477	-$0.00942	$0.00040	$0.05680	$0.02209	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00270	-$0.00035	$0.00001	$0.00233	$0.00000			$0.01367	$0.16106	5.1%
Total B-19 T	34,058,169	$0.09795	$0.03474	$0.00770	-$0.00477	-$0.00942	$0.00022	$0.03621	$0.01862	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00270	-$0.00035	$0.00001	$0.00233	$0.00000			$0.01523	$0.10892	11.2%
B-19 FIRM P	482,802,923	$0.17006	$0.03134	$0.00770	-$0.00477	-$0.00942	$0.00020	$0.10733	$0.02083	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00322	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.00948	$0.17360	2.1%
B-19 V P	400,064,209	$0.12367	$0.02245	$0.00770	-$0.00477	-$0.00942	$0.00014	$0.06995	$0.02114	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00322	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.01266	$0.13076	5.7%
Total B-19 P	882,867,132	$0.14904	$0.02731	$0.00770	-$0.00477	-$0.00942	$0.00017	$0.09039	$0.02097	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00322	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.01092	$0.15419	3.5%
B-19 FIRM S	2,972,695,521	$0.21896	$0.03538	$0.00770	-$0.00477	-$0.00942	$0.00022	$0.15109	$0.02226	-$0.00024	$0.00593	$0.00645	-$0.00645	$0.00366	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.01246	$0.22625	3.3%
B-19 V S	7,674,800,129	$0.17684	$0.02522	$0.00770	-$0.00477	-$0.00942	$0.00016	$0.11841	$0.02146	-$0.00024	$0.00591	$0.00643	-$0.00643	$0.00365	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.01077	$0.18084	2.3%
Total B-19 S	10,647,495,650	$0.18860	$0.02805	$0.00770	-$0.00477	-$0.00942	$0.00018	$0.12754	$0.02169	-$0.00024	$0.00592	$0.00644	-$0.00644	$0.00365	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.01124	$0.19351	2.6%
B-19 T	34,058,169	$0.09795	$0.03474	$0.00770	-$0.00477	-$0.00942	$0.00022	$0.03621	$0.01862	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00270	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.01523	$0.10892	11.2%
B-19 P	882,867,132	$0.14904	$0.02731	$0.00770	-$0.00477	-$0.00942	$0.00017	$0.09039	$0.02097	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00322	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.01092	$0.15419	3.5%
B-19 S	10,647,495,650	$0.18860	$0.02805	$0.00770	-$0.00477	-$0.00942	$0.00018	$0.12754	$0.02169	-$0.00024	$0.00592	$0.00644	-$0.00644	$0.00365	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.01124	$0.19351	2.6%
TOTAL B-19	11,564,420,950	$0.18531	$0.02801	$0.00770	-$0.00477	-$0.00942	$0.00018	$0.12443	$0.02162	-$0.00024	$0.00592	$0.00644	-$0.00644	$0.00362	-$0.00035	$0.00001	$0.00233	$0.00000	$0.00000		$0.01122	$0.19026	2.7%
STREETLIGHTS	154,186,308	$0.30288	$0.03022	$0.00770	-$0.00477	-$0.00889	$0.00019	$0.24621	$0.01223	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00482	-$0.00029	$0.00001	$0.00257	$0.00000	$0.00000		$0.01094	$0.30665	1.2%
STANDBY																							
STANDBY T	120,282,187	$0.10737	$0.03384	$0.00770	-$0.00477	-$0.00968	$0.00021	$0.04324	$0.01909	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00247	-$0.00025	$0.00001	$0.00251	$0.00000	$0.00000		$0.00834	$0.10841	1.0%
STANDBY P	5,143,455	$0.77173	$0.06434	$0.00770	-$0.00477	-$0.00968	$0.00040	$0.66946	$0.02787	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00852	-$0.00025	$0.00001	$0.00251	$0.00000	$0.00000		$0.00509	$0.77691	0.7%
STANDBY S	2,587,363	$0.28656	$0.02820	$0.00770	-$0.00477	-$0.00968	$0.00018	$0.22803	$0.10249	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00448	-$0.00025	$0.00001	$0.00251	$0.00000	$0.00000		$0.01185	$0.37646	31.4%
TOTAL STANDBY	128,013,005	$0.13768	$0.03495	$0.00770	-$0.00477	-$0.00968	$0.00022	$0.07213	$0.02113	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00275	-$0.00025	$0.00001	$0.00251	$0.00000	$0.00000		$0.00828	$0.14069	2.2%
AGRICULTURE																							
AG-A1	72,682,990	$0.41345	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.34892	$0.02507	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	$0.00000	$0.00000		$0.01072	$0.42280	2.3%
AG-A2	46,903,389	$0.27637	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.21189	$0.02507	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	$0.00000	$0.00000		$0.01077	$0.28582	3.4%
AG B	225,324,257	$0.37061	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.30550	$0.02745	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	$0.00000	$0.00000		$0.01045	$0.38149	2.9%
AG C	1,466,981,143	$0.21262	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.15035	$0.02261	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	$0.00000	$0.00000		$0.01076	$0.22181	4.3%
TOTAL AG	$1,811,891,779	$0.24197	$0.03216	$0.00770	-$0.00477	-$0.00946	$0.00020	$0.17921	$0.02338	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00438	-$0.00033	$0.00001	$0.00249	$0.00000	$0.00000		$0.01072	$0.25139	3.9%
B-20 CLASS																							
B-20 FIRM T	3,853,957,342	$0.06952	$0.02810	$0.00770	-$0.00477	-$0.00788	$0.00018	$0.01337	$0.01809	-$0.00024	$0.00515	$0.00560	-$0.00560	$0.00213	-$0.00031	$0.00001	$0.00200	$0.00000	$0.00000		$0.00839	$0.07192	3.5%
FPP T	290,054,572	$0.03213	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.01111	$0.01809	-$0.00024	$0.00000	$0.00647	-$0.00647	$0.00213	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		$0.00000	$0.03109	-3.2%
TOTAL	4,144,011,914	$0.06690	$0.02613	$0.00716	-$0.00444	-$0.00733	$0.00016	$0.01321	$0.01809	-$0.00024	$0.00479	$0.00566	-$0.00566	$0.00213	-$0.00028	$0.00001	$0.00186	$0.00000	$0.00000		$0.00780	$0.06906	3.2%
B-20 FIRM P	5,881,551,631	$0.13712	$0.02742	$0.00770	-$0.00477	-$0.00788	$0.00017	$0.07955	$0.01899	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00305	-$0.00031	$0.00001	$0.00200	$0.00000	$0.00000		$0.00920	$0.14084	2.7%
FPP P	18,991,044	$0.12976	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.10645	$0.01899	-$0.00024	$0.00000	$0.00647	-$0.00647	$0.00305	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		$0.00000	$0.12825	-1.2%
TOTAL	5,900,542,675	$0.13710	$0.02734	$0.00768	-$0.00475	-$0.00785	$0.00017	$0.07964	$0.01899	-$0.00024	$0.00593	$0.00647	-$0.00647	$0.00305	-$0.00031	$0.00001	$0.00199	$0.00000	$0.00000		$0.00917	$0.14080	2.7%
B-20 FIRM S	2,017,422,102	$0.15819	$0.02916	$0.00770	-$0.00477	-$0.00788	$0.00018	$0.09891	$0.01909	-$0.00024	$0.00595	$0.00647	-$0.00647	$0.00328	-$0.00032	$0.00001	$0.00200	$0.00000	$0.00000		$0.01046	$0.16352	3.4%
FPP S	50,954,384	$0.12374	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.09984	$0.01909	-$0.00024	$0.00000	$0.00647	-$0.00647	$0.00328	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		$0.00000	$0.12196	-1.4%
TOTAL	2,068,376,487	$0.15734	$0.02844	$0.00751	-$0.00465	-$0.00769	$0.00018	$0.09894	$0.01909	-$0.00024	$0.00580	$0.00647	-$0.00647	$0.00328	-$0.00032	$0.00001	$0.00195	$0.00000	$0.00000		$0.01020	$0.16250	3.3%
B-20 T	4,144,011,914	$0.06690	$0.02613	$0.00716	-$0.00444	-$0.00733	$0.00016	$0.01321	$0.01809	-$0.00024	$0.00479	$0.00566	-$0.00566	$0.00213	-$0.00028	$0.00001	$0.00186	$0.00000	$0.00000		$0.00780	$0.06906	3.2%
B-20 P	5,900,542,675	$0.13710	$0.02734	$0.00768	-$0.00475	-$0.00785	$0.00017	$0.07964	$0.01899	-$0.00024	$0.00593	$0.00647	-$0.00647	$0.00305	-$0.00031	$0.00001	$0.00199	$0.00000	$0.00000		$0.00917	$0.14080	2.7%
B-20 S	2,068,376,487	$0.15734	$0.02844	$0.00751	-$0.00465	-$0.00769	$0.00018	$0.09894	$0.01909	-$0.00024	$0.00580	$0.00647	-$0.00647	$0.00328	-$0.00032	$0.00001	$0.00195	$0.00000	$0.00000		$0.01020	$0.16250	3.3%
TOTAL B-20	12,112,931,076	$0.11654	$0.02711	$0.00747	-$0.00463	-$0.00765	$0.00017	$0.06021	$0.01870	-$0.00024	$0.00552	$0.00619	-$0.00619	$0.00277	-$0.00030	$0.00001	$0.00194	$0.00000	$0.00000		$0.00888	$0.11996	2.9%
SYSTEM	**53,048,287,121**	**$0.21271**	**$0.03723**	**$0.00765**	**-$0.00474**	**-$0.01092**	**$0.00023**	**$0.14441**	**$0.02184**	**-$0.00024**	**$0.00544**	**$0.00602**	**-$0.00602**	**$0.00372**	**-$0.00034**	**$0.00001**	**$0.00273**	**$0.00000**	**$0.00000**	**$0.00026**	**$0.01162**	**$0.21889**	**2.9%**

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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 14

GREEN TARIFF SHARED RENEWABLES

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 14
GREEN TARIFF SHARED RENEWABLES

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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) 2026 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 component of the GTSR Program was eliminated.

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 (MW) located within PG&E's service area and under contract with PG&E.

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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 (AL), which was allowed under D.15-01-051, COL 51. However, given the interdependency of the GTSR Program rates on the Power Charge Indifference Adjustment (PCIA) and generation rates set in the Energy Resource Recovery Account (ERRA) Forecast proceeding, PG&E consolidates the GTSR rate request with the Annual ERRA Forecast proceeding.

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 2025 GTSR Forecast, approved in D.24-12-038, was consolidated with other electric rate changes in PG&E's Advice Letter (AL) 7469-E, the Annual Electric True-Up (AET) on December 30, 2024, for rates effective January 1, 2025.

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 GAPs 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

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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—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 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 Decision with more granular implementation details is expected by January 1, 2026 in the proceeding, at which point, PG&E will begin the implementation process. It is expected that full implementation of the Modified GT would not be complete until sometime in 2027 at the earliest. The existing Green Tariff will remain in place as PG&E develops implementation plans to transition existing GT customers to the Modified GT.

As such, this testimony presents a 2026 rate forecast for PG&E’s existing GTSR Solar Choice program. PG&E anticipates the existing Solar Choice program will be relevant to 2026 ratemaking and will continue to be relevant through 2026 until an implementation 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 2024 and ended the year at approximately 90 MW, which was approximately 47 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.

PG&E implemented new 2025 rates effective January 1, 2025, which resulted in an increase for most rate schedules with a few exceptions. Overall, the 2025 Solar Choice rates remain a slight premium above the otherwise applicable tariffs for all rate classes relative to the otherwise applicable tariff. PG&E expects continued attrition of customers during 2025 given the increase in rates for most schedules. However, at the time of filing, PG&E has only billed usage data through March 2025, which makes it difficult to accurately project the customer attrition in 2025 with 100 percent confidence. At this time, PG&E’s

2026 forecast load does not reflect attrition of its Solar Choice customers in 2026 compared to the 2025 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 2025 with actuals at least through August.

PG&E's initial projection for its GTSR Solar Choice load forecast for the balance of 2025 and 2026 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	Recorded			Forecast	
1	Fiscal Year	2022	2023	2024	2025	2026
2	Program Year	PY 6	PY 7	PY 8	PY 9	PY 10
3	E-GT Sales (MWh/yr)	440,481	375,231	316,358	184,534	158,633

In 2026, 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. 2026 Rate Forecast for GTSR Program

PG&E's request is to update the GTSR Program rate components for rates effective January 1, 2026. 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 Marketing Costs and (4) Class Average Generation Rate credit. The Table 14-2 below summarizes the GTSR Program's rate components.

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6 AL 6451-E, filed December 28, 2021.

TABLE 14-2
GTSR PROGRAM CHARGES AND CREDITS

GTSR Program Rate Components	Charges	Credits
SOLAR CHARGE		
- Solar Choice Interim Pool Resources	✓	
- Solar Choice Dedicated Resources	✓	
PROGRAM CHARGES		
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 Value Adjustments		
- Time of Delivery	✓	
- Resource Adequacy from Dedicated Resources		✓
Administration and Market Program Charge		
- Solar Choice Marketing	✓	
- Administration Charge	✓	
CLASS AVERAGE GENERATION RATE CREDIT		✓

All the rate components have been reviewed and updated as appropriate in this request for 2026 except for the RIC, which will remain unchanged for 2026.[7]

The GTSR rate component forecast for 2024 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 2026 ERRA Forecast values, to be updated through the Fall Update. In

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

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 2026 MPB when the Energy Division issues the final 2025 and forecast 2026 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 will update the GTSR Balancing Account forecast in its Fall Update, which will include a true-up of the RA charge using the final RA MPB value issued by Energy Division for 2025 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.[8] PG&E will be submitting its 2025 ERRA Compliance Review to the Commission in February 2026, reviewing balancing account activity for the 2025 record period.

Tables 14-3 and 14-4 below summarize the 2026 GTSR Program charges and credits for Solar Choice program for a 2026 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 14-14 summarize the 2026 GTSR Program charges and credits for customers currently being served under the Solar Choice program, which includes vintage customers 2015 through 2024. The Solar

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

Choice rate results in Table 14-3, and Tables 14-5 through 14-14, show a mix of increases and decrease in the GTSR net rate results compared to the 2025 net rate results with all schedules showing a net premium compared to the otherwise applicable tariff. This increases and decreases to the Solar Choice net result is attributable to multiple factors including a lower solar charge and lower resource adequacy charge credit paired with increases in the PCIA rate and a lower 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 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**	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136
2	PCIA	0.843	0.820	0.820	0.863	0.819	0.689	0.776	0.722	0.741	0.763	0.694	0.779
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468
5	Resource Adequacy	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485
6	CAISO Charges	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118
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**	**12.051**	**12.028**	**12.028**	**12.071**	**12.027**	**11.897**	**11.984**	**11.930**	**11.949**	**11.971**	**11.902**	**11.987**
9	**Credits**												
10	**Class Average Generation Rate**	13.179	12.814	12.814	13.490	12.796	10.753	12.117	11.278	11.573	11.925	12.814	12.796
11	Solar Value Adjustment												
12	TOD	(4.415)	(3.921)	(3.921)	(3.278)	(3.276)	(3.129)	(1.721)	(2.774)	(2.847)	(2.934)	(3.921)	(3.276)
13	RA	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	9.684	9.813	9.813	11.132	10.440	8.544	11.316	9.424	9.646	9.911	9.813	10.440
16	**2026 Premium (cents/kwh)**	**2.367**	**2.215**	**2.215**	**0.939**	**1.587**	**3.353**	**0.668**	**2.506**	**2.303**	**2.060**	**2.089**	**1.547**

TABLE 14-4
GTSR PROGRAM – VINTAGE 2025

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**	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136
2	PCIA	0.721	0.701	0.701	0.738	0.700	0.589	0.663	0.618	0.634	0.653	0.594	0.667
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468
5	Resource Adequacy	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485
6	CAISO Charges	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118
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**	**11.929**	**11.909**	**11.909**	**11.946**	**11.908**	**11.797**	**11.871**	**11.826**	**11.842**	**11.861**	**11.802**	**11.875**
9	**Credits**												
10	**Class Average Generation Rate**	13.179	12.814	12.814	13.490	12.796	10.753	12.117	11.278	11.573	11.925	12.814	12.796
11	Solar Value Adjustment												
12	TOD	(4.415)	(3.921)	(3.921)	(3.278)	(3.276)	(3.129)	(1.721)	(2.774)	(2.847)	(2.934)	(3.921)	(3.276)
13	RA	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	9.684	9.813	9.813	11.132	10.440	8.544	11.316	9.424	9.646	9.911	9.813	10.440
16	**2026 Premium (cents/kwh)**	**2.245**	**2.096**	**2.096**	**0.814**	**1.468**	**3.253**	**0.555**	**2.402**	**2.196**	**1.950**	**1.989**	**1.435**

TABLE 14-5
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**	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136
2	PCIA	2.872	2.792	2.792	2.939	2.788	2.343	2.641	2.458	2.522	2.599	2.365	2.654
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468
5	Resource Adequacy	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485
6	CAISO Charges	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118
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**	**14.080**	**14.000**	**14.000**	**14.147**	**13.996**	**13.551**	**13.849**	**13.666**	**13.730**	**13.807**	**13.573**	**13.862**
9	**Credits**												
10	**Class Average Generation Rate**	13.179	12.814	12.814	13.490	12.796	10.753	12.117	11.278	11.573	11.925	12.814	12.796
11	Solar Value Adjustment												
12	TOD	(4.415)	(3.921)	(3.921)	(3.278)	(3.276)	(3.129)	(1.721)	(2.774)	(2.847)	(2.934)	(3.921)	(3.276)
13	RA	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	9.684	9.813	9.813	11.132	10.440	8.544	11.316	9.424	9.646	9.911	9.813	10.440
16	**2026 Premium (cents/kwh)**	**4.396**	**4.187**	**4.187**	**3.015**	**3.556**	**5.007**	**2.533**	**4.242**	**4.084**	**3.896**	**3.760**	**3.422**

TABLE 14-6
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**	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136
2	PCIA	3.157	3.069	3.069	3.231	3.065	2.576	2.903	2.702	2.773	2.857	2.600	2.917
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468
5	Resource Adequacy	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485
6	CAISO Charges	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118
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**	**14.365**	**14.277**	**14.277**	**14.439**	**14.273**	**13.784**	**14.111**	**13.910**	**13.981**	**14.065**	**13.808**	**14.125**
9	**Credits**												
10	**Class Average Generation Rate**	13.179	12.814	12.814	13.490	12.796	10.753	12.117	11.278	11.573	11.925	12.814	12.796
11	Solar Value Adjustment												
12	TOD	(4.415)	(3.921)	(3.921)	(3.278)	(3.276)	(3.129)	(1.721)	(2.774)	(2.847)	(2.934)	(3.921)	(3.276)
13	RA	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	9.684	9.813	9.813	11.132	10.440	8.544	11.316	9.424	9.646	9.911	9.813	10.440
16	**2026 Premium (cents/kwh)**	**4.681**	**4.464**	**4.464**	**3.307**	**3.833**	**5.240**	**2.795**	**4.486**	**4.335**	**4.154**	**3.995**	**3.685**

TABLE 14-7
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**	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136
2	PCIA	3.035	2.951	2.951	3.106	2.947	2.476	2.790	2.597	2.665	2.746	2.499	2.805
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468
5	Resource Adequacy	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485
6	CAISO Charges	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118
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**	**14.243**	**14.159**	**14.159**	**14.314**	**14.155**	**13.684**	**13.998**	**13.805**	**13.873**	**13.954**	**13.707**	**14.013**
9	**Credits**												
10	**Class Average Generation Rate**	13.179	12.814	12.814	13.490	12.796	10.753	12.117	11.278	11.573	11.925	12.814	12.796
11	Solar Value Adjustment												
12	TOD	(4.415)	(3.921)	(3.921)	(3.278)	(3.276)	(3.129)	(1.721)	(2.774)	(2.847)	(2.934)	(3.921)	(3.276)
13	RA	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	9.684	9.813	9.813	11.132	10.440	8.544	11.316	9.424	9.646	9.911	9.813	10.440
16	**2026 Premium (cents/kwh)**	**4.559**	**4.346**	**4.346**	**3.182**	**3.715**	**5.140**	**2.682**	**4.381**	**4.227**	**4.043**	**3.894**	**3.573**

TABLE 14-8
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**	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136
2	PCIA	3.028	2.945	2.945	3.100	2.940	2.471	2.785	2.592	2.660	2.740	2.494	2.799
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468
5	Resource Adequacy	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485
6	CAISO Charges	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118
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**	**14.236**	**14.153**	**14.153**	**14.308**	**14.148**	**13.679**	**13.993**	**13.800**	**13.868**	**13.948**	**13.702**	**14.007**
9	**Credits**												
10	**Class Average Generation Rate**	13.179	12.814	12.814	13.490	12.796	10.753	12.117	11.278	11.573	11.925	12.814	12.796
11	Solar Value Adjustment												
12	TOD	(4.415)	(3.921)	(3.921)	(3.278)	(3.276)	(3.129)	(1.721)	(2.774)	(2.847)	(2.934)	(3.921)	(3.276)
13	RA	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	9.684	9.813	9.813	11.132	10.440	8.544	11.316	9.424	9.646	9.911	9.813	10.440
16	**2026 Premium (cents/kwh)**	**4.552**	**4.340**	**4.340**	**3.176**	**3.708**	**5.135**	**2.677**	**4.376**	**4.222**	**4.037**	**3.889**	**3.567**

TABLE 14-9
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**	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136
2	PCIA	1.295	1.259	1.259	1.325	1.257	1.057	1.191	1.108	1.137	1.172	1.066	1.196
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468
5	Resource Adequacy	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485
6	CAISO Charges	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118
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**	**12.503**	**12.467**	**12.467**	**12.533**	**12.465**	**12.265**	**12.399**	**12.316**	**12.345**	**12.380**	**12.274**	**12.404**
9	**Credits**												
10	**Class Average Generation Rate**	13.179	12.814	12.814	13.490	12.796	10.753	12.117	11.278	11.573	11.925	12.814	12.796
11	Solar Value Adjustment												
12	TOD	(4.415)	(3.921)	(3.921)	(3.278)	(3.276)	(3.129)	(1.721)	(2.774)	(2.847)	(2.934)	(3.921)	(3.276)
13	RA	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	9.684	9.813	9.813	11.132	10.440	8.544	11.316	9.424	9.646	9.911	9.813	10.440
16	**2026 Premium (cents/kwh)**	**2.819**	**2.654**	**2.654**	**1.401**	**2.025**	**3.721**	**1.083**	**2.892**	**2.699**	**2.469**	**2.461**	**1.964**

TABLE 14-10
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**	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136
2	PCIA	1.393	1.355	1.355	1.426	1.353	1.137	1.281	1.193	1.224	1.261	1.147	1.288
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468
5	Resource Adequacy	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485
6	CAISO Charges	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118
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**	**12.601**	**12.563**	**12.563**	**12.634**	**12.561**	**12.345**	**12.489**	**12.401**	**12.432**	**12.469**	**12.355**	**12.496**
9	**Credits**												
10	**Class Average Generation Rate**	13.179	12.814	12.814	13.490	12.796	10.753	12.117	11.278	11.573	11.925	12.814	12.796
11	Solar Value Adjustment												
12	TOD	(4.415)	(3.921)	(3.921)	(3.278)	(3.276)	(3.129)	(1.721)	(2.774)	(2.847)	(2.934)	(3.921)	(3.276)
13	RA	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	9.684	9.813	9.813	11.132	10.440	8.544	11.316	9.424	9.646	9.911	9.813	10.440
16	**2026 Premium (cents/kwh)**	**2.917**	**2.750**	**2.750**	**1.502**	**2.121**	**3.801**	**1.173**	**2.977**	**2.786**	**2.558**	**2.542**	**2.056**

TABLE 14-11
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**	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136
2	PCIA	1.167	1.135	1.135	1.195	1.133	0.953	1.073	0.999	1.025	1.056	0.961	1.079
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468
5	Resource Adequacy	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485
6	CAISO Charges	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118
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**	**12.375**	**12.343**	**12.343**	**12.403**	**12.341**	**12.161**	**12.281**	**12.207**	**12.233**	**12.264**	**12.169**	**12.287**
9	**Credits**												
10	**Class Average Generation Rate**	13.179	12.814	12.814	13.490	12.796	10.753	12.117	11.278	11.573	11.925	12.814	12.796
11	Solar Value Adjustment												
12	TOD	(4.415)	(3.921)	(3.921)	(3.278)	(3.276)	(3.129)	(1.721)	(2.774)	(2.847)	(2.934)	(3.921)	(3.276)
13	RA	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	9.684	9.813	9.813	11.132	10.440	8.544	11.316	9.424	9.646	9.911	9.813	10.440
16	**2026 Premium (cents/kwh)**	**2.691**	**2.530**	**2.530**	**1.271**	**1.901**	**3.617**	**0.965**	**2.783**	**2.587**	**2.353**	**2.356**	**1.847**

TABLE 14-12
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**	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136
2	PCIA	1.227	1.193	1.193	1.256	1.192	1.002	1.129	1.051	1.078	1.111	1.011	1.134
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468
5	Resource Adequacy	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485
6	CAISO Charges	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118
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**	**12.435**	**12.401**	**12.401**	**12.464**	**12.400**	**12.210**	**12.337**	**12.259**	**12.286**	**12.319**	**12.219**	**12.342**
9	**Credits**												
10	**Class Average Generation Rate**	13.179	12.814	12.814	13.490	12.796	10.753	12.117	11.278	11.573	11.925	12.814	12.796
11	Solar Value Adjustment												
12	TOD	(4.415)	(3.921)	(3.921)	(3.278)	(3.276)	(3.129)	(1.721)	(2.774)	(2.847)	(2.934)	(3.921)	(3.276)
13	RA	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	9.684	9.813	9.813	11.132	10.440	8.544	11.316	9.424	9.646	9.911	9.813	10.440
16	**2026 Premium (cents/kwh)**	**2.751**	**2.588**	**2.588**	**1.332**	**1.960**	**3.666**	**1.021**	**2.835**	**2.640**	**2.408**	**2.406**	**1.902**

TABLE 14-13
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**	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136
2	PCIA	1.265	1.230	1.230	1.294	1.228	1.032	1.163	1.083	1.111	1.145	1.041	1.169
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468
5	Resource Adequacy	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485
6	CAISO Charges	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118
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**	**12.473**	**12.438**	**12.438**	**12.502**	**12.436**	**12.240**	**12.371**	**12.291**	**12.319**	**12.353**	**12.249**	**12.377**
9	**Credits**												
10	**Class Average Generation Rate**	13.179	12.814	12.814	13.490	12.796	10.753	12.117	11.278	11.573	11.925	12.814	12.796
11	Solar Value Adjustment												
12	TOD	(4.415)	(3.921)	(3.921)	(3.278)	(3.276)	(3.129)	(1.721)	(2.774)	(2.847)	(2.934)	(3.921)	(3.276)
13	RA	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	9.684	9.813	9.813	11.132	10.440	8.544	11.316	9.424	9.646	9.911	9.813	10.440
16	**2026 Premium (cents/kwh)**	**2.789**	**2.625**	**2.625**	**1.370**	**1.996**	**3.696**	**1.055**	**2.867**	**2.673**	**2.442**	**2.436**	**1.937**

TABLE 14-14
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**	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136	7.136
2	PCIA	1.267	1.232	1.232	1.297	1.231	1.035	1.166	1.085	1.113	1.147	1.044	1.171
3	Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-
4	Marketing & Administration	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468	1.468
5	Resource Adequacy	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485	2.485
6	CAISO Charges	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118
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**	**12.475**	**12.440**	**12.440**	**12.505**	**12.439**	**12.243**	**12.374**	**12.293**	**12.321**	**12.355**	**12.252**	**12.379**
9	**Credits**												
10	**Class Average Generation Rate**	13.179	12.814	12.814	13.490	12.796	10.753	12.117	11.278	11.573	11.925	12.814	12.796
11	Solar Value Adjustment												
12	TOD	(4.415)	(3.921)	(3.921)	(3.278)	(3.276)	(3.129)	(1.721)	(2.774)	(2.847)	(2.934)	(3.921)	(3.276)
13	RA	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920	0.920
14	Other	-	-	-	-	-	-	-	-	-	-	-	-
15	**Subtotal**	9.684	9.813	9.813	11.132	10.440	8.544	11.316	9.424	9.646	9.911	9.813	10.440
16	**2026 Premium (cents/kwh)**	**2.791**	**2.627**	**2.627**	**1.373**	**1.999**	**3.699**	**1.058**	**2.869**	**2.675**	**2.444**	**2.439**	**1.939**

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 15

GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION – COST CALCULATIONS

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

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

A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) develops the necessary information as required by the Commission in Decision (D.) 12-12-033, D.14-10-033, D.15-01-024, and D.21-08-026.

This chapter partly relies on PG&E's forecast of the direct greenhouse gas (GHG) emissions compliance expenses PG&E expects to incur and record to its balancing accounts in 2026.[1]

To develop the necessary information, this chapter:

1) Adds that amount to the estimate of direct GHG emissions compliance expenses that PG&E anticipates will be recorded in 2026, which is included in the cost forecasts presented in PG&E's 2026 Energy Resource Recovery Account (ERRA) Forecast 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 2024 GHG cost forecast that was included in PG&E's 2024 ERRA Forecast proceeding, Application (A.) 23-05-012.[2]

Consistent with last year's ERRA application, A.24-05-009, PG&E utilizes California Public Utilities Commission (the Commission or CPUC) adopted D.21-08-026 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 the Decision, the Energy Division facilitated a workshop

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1 The CARB Cap-and-Trade Program results in direct GHG Compliance costs which are reflected in this chapter.

2 This testimony is being provided consistent with the CPUC direction in 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 ERRA forecast application. In D.14-10-033, the CPUC ordered PG&E, beginning in 2015, to file its GHG FR&R as part of its ERRA Forecast application.

on August 30, 2021, to discuss updates needed for existing CPUC-approved templates in order to comply with changes in crediting methodologies. In compliance with OP 13, the Joint IOUs submitted several Advice Letters (AL)[3] proposing changes to Appendix D of D.14-10-033. In its disposition of AL 6326-E, Energy Division staff approved: (1) the Joint IOUs requested changes to Templates D-1 and D-2 and associated notes pages, (2) the continued use of Template D-3 in its current form, and (3) 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 B – Calculation of Forecast GHG Costs;
- Section C – Reconciliation of Forecast GHG Costs;[4] and
- Section D – Conclusion.

B. Calculation of Forecast GHG Costs

1. Forecast Direct GHG Costs

The Direct GHG costs PG&E forecasts to incur for contracted and Utility-Owned Generation resources are included in the total costs presented in PG&E's 2026 ERRA Forecast testimony.

C. Reconciliation of Forecast GHG Costs

PG&E includes in this application a reconciliation of GHG procurement costs previously forecasted for 2024 in Portfolio Allocation Balancing Account (PABA) with recorded direct GHG costs. The 2025 GHG cost forecast will be fully-reconciled next year in the 2027 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,

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[3] 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.

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

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 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.[5]

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 with the direct emissions costs recorded in that same period. For example, GHG allowances and offset credits purchased from other third-party sellers are recorded to PG&E's inventory when they are received. Such purchased quantities of compliance instruments may be greater or lesser than PG&E's monthly emissions. For each month, GHG emissions costs were recorded in PABA based on the accrual method of accounting using the best available volume of emissions and WAC price

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5 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.

at the time the emissions costs are recorded. Physical compliance obligation costs were calculated as the WAC price of Eligible Compliance Instruments held in inventory at the end of a month multiplied by the quantity of emissions generated in that month. The accrual amount will continue to be trued-up in subsequent months as new or additional information becomes available for emission quantities and for WAC price changes.[6]

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).[7] 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$)) multiplied by emissions volumes ($/$mtCO_2e$).

---

6 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.

7 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.

Table 15-3 shows the WAC calculation and direct emissions expense recorded to the PABA in 2024, as ordered in D.14-10-033, Appendix C, corrected and replaced Attachment C in its entirety in D.15-01-024.

D. Conclusion

In this chapter, PG&E presents forecasted direct GHG costs for 2026, and a reconciliation of the 2024 GHG cost forecast, including a detailed report of the monthly WAC and direct GHG emissions quantities for 2024 used to calculate 2024 recorded direct GHG costs.

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

Line No.	Description	Forecast	Recorded	Final	Forecast	Recorded	Final	Forecast	Recorded	Final
1	Direct GHG Emissions (MT CO2e)									
2	Utility Owned Generation (UOG)									
3	Tolling Agreements									
4	Energy Imports (Specified)									
5	Energy imports (Unspecified)									
6	Qualifying Facility (QF) Contracts									
7	Contracts with Financial Settlement									
8	Subtotal									
9	**Total Emissions (MT CO2e)**	**2,805,090**	**2,137,158**	**2,360,101**	**2,179,565**	**2,179,565**	**-**	**1,747,980**	**-**	**-**
10	Proxy GHG Price ($/MT) (a)	39.62	38.65	39.14	37.58	37.58	-	32.85	-	-
11	GHG Costs ($)									
12	Direct GHG Costs (b)									
13	Direct GHG Costs - Financial Settlement									
14	Previous Year's Forecast Reconciliation (Line 21)	N/A	N/A		(14,438,958)	(14,438,958)		8,634,837	-	
15	**Total Costs ($)**	**89,829,621**	**75,390,663**	**84,025,499**	**65,645,983**	**65,645,983**		**64,661,712**	**-**	
16	Forecast Variance ($)	N/A	(14,438,958)	8,634,837	N/A	-		N/A	-	

(a) The difference between PG&E's confidential 2022 forecast GHG price and the 2022 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	2024 Forecast	2024 Recorded	2024 Final	2025 Forecast	2025 Recorded	2025 Final	2026 Forecast	2026 Recorded	2026 Final
1	Direct GHG Emissions (MT CO2e)									
2	Utility Owned Generation (UOG)									
3	Tolling Agreements									
4	Energy Imports (Specified)									
5	Energy imports (Unspecified)									
6	Qualifying Facility (QF) Contracts									
7	Contracts with Financial Settlement									
8	Subtotal									
9	**Total Emissions (MT CO2e)**	**2,805,090**	**2,137,158**	**2,360,101**	**2,179,565**	**2,179,565**	**-**	**1,747,980**	**-**	**-**
10	Proxy GHG Price ($/MT) (a)	39.62	38.65	39.14	37.58	37.58	-	32.85	-	-
11	GHG Costs ($)									
12	Direct GHG Costs (b)									
13	Direct GHG Costs - Financial Settlement									
14	Previous Year's Forecast Reconciliation (Line 21)	N/A	N/A		(14,438,958)	(14,438,958)		8,634,837	-	
15	**Total Costs ($)**	**89,829,621**	**75,390,663**	**84,025,499**	**65,645,983**	**65,645,983**		**66,055,964**	**-**	
16	Forecast Variance ($)	N/A	(14,438,958)	8,634,837	N/A	-		N/A	-	

(a) The difference between PG&E's confidential 2022 forecast GHG price and the 2022 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 4[(a)]

Date	Transaction Type (b)	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)

Compliance Period 4[(a)]								
Date	Transaction Type (b)	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)

Compliance Period 4[(a)]

Date	Transaction Type (b)	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)

	Compliance Period 4[(a)]								
	Date	Transaction Type (b)	Quantity	Cost ($/MT)	Sales price($/unit)	Total Cost ($)	Inventory Balance($)	Total Qty in Inventory	WAC ($)
776									
777									
778									
779									
780									
781									
782									

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-24	[redacted]				
Feb-24					
Mar-24					
Apr-24					
May-24					
Jun-24					
Jul-24					
Aug-24					
Sep-24					
Oct-24					
Nov-24					
Dec-24					

Transaction Type Definition:

Purchase — Purchase of compliance instruments

Retirement — Compliance instruments retired to CARB or transferred to a third-party

[redacted]

Wacog Adjustment — Premium paid to a third-party relating to the purchase of compliance instruments.

Notes:

[redacted]

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

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

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

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

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 16

GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION – ADMINISTRATIVE AND OUTREACH EXPENSES

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

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

A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) presents its 2024 recorded and 2026 forecasted greenhouse gas (GHG) administrative and outreach (A&O) expenses for reasonableness review, as directed by the California Public Utilities Commission (CPUC or Commission) 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]

B. GHG Administrative Recorded and Forecast Expenses

1. Recorded Administrative Expenses

In 2024, PG&E incurred approximately $0.544 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 Emissions-Intensive and Trade-Exposed (EITE) customers. A breakdown of the total can be found in Table 16-1.

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1 Ordering Paragraph (OP) 23 and 24.

2 OP 9, 10, and 11.

3 OP 6, 9 and 10.

4 OP 4.

5 OP 7 and 8.

6 OP 5.

7 Findings 7 and 13.

TABLE 16-1
2024 RECORDED ADMIN EXPENSES
(IN MILLIONS OF DOLLARS)

Line No.	Admin	Expenses
1	Program Management	$0.288
2	Information Technology (IT) Billing	0.040
3	Call Center	0.215
4	Total	$0.544

2. Forecast Administrative Expenses

In 2026, PG&E expects to incur approximately $0.593 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.

TABLE 16-2
2026 FORECAST ADMIN EXPENSES
(IN MILLIONS OF DOLLARS)

Line No.	Admin	Expenses
1	Program Management	$0.315
2	IT Billing	0.047
3	Call Center	0.230
4	Total	$0.593

The Program Management forecast expense is approximately $0.315 million. This includes $0.289 million to administer the GHG revenue return and $0.026 million to host and maintain the EITE attestation website.[8] 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.

8 Res.E-4716, OP 2.

Due to the complexities associated with matching California Air Resources Board'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.

The IT/billing system forecast expense is approximately $0.047 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 $0.230 million and includes call center operations support for CCC and SMB customers and assigned account representatives for EITE customers. PG&E's 2026 customer inquiry support forecast assumes a similar call volume as 2024.

C. GHG Customer Outreach Recorded and Forecast Expenses

1. Recorded Outreach Expenses

The 2024 total recorded outreach expense of $0.165 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.

TABLE 16-3
2024 RECORDED OUTREACH EXPENSES
(IN MILLIONS OF DOLLARS)

Line No.	Outreach	Expenses
1	Marketing Materials	$0.124
2	Labor	0.041
3	Total	$0.165

a. CCC/SMB/EITE

Pursuant to Res.E-4611,[9] D.16-06-041,[10] D.21-08-026[11] and Res.E-5339,[12] PG&E distributed 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 2024 expenditure of $0.165 million, PG&E incurred $0.124 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 or by their financial institution 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 $0.041 million to administer these outreach efforts.

2. Forecast Outreach Expenses

For 2026, PG&E estimates approximately $0.219 million to administer CCC, SMB, EITE credit outreach. A breakdown of the total can be found in Table 16-4.

---

9 Addressed Education and Outreach plans for GHG allowance revenue return.

10 OP 1 and 2.

11 OP 7.

12 OP 4 and 6.

TABLE 16-4
2026 FORECAST OUTREACH EXPENSES
(IN MILLIONS OF DOLLARS)

Line No.	Outreach	Forecast
1	CCC Marketing Materials	$0.130
2	SMB Marketing Materials	0.022
3	EITE Marketing Materials	0.002
4	Labor	0.065
5	Total	$0.219

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.

a. Residential Climate Credit

PG&E forecasts approximately $0.130 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 April and October. The content of these communications is provided by the Energy Division staff, and the same content is expected to be authorized for use in 2026. PG&E plans to use the following outreach methods to notify residential customers of the CCC during April and October:

1) A 1-panel bill insert in April and October bill packages to approximately 2.9 and 2.6 million electric customers, respectively;
2) An email message to PG&E's electronically billed residential customers;
3) An email message sent by third-party financial institutions, on behalf of PG&E, to residential customers who uses these institutions' electronic billing systems to pay their utility bills. Third-party institutions bill PG&E for the costs associated with sending the email to customers using their e-bill system;
4) A letter to approximately 73,500 and 37,000 master-meter customers sent during April and October, 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

5) 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[13] to SMB customers. This outreach includes:

1) A 1-panel bill insert in April and October bill packages to approximately 1.0 million total eligible customers, 0.500 million during April and October**;**
2) An email message to eligible SMB customers who are electronically billed through PG&E; and
3) An email message to notify SMB entities exceeding the 100+ account cap, and their eligibility change for the current year to receive the credit.[14]

c. EITE Credit

PG&E forecasts that it will incur expenses of approximately $0.002 million for outreach to EITE customers in 2026. This outreach will include:

1) Email notification to eligible customers; and
2) A letter to customers who requests their EITE credit in the form of a check, rather than an on-bill credit.

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.

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13 D.21-08-026, OP 7.

14 Fn. 12.

D. Conclusion

In this chapter, PG&E describes its 2024 recorded and 2026 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) 2024 recorded A&O expenses of $0.708 million; and
2) 2026 forecast A&O expenses of $0.812 million.

TABLE 16-5
DETAIL OF A&O EXPENSES 2024-2026
(TEMPLATE D-3)
(THOUSANDS OF DOLLARS)

Template D-3: Detail of Outreach and Administrative Expenses (In $'000)

		2024		2025		2026	
Line	Description	Forecast	Recorded	Forecast	Recorded*	Forecast	Recorded
1	**Utility Administrative**						
2	General Program Management	451	288	360	68	315	
3	IT/Billing System Enhancements	42	40	215	23	47	
4	Customer Inquiry Support Cost	172	215	180	12	230	
5	**Subtotal Administrative**	666	544	754	103	593	
6	**Utility Outreach**						
7	Marketing - Internal						
8	Marketing - Contract/Consultant						
9	Targetbase						
10	Customer Outreach & Education	177	164	193	22	219	
11	**Subtotal Outreach**	177	164	193	22	219	
12	**Utility Outreach and Administrative Expenses (Line 5 + Line 11)**	843	708	947	126	812	
13	**Additional (Non-Utility) Statewide Outreach**			-		-	
14	**Total Outreach and Administrative Expenses (Line 12 + Line 13)****	843	708	947	126	812	

Information not yet available

*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

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

A. Introduction

Pursuant to Decision (D.) 12-12-033,[1] D.14-10-033,[2] D.15-01-024,[3] and D.21-08-026[4] Pacific Gas and Electric Company (PG&E) presents its: (1) forecasted 2026 greenhouse gas (GHG) allowance return revenue requirement; and (2) 2025 year-end forecast balance, including reconciliation of the GHG Revenues Subaccount within the Greenhouse Gas Revenue Balancing Account (GHGRBA), as well as (3) the methodology for returning GHG allowance revenue to eligible customers. The methodologies discussed, and tables included in this testimony are in accordance with the California Public Utilities Commission (CPUC or Commission) requirements as ordered in D.12-12-033, D.14-10-033, D.15-01-024, and D.21-08-026.[5]

Ordering Paragraph (OP) 1 of D.15-01-024 requires PG&E and the other Investor-Owned Utilities (IOU) 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

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

> Beginning in 2014, the [GHG forecast revenue and reconciliation] applications must also include a detailed accounting of actual GHG costs incurred for the previous year as well as revenues distributed to eligible customers classes.
>
> The presentation of GHG costs is discussed in Chapter 16.

2 D.14-10-033, OP 10 requires PG&E to file its "greenhouse gas forecast revenue and reconciliation request as an additional chapter or section within its annual Energy Resource Recovery Accounts … forecast application."

3 D.15-01-024 corrected certain errors to tables initially published as part of D.14-10-033

4 D.21-08-026, OP 13 (ordering revisions to the applicable templates following a workshop and advice letter process). Following such a process, the Commission approved Advice Letter (AL) 6326 E-C, approving revisions to Templates D-1 and D-2 and associated notes pages, directing the continued use of Template D-3 in its current form, and the removal of Templates D-4 and D-5.

5 D.12-12-033, OP 23; D.14-10-033, OPs 5, 9 and 10; D.15-10-024, OP 1; and D.21-08-026, OP 13.

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.

TABLE 17-1
(TEMPLATE D-1)
ANNUAL ALLOWANCE REVENUE RECEIPTS AND CUSTOMER RETURNS
(THOUSANDS OF DOLLARS)

Template D-1: Annual Allowance Revenue Receipts and Customer Returns (In $000)

Line	Description	2024 Forecast [1]	2024 Recorded	2025 Forecast [1]	2025 Recorded [2]	2026 Forecast	2026 Recorded
1	**Proxy GHG Price ($/MT)**	$39.62	N/A	$37.58	N/A	$32.87	
2	**Allocated Allowances ('000 MT) [3]**	16,757	16,364	21,426	21,070	23,023	
3	**Revenues**						
4	Prior Balance (From Line 31 of previous year)	(53,866)	(69,693)	53,324	28,767	150,034	
5	Allowance Revenue	(663,932)	(576,556)	(805,193)	(633,312)	(756,770)	
6	Interest		(2,999)		2,710		
7	Revenue Franchise Fees and Uncollectibles (RF&U)	(7,394)	(7,244)	(8,016)	(8,016)	(7,160)	
8	**Subtotal Revenues**	(725,192)	(656,492)	(759,885)	(609,851)	(613,895)	
9	**Expenses**						
10	Outreach and Administrative Expenses	808	695	817	674	820	
11	RF&U						
12	Interest	(112)		(144)		(183)	
13	**Subtotal Expenses**	695	695	674	674	637	
14	**Allowance Revenue Approved for Clean Energy or Energy Efficiency Programs**	33,208	33,208	38,303	38,303	34,232	
	(a) SOMAH including true-ups	28,165	28,165	34,626	34,626	15,196	
	(b) DAC-SASH	4,370	4,370	4,370	4,370	4,370	
	(c) DAC-GT and CS-GT including true-ups	9,947	9,947	5,664	5,664	18,219	
	(d) CCAs' DAC-GT and CS-GT including true-ups	3,668	3,668	9,667	9,667	13,206	
	(e) 2023/2024 CCA Disbursement Reconciliation to PG&E	812	812	34	34	(715)	
	(f) Funding from Public Purpose Program (PPP)	(13,754)	(13,754)	(16,059)	(16,059)	(16,046)	
15	**Net GHG Revenues (Line 8 + Line 13 + Line 14)**	(691,289)	(622,590)	(720,909)	(570,875)	(579,026)	
16	**GHG Revenues to be Distributed in Future Years**						
17	**Net GHG Revenues Available for Customers in Forecast Year(Line 15 + Line 16)**	(691,289)	(622,590)	(720,909)	(570,875)	(579,026)	
18	**GHG Revenue Returned to Eligible Customers**						
19	EITE Customer Return	43,242	41,916	42,978	42,978	51,257	
20	Small Business Volumetric Return	0	0	0	0	0	
21	Residential Volumetric Return	0	2	0	0	0	
22	**Subtotal EITE + Volumetric Returns**	43,242	41,918	42,978	42,978	51,257	
23	**Semi-Annual Climate Credit [4]**						
24	Number of Households Eligible for the California Climate Credit						
25	Number of Eligible Residential Bundled Households	1,973,235	1,863,785	1,868,362	1,868,362	1,821,224	
26	Number of Eligible Residential Unbundled Households	3,419,100	3,219,592	3,559,652	3,559,652	3,652,541	
27	Number of Eligible Small Business Customers	480,629	439,698	393,473	393,473	379,232	
28	**Total Customers Eligible for Climate Credit (Sum 24..27)**	5,872,964	5,523,075	5,821,487	5,821,487	5,852,997	
29	**Per - Customer Semi-Annual Climate Credit (0.5 x (Line 17 + 22) ÷ Line 28)**	(55.17)	(55.17)	(58.23)	(58.23)	(45.09)	
30	**Total Revenue Distributed for the Climate Credit (2 x Line 28 x Line 29)**	(648,047)	(609,439)	(677,931)	(677,931)	(527,770)	
31	**Revenue Balance (Line 17 + Line 22 - Line 30)**	0	28,767	0	150,034	0	
			0				

Information not yet available

Note 1 "Forecast" are derived from corresponding tables authorized by the Commission in D.23-12-022 and D. 24-12-038.

Note 2 2025 "Recorded" includes January through March 2025 recorded, plus forecast through the rest of the year.

Note 3 Forecast based on "Unofficial electronic version of the Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms "

Note 4 2024 and 2025 "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.

The remainder of this chapter further describes the items reflected in the forecast 2026 column Table 17-1.

- Section B – Forecast 2026 Net Available GHG Allowance Proceeds;
- Section C – Low-Income and Disadvantaged Community Solar Programs Funded in Whole or in Part from the GHG Allowance Revenues;
- Section D – Amortization of the 2025 Year-End Forecast Balance;
- Section E – Forecast 2026 GHG Allowance Return Revenue Requirement;
- Section F – Distribution of 2026 GHG Allowance Revenue Return; and
- Section G – Conclusion.

B. Forecast 2026 Net Available GHG Allowance Proceeds

Pursuant to D.12-12-033 and D.14-10-033, PG&E's forecast 2026 net available GHG allowance proceeds for distribution to eligible customers is calculated after setting aside the following from its forecast 2026 GHG Allowance Revenue Proceeds:

- GHG Administrative and Outreach (A&O) Expenses; and
- Clean Energy and Energy Efficiency (CEEE) Funds.

Below are details of the calculation of the forecast 2026 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.[6]

PG&E's forecast of 2026 GHG allowance allocation (measured in metric tons (MT)) is approximately 23.0 million MT, based on 2026 allowances allocated to PG&E as reflected in the "Unofficial electronic version of the Regulation for the California Cap on GHG Emissions and Market-Based Compliance Mechanisms" produced by CARB (the Cap-and-Trade

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6 D.14-10-033, p. 5.

Regulation).[7] Using the proxy price of $32.87/MT, shown in Table 17-1, line 1, PG&E's forecasted 2026 GHG allowance revenue proceeds are $756.8 million, as shown in Table 17-1, line 5. PG&E will provide an updated forecast in its Fall Update to Prepared Testimony (Fall Update) that incorporates any regulatory and market changes to the 2026 allowance allocation and proxy price.

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 $0.637 million to pay for the 2026 forecast GHG A&O expenses, as shown in Table 17-2, line 15, Column E below.

Since inception, the Commission had authorized PG&E to set aside a total of $12.6 million to pay for its GHG A&O expenses (See Table 17-2, line 15, Column A). Recorded and Forecast GHG A&O expenses is $13.4 million, as shown in Table 17-2, line 15, Column B, resulting in a shortfall of $0.820 million, as shown in Table 17-2, line 15, Column C.[8] After deducting the $0.183 million recorded accumulated balancing account interest as of December 2024[9] (see Table 17-2, line 14, Column D), the cumulative set aside amount required by PG&E to pay for its 2026 GHG A&O Expenses is $0.637 million as shown in Table 17-2, line 15, Column E. These amounts will be updated in the Fall Update of this application.

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7 The unofficial version of the Cap-and-Trade Regulation is available at: Cap-and-Trade Regulation (Unofficial Electronic Version). Table 9-4 is provided in Section 95892. PG&E's allocation is located on p. 215, third row of the table.

8 Recorded A&O Expenses as of December 2023 is $10.9 million. Forecast GHG A&O Expenses refer to 2025 Forecast GHG A&O Expenses of $0.8 million authorized in D.23-12-022 and 2026 Forecast GHG A&O Expenses of $0.8 million requested in Chapter 17 of this application.

9 Consistent with recorded GHG A&O expenses, recorded balancing account interest of partial test year 2025 is not included in the table.

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	(947)	(273)		(273)
14	2026	A. 25-05-XXX		(812)	(812)		(812)
15	**Total**		**12,588**	**(13,408)**	**(820)**	**183**	**(637)**

Note 1: Recorded through 2024 is $11.649 million and Forecast 2025 and 2026 is $1.759 million.
Note 2: A full year of 2025 recorded Balancing Account interest is not yet available

3. Clean Energy and Energy Efficiency Funds

Public Utilities Code (Pub. Util. Code) Section 748.5(c) provides that the Commission may allocate up to 15 percent of the GHG allowance revenues to fund authorized CEEE projects that are not otherwise funded by another source. Accordingly, up to 15 percent or $113.5 million, as presented in Table 17-9, line 1, can be set-aside in 2026 from GHG allowance revenues for CEEE Programs.

Including a subtotal true-up amount of $8.4 million over-collected[10] and as discussed in Section C of this testimony, the total amount PG&E is proposing to set-aside in this application is $34.2 million, as presented in Table 17-1, line 14.[11] These amounts are subject to further review of forecast and actual expenditures for these programs.

[10] See Table 17-8, lines 3, 9, and 10.

[11] See also Table 17-8, line 14.

C. Low-Income and Disadvantaged Community Solar Programs Funded in Whole or in Part from the GHG Allowance Revenues

1. Introduction

PG&E currently has three CEEE programs 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). Throughout 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 plans to formally close this program in 2025. Additionally, PG&E also funds the DAC-GT (and previously CS-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.

2. SOMAH Program

In 2015, the Legislature enacted Assembly Bill 693 establishing the SOMAH Program,[12] directing the CPUC to use 10 percent of GHG allowance funding for the program, up to a state-wide total of $100 million annually. The SOMAH Program was established by the CPUC in December 2017 with D.17-12-022. The Center for Sustainable Energy was selected to administer the SOMAH Program, which provides incentives for solar on multi-family housing. The five IOUs[13] 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.[14]

PG&E expects the total GHG revenues from all IOUs will exceed $1 billion for 2025 and 2026. In accordance with D.22-09-009, if the

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12 This bill added Pub. Util. Code Section 2870.

13 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).

14 D.20-02-047, pp. 21-22.

combined forecasted GHG revenue of the IOUs is likely to exceed $1 billion, the IOUs are required to allocate their annual proportionate share limit of $100 million. For PG&E, this equates to $39.76 million in a full program funding year.[15]

However, D.20-04-012 stipulates that, through its ERRA forecast proceeding, PG&E should propose funding for the SOMAH Program until June 30, 2026.[16] As illustrated in Table 17-3 below, since the combined forecasted GHG proceeds for 2026 from the three large IOUs significantly exceed $1 billion, PG&E's proposed set aside for SOMAH in 2026 is $19.88 million, which represents funding for half of the typical program year.

TABLE 17-3
IOU GHG PROCEEDS TO DETERMINE SOMAH SHARE METHODOLOGY

Line No.	IOU	2024 Recorded GHG Proceeds	2025 Forecasted GHG Proceeds[(a)]	2026 Forecasted GHG Proceeds
1	PG&E	$576,556,216	$633,312,006	$756,769,724
2	SCE	819,525,252	692,052,757	742,685,133
3	SDG&E	223,553,623	215,658,541	208,453,607
4	Total	$1,619,635,091	$1,541,023,304	$1,707,908,464

(a) 2025 Forecasted GHG Proceeds includes January through March recorded values plus April through December forecast for PG&E, SCE, and SDG&E. The final 2025 Recorded GHG Proceeds for all IOUs, including PacifiCorp and Liberty, will be updated in the True-Up Advice Letter to be filed by March 1, 2026.

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.[17] The total recorded GHG revenues from the IOUs in 2024 exceeded $1 billion. Therefore, in AL 7521-E-B[18] PG&E presented its 2024 SOMAH true-up (credit) amount

15 D.22-09-009, Table 2, p. 11 and OP 3, p. 14.

16 D.20-04-012, OP6.

17 D.17-12-022, OP 7, pp. 69-70.

18 See, PG&E AL 7521-E-B, available at: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7521-E-B.pdf.

and proposed to credit the $4.68 million over forecast for 2024 to the 2026 set aside amount, as reflected in Table 17-8. The credit for the 2024 true-up is not included in the 15 percent CEEE allowance calculation for 2026 but is within the 15 percent allowance calculation for 2024.

Pursuant to D.20-04-012, Table 17-4 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.[19] Collections for prior years (2016-2023) are under the 15 percent allowance for the respective year each collection would have occurred.

TABLE 17-4
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	–
2	2017	345,513,934	34,551,393	34,551,393	–
3	2018	348,098,763	34,809,876	34,809,876	–
4	2019	389,040,958	38,904,096	38,904,096	–
5	2020	385,893,957	38,589,396	38,589,396	–
6	2021	384,773,215	34,518,517	34,518,517	–
7	2022	486,243,930	34,816,563	34,816,563	–
8	2023	544,616,174	34,626,367	34,626,367	–
9	2024	576,556,216	35,074,821	39,757,379	$4,682,558
10	Total	$3,762,407,303	$300,974,537	$305,657,095	$4,682,558

(a) Years 2016 through 2022 include already-executed true-ups: Years 2016-2018 include true-ups for previous under-collections, which were collected in 2020 ($29.52 million) per D.20-02-047 and 2021 ($4.45 million) per D.20-12-038. Year 2019 includes the true-up ($1.17 million under-collected), which was collected in 2019. 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 over-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 is the actual set aside performed quarterly in 2024 based on the forecast approved in D.23-12-022. Year 2024 is the only year with a pending true-up ($4.68 million over-collected), which PG&E proposes to net from the 2026 SOMAH set aside request.

(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.

19 D.20-04-012, Table 1: Recorded and Forecasted GHG Revenues, p. 3.

3. DAC-SASH Program

In D.18-06-027, in order to implement the Legislature's directive,[20] the Commission created the DAC-SASH Program, designed to incentivize the installation of solar generation on low-income single-family homes in disadvantaged communities. GRID Alternatives was selected to administer the DAC-SASH Program. The annual budget is $10 million statewide, apportioned among the IOUs. PG&E's share of the $10 million is $4.37 million annually.[21]

In that same decision, the Commission established the DAC-GT and CS-GT Programs, with no specific funding minimum or maximum. D.18-06-027 directed the IOUs to fund the DAC-SASH, DAC-GT, and CS-GT Programs first from GHG revenues, and then through Public Purpose Program (PPP) funds if the GHG revenues were exhausted.

In 2025 and 2026, the DAC-SASH budget is $4.37 million each year. For 2025 and 2026, GHG revenues are sufficient to fund DAC-SASH fully, and PPP funds are not anticipated to be needed.

Pursuant to D.18-06-027, DAC-SASH expenses are reviewed annually in the ERRA Compliance Review proceeding.[22] 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.[23] The 2024 ERRA Compliance Review proceeding (A.25-02-013) is in progress. Review of the DAC-SASH balancing and memorandum accounts is expected in late May 2025.

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20 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).)

21 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.

22 D.18-06-027, OP 8, pp. 102-103.

23 Applications (A.) 20-02-009, A.21-03-008, A.22-02-015, A.23-02-018, A. 24-02-012.

4. DAC-GT and CS-GT Programs

In D.18-06-027, in order to implement legislative direction,[24] 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 DACs. The DAC-GT Program is similar to PG&E's Green Tariff Program, available to all customers, with the critical differences that it is available only to low-income residential customers in DACs and that participants are provided a 20 percent bill discount, compared to their otherwise-applicable tariff.[25] As mentioned earlier, D.24-05-065 discontinued the CS-GT Program. Therefore, no IOUs or CCAs requested funding for CS-GT in 2026, though 2024 CS-GT true-ups are included. PG&E plans to formally close the CS-GT Program in 2025.

D.18-06-027 set no budget for the DAC-GT and CS-GT Programs, 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,[26] the CARB prohibits using GHG funds to deliver volumetric discounts. Beginning with its 2022 ERRA Forecast filing, generation costs are funded from GHG proceeds and all other costs are funded from PPP for both PG&E and the CCAs' DAC-GT and CS-GT Programs. 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 Budget AL.

PG&E requested a DAC-GT budget for Program Year (PY) 2026 and a true-up for PY 2024 in AL 7554-E, as shown in Table 17-5 below. For all other costs except generation resources, PG&E intends to request $10.6 million for the PG&E DAC-GT program from PPP funds in the AET.[27]

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[24] See Pub. Util. Code § 2827.1(b)(1).

[25] D.18-06-027, pp. 50-53.

[26] See PG&E AL 6308-E, available at: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6308-E.pdf.

[27] $10.6 million is the anticipated PPP funding need, based on the net 2024 true-up and 2026 PPP funding request for DAC-GT, as shown in Table 17-5.

TABLE 17-5
FUNDING REQUESTS FOR PG&E'S DAC-GT AND CS-GT PROGRAMS

Line No.	PG&E Program	PPP 2024 True-Up[a]	PPP 2026 Funding[b]	GHG 2024 True-Up[a]	GHG 2026 Set Aside	Total
1	DAC-GT	$(1,663,347)	$12,312,335	$2,174,665	$11,334,222	$24,157,875
2	CS-GT[c]	–	–	(5,938,644)	–	(5,938,644)
3	Total	$(1,663,347)	$12,312,335	$(3,763,979)	$11,334,222	$18,219,231

(a) The 2024 DAC-GT PPP and GHG true-ups are final actuals-based as described in the approved PG&E Budget AL 7554-E-A.

(b) This is a sum of the five budget line items (20 percent bill discount, program management costs, IT costs, program evaluator costs, and CCA integration costs) in AL 7554-E-A to be funded from PPP. This does not include CCA PPP true-up costs.

(c) The 2024 CS-GT PPP true-up resulted in an overcollection of ($87,230). However, since the CS-GT Program concluded in 2024, and consistent with the 2026 budget advice letter filed on April 1, 2025, both the ($87,230) 2024 CS-GT PPP overcollection and the 2023 CS-GT PPP overcollection of ($2,215,431), totaling ($2,302,662), are deducted from the 2026 DAC-GT PPP funding request. Therefore, the 2024 CS-GT PPP true-up is shown as $0 above. Upon approval of the budget advice letter, PG&E will transfer any remaining CS-GT PPP balance to the DAC-GT balancing account.

Pursuant to D.18-06-027, DAC-GT and CS-GT expenses are reviewed annually in the ERRA Compliance proceeding,[28] in which PG&E has presented the costs recorded to the DAC-GT and CS-GT subaccounts in the Public Policy Charge Balancing Account for years 2019-2023.[29] The 2024 ERRA Compliance Review proceeding (A.25-02-013) is in progress. Review of the DAC-GT and CS-GT balancing accounts is expected in late May 2025.

5. CCAs' DAC-GT and CS-GT Budget Requests

Under D.18-06-027, CCAs may choose to offer their own versions of the DAC-GT and CS-GT Programs. In PG&E territory, there are five CCAs that typically submit budget ALs for DAC-GT and CS-GT. The CCAs that typically request DAC-GT and CS-GT Program budgets for the subsequent year and carryover from the prior Program Year are:

- Marin Clean Energy (MCE);
- Ava Community Energy (Ava);

28 D.18-06-027, OP 10, p. 103.

29 A.20-02-009, A.21-03-008, A.22-02-015, A.23-02-018, and A.24-02-012.

- San Jose Clean Energy (SJCE);
- Peninsula Clean Energy (PCE); and
- CleanPower SF (CPSF)

In accordance with Decision 24-05-065, the CCAs have also discontinued their CS-GT Programs. Consequently, they have only requested funding for their DAC-GT programs for the year 2026. Table 17-6 presents the funding requests in accordance with each of the CCA's 2026 budget advice letters submitted on April 1, 2025. This table details the 2026 funding requests and the 2024 true-ups for the CCAs' DAC-GT and CS-GT Programs, categorized by PPP and GHG funding sources. These will be validated and updated, as necessary, upon the approval of these budget advice letters in PG&E's ERRA Forecast Fall update.

TABLE 17-6
FUNDING REQUESTS FOR CCA PROGRAMS

		PPP		GHG		
Line No.	CCA	2024 True-Up	2026 Funding[(a)]	2024 True-Up	2026 Set Aside	Total
1	MCE	$152,929	$1,980,832	$(426,718)	$921,536	$2,628,579
2	Ava	(256,746)	2,576,901	622,374	4,326,339	7,268,868
3	SJCE	(137,118)	384,838	(2,217)	183,751	429,254
4	PCE	78,520	957,428	210,618	1,229,386	2,475,953
5	CPSF	(75,561)	449,011	(225,895)	256,250	403,805
6	Total	$(237,976)	$6,349,010	$178,162	$6,917,262	$13,206,459

(a) This is the sum of the bill discount, program administration subtotal, and the marketing, evaluation, and outreach (ME&O) subtotal in the CCAs' budget advice letters to be funded from PPP.

6. PPP Funding for CEEE Programs

To provide a complete picture of the program funding requests, Table 17-7 below reflects the forecasted funding for CEEE programs to be recovered through PPP as described previously, which include all costs except generation costs for the DAC-GT and CS-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 CCA's budget ALs will be included in PG&E's ERRA Forecast Fall update.

TABLE 17-7
FORECASTED PPP FUNDING FOR CEEE PROGRAMS

Line No.	CEEE Program PPP Funding Request[a]	2025	2026
1	PG&E's DAC-GT	$6,872,838	$12,312,335
2	PG&E's CS-GT	–	–
3	PG&E's DAC-GT 2023 True-Up	2,750,370	–
4	PG&E's CS-GT 2023 True-Up[b]	–	–
5	PG&E's DAC-GT 2024 True-Up	–	(1,663,347)
6	PG&E's CS-GT 2024 True-Up[b]	–	–
7	CCAs' DAC-GT and CS-GT	6,068,943	6,349,010
8	CCAs' DAC-GT and CS-GT 2023 True-Up	332,928	–
9	CCAs' DAC-GT and CS-GT 2024 True-Up	–	(237,976)
10	2023 CCA Disbursement Reconciliation to PG&E	34,195	–
11	2024 CCA Disbursement Reconciliation to PG&E	–	(714,507)
12	Total PPP Funds	$16,059,274	$16,045,516

(a) DAC-GT and CS-GT costs except generation costs are funded from PPP.

(b) The 2023 and 2024 CS-GT PPP true-ups resulted in an overcollection of ($2,215,431) and ($87,230), respectively. Since the CS-GT program concluded in 2024, and consistent with the 2026 budget advice letter filed on April 1, 2025, both overcollections, totaling ($2,302,662), are deducted from the 2026 DAC-GT PPP funding request. Therefore, the 2023 and 2024 CS-GT PPP true-ups are shown as $0 above. Upon approval of the budget advice letter, PG&E will transfer any remaining CS-GT PPP balance to the DAC-GT balancing account.

7. GHG Funding for CEEE Programs

Table 17-8 below lists the program-by-program 2025 and 2026 set aside amounts from GHG funding.

TABLE 17-8
FORECASTED GHG FUNDING FOR CEEE PROGRAMS

Line No.	CEEE Program GHG Set Aside[a]	2025	2026
1	SOMAH	$39,757,379	$19,878,689
2	SOMAH 2023 True-Up[b]	(5,131,012)	–
3	SOMAH 2024 True-Up[c]	–	(4,682,558)
4	DAC-SASH	4,370,000	4,370,000
5	PG&E's DAC-GT	4,742,848	11,334,222
6	PG&E's CS-GT	–	–
7	PG&E's DAC-GT 2023 True-Up	(2,883,049)	–
8	PG&E's CS-GT 2023 True-Up	(5,818,644)	–
9	PG&E's DAC-GT 2024 True-Up	–	2,174,665
10	PG&E's CS-GT 2024 True-Up	–	(5,938,644)
11	CCAs' DAC-GT and CS-GT	3,944,204	6,917,262
12	CCAs' DAC-GT and CS-GT 2023 True-Up	(679,154)	–
13	CCAs' DAC-GT and CS-GT 2024 True-Up	–	178,162
14	Total GHG Funds	$38,302,572	$34,231,799

(a) DAC-GT and CS-GT GHG set asides will be used for generation resource costs only.

(b) Pursuant to Table 17-4, PG&E's proportional share of 2023 SOMAH funding was $34.63 million, resulting in an over-collection of $5.13 million. This $5.13 million credit amount is not included in the CEEE allowance cap calculation for 2025 in Table 17-9.

(c) Pursuant to Table 17-4, PG&E's proportional share of 2024 SOMAH funding was $35.10 million, resulting in an over-collection of $4.68 million. This $4.68 million credit amount is not included in the CEEE allowance cap calculation for 2026 in Table 17-9.

PG&E proposes to set aside $34.2 million from GHG allowance revenues for CEEE programs in 2026. This includes 2024 true-ups for the SOMAH Program, half a year of 2026 SOMAH funding, 2024 true-ups from PG&E and the CCAs' DAC-GT and CS-GT Programs, and expanded DAC-GT programs. PG&E proposes to exclude the SOMAH true-up from the 15 percent cap for 2024 since it is associated with a prior year. Instead, PG&E will ensure that any true-up amounts from the DAC-GT and CS-GT Programs and the SOMAH *true*-up are still within the 15 percent cap as applied in the relevant year.

Total available CEEE funds for 2026 based on 15 percent of forecasted allowance revenues are forecasted to be $113.5 million. Excluding prior year true-ups, the forecasted set asides from GHG revenues for year 2026 total $42.5 million, which is below the CEEE cap of $113.5 million for 2026. Table 17-9 below reflects the CEEE 15 percent cap for GHG funds.

TABLE 17-9
GHG ALLOWANCE FOR CEEE PROGRAMS

Line No.	Clean Energy and Energy Efficiency Program Set Aside	2024	2025	2026
1	CEEE 15% Allowance from GHG Funds[(a)]	$86,483,432	$94,996,801	$113,515,459
2	SOMAH	35,074,821	39,757,379	19,878,689
3	DAC-SASH	4,370,000	4,370,000	4,370,000
4	PG&E's DAC-GT	2,174,665	4,742,848	11,334,222
5	PG&E's CS-GT	(5,938,644)	–	–
6	CCAs' DAC-GT and CS-GT	2,399,586	3,944,204	6,917,262
7	CEEE Programs Funds Subtotal	$38,080,428	$52,814,431	$42,500,173
8	Remaining CEEE Funds (line 1-line 7)	$48,403,004	$42,182,370	$71,015,285

(a) 15 percent of line 5 in Table 17-1.

For 2026, it is forecasted that $71.0 million remain for CEEE programs funded from GHG proceeds. PG&E anticipates there will be remaining CEEE funds from GHG proceeds over the next few years.

The GHG revenue forecasts and CEEE program set aside amounts will be reviewed and refreshed in the Fall Update.

D. Amortization of the 2025 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 2024 year-end recorded balance of the subaccount was $29 million under-collected. A comparison between the recorded and forecasted 2024 transactions is shown in Table 17-1, lines 3 through 31. The primary reason for the under-collection is due to lower-than-forecast recorded GHG allowance revenue proceeds resulted from the lower-than-forecast allocated allowances.

Based on recorded transactions through March 2025, and forecast amounts from April 2025 through December 2025, the GHG Revenue Subaccount is forecast to be $143 million under-collected by year-end 2025, as presented in Table 17-1, line 31. PG&E will update the year-end 2025 balance in the Fall Update and will amortize any remaining balance in the 2026 AET process, or subsequent electric rate change authorized by the Commission.

E. 2026 GHG Allowance Return Revenue Requirement

As shown in Table 17-1, line 17, PG&E's 2026 GHG allowance return revenue requirement to be included in its 2026 electric rates is $586.4 million, comprised of the following components:

- Forecast 2026 GHG allowance revenue, after setting aside the GHG Expenses and CEEE Funds is $721.9 million, as discussed in Section B and C;
- Less: The forecast 2025 GHG Revenues Subaccount *under*-collected balance within the GHGRBA of $142.7 million, as discussed in Section D; and
- Plus: An allowance of Revenue Fees and Uncollectibles (RF&U) of $7.3 million (see Table 17-1, line 7).[30]

The forecast 2026 GHG allowance revenue requirement will be updated in the Fall Update, and effective on or after January 1, 2026, through the AET process, or subsequent electric rate change.

F. Distribution of 2026 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 California Climate Credit (CCC) for residential households and eligible small business customers).[31]

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30 Calculated based on the RF&U Factor authorized by the Commission in Tier 1 AL 4889-G/7419-E.

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

a. EITE Revenue Return

D.12-12-033 requires that EITE entities receive allowance revenues to cover all or a portion of their GHG compliance costs in the form of a yearly on-bill credit or rebate check.[32] Customers that are either identified as EITE by 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, now called the "California Industry Assistance."

In 2020 CARB indicated that it will no longer allocate allowances to utilities for the cap-and-trade cost burden of the electricity used by the large EITE entities that it regulates.[33] Instead, CARB intends to directly allocate allowances to EITE entities itself for this purpose, without going through the utilities.[34] However, pursuant to D.21-08-026, in order to ensure that customers do not miss an EITE credit, PG&E will continue to allocate EITE credits to all eligible customers until CARB takes over distribution to the large customers it manages.

In order to forecast the EITE credit, the 2026 forecasted return is set to be equal to the recorded 2025 return for each rate schedule and adjusted for forecasted sales changes between 2025 and 2026. Total revenue for the EITE return is given in Table 17-1, line 19.

b. Semi-Annual CCC Payment

As the Commission directed in D.12-12-003, all residential households receive a CCC distributed as a separate on-bill line item

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32 *Id.*, OP 25.

33 CARB 2016 Cap-and-Trade Regulation (effective Oct. 1 2017), available at: https://ww3.arb.ca.gov/regact/2016/capandtrade16/capandtrade16.htm.

34 See CARB Final Statement of Reasons for the 2016 Cap-and-Trade Regulation (e.g., Staff "Having a single agency–ARB–distribute this value to all industrial covered entities will help ensure that allocation is done in a manner that is timely and consistent with the Regulation, and will ensure that industrial covered entities in publicly owned utility (POU) and electrical cooperative (co-op) territory are provided the same leakage protection as IOU customers.") Available at: https://ww3.arb.ca.gov/regact/2016/capandtrade16/ctfinsor.pdf.

credit twice a year—every April and October billing cycle.[35] 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.[36] In equation form, this calculation is as follows:

FIGURE 17-1
CCC CALCULATION EQUATION

$$\frac{1}{2} \times \frac{\text{Total Annual Climate Credit Revenue}}{\text{Eligible Single Meter Residential \& Small Business Accounts + (MM Sub-accounts – MM Host Accounts)}}$$

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.[37] Total revenue for the semi-annual CCC Payment is given in Table 17-1, line 30.

In D.15-12-022, the Commission directed PG&E to use the public proxy price and formulas to determine the semi-annual CCC Payment.[38] Therefore, the semi-annual CCC Payment included in

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35 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.

36 Since the master-meter aggregated—or "host"—account does not represent a true household, these accounts will be subtracted from the total.

37 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").

38 D.15-12-022, pp. 12-13, and Conclusion of Law 2.

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 2026 GHG allowance revenue return requirement of $579.0 million, which includes a forecast of the end of year 2025 balance;
2) Approve the GHG A&O expense set-aside of $0.637 million;
3) Approve the CEEE funds set-aside of $34.2 million, subject to revisions resulting from Commission Decision and Advice Letter processes, as discussed above;
4) Approve its revenue distribution proposals; and
5) Adopt the semi-annual CCC of $45.09 per household.

The forecast amounts presented in this testimony will be updated in the Fall Update, and be effective on January 1, 2026, through the AET process, or subsequent electric rate change.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENTS OF QUALIFICATIONS

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 2026 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, G; and
- Chapter 15, "Greenhouse Gas Forecast Revenue and Reconciliation – Cost Calculations":
  - Sections A 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 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 have 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 2026 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 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 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 2026 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 and D.3b; and
- Chapter 4, "Generation Supply Portfolio Costs and Volumes":
  - Sections B.3a, B.6b through B.6c; and
- Chapter 5, "Bundled Portfolio Open Positions and Other Costs":
  - Section E; and
- Chapter 8, "Power Charge Indifference Adjustment and Ongoing Competition Transition Charge":

- Section 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 20 years; I have been in the utility industry for most of that time. I left Dominion Virginia Power in 2007 to join PG&E, where I have worked as a 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 2026 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 2, "Sales and Peak Demand Forecast":
  - Sections A, B.1, and D.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF 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), 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 2026 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.

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 2026 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 an Electric Rates Analyst for the Electric Rates team under the Rates Department within the Regulatory Proceedings and Rates. 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 an 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 2026 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 an Expert Quantitative Analyst in the System Planning Department in PG&E's Strategy organization. I work on the 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 in various regulatory proceedings.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2026 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 B.1.c and C.

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 an Expert 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 – Emerging 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 2026 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 2, "Sales and Peak Demand Forecast":
  - Section B.2.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JENNIFER NICHOLSEN

Q 1 Please state your name and business address.

A 1 My name is Jennifer Nicholsen, 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 Program Manager in PG&E's Distributed Generation Programs team in the Utility Partnerships and Innovations organization. In this role, I oversee the development and management of PG&E's customer-facing solar incentive and renewable energy programs. My focus in this role is management of the Green Tariff Shared Renewables Program.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Economics from Humboldt State University and hold a certificate in Data Analysis from University of California Berkeley Extension as well as two certifications in Scrum methodologies. I joined PG&E in 2015 as a Strategic Analyst on the Customer Experience team before moving to the Distributed Generation team in 2019, where I worked as a Business Analyst supporting the Net Energy Metering and Distributed Generation programs. I began my current role as a Program Manager in 2023. Prior to starting at PG&E, I held positions in the non-profit and education industries.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2026 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"; and
- 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 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, Central Procurement Entity (CPE) Implementation, I oversee the CPE department which focuses on the implementation of 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 (CSU). 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 Implementation.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2026 Energy Resource Recovery Account Forecast 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 WILLIAM REINWALD

Q 1 Please state your name and business address.

A 1 My name is William Reinwald, and my business address is Pacific Gas and Electric Company (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 Risk and Compliance Department within the Energy Policy and Procurement organization. I am responsible for preparing, validating, and submitting energy procurement reports to state and federal regulatory agencies.

Q 3 Please summarize your educational and professional background.

A 3 I graduated with a Bachelor of Science degree in Nuclear Engineering in 1994 and a Master of Business degree in 2001, both from the University of Cincinnati.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2026 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation proceeding:

- Chapter 15, "Greenhouse Gas Forecast Revenue and Reconciliation – Cost Calculations":
  - Section C.1.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF RYAN 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 18 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 2026 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, D, and I; and
- Chapter 15, "Greenhouse Gas Forecast Revenue and Reconciliation – Cost Calculations":
  - Section C.1.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF 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 Proceeding 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 took on a temporary assignment supporting Calpine Energy's legal team and then worked as a Regulatory Analyst IV with the Public Advocates Office Wildfire Safety division before eventually moving to PG&E as an Expert Projects Lead in Electric Operations in August 2020. I spent three years in that role before moving to the Regulatory Proceedings team to work on rate and policy-related projects before the California Public Utilities Commission. Today, these projects include: (1) post-ruling matters relating to the Power Charge Indifference Adjustment (PCIA); (2) the newly opened the Order Instituting New Rulemaking Updating and Reforming PCIA and ERRA Processes and Policies (Rulemaking (R.)25-02-005); (3) the Electric Generation Integrated Resource Plan (R.20-05-003); and (4) the annual ERRA Forecast proceeding.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2026 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 Portfolio and Resource Forecasting (PRF) Department within the Energy Policy and Procurement organization. I am responsible for developing testimony and analysis to support proceedings filed at the California Public Utilities Commission (CPUC) on matters related to generation procurement.

Q 3 Please summarize your educational and professional background.

A 3 I am a Fellow of the Chartered Association of Certified Accountants from the United Kingdom. I joined PG&E in 2005, initially working as a Senior Accounting Analyst within the Controllers' Department, and then as an Expert Regulatory Analyst in the Rates and Regulatory Analytics Department. My assignments in these departments were: accounting for various balancing accounts; participating in the development and implementation of accounting process improvements; providing analysis on recorded and forecast electric revenue and cost; and developing testimony and analysis to support proceedings filed at the CPUC on matters related to generation procurement. My job was transferred to the PRF Department of the Energy Policy and Procurement organization at PG&E in winter 2018. I have previously sponsored testimony before the CPUC, including in prior Energy Resource Recovery Account Forecast proceedings.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2026 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, B, C, D.1.a.1, D.2. through D.7., E, and F.1, F.2., G through I; and
- 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; and
- 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 ALAN WECKER

Q 1 Please state your name and business address.

A 1 My name is Alan Wecker, 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.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Arts degree in Psychology from Pitzer College in 2008 and a Master's in Business Administration from the University of California, Davis in 2012. From 2014 to present, I have been employed by PG&E in various positions including Portfolio Management Analyst, Structured Energy Transactions 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 2026 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 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 2026 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 assisting in developing models and serving as witness assistant in the 2023 General Rate Case Phase II.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2026 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.