STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE

SAN FRANCISCO, CA 94102-3298

FILED

11/25/24

09:25 AM

A2405009

November 25, 2024

Agenda ID #23113
Ratesetting

TO PARTIES OF RECORD IN APPLICATION 24-05-009:

This is the proposed decision of Administrative Law Judge Elizabeth Fox. It will appear on the Commission's December 19, 2024 agenda. The Commission may act then, or it may postpone action until later.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Pursuant to Rule 14.6(b), comments on the proposed decision must be filed within five (5) days of its mailing and reply comments must be filed within ten (10) days of its mailing.

Comments must be filed pursuant to Rule 1.13 electronically. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic copies of comments should be sent to ALJ Fox at Elizabeth.Fox@cpuc.ca.gov and the assigned Commissioner's advisor, Amin Younes at Amin.Younes@cpuc.ca.gov. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ MICHELLE COOKE

Michelle Cooke
Chief Administrative Law Judge

MLC:jnf
Attachment

Decision **PROPOSED DECISION OF ALJ FOX (Mailed 11/25/2024)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2025 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation. (U39E.)	Application 24-05-009

DECISION APPROVING PACIFIC GAS AND ELECTRIC COMPANY'S 2025 ENERGY RESOURCE RECOVERY ACCOUNT RELATED FORECAST REVENUE REQUIREMENT AND 2025 ELECTRIC SALES FORECAST

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DECISION APPROVING PACIFIC GAS AND ELECTRIC COMPANY'S 2025 ENERGY RESOURCE RECOVERY ACCOUNT RELATED FORECAST REVENUE REQUIREMENT AND 2025 ELECTRIC SALES FORECAST

Summary

This decision adopts the 2025 Energy Resource Recovery Account (ERRA) and related forecasted energy costs and the 2025 electric sales forecast for Pacific Gas and Electric Company (PG&E). The decision also adopts PG&E's Common Cost allocation proposal, as described herein, and PG&E's 2025 forecast revenue requirements for greenhouse gas and climate-related costs.

The estimated 12-month net revenue requirement for 2025 is approximately $2.25 billion, 17 percent less than the adopted 12-month revenue requirement for 2024. As a result of this decision, bundled residential customers' rates will decrease by about 2 percent or 0.7 cents per kilowatt-hour (cents/kWh) to a total rate of 34.6 cents/kWh. For residential Direct Access (DA) and Community Choice Aggregator (CCA) customers, generation rates will decrease by about 4.4 percent or 0.9 cents/kWh to a total rate of 19.7 cents/kWh.

PG&E forecasts an energy load requirement of 28,655 gigawatt-hours (GWh) for 2025. This forecast is about 10.6 percent lower than the forecast adopted in PG&E's 2024 ERRA Forecast Application. In contrast to the forecasted decrease in total load, PG&E's 2025 system peak forecast is about five percent higher than the 2024 peak forecast adopted in the 2024 ERRA Forecast proceeding.

Rate changes do not include the bi-annual residential California Climate Credit. This decision adopts a 2025 California Climate Credit of $58.23, a $3.06 decrease compared to 2024.

This proceeding is closed.

1. Background

1.1. Energy Resource Recovery Account

Pursuant to Decision (D.) 02-10-062 and D.02-12-074, the purpose of the Energy Resource Recovery Account (ERRA) is to provide recovery of energy procurement costs, including expenses associated with fuel and purchased power, utility-owned generation (UOG), California Independent System Operator (CAISO) related costs, and costs associated with the residual net short procurement requirements to bundled[1] electric service customers.

The ERRA regulatory process includes: (1) an annual forecast proceeding to adopt a forecast of the utility's electric procurement cost revenue requirement and electricity sales for the upcoming year; (2) an annual compliance proceeding to review the utility's compliance in the preceding year regarding energy resource contract administration, least cost dispatch, prudent maintenance of UOG and the ERRA Balancing Account (ERRA-Main); and (3) the quarterly compliance report where Energy Division reviews procurement transactions "to ensure the prices, types of products, and quantities of each product conform to the approved plan."[2]

The Commission adopted the Cost Responsibility Surcharge in D.02-11-022 (as modified by D.03-07-030), which consisted of the Competition Transition Charge (CTC). The CTC is used to recover the above-market costs of resources procured prior to market restructuring after the 2000-2001 Energy Crisis. In

[1] Bundled electric service customers are customers that receive both electricity generation and distribution services from PG&E. They are distinct from unbundled customers, such as DA and CCA customers, who receive energy delivery services from PG&E but take energy from another supplier. Departed load customers are unbundled customers that have departed from bundled service.

[2] D.02-10-062.

D.06-07-030 (as modified by D.07-01-030, D.11-12-018, D.14-10-045, and D.18-10-019, among other decisions), the Commission adopted the Power Charge Indifference Adjustment (PCIA) to ensure that when electric customers of an investor-owned utility (IOU) depart from IOU service and receive their electricity from a non-IOU provider, those customers remain responsible for costs previously incurred on their behalf by the IOU, including the above-market costs associated with the California Department of Water Resources (CDWR) Power Charge.

The electric utilities are also required to incorporate greenhouse gas (GHG) costs into the generation component of electricity rates through the ERRA process.[3] Incorporating the costs of GHG emissions into rates results in a carbon price signal intended to induce an overall decrease in energy consumption and reduction in GHG emissions.[4]

Finally, the electric utilities are required to report and return annual GHG allowance proceeds to eligible customers. Pursuant to Public Utilities Code (Pub. Util.) Code Section 748.5(c), the Commission can allocate up to 15 percent of GHG allowance proceeds for clean energy and energy efficiency projects that are administered by a utility, or a qualified third-party administrator, and are not otherwise funded by another source.

1.2. Procedural Background

On May 15, 2024, Pacific Gas and Electric Company (PG&E) filed Application 24-05-009 requesting Commission approval of the 2025 ERRA forecast revenue requirement (Application). Pacific Gas & Electric Company

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[3] D.12-12-033; D.14-10-033.

[4] D.14-10-033.

(PG&E) filed an amended application on May 24, 2024. On June 14, 2024, Small Business Utility Advocates (SBUA) filed a timely response to the Application. On June 17, 2024, Direct Access Customer Coalition (DACC) and California Community Choice Association (CalCCA) filed timely protests to the Application. On June 24, 2024, the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) filed a timely protest to the Application. On July 3, 2024, PG&E filed a reply to parties' protests.

A prehearing conference (PHC) was held on July 9, 2024, to discuss the issues of law and fact and determine the need for hearing and schedule for resolving the matter. The assigned Commissioner issued a Scoping Memo and Ruling on August 1, 2024.

On September 3, 2024, CalCCA and SBUA served intervenor testimony. On September 26, 2024, PG&E served rebuttal testimony. On September 27, 2024, parties filed a joint case management statement, with CalCCA requesting to cross-examine two witnesses from PG&E in an evidentiary hearing. On September 30, 2024, after review of the request for cross-examination, the assigned Administrative Law Judge (ALJ) removed evidentiary hearings from the proceeding calendar by ruling.

Pursuant to D.22-01-023, the Commission issued 2024 Market Price Benchmark (MPB) calculations on October 2, 2024, with figures used to calculate the 2025 PCIA. This issuance did not include MPBs for System Resource Adequacy (RA), Local RA, and Flexible RA for 2024 Final MPBs and 2025 Forecast MPBs. On October 4, 2024, the Commission issued an addendum to the 2024 MPB calculations, which included the previously unavailable MPB figures. On October 7, 2024, given the delay in issuance of all MPBs, the ALJ partially granted an email request from parties to extend to the deadline for service of testimony (Fall Update),[5] and for parties to file comments on the Fall Update.

On October 7, 2024, PG&E, Cal Advocates, CalCCA, DACC, and SBUA filed a joint motion to offer exhibits into evidence and admit into the record. Concurrently, the same parties filed a joint motion to seal portions of the evidentiary record. The ALJ granted that motion, with modification, on November 4, 2024.

On October 8, 2024, the ALJ issued an email ruling that requested party comments on procedural options to address whether this proceeding should consider approaches to ensure there is not an over-collection or under-collection for the Applicant as a result of the existing MPB calculation methodology. CalCCA, DACC, and PG&E responded to this ALJ ruling on October 14, 2024.

PG&E served the Fall Update on October 23, 2024, concurrent with a motion to file the Fall Update (Confidential Version) under seal.

On October 28, 2024, the Alliance for Retail Energy Markets (AReM) filed a motion to request party status. The ALJ granted that motion on October 30, 2024.

On October 21, 2024, PG&E and CalCCA filed opening briefs. CalCCA concurrently filed a motion for leave to submit a confidential version of opening brief under seal, noting that certain information in its opening brief is derived from confidential data provided by PG&E in its testimony and discovery responses. On October 31, 2024, CalCCA, PG&E, and SBUA filed reply briefs.

On October 30, 2024, PG&E and SBUA filed a joint motion to offer stipulation into the record.

5 Hereafter, Exhibit PG&E-4.

On October 31, 2024, CalCCA filed a motion for leave to submit a confidential version of its reply brief under seal. In that motion, CalCCA noted that certain information contained in the reply brief was derived from confidential data provided by PG&E in the Fall Update.

On November 1, 2024, CalCCA and DACC filed a joint motion to strike portions of PG&E's Fall Update Testimony (First Motion to Strike). The First Motion to Strike regarded PG&E's requests to submit alternative revenue requirement scenarios in response to escalated MPBs. CalCCA and DACC argued that these matters were out of scope for the instant proceeding.

On November 12, 2024, PG&E requested that the Commission deny the Motion to Strike, stating that the contested testimony "fundamentally concerns the reasonableness of PG&E's forecasted revenue requirements and resulting rates." PG&E also argued that the contested testimony is relevant to adjudication of the Application, to the Commission's legal obligations to prevent cost shifting, and to enforcement of just and reasonable rates. PG&E's stated that the contested testimony is relevant to multiple issues identified in the Scoping Memo and should remain in the proceeding's record.

On November 12, 2024, AReM, CalCCA, and PG&E filed comments on the Fall Update.

On November 12, 2024, CalCCA filed a motion to move into evidence certain data request responses from PG&E, material from exhibits in other proceedings, and statistics. Concurrently, CalCCA filed a motion to submit under seal the confidential version of its November 12, 2024 comments on the Fall Update. CalCCA noted that its comments reference confidential portions of the Fall Update or relate to market-sensitive information.

On November 18, 2024, CalCCA, DACC, and AReM filed a second joint motion to strike portions of PG&E's Fall Update Testimony (Second Motion to Strike) related to MPBs. The joint parties argued that certain portions of testimony directly contradict the Scoping Ruling, which determined that certain MPB issues were out of scope, procedurally improper, and prejudicial to other parties.

1.3. Submission Date

This matter was submitted on November 12, 2024, upon submission of comments on the Fall Update.

2. Issues Before the Commission

The issues to be determined or otherwise considered are:

1. Whether PG&E's requested 2025 ERRA forecast revenue requirement is reasonable, including the following:
    a. PG&E's forecasted 2025 energy procurement revenue requirements to become effective in rates on January 1, 2025;
    b. PG&E's forecast December 31, 2024 year-end balancing account balances, including year-end ERRA-PFS[6] and PCIA Undercollection Balancing Account (PUBA) balances, subject to adjustments in the Annual Electric True-Up process, except for disposition of balances recorded to the Modified Cost Allocation Mechanism Balancing Account (MCAMBA);
    c. Recorded Voluntary Allocation Market Offer Memorandum Account (VAMOMA) balances;
    d. PG&E's proposal to update its methodology to allocate Common Costs of the PCIA-eligible portfolio (Common Cost Issue).[7]

[6] ERRA-Power Charge Indifference Adjustment Financing Subaccount.

[7] Exhibit PG&E-2.

2. Whether to adopt forecasted electric sales for 2025.
3. Whether to adopt a forecast of GHG administrative and outreach expenses, customer generation programs, net GHG revenue return, and the semi-annual California Climate Credit value for 2025.
4. Whether PG&E's 2023 recorded GHG administrative and customer outreach costs of $382,000[8] are reasonable.
5. Whether PG&E's rate design proposals, associated with its proposed total electric procurement revenue requirements to be effective in rates on January 1, 2025, including Green Tariff Shared Renewables (GTSR) rates, are reasonable.

In testimony, PG&E requested that the Commission consider a proposal to address "significant volatility in the resource adequacy (RA) market … including potential cost shifts, should the [RA MPB] continue to escalate." The Commission declined to include this item in scope for this proceeding, given clear direction in prior decisions regarding ratemaking calculation methodologies to be applied in ERRA forecast applications, and the expedited schedule for resolving this proceeding. Nonetheless, the Commission acknowledged that the RA MPB issue may merit additional consideration in a rulemaking and encouraged PG&E to submit a Petition for Rulemaking to address its concerns and to raise potential solutions.

While this proceeding was pending resolution, PG&E did not submit a Petition for Rulemaking but argued that Commission should consider the RA MPB issue as part of scoped issues 1 and 5.[9] PG&E argued that the Commission is empowered to enforce a "just and reasonable" standard regarding PG&E's

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[8] The Scoping Memo erroneously referred to this value as $588,000. We have corrected that error here.

[9] PG&E's (U39E) Response to Administrative Law Judge's Email Ruling Regarding Procedural Mechanisms at 3; PG&E Opening Brief at 3.

rates, pursuant to Pub. Util. Code Section 451 and California Constitution, Article XII, Section 5. Further, PG&E argued that, pursuant to Pub. Util Code Sections 365.2, 366.2(d)(1), 366.2 (a)(4), and 366.3, the Commission shall "prevent any shifting of recoverable costs."

The November 1, 2024 and November 18, 2024 Motions to Strike are moot, since the Commission did not consider this matter or related testimony in scope. However, the Commission may in another proceeding consider revisions to the MPB methodology that may impact the adopted 2025 Final MPBs.

3. Revenue Requirement

PG&E forecasts its 2025 total net revenue requirement of approximately $2.25 billion. In Table 1,[10] PG&E summarizes its revenue requirement request as the sum of nine accounts with positive values, reduced by negative values of six accounts for which PG&E expects to recover costs in other proceedings.

Table 1: 2025 Revenue Requirement (in thousands)

	Amended Application	Fall Update
Cost Allocation Mechanism (CAM) and New System Generation Charge	$168,542	$294,748*
Modified Cost Allocation Mechanism Balancing Account (MCAMBA)	$9,797	$2,823
Voluntary Allocation Market Offer Memorandum Account	$353	$635
Power Charge Indifference Adjustment (PCIA)	$997,580	-$381,617*
Ongoing Competition Transition Charge (CTC)	$3,166	-$47,114
Energy Resource Recovery Account (ERRA) – Main	$3,769,750	$4,342,049*

[10] Exhibit PG&E-4, Table 1-1. Values marked with an asterisk are adjusted in accordance with PG&E's Revised Proposal for Common Cost allocation as described in Section 5.

	Amended Application	Fall Update
Public Policy Charge Procurement	-$82	-$1,896
Tree Mortality Non-bypassable Charge	$40,302	$47,367
Bioenergy Market Adjusting Tariff	$13,220	-$3,896
Gross Revenue Requirement	**$5,002,628**	**$4,253,101**
Adjustments for Revenue Requirements Authorized in Other Proceedings		
Utility-Owned Generation – Related Costs	-$1,885,078	-$1,944,932
MCAMBA	-$9,797	-$2,823
ERRA-PCIA Financing Subaccount	$6	-$1
PCIA Undercollection Balancing Account (PUBA)	-$1,723	-$1,914
Risk Transfer Balancing Account Electric (RTBA-E)	-$38,779	-$38,480
Residential Uncollectibles Balancing Account (RUBA-E)	-$2,845	-$16,050
Subtotal of Adjustments	-$1,938,216	-$2,004,200
Net Revenue Requirement Requested in Application	**$3,064,411**	**$2,248,901**

Section 3 of this decision addresses the nine accounts with positive values, which total $4.25 billion. Section 4 addresses the remaining accounts, with negative values that total about $2 billion, that are to be authorized in other proceedings.

3.1. Cost Allocation Mechanism

PG&E forecasts its 2025 CAM revenue requirement to $294.748 million if the Commission adopts PG&E's request to change the Common Cost allocation methodology. We separately address PG&E's Common Cost proposal in Section 5. We have reviewed this forecast and find that it is reasonable.

The purpose of the CAM is to allocate certain costs and benefits, including Resource Adequacy (RA) benefits, among all Load-Serving Entities (LSEs)[11] in an IOU's service territory. The LSE's customers receiving the RA benefit pay the net cost of this capacity, with net cost defined as *total cost of the contract* minus the *market revenues* associated with dispatch of the contract.

The CAM charge was authorized in D.06-07-029. Its calculation method was approved in D.07-09-044 and modified in D.10-12-035. Resolution (Res.) E-4949[12] approved CAM treatment for certain energy storage projects, including PG&E's Elkhorn Moss Landing Energy Storage facility.

D.20-06-002 ordered PG&E to serve as the Central Procurement Entity (CPE) for PG&E's distribution service area for the multi-year local RA program beginning with the 2023 RA compliance year.[13] Pursuant to D.20-06-002, administrative costs incurred in serving the central procurement function are recoverable under the CAM.

D.22-05-015 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. PG&E stated that 0.2 percent of D.19-11-016 costs have been included in the 2025 CAM from the inactive opt-out position.[14]

For the 2025 ERRA Forecast, the CAM includes combined heat and power generation authorized under D.10-12-035, energy storage Power Purchase

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[11] An LSE is any company that (a) sells or provides electricity to end users located in California, or (b) generates electricity at one site and consumes electricity at another site that is in California and that is owned or controlled by the company.

[12] Approved November 9, 2018.

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

[14] Exhibit PG&E-2.

Agreements approved pursuant to Res. E-4949, and collateral- and UOG-related costs allocated to CAM, and CPE costs.

3.2. Modified Cost Allocation Mechanism Balancing Account

PG&E forecasts its 2025 Modified Cost Allocation Mechanism Balancing Account (MCAMBA) revenue requirement at $2.823 million.[15] We have reviewed this forecast and find that it is reasonable.

In Res. E-5239, the Commission approved a MCAMBA to recover costs from procurement conducted on behalf of LSEs that opted out of procurement required by D.19-11-016 or that fail to meet their procurement requirements under D.19-11-016, D.21-06-035, or future procurement orders.[16] Pursuant to Res. E-5239, PG&E was permitted to recover opt-out procurement and administrative costs through a single MCAM rate for all customers of opt-out load serving entities.

3.3. Voluntary Allocation Market Offer Memorandum Account

PG&E forecasts its Voluntary Allocation Market Offer (VAMO) Memorandum Account (VAMOMA) revenue requirement at $635,000 for 2025. PG&E requests disposition of the VAMOMA balance through the Portfolio Allocation Balancing Account (PABA) for recovery in PCIA rates via the Annual Electric True-Up AL process.[17] We have reviewed this forecast and find that it is reasonable.

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[15] Exhibit PG&E-2.

[16] Res. E-5239, dated January 12, 2023, approved PG&E AL 6654-E-A.

[17] Exhibit PG&E-2.

The purpose of the VAMOMA[18] is to record and track incremental costs incurred for staffing and information technology systems needed to administer the VAMO process. VAMO costs may include amounts related to information technology work, systems, staffing, reporting, and forecasting.

In its Fall Update, PG&E addressed increases in the VAMO that had taken place since submission of Prepared Testimony. PG&E attributed these increases to:

- PG&E's implementation of the VAMO process including updating the processes for the Request for Information (RFI) and VAMO and implementing the RFI and Voluntary Allocation processes;
- Inclusion of the accrued PG&E attorney costs, and
- continuation of the Information Technology (IT) project to perform various systems upgrades to fully implement and manage the VAMO process. For the IT project, PG&E added functionality to its existing system(s) to support the VAMO process and has been focused on developing systems capabilities to accommodate the VAMO process.

PG&E also updated its forecasted VAMO volumes to reflect updated 2025 Load-Serving Entity load shares and updated generation forecast volumes.

The Commission adopted the VAMO process for PCIA eligible Renewable Portfolio Standard (RPS)- resources in D.21-05-030. In D.23-12-022, PG&E received disposition of the VAMOMA costs that accrued from September 2022 to August 2023.[19] The VAMOMA balance of recorded costs is $635,000.[20]

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[18] The VAMOMA was established pursuant to D.21-05-030 and D.22-11-021 and authorized in AL 6275-E, effective July 27, 2021.

[19] D.23-12-022.

[20] Exhibit PG&E-2, Tables 8-2 and 8-3.

3.4. Power Charge Indifference Adjustment

PG&E forecasts that its 2025 PCIA revenue requirement will be -$381.617 million if the Commission adopts PG&E's Common Cost proposal. We have reviewed this forecast and find that it is reasonable. We separately address PG&E's Common Cost proposal in Section 5.

3.4.1. Background

The PCIA is a rate component designed to allocate certain costs associated with procurement made by IOUs to customers on whose behalf the procurement was made, including both bundled and unbundled customers. D.06-07-030 adopted a PCIA to preserve bundled customer "indifference"[21] resulting from the departure of customers, to ensure that customer departure does not result in cost-shifting, pursuant to Pub. Util. Code Sections 366.2 and 366.3.[22]

The PCIA varies by the generation resources in that vintage. PCIA costs are assigned by customer vintage year, which is determined by the date of a customer's departure from bundled customer service. Customers who depart in the first half of each year are assigned to the prior year's vintage and customers who depart in the second half of each year are assigned to the current year's vintage. For example, 2023 vintage departing load customers are those who departed PG&E's bundled customer service between July 1, 2023 and June 30, 2024.

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[21] Pub. Util. Code Sections 366.2 and 366.3 require the Commission to make sure that departing (unbundled) customers do not burden remaining (bundled) utility customers with costs incurred to serve them. D.02-11-022 addressed the Commission's definition of customer indifference.

[22] D.06-07-030.

3.4.2. "Excess RPS"

PG&E initially forecasted that its RPS-eligible generation in 2025 would exceed its RPS compliance requirement for bundled customers.[23] In its PCIA calculation, PG&E assigned this "Excess RPS" generation a zero-dollar value and said that "[a]ny excess RPS generation in 2025 will be marked as such and utilized in future years once pre-2018 [Renewable Energy Credits (RECs)] and unsold volumes have been utilized."[24]

In direct testimony, CalCCA contested PG&E's assignment of Excess RPS with a zero-dollar value and states that "PG&E's testimony inappropriately creates a new category of RPS attributes not previously recognized by the Commission in the context of the PCIA calculation."[25] Rather than consider the excess generation a new category, CalCCA argued that these volumes should instead be considered Retained RPS under the Commission's existing PCIA framework. CalCCA also argued that PG&E, as a prudent utility manager, should attempt to maximize its revenue by selling excess RPS to benefit its customers. If PG&E did not sell these volumes, CalCCA asked that PG&E be required to count this generation as Retained RPS and apply the RPS Adder to value the Excess RPS in the PCIA.

In rebuttal testimony, PG&E responded that this issue was now moot because it had sold the additional volumes of 2025 RECs and there was no longer a need to categorize any volume of 2025 RECs as "Excess RPS."[26] In addition, PG&E explained that to meet the forecast 2025 Minimum Retained RPS

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[23] Exhibit PG&E-2.

[24] Exhibit PG&E-2.

[25] Exhibit CalCCA01.

[26] Exhibit PG&E-3.

requirement, it anticipated using RECs generated and banked in 2018, and possibly in 2020.

In its Opening Brief, CalCCA stated that, in response to a data request, PG&E confirmed it would value any 2018 or 2020 banked RECs that it uses at the 2025 Forecast RPS Adder. CalCCA stated that this is consistent with its approach in prior ERRA Forecast proceedings and the Commission's decisions in those cases. PG&E also confirmed it would first use excess RECs generated and retained in 2018 until exhausted before using excess RECs generated and retained in 2020, if necessary.[27]

Although CalCCA continued to take the position that creating an "Excess RPS" category and valuing Excess RPS volumes at zero is not consistent with the Commission's PCIA framework, CalCCA agreed that PG&E's Excess RPS proposal is moot to the extent PG&E no longer forecasts surplus RPS-eligible generation in 2025. CalCCA also did not object to PG&E's intended approach to addressing its forecast RPS deficiency in 2025, as described in PG&E rebuttal testimony and responses to CalCCA's discovery requests. This issue is therefore not disputed.

3.4.3. Unsold RA

In direct testimony, CalCCA argued that PG&E should adjust the allocation of Sold RA and Unsold RA in the Indifference Amount calculation.[28] PG&E agreed with CalCCA and made the proposed adjustment in its Fall Update.

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[27] Consistent with the First-In-First-Out method directed by Ordering Paragraph 12 in D.23-12-022

[28] Exhibit CalCCA-01.

PG&E initially reported a negative quantity of Retained System RA from PCIA-eligible resources.[29] CalCCA argued that this negative Retained RA value was due to PG&E's incorrect treatment of forecasted sales of residual RA capacity and the remaining Unsold RA for 2025.[30]

In its initial forecast of RA sales, PG&E calculated the quantity of System RA needed for its bundled customer RA compliance and compared that amount to the total, outage adjusted, NQC available from its portfolio, including its PCIA-eligible resources.[31] For months with a long system RA position, PG&E assumed some portion of the excess would remain unsold.[32] PG&E assumed other excess RA would be sold, and included these RA sales in the Indifference Amount calculation as a reduction to the available System RA from PCIA resources and a revenue credit that reduces PCIA portfolio procurement costs.[33] PG&E included unsold RA as a reduction to System RA in the Indifference Amount and valued it at zero.[34]

PG&E counted PCIA resources that provide System RA in PG&E's portfolio when it calculates its RA position and resulting Sold and Unsold RA quantities. According to CalCCA, many of those same resources also provide Local or Flexible RA capacity.[35] When the RA from its PCIA-eligible generation portfolio is included in the Indifference Amount calculation, it is categorized as

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29 Exhibit PG&E-2, Table 10-9.

30 Exhibit CalCCA-01.

31 Exhibit PG&E-2.

32 Exhibit PG&E-2.

33 Exhibit PG&E-2.

34 Exhibit PG&E-2.

35 Exhibit CalCCA-01.

System, Local, or Flexible RA based on the type of RA the resource provides.[36] Pursuant to D.18-10-019, resources that provide System RA but also provide Local RA or Flexible RA are categorized as either Local RA or Flexible RA.[37]

As CalCCA noted, reducing only System RA for residual RA sales and Unsold RA creates a mismatch between the Sold and Unsold RA quantities and the available NQC in different RA categories. PG&E confirmed that the result of this approach for 2024 results in a negative quantity for Retained System RA based on how PG&E's PCIA-eligible RA resource supply was divided between System Local, and Flex RA.[38]

CalCCA argued that Negative Retained RA does not make sense in the context of the PCIA, and when a negative quantity is applied to the RA Adder, it would result in a charge, rather than a credit, to the PCIA for Retained RA.[39] To correct this mismatch, CalCCA asked the Commission to require PG&E to spread the forecasted Sold and Unsold RA between all of the RA categories rather than assign it all to System RA, based on the proportion of available RA by category.[40]

In rebuttal testimony, PG&E agreed with CalCCA's proposal to spread the Residual RA sales and Unsold RA forecast volumes across System, Flexible, and Local RA based on the available forecast proportion.[41] PG&E said it would make that change in its Fall Update forecast, decreasing PG&E's PCIA Revenue

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36 Exhibit PG&E-2.

37 D.18-10-019 at 74.

38 Exhibit CalCCA-01.

39 Exhibit CalCCA-01.

40 Exhibit CalCCA-01.

41 Exhibit PG&E-3.

Requirement presented in the May Prepared Testimony by approximately $68.6 million.

This issue is not in dispute.

3.4.4. PABA Calculation

The Commission established the PABA in 2019[42] to recover above-market costs for PCIA-eligible generation resources from both bundled and departing load customers. Costs authorized to be recorded in PABA include those that are related to contracts executed with third parties, as well as UOG.

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

The PABA is comprised of subaccounts for each year's vintage portfolio that records the costs, market revenues, and imputed revenues of all generation resources executed or approved by the Commission for cost recovery that year. Disposition of the PABA is through PCIA rates.

As CalCCA noted in direct testimony, the PABA is a "rolling true-up" of the actual above-market costs of PG&E's PCIA-eligible resource portfolio and the amount collected from customers through PCIA rates to recover such above-market costs. Any over-or under-collection in the PABA through the end of 2024 is added to the PCIA revenue requirement, by vintage, and used to establish the 2025 PCIA rates. The PABA is calculated using MPBs that the Commission

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[42] D.19-10-001.

calculates and publishes each year. In its 2024 Fall Update, PG&E forecasted the PABA to be under-collected by $806 million.

3.4.5. 2024 Final MPBs

The MPB is a calculation of the market value of the three revenue streams in the IOU portfolio: the Energy Index; RPS Adder; and RA Adder. The RA Adder is the MPB that reflects the estimated value of each unit of capacity in an IOU's PCIA-eligible portfolio that can be used to satisfy RA obligations, in dollars per kilowatt-month, based on a weighted average of all RA transactions of the load-serving entities subject to the PCIA.

The RA Adder has three subcomponents, reflecting each type of RA product required for compliance with the RA program: system, local, and flexible:

a. RA that provides both system and flexible capacity shall be counted as flexible capacity:
b. RA that provides both system and local capacity shall be counted as local RA capacity: and
c. If the RA provides all three types of RA capacity, it shall be counted as local capacity.

The Commission's Energy Division issued the MPB calculations for the RA Adder on October 4, 2024, noting anomalies in the MPBs. These anomalies included: (1) low transaction volumes relative to overall size of the portfolio, (2) the inclusion of swap and affiliate transactions; and (3) the nearly threefold increase in the system RA MPB, as driven by the summer versus winter differential.

As in the past, PG&E is directed to use the 2024 MPBs for inclusion in rates and the calculation of the PCIA. However, due to the issues described above, the

Commission may in another proceeding consider revisions to the MPB methodology that may impact the adopted 2025 Final MPBs.

Due to the anomalies identified in swap and affiliate transactions, the Energy Division will conduct an inquiry and provide a report on transactions that should not be included in the MPBs.

3.5. Ongoing Competition Transition Charge

PG&E forecasts that its Ongoing Competition Transition Charge (CTC) revenue requirement for 2025 will be -$47.114 million.[43] We have reviewed this forecast and find that it is reasonable. The Ongoing CTC recovers the cost of power purchase agreements signed before December 20, 1995, as defined in Section 367(a) of the Pub. Util. Code.

3.6. Energy Resource Recovery Account – Main

PG&E forecasts that its 2025 main ERRA revenue requirement will be $4.342 billion if the Commission adopts PG&E's proposed Common Cost allocation methodology.[44] We have reviewed this forecast and find that it is reasonable.

3.7. Public Policy Charge Procurement

PG&E forecasts that its 2025 Public Policy Charge Procurement (PPCP) revenue requirement will be -$1.896 million. We have reviewed this forecast and find that it is reasonable.

The PPCP subaccount is a two-way balancing subaccount in the Public Purpose Policy Charge Balancing Account.[45] The PPCP subaccount was established to record the recovery of the above-market costs associated with: (1)

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[43] Exhibit PG&E-2.

[44] Exhibit PG&E-2.

[45] The PPCP subaccount was established in AL 6524-E.

the Public Utility Regulatory Policies Act (PURPA) Standard Offer Contract approved in D.20-05-006, and (2) existing under 20 megawatts (MW) QF contracts pursuant to D.10-12-035.

3.8. Tree Mortality Non-bypassable Charge

PG&E forecasts its Tree Mortality Non-bypassable Charge (TMNBC) revenue requirement at $47.367 million for 2025. This forecast is calculated by subtracting the forecasted value of energy, RA sales, and REC sales from the TMNBC contracts' forecasted cost.[46]

Res. E-4770 requires each IOU to use the Renewable Auction Mechanism procurement process to purchase its share of at least 50 MW of generating capacity from facilities that can use biofuel from high hazard zones.[47] Senate Bill (SB) 859, Statutes 2016, Chapter 368,[48] required electric IOUs to procure respective shares of 125 MW from existing biomass facilities using prescribed amounts of dead and dying trees located in high-hazard zones as feedstock, for 5-year contracts. SB 859 required that the procurement costs to satisfy this requirement be recovered from all customers on a non-bypassable basis.

Res. E-4805, which implemented the requirements of SB 859,[49] required IOUs to track electric procurement costs associated with power purchase agreements. D.18-12-003 established a non-bypassable charge for costs associated with tree mortality biomass energy procurement. The TMNBC recovers net costs of the tree mortality-related biomass energy procurement.[50]

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[46] Exhibit PG&E-2.

[47] Res. E-4770, March 17, 2016.

[48] As codified in Pub. Util. Code Section 399.20.03(f).

[49] Res. E-4805, October 21, 2016.

[50] Exhibit PG&E-2.

PG&E calculated its 2025 procurement cost forecast for the TMNBC revenue requirement based on executed supply purchase contracts, executed RA and RPS sales, and CAISO market energy and ancillary service revenues for unsold RPS-eligible generation.[51] Executed supply contracts that are forecasted to provide deliveries to PG&E in 2025 include: 1) Burney Forest Products; 2) Wheelabrator Shasta; and 3) Woodland Biomass.[52]

We have reviewed this forecast and find that it is reasonable.

3.9. Bioenergy Market Adjusting Tariff

PG&E forecasts that its Bioenergy Market Adjustment Tariff (BioMAT) revenue requirement will be -$3,896,000 for 2025. SB 1122, Statutes 2012, Chapter 612, requires IOUs to procure 250 MW of RPS-eligible generation from bioenergy generation facilities. The Commission implemented SB 1122 with D.14-12-081, setting the quantities of each type of generation to be procured by each IOU and establishing the pricing mechanism and other rules for the BioMAT Program.

We have reviewed this forecast and find that it is reasonable.

4. Revenue Requirement Adjustments Authorized in Other Proceedings

PG&E proposes to reduce its proposed revenue requirement by $1.938 billion to account for revenue requirements authorized in other proceedings. Therefore, the six accounts described in this section each have negative values. PG&E is not requesting cost recovery for these adjustments in the instant proceeding and therefore we did not assess these subaccounts for

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[51] Exhibit PG&E-2.

[52] Exhibit PG&E-2.

reasonableness. It is reasonable to reduce the net revenue requirement by these amounts to ensure that PG&E does not recover the same costs more than once.

4.1. Utility-Owned Generation – Related Costs

UOG-Related Costs are those authorized in PG&E's 2023 General Rate Case, D.23-11-069, or approved in other regulatory proceedings. PG&E did not request approval of these costs in this Application. PG&E forecasts that its revenue requirement for UOG-Related Costs will be -$1.945 billion for 2025.

For reference, these costs are as follows:

Table 2: UOG-Related Costs[53]

	Authorization	**Revenue Requirement (Thousands)**
Revenue Requirement from 2023 GRC + attrition		$1,850,684
Estimated Department of Energy proceeds[54]		-$1,939
Subtotal	**D.23-11-069**	**$1,848,745**
GRC Undercollection amortized in 2025	D.23-11-069	-$994
Cost of Capital (COC) Adjustment	D.23-01-002	$34,293
Hydro Sales	AL 7216-E	-$17,743
Pension	D.09-09-020	$31,708
Diablo Canyon Power Plant (DCPP) Retirement	D.18-11-024	$2,356
Gain on Sale of San Francisco General Office	D.21-08-027	-$21,623

53 Exhibit PG&E-2, Table 10-1.

54 A Joint Proposal approved by the Commission in the 2014 GRC requires PG&E to credit its customers' rates certain proceeds of a settlement related to spent fuel-related storage costs.

	Authorization	**Revenue Requirement (Thousands)**
Purchase of Oakland General Office	D.24-08-009	$68,190
Total		**$1,944,932**
The above is recovered in the following accounts, per the Common Cost methodology described in Section 5.4.		
PCIA		$1,984,024
ERRA		-83,742
CAM		$44,650
Total		**$ 1,944,932**

In direct testimony, CalCCA recommended that PG&E correct the amount included as the amortization of the gain on sale of its San Francisco General Office.[55] Whereas PG&E provided a value of $13.287 million for this gain on sale,[56] CalCCA identified a calculation error of about $8.0 million.

PG&E agreed this was an error and stated in rebuttal testimony that it has inadvertently applied 24.24 percent to the gain on sale of the San Francisco General Office to the electric portion, instead of the corrected 39.45 percent. PG&E committed to update its calculation to correctly reflect the 39.45 percent.[57]

PG&E corrected the error in its Fall Update. The corrected value is $21.623 million.

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55 Exhibit CalCCA-01.

56 Exhibit PG&E-2.

57 Exhibit PG&E-3.

4.2. Modified Cost Allocation Mechanism Balancing Account

PG&E proposes to exclude the full value of the MCAMBA, $2,823 million, from its revenue requirement request in this proceeding. In Res. E-5239,[58] the Commission approved PG&E's request[59] for a MCAMBA to recover contract expenses for LSEs that opted-out of or failed to meet certain procurement obligations established in D.19-11-016 and D.21-06-035.

4.3. ERRA-PCIA Financing Subaccount

The ERRA-PCIA Financing Subaccount tracks any amounts financed by bundled customers related to revenue shortfalls associated with capped PCIA rates for eligible departing load customers.[60] Pursuant to D.20-12-038, the Commission adopted PG&E's proposal to recover the departing load customer revenue shortfall from the 2020 PCIA revenue requirement over three years, effective 2021. Consistent with prior ERRA Forecasts applications, PG&E is transferring the residual ERRA-PFS to PABA Vintage 2020 Subaccount and anticipates filing an advice letter to close this subaccount when it is no longer required.

4.4. PUBA

The purpose of the PUBA is 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 on the PCIA rate was previously set at 0.5 cents/kWh more than the current cumulative system average rate per vintage (PCIA rate cap). This PCIA rate cap was removed in D.21-05-030.

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[58] Effective January 12, 2023.

[59] PG&E AL 6654-E-A.

[60] On May 20, 2021, the Commission issued D.21-05-030 to eliminate the PCIA rate cap.

Pursuant to D.20-12-038, the Commission adopted PG&E's proposal to recover the forecasted 2020 year-end PUBA balance through a vintage-specific PUBA rate adder on top of PCIA rates from 2021 through 2024.[61] The forecast year to date PUBA balance is the residual from the 2024 amortization.[62] PG&E in the instant application proposes to transfer the PUBA to PABA Vintage UOG Legacy Subaccount and anticipates filing an AL to close this balancing account when it is no longer required.[63]

4.5. Risk Transfer Balancing Account Electric (RTBA-E)

The RTBA-E was established to track and record actual expenses compared to the adopted expenses for financial risk transfer costs. These risk transfer costs include insurance, reinsurance, catastrophe bonds, captives and related costs such as broker fees and excise taxes allocated to PG&E's electric distribution and generation functions.[64]

In the Fall Update, PG&E reported a balance in the RTBA-E of negative $38.48 million.

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[61] D.20-12-038, Conclusion of Law (COL) 9.

[62] D.20-12-038, COL 9 authorized PG&E to amortize its 2020 PUBA balance over three years from 2021 through 2023. Part of the 2020 PUBA is already amortized in rates over 2021 and 2023. The residual unamortized 2022 undercollected balance was included in 2024 rates consistent with prior years. D. 23-12-022 addressed the requirements to close the PUBA rate adder by the end of 2024.

[63] Ordering Paragraph (OP 8) of D 23-12-022 states:

> Pacific Gas and Electric Company shall file a Tier 1 Advice Letter to close the Power Charge Indifference Adjustment Undercollection Balancing Account rate adder once the balance in that account reaches $1 million, or at the end of 2024, whichever is sooner.

[64] Exhibit PG&E-2.

4.6. Residential Uncollectibles Balancing Account (RUBA-E)

In 2020, the Commission authorized the creation of the RUBA-E to compare uncollectibles recovered from residential electric customers to actual uncollectibles.[65] 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.

In its Fall Update, PG&E recorded $16.05 million in its RUBA-E generation subaccount.

5. Common Cost Allocation Methodology

The Common Cost allocation issue in this case concerns PG&E's method of recovering its Energy Supply Administration and other procurement management costs. PG&E stated in the instant application that the current Common Cost allocation methodology creates inequitable cost shifts for its bundled service customers and proposed to change the methodology.[66] PG&E proposed to remedy the cost shifts it identified by attempting to align its methodology more closely with the methodology adopted by Southern California Edison (SCE). CalCCA opposed PG&E's initial proposal and offered an alternative proposal (CalCCA Proposal). PG&E responded with an updated

[65] AL 6001-E-A.

[66] Exhibit PG&E-2.

proposal (PG&E Revised Proposal or Revised Proposal) in its rebuttal testimony. Following the update, CalCCA continued to oppose PG&E's Revised Proposal.

We are persuaded to adopt PG&E's Revised Proposal as described in rebuttal testimony, and with calculations provided in the Fall Update, to mitigate cost shifts from unbundled to bundled customers that are prohibited under Pub. Util. Code Sections 365.2 and 366.3. However, we agree with CalCCA that this proceeding is not the proper forum to consider additional revisions to the Common Cost allocation methodology. The Commission may, in another proceeding with participation from all three electric IOUs and other stakeholders, consider broader revisions to the Common Cost allocation methodology.

5.1. Background

Pursuant to D.18-10-019, OP 7 and 8, each electric IOU was directed to submit a Tier 2 advice letter to establish a PABA account and to adjust other balancing accounts as needed to be consistent with the adopted PABA vintaged subaccount structure. Each advice letter used its own methodology for allocating ESA costs in the PABA, and PG&E's methodology was approved in AL 5440-E.

PG&E defines the Common Costs under consideration in two general categories: (1) Energy Supply Administration (ESA) costs, which relate to the costs to manage PG&E's generation-related portfolio and (2) non-ESA costs, such as collateral posting costs.

PG&E stated that as the market value of energy and RA has increased in recent years, the MPBs used to value revenues associated with the PCIA-fleet have increased. PG&E argued that bundled customers have paid for larger portions of the overall net costs of managing the PCIA-fleet relative to departing load customers with PCIA responsibility. At the same time, the PCIA recovers a smaller percentage of total funds from departing load customers. Because the net revenue requirement allocation methodology allocates Common Costs to the customers paying the above-market costs, PG&E argued that its bundled service customers now pay an outsized, inequitable allocation of these Common Costs.[67]

PG&E argued that the adopted net revenue requirement Common Cost Allocation Factors linked responsibility for the Common Costs to above-market costs, not with cost responsibility. As a result, a disproportionate percentage of Common Cost responsibility shifted to the bundled customers while the amount of work being performed by PG&E to manage its generation portfolio on behalf of all customers remains relatively unchanged.[68]

5.2. PG&E's Initial Proposal

PG&E's initial proposal would have allocated Common Costs to the Legacy UOG vintaged PCIA-subaccount. PG&E stated that this methodology is consistent with the approach taken by SCE.[69]

5.3. CalCCA Proposal

CalCCA agreed with PG&E that allocating Common Costs based on net revenue requirements may produce unintended results as PCIA-eligible resource market values increase.[70] But CalCCA argued that the Commission should not adopt PG&E's proposed methodology to assign all Common Costs to the Legacy UOG PCIA Vintage. According to this methodology, costs would be recovered only from PCIA-eligible bundled and unbundled customers based on those

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[67] Exhibit PG&E-2.

[68] Exhibit PG&E-2.

[69] Exhibit PG&E-2.

[70] Exhibit CalCCA-01.

customers' share of retail sales. As a result, no costs would be allocated to the ERRA or CAM.

CalCCA argued that PG&E's Common Cost allocation method is "not consistent with SCE's authorized approach," as PG&E claimed it to be. Unlike PG&E's proposal, SCE treated the cost of its Energy Procurement & Management (EPM) organization – which is analogous to PG&E's ESA costs – and its collateral carrying costs separately. According to CalCCA, EPM and collateral costs are allocated among SCE's generation balancing accounts and PCIA vintages in different ways.

CalCCA maintained that the Commission should implement a consistent resolution across utilities for the recovery of Common Costs. Specifically, CalCCA argued that Common Costs allocated to PABA should also be allocated to PCIA vintages based on the gross revenue requirement by vintage. According to CalCCA, this allocation method would better align the allocation of ESA costs with cost causation principles and would more equitably distribute costs across customer groups.

5.4. PG&E Revised Proposal

In rebuttal testimony,[71] PG&E addressed additional details that SCE provided[72] about its common cost allocation methodology. Specifically, PG&E had learned that:

- SCE allocates Common Costs to its ERRA, NSGBA, and PABA according to the net revenue requirement in each account.
- The portion allocated to PABA is then allocated to PCIA vintages based on the gross procurement costs.

[71] Exhibit PG&E-3.

[72] Exhibit CalCCA-02.

- Credit and collateral interest costs are allocated between PABA, ERRA, and NSGBA, based on the authorized revenue requirements of each account.
- SCE's Energy Procurement & Management costs, which are equivalent to PG&E's ESA costs, are included as fixed costs, split between the Legacy UOG and 2004 and 2009 vintages.

According to PG&E, its current cost allocation methodology results in a cost shift for bundled customers that SCE customers do not face.

PG&E updated its initial proposal in response to the new information from SCE to more fully align with SCE's Common Cost allocation methodology. Table 3 from PG&E[73] shows how the IOU's $92.7 million in 2025 ESA Costs,[74] would be recovered under the status quo, under CalCCA's proposal, and under PG&E's Revised Proposal.

Table 3: Comparison of 2025 ESA Common Cost Allocation Between PCIA-Eligible Bundled and Departed Customers

	Status Quo (Net Costs)		**CalCCA Proposal (Gross Costs)**		**PG&E Revised Proposal**	
	Bundled	Departed	Bundled	Departed	Bundled	Departed
PCIA *('000s)*	-$6,148	$189	$20,866	$34,324	$29,559	$51,307
ERRA *('000s)*	$91,664	–	$32,554	–	$8,882	–
NSGBA *('000s)*	$2,485	$4,603	$1,770	$3,278	$1,068	$1,977
Total *('000s)*	$88,001	$4,792	$55,190	$37,603	$39,508	$53,285
Total	**94.8%**	**5.2%**	**59.5%**	**40.5%**	**42.6%**	**57.4%**

PG&E argues that this table demonstrates that an allocation methodology that mimics SCE's would most equitably allocate ESA Common Costs between PCIA-

[73] Exhibit PG&E-3, Table 1.

[74] As authorized in PG&E's 2023 GRC, D.23-11-069.

eligible bundled and departed customers. According to PG&E, its 2025 bundled load share is 36.7 percent and eligible departed load share is the balance of 63.3 percent. Under the status quo methodology, 94.8 percent of the ESA Common Costs would be allocated to bundled customers. Under the CalCCA Proposal, bundled customers would be allocated 59.5 percent of costs.

PG&E also stated that under the CalCCA Proposal, cost allocation would still be significantly affected by energy market prices, which do not reflect on whose behalf Common Costs are being incurred. Specifically, CalCCA's methodology would allocate ESA costs to ERRA, and costs could vary significantly as energy prices fluctuate annually.

Although PG&E previously supported a gross revenue cost allocation methodology like the one proposed by CalCCA, PG&E noted that such a methodology could have similarly distortionary effects on cost allocation and retracted support on this basis.

We agree with PG&E that the status quo methodology results in a significant cost shift from bundled customers to unbundled customers, since nearly 95 percent of shared costs are allocated to the bundled customers who represent about 37 percent of load share. We also agree that PG&E's Revised Proposal better aligns the share of costs with the customer groups most responsible for the costs, is appropriately aligned with the methodology that SCE uses, and is subject to less market price variation than the CalCCA Proposal.

5.5. Fall Update

In its Fall Update, and using a revised revenue requirement, PG&E provided two scenarios for the Commission to consider: one that maintains the status quo and the other in which the Commission adopted its Revised Proposal.

Under the Status Quo scenario, the system average bundled rate would decrease by approximately 0.3 cents/kWh, or 0.9 percent, to a total rate of 35.0 cents/kWh, when compared to the currently effective system average bundled rate of 35.3 cents/kWh. The system average rate for DA and CCA customers, whose average rates exclude commodity charges that are provided by other service providers, would decrease by approximately 1.1 cents/kWh, or 5.4 percent, to a total rate of 19.5 cents/kWh, when compared to the currently effective system average rate for DA and CCA customers of 20.6 cents/kWh.

With the Revised Proposal, bundled customer rates would decrease by 2 percent or 0.7 cents/kWh to a total rate of 34.6 cents/kWh, when compared to the currently effective system average bundled rate of 35.3 cents/kWh. The system average rate for CCA and DA customers would decrease by approximately 0.9 cents/kWh, or 4.4 percent, to a total rate of 19.7 cents/kWh, when compared to the currently effective system average rate for DA and CCA customers of 20.6 cents/kWh. We find the allocation of costs detailed in the Fall Update, and as described in PG&E's rebuttal testimony, to be reasonable.

5.6. Retroactive Ratemaking Concerns

PG&E proposed to modify its Common Cost allocation methodology for the 2025 ERRA Forecast, effective January 1, 2024.[75] CalCCA cautioned against the Commission adopting PG&E's Revised Proposal, effective January 1, 2024, on grounds that such approval would constitute retroactive ratemaking and "abuse" of the true-up.[76] According to CalCCA:

> In essence, PG&E recommends the Commission use the 2024 true-up to modify revenue requirements approved in PG&E's

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[75] Exhibit PG&E-2.

[76] Exhibit CalCCA-01, CalCCA Opening Brief, CalCCA Reply Brief.

> 2024 ERRA Forecast proceeding based on a methodology approved in this year's proceeding…. The true-up is not an opportunity for PG&E to retroactively unsettle authorized revenue requirements simply because it did not get the result it wanted in the prior year's proceeding. Any other interpretation of the true-up would introduce into … ERRA Forecast proceedings significant uncertainty regarding the magnitude of the true-up and its impact on rates. The Commission should decline to create that uncertainty and apply any new methodology adopted in this proceeding strictly on a going forward basis.[77]

CalCCA cites *The Ponderosa Telephone Co. v. Public Utilities Com* (Ponderosa Telephone),[78] in which certain rural telephone companies appealed the Commission's decision to allocate the proceeds from the redemption of stock to the telephone companies' ratepayers. The appellants contended that the Commission's action resulted in improper retroactive ratemaking because the allocation of stock redemption proceeds to ratepayers related to a past cost that was factored into an approved rate.

PG&E addressed CalCCA's concern about retroactive ratemaking, arguing that the prohibition on retroactive ratemaking does not extend to correcting allocation of costs that are in balancing accounts among customers. According to PG&E, the retroactive ratemaking doctrine addresses changes to past-authorized recovery of costs that were not subject to established balancing account or memorandum account treatment. PG&E argued that, in Ponderosa Telephone, the Court of Appeals decision annulled a retroactive change to the *total amount collected in rates*, whereas adoption of the Common Cost proposal would change

[77] CalCCA Opening Brief.

[78] 197 Cal. App. 4th 48 (5th Dist. 2011).

the *allocation of costs within balancing accounts without affecting the total amount collected in rates*.[79]

According to PG&E, the amount of ESA and collateral costs it is authorized to recover are established in its GRC, with the allocation of the costs in the balancing accounts, among customer groups left to the methodology in the ERRA proceedings. Recovery to PG&E remains the same whether the costs are recovered from bundled service or from departing load customers and correcting the flawed ESA methodology does not implicate retroactive ratemaking.[80]

In Reply Briefs, CalCCA countered that balancing accounts are not meant to permit post hoc modifications to approved revenue requirements based on new proposals made after rates went into effect—whether or not PG&E believes those approved rates are unreasonable or unfair.

PG&E reiterated in Reply Briefs that there is no retroactive ratemaking issue because the Commission's deliberative process concerning the allocation of those costs are in scope of this proceeding. As PG&E stated, "[t]here is no reason that the Commission should leave untouched an erroneous application of a methodology that credited departing load customer vintages for costs such as work performed by PG&E, as part of the 2024 true-up process."

We agree with CalCCA that the Commission should not adopt the Revised Proposal starting with January 1, 2024 rates since the rates in question have already been adopted. We therefore adopt the Revised Proposal beginning with January 1, 2025 rates.

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79 PG&E Opening Brief.

80 PG&E Opening Brief.

5.7. Conclusion

We are persuaded that the cost shifts that PG&E identified exist and would be remedied by the adoption of the PG&E Revised Proposal. We agree with CalCCA that the Commission should not adopt the Revised Proposal starting with January 1, 2024 rates since the rates in question have already been adopted. We therefore adopt the PG&E Revised Proposal for allocation of Common Costs beginning with January 1, 2025 rates.

6. 2025 Sales and Peak Demand Forecast

6.1. Overview

PG&E forecasts an energy load requirement of 28,655 Gigawatt-hours (GWh) for 2025.[81] This forecast is calculated as the residual of the total system sales forecast (77,873 GWh), forecasted departing load (-49,777 GWh) and unaccounted for energy/losses (2,451 GWh). The departing load forecast includes acceptance of all 12 of the CCA–provided 2025 monthly sales forecasts.

PG&E's bundled electricity sales forecast for 2025 is about 10.6 percent lower than the forecast adopted in PG&E's 2024 ERRA Forecast Application, A.23-05-012.[82] PG&E attributes the decrease to multiple factors, including a recent spike in rooftop solar and relatively low 2023 recorded sales. Most of this effect accrued to the bundled portion of system sales.[83]

PG&E expects CCA and DA providers to serve nearly two-thirds of total system sales in 2025. In addition, PG&E finds that customer-sited solar energy

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81 Exhibit PG&E-4, Table 3-3.

82 2024 Fall Update, Table 2-3; D.23-12-022.

83 Exhibit PG&E-2.

contributes to relatively flat systemwide electricity sales, and that effects of the COVID-19 pandemic are diminishing.[84]

The 2025 system peak forecast is about a five-percent higher than to the 2024 peak forecast adopted by D.23-12-022 in PG&E's 2024 ERRA Forecast proceeding.[85] PG&E attributes this increase primarily to an update in its climate forecast and modeling, and to a lesser extent to updated historical data, which included the extreme weather events of September 2022. PG&E notes that customer-owned solar generation has a small impact on the annual system and that customer-owned storage is beginning to have an impact that is expected to grow over time.[86]

6.2. Methodology

For its bundled sales forecast, PG&E first forecasts total electric sales at the "retail system" level. Then PG&E determines its bundled sales forecast by subtracting the energy requirements of customers who buy electricity from entities other than PG&E, such as DA customers, CCA customers, and the Bay Area Rapid Transit District (BART).[87]

PG&E calculated total energy requirements for its bundled customers by applying unaccounted for energy, and transmission and distribution losses to forecasted sales at the meter.

PG&E's retail sales forecast is influenced by economic measures, price variables, and weather variables, and other factors such as customer-sited solar

[84] Exhibit PG&E-2.

[85] Exhibit PG&E-2.

[86] Exhibit PG&E-2.

[87] Exhibit PG&E-4, Table 3-3.

generation, energy efficiency savings, electric vehicle charging, and building electrification.[88]

PG&E calculates the revenue requirement necessary for procuring bundled customer energy in 2025 is $3.876 billion.[89]

6.3. Party Comments

In opening testimony, SBUA challenged PG&E's approach to accounting for demand shifts prompted by the COVID-19 pandemic, such as increased work from home and hybrid work schedules. SBUA also questioned how PG&E handled large new load additions.[90]

PG&E addressed these alleged errors in rebuttal testimony and defended its original methodology. PG&E explained that its forecast did take residual effects of the COVID-19 pandemic into account in its load forecasts, but by using real-world data and quantitative analysis of sales and the PG&E system (e.g., a "simple exponential decay model") rather than high-level components proposed by SBUA, like "lockdowns, economic impacts, and a 'new normal' long-term impact," which lacked underlying data or analysis.[91]

PG&E argued that its

> "models do not ignore the underlying drivers or components of shifts in energy usage. To the contrary, PG&E's model aggregates them to a level that is analytically tractable and where there are clear historical data. Thus, it is neither necessary nor feasible to reliably distinguish between the three components SBUA identifies for the purposes of PG&E's sales forecast. This is because PG&E's forecast builds from

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88 Exhibit PG&E-2.

89 Exhibit PG&E-4, Table 19-1.

90 Exhibit SBUA-01.

91 Exhibit PG&E-3.

> historical data of metered energy usage in PG&E's service territory which includes all of these impacts in aggregate."[92]

PG&E further noted that SBUA only graphs PG&E's historical sales and argued qualitatively that "changes in behavior persist." According to PG&E, the data SBUA selected for extrapolation covers an arbitrary timeframe and SBUA's figures do not show anything about persisting changes in behavior.

Subsequently, PG&E and SBUA stipulated that PG&E would, in future ERRA Forecast Applications, identify in its load forecast workpapers whether a post-regression adjustment is applied to any customer class.[93] This issue is no longer in dispute, and we appreciate and agree with the stipulation.

We have reviewed PG&E's workpapers and load forecasts and find that the load forecasts are reasonable.

7. GHG Forecast Costs, Revenues and Reconciliation

The Commission adopted standard procedures for electric utilities to request GHG forecast revenue and reconciliation requirements filed after 2013 in D.14-10-033. The decision also adopted Confidentiality Protocols for Cap-and-Trade-related data and required the utilities to use a proxy price in their forecasts. Finally, the decision required the utilities to file GHG Forecast Revenue and Reconciliation Applications annually as part of their ERRA forecast applications. We use the standards adopted in D.14-10-033 to review PG&E's current Forecast Application to determine the reasonableness of both the recorded and forecast variables.

R.20-05-002 reviewed the customer climate credits the State of California provides through the California Air Resources Board's (CARB) Cap-and-Trade

92 Exhibit PG&E-3.

93 Joint Exhibit-1

Program and adopted revisions to ensure that the credits were compliant with current statutes and regulations and streamlined certain existing processes. In D.21-08-026, the Commission determined that the volumetric dispersion of the small business California Climate Credit did not comply with CARB's Cap-and-Trade Regulation. To bring the small business return into compliance, starting in 2022 the Commission modified the small business California Climate Credit methodology to a flat rate approach mirroring and equal in size to the residential California Climate Credit.

PG&E AL 6326-E developed new D-series templates to calculate credit amounts accounting for the methodological adjustments in D.21-08-026. Template D-4 and Template D-5, previously submitted as part of the ERRA application, were removed.

PG&E forecasts $61,006,514 in GHG Cap-and-Trade costs for 2025.[94] PG&E calculates the net GHG allowance proceeds available for customer return at $805,193,101[95] and the net GHG revenue return at 720,909,000.[96] PG&E's net GHG revenues and expenses consist of the following: (1) a prior balance; (2) allowance revenue; (3) revenue franchise fees and uncollectibles; (4) administrative and customer outreach expenses; (5) interest; and (6) expenses for approved incremental clean energy and energy efficiency projects which may be funded by GHG allowance proceeds.

PG&E proposes to distribute $42.978 million to emissions-intensive trade-exposed (EITE) customers through the EITE customer return and

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94 Exhibit PG&E-4, Table 16-1, Template D-2.

95 Exhibit PG&E-4, Table 18-3.

96 Exhibit PG&E-4, Table 18-1, Template D-1.

$677.931 million[97] to residential and small commercial customers through the California Climate Credit.[98] Finally, PG&E proposes to return a semi-annual residential California Climate Credit of $58.23 per eligible account.[99]

The Commission therefore finds PG&E's GHG allowance-related revenues and expenses reasonable and in compliance with applicable rules, orders and Commission decisions.

A summary of PG&E's proposed GHG allowance-related revenues and expenses, which is also the Commission's adopted GHG allowance-related revenues and expenses, are provided in Table 4 below and explained in the following sections:

Table 4: Summary of GHG Allowance Auction-Related Revenues and Expenses[100]

Program	PG&E Proposed 2025 (thousands)
GHG auction revenues	
Prior Balance	$53,324
Allowance Revenue	-$805,193
Revenue Franchise Fees and Uncollectibles	-$8,016
GHG Revenue Subtotal	**-$759,885**
Expenses	
Outreach and Administrative Expenses	$817
Interest	-$144
Expenses Subtotal	**$674**
Clean Energy and Energy Efficiency Programs	
PG&E 2025 SOMAH[101] Including True-Ups	$34,626

[97] Exhibit PG&E-2; Exhibit PG&E-4, Table 18-1, Template D-1.

[98] Exhibit PG&E-4, Table 18-1, Template D-1.

[99] Exhibit PG&E-4, Table 18-1, Template D-1.

[100] Exhibit PG&E-4, Table 18-1, Template D-1.

[101] Solar on Multifamily Affordable Housing program.

Program	PG&E Proposed 2025 (thousands)
PG&E 2025 DAC-SASH[102]	$4,370
PG&E 2025 DAC-GT[103] and CS-GT[104] Including True-Ups	$5,664
CCA DAC-GT and CS-GT Including True-Ups	$9,667
CCA Disbursement Reconciliation to PG&E	$34
Funding from Public Purpose Programs	-$16,059
Clean Energy and Energy Efficiency Programs Subtotal	**$38,303**
Revenue Distributed for the Climate Credit	
EITE Customer Return	$42,978
California Climate Credit	-$677,931

7.1. GHG Costs

Under California's Cap-and-Trade program, utilities directly and indirectly incur GHG emissions costs. Direct costs include, generally, the costs incurred to purchase compliance instruments for plants run by the utility or the costs of providing physical or financial settlements specifically for GHG emissions from plants not owned or operated by the utility. Indirect costs generally reflect GHG costs embedded in the price of power purchased on the market or through contracts that do not include GHG settlement terms.

PG&E's Fall Update forecasts $61.006 million for direct GHG costs in 2025.[105] PG&E calculates direct GHG costs by multiplying the 2025 forecast price of $37.58/metric ton (MT), which is the Intercontinental Exchange settlement price as of September 3, 2024, by the forecast GHG emissions volume for

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[102] Disadvantaged Communities — Single-Family Solar Homes.

[103] Disadvantaged Communities Green Tariff.

[104] Community Solar Green Tariff.

[105] Exhibit PG&E-4, Table 16-1, Template D-2.

non-imported power.[106] PG&E forecasts GHG emissions costs associated with imported power by taking the volume of energy PG&E expects to generate or buy by resource type and multiplying by the emissions intensity for each resource type.[107]

No parties opposed or commented on PG&E's GHG costs. Upon review, the Commission finds PG&E's 2025 forecast GHG costs reasonable and in compliance with applicable rules, orders and Commission decisions.

7.2. GHG Allowance Proceeds

GHG allowance proceeds comes from the sale of GHG allowances allocated by the State of California for the benefit of ratepayers, which PG&E sells on behalf of ratepayers at quarterly GHG allowance auctions. PG&E forecasts its GHG allowance proceeds by multiplying a proxy GHG allowance price of $37.58/MT by the total volume of allowances CARB allocated to PG&E (21,426,000 allowances) in 2025.[108] PG&E's total forecast GHG allowance proceeds in 2025 is $805.193 million.[109] PG&E adjusts this forecast to reflect: (1) a prior balance of $53.324 million; and (2) $8.016 million in revenue franchise fees and uncollectibles, for a net 2025 GHG allowance proceeds forecast of $759.885 million.[110]

No parties opposed or commented on PG&E's GHG proceeds calculations. We reviewed PG&E's net 2025 forecast allowance proceeds amount and find it

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106 Exhibit PG&E-4.

107 Exhibit PG&E-2.

108 Exhibit PG&E-2; Exhibit PG&E-4.

109 Exhibit PG&E-4.

110 Exhibit PG&E-4.

reasonable and in compliance with applicable rules, orders and Commission decisions.

7.3. Administrative and Customer Outreach Expenses

The recorded and forecast administrative and customer outreach expenses are the costs incurred by a utility for administrative and customer outreach expenditures that relate to the GHG allowance proceeds return program.

7.3.1. 2023 Recorded Administrative and Customer Outreach Costs

PG&E's 2023 recorded administrative and customer outreach costs were $382,000.[111] We note a discrepancy between the value of $382,000 that PG&E provided in testimony at 17-1 and the value that PG&E provided in its total for Table 17-1, as shown:

Program Management	$198,000
IT Billing	$30,000
Call Center	$154,000
Total	**$528,000**

In sum, the values for Program Management, IT Billing, and Call Center equal $382,000, not $528,000.

No parties opposed or commented on PG&E's 2023 recorded administrative and customer outreach costs. We find that PG&E's 2023 recorded administrative and customer outreach expense cost of $382,000 is reasonable and in compliance with applicable rules, orders, and Commission decisions.

[111] Exhibit PG&E-2.

7.3.2. 2025 Forecast GHG Administrative and Customer Outreach Costs

PG&E's 2025 forecast of administrative and customer outreach expenses is $817,000, consisting primarily of outreach efforts for the California Climate Credit and assistance[112] for eligible EITE customers.[113]

No parties opposed or commented on PG&E's 2025 forecast of administrative and customer outreach expenses. Upon consideration, the Commission finds PG&E's 2025 forecast administrative and customer outreach expense costs reasonable and in compliance with applicable rules, orders, and Commission decisions.

7.4. Clean Energy and Energy Efficiency Projects

Under Pub. Util. Code Section 748.5(c), the Commission may allocate up to 15 percent of the revenue received by an electric corporation from its sales of allocated GHG allowances to specific clean energy and energy efficiency projects that are not funded by another source and are already approved by the Commission. PG&E's total request for clean energy and energy efficiency projects is $38.303 million.[114] PG&E has four programs funded in whole or in part from the sales of GHG allowances: (1) Solar on Multifamily Affordable Housing (SOMAH); (2) Disadvantaged Communities—Single-Family Solar Homes (DAC-SASH); (3) Disadvantaged Communities Green Tariff (DAC-GT); and (4) Community Solar Green Tariff (CS-GT).[115]

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[112] D.14-12-037.

[113] Exhibit PG&E-4, Table 18-1, Template D-1.

[114] Exhibit PG&E-4, Table 18-1, Template D-1.

[115] Exhibit PG&E-2.

D. 24-05-065 allows Program Administrators to discontinue the CS-GT program and transfer all remaining unprocured capacity to a Modified DAC-GT program. Therefore, PG&E is closing its CS-GT program and expects to propose the transfer of unspent funds from its CS-GT balancing account to the DAC-GT balancing account in its April 1, 2025 Annual Budget Advice Letter.[116]

7.5. EITE Emissions Customer Return

A portion of the GHG allowance proceeds is returned to customers who qualify for industry assistance. The EITE customer return is facility-specific and made to qualifying customers once per year in April. PG&E's 2025 forecast EITE customer return is $42.978 million.[117]

No parties opposed or commented on PG&E's 2025 forecast EITE customer return as proposed in the Fall Update. Upon consideration, the Commission finds PG&E's forecast 2025 EITE customer return reasonable and in compliance with applicable rules, orders and Commission decisions.

7.6. California Climate Credit

The California Climate Credit is distributed to residential and small business accounts after all applicable GHG-related expenses and other customer returns have been made. It appears as a credit on all residential and eligible small business[118] customers' bills twice a year in April and October. The California Climate Credit is not related to the volume of electricity used by the applicable account; each residential or eligible small business account within PG&E's territory receives the same California Climate Credit.

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116 PG&E AL 7313-E.

117 Exhibit PG&E-4, Table D-1.

118 Res. E-5339, August 22, 2024, modified eligibility rules for small business customers.

In 2024, the total recorded GHG allowance proceeds available for distribution were approximately $53.324 million less than forecast for 2024.[119] PG&E proposes to return the 2024 balance through the total 2025 GHG allowance proceeds available for distribution through the California Climate Credit.[120]

PG&E's 2025 forecast of the total number of households and small businesses eligible for the California Climate Credit is 5,821,487 and the proposed total revenue available for the California Climate Credit is $677,931 million.[121] PG&E proposes a California Climate Credit of $58.23, to be distributed as a credit on residential and small business account customers' bills in April and October of 2025.[122] This credit value is 5.5 percent higher than the California Climate Credit distributed in 2024.

No parties opposed or commented on PG&E's California Climate Credit in the Fall Update. The residential and small business California Climate Credit increases to $58.23.

The Commission finds PG&E's forecast 2025 California Climate Credit reasonable and in compliance with applicable rules, orders and Commission decisions.

8. Rate Design Proposal

8.1. Background

PG&E's proposed rates would recover the revenue requirements for: (1) PCIA, (2) ERRA - Main, (3) Ongoing CTC, (4) CAM, (5) MCAMBA, (6) Central

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[119] Exhibit PG&E-4, Table D-1.

[120] Exhibit PG&E-2.

[121] Exhibit PG&E-4, Table D-1.

[122] Exhibit PG&E-4, Table D-1.

Procurement Entity, (7) TMNBC, (8) BioMAT non-bypassable charge, and (9) VAMO.

To recover these revenue requirements, PG&E requested to change: (1) vintage PCIA rates, (2) generation rates, (3) Ongoing CTC rates, (4) New System Generation Charge (NSGC) rates, (5) TMNBC rates, (6) BioMAT rates, and (7) PPCP rates with these rate changes going into effect on January 1, 2025.

PG&E calculated illustrative rates[123] by applying the incremental revenue requirements requested in the instant application on top of present rates effective April 1, 2024. For the Application, PG&E used the revenue allocation and rate design methodology used to design the rates effective April 1, 2024 in D.21-11-016. All illustrative rates reflect adoption of the Common Cost methodology.[124]

Using this methodology and proposed revenue requirements, the system average bundled rate would decrease by about 0.7 cents/kWh, or 2.0 percent, to 34.6 cents/kWh when compared to the average bundled rate of 35.3 cents per kWh in effect at the time of the Fall Update. The system average rate for DA and CCA customers, whose average rates exclude commodity charges that are provided by third-party service providers, would decrease by about 0.9 cents/kWh, or 4.4 percent, to 19.7 cents per kWh, when compared to the system average rate for DA and CCA customers of 20.6 cents per kWh in effect at the time of the Fall Update.[125]

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[123] Exhibit PG&E-2 at Attachment A.

[124] PG&E Revised Proposal, as detailed in Section 5.4.

[125] Exhibit PG&E-4.

8.2. Revenue Allocation and Rate Design

We have reviewed PG&E's proposed revenue allocation and rate design and find it to be reasonable.

8.2.1. Vintage PCIA Rates

The Commission adopted the calculation methodology to determine the vintage PCIA revenue requirements in D.08-09-012 and modified the calculation in D.11-12-018, D.18-10-019, and D.21-05-030. To develop the PCIA rate for each vintage year and customer class, PG&E used the same proportional ratio of the rate class average generation rate to the total system average generation rate. PG&E then multiplied the proportional ratio by the total system average PCIA rate, by vintage year, to calculate the PCIA rate by vintage year and by rate class. PG&E calculated proportional generation ratios using the 2025 generation rates presented in the instant application, which are designed using the 2025 forecast bundled sales by customer class. All PCIA rates include CDWR franchise fees.

In addition to the methodology described above, PG&E noted the following PCIA rate design steps that are part of the Application:

- PG&E's calculation of PCIA rates in the Application no longer includes the calculation of PUBA rate adders;[126] and
- PG&E will transfer the 2024 year-end ERRA-Main balance to the most recent vintage subaccount in PABA.[127]

D.20-12-038 authorized PG&E to recover the 2020 PUBA year-end balance over a three-year period from 2021 to 2023 using vintage-specific PUBA rate adders.[128] In PG&E's 2023 ERRA Forecast application, PG&E proposed using PUBA rate adders to amortize the forecasted 2022 year-end PUBA balance over the course of

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[126] D.23-12-022.

[127] As authorized in D.22-01-023.

[128] D.20-12-038.

2023 so the remaining PUBA balance would be fully amortized by the end of 2023.[129]

In PG&E's 2024 ERRA Forecast Application, PG&E forecasted a residual PUBA balance of $7.4 million remaining in PUBA vintage subaccounts by the end of 2023.[130] To bring this balance closer to zero before closing the account, PG&E proposed to amortize this residual PUBA balance in rates in 2024 through the continued implementation of PUBA rate adders for an additional year.[131] By amortizing this residual PUBA balance in rates in 2024, PG&E expected the balance to be closer to zero by the end of 2024, allowing PG&E to submit an AL to close the PUBA.[132]

In D.23-12-022, the Commission authorized PG&E to discontinue the use of PUBA rate adders once the balance in PUBA balancing account reached $1 million, or at the end of 2024, whichever is sooner.[133] The instant application presents a residual PUBA balance forecast of approximately $2 million by the end of 2024. As a result, PG&E currently expects to transfer the 2024 year-end PUBA balance to the UOG Legacy Subaccount in PABA in its 2025 Annual Electric True-Up AL, effective January 1, 2025 and subsequently retire the PUBA balancing account.

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[129] A.23-05-012.

[130] A.23-05-012, Application of Pacific Gas and Electric Company (U 39 E) for 2024 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation, May 15, 2023 at 10-11.

[131] D.23-12-022.

[132] Exhibit PG&E-2.

[133] D.23-12-022.

In D.22-01-023, the Commission adopted a process to transfer the year-end ERRA balance to the most-recent vintage subaccount of PABA each year.[134] To comply with this decision, PG&E transferred the forecast 2024 year-end ERRA-Main balance to the 2024 vintage subaccount in PABA in the instant application. Amortizing this balance in the 2024 vintage subaccount in PABA allows the balance to be applied to both bundled customers and PCIA-eligible departed load customers that departed on or after July 1, 2024. PG&E currently forecasts an overcollection of $84 million in ERRA-Main at the end of 2024.[135]

Table 5 shows illustrative PCIA rates for all vintages and customer classes, with adoption of the Common Cost proposal.[136] For vintages prior to 2024, PCIA rates increase by a range of 0.5 cents per kWh to 2.4 cents per kWh, compared to 2024 PCIA rates implemented March 1, 2024.

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[134] D.22-01-023 at 13-15.

[135] Exhibit PG&E-4.

[136] Any revenue requirement component changes approved in this proceeding will be implemented in the 2025 Annual Electric True-Up and will be consolidated with other changes approved for implementation at that time.

Table 5: Proposed Power Charge Indifference Adjustment Rates by Class and Vintage ($/kWh)

Vintage	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Residential	$0.00806	$0.00835	$0.00834	$0.00830	$0.00782	$0.00777	$0.00771	$0.00770	$0.00734	$0.00336	$0.00070	$0.00058	-$0.01966	-$0.01999	-$0.02288	-$0.02538
Small Light & Power	$0.00762	$0.00790	$0.00789	$0.00785	$0.00739	$0.00735	$0.00730	$0.00729	$0.00694	$0.00318	$0.00066	$0.00055	-$0.01859	-$0.01891	-$0.02163	-$0.02400
Medium Light & Power	$0.00800	$0.00829	$0.00828	$0.00824	$0.00776	$0.00771	$0.00765	$0.00765	$0.00728	$0.00334	$0.00069	$0.00057	-$0.01951	-$0.01985	-$0.02271	-$0.02519
E19	$0.00758	$0.00785	$0.00784	$0.00780	$0.00735	$0.00730	$0.00725	$0.00724	$0.00690	$0.00316	$0.00066	$0.00054	-$0.01847	-$0.01879	-$0.02150	-$0.02384
Streetlights	$0.00645	$0.00669	$0.00668	$0.00665	$0.00626	$0.00622	$0.00617	$0.00617	$0.00587	$0.00270	$0.00056	$0.00047	-$0.01571	-$0.01598	-$0.01829	-$0.02029
Standby	$0.00543	$0.00563	$0.00562	$0.00559	$0.00527	$0.00524	$0.00520	$0.00519	$0.00495	$0.00227	$0.00048	$0.00040	-$0.01321	-$0.01343	-$0.01537	-$0.01705
Agriculture	$0.00717	$0.00743	$0.00742	$0.00738	$0.00695	$0.00691	$0.00686	$0.00685	$0.00653	$0.00299	$0.00062	$0.00052	-$0.01748	-$0.01777	-$0.02034	-$0.02256
B20/E20 T	$0.00645	$0.00669	$0.00668	$0.00665	$0.00626	$0.00622	$0.00617	$0.00617	$0.00587	$0.00270	$0.00056	$0.00047	-$0.01571	-$0.01598	-$0.01829	-$0.02029
B20/E20 P	$0.00689	$0.00714	$0.00714	$0.00710	$0.00669	$0.00665	$0.00660	$0.00659	$0.00628	$0.00288	$0.00060	$0.00050	-$0.01680	-$0.01708	-$0.01955	-$0.02169
B20/E20 S	$0.00720	$0.00746	$0.00745	$0.00741	$0.00698	$0.00694	$0.00689	$0.00688	$0.00655	$0.00301	$0.00062	$0.00052	-$0.01754	-$0.01784	-$0.02042	-$0.02265
BEV1	$0.00663	$0.00687	$0.00686	$0.00683	$0.00643	$0.00639	$0.00634	$0.00634	$0.00603	$0.00277	$0.00057	$0.00048	-$0.01616	-$0.01644	-$0.01881	-$0.02087
BEV2	$0.00732	$0.00758	$0.00758	$0.00754	$0.00710	$0.00706	$0.00700	$0.00699	$0.00666	$0.00306	$0.00063	$0.00053	-$0.01784	-$0.01815	-$0.02077	-$0.02304
System Average	$0.00708	$0.00725	$0.00793	$0.00765	$0.00742	$0.00756	$0.00734	$0.00741	$0.00693	$0.00327	$0.00064	$0.00055	-$0.01880	-$0.01858	-$0.02015	-$0.02433

Table 6[137] summarizes the PCIA revenues allocated to bundled, DA, and CCA customers based on the PCIA rates presented in Table 6. We have reviewed these rates and find them to be reasonable.

Table 6: Forecast PCIA Revenues from Proposed PCIA Rates (Thousands)

Bundled Customers	$(51,278)
DA/CCA Customers	1,049,210
Total Revenues	$997,932

8.2.2. Generation

The generation revenue requirement used for rates is shown in Table 1. PG&E used the methodology, adopted in D.21-11-016, that allocates incremental generation revenue using an equal percentage of functional revenues. First, PG&E adjusted bundled customers' current generation revenue, using current rates and the sales forecast for the 2025 test year, by subtracting non-allocated revenue to create an "adjusted present rate revenue." Next, PG&E compared the adjusted present rate revenue to the total generation revenue requirement to determine the incremental generation revenue necessary to collect the generation revenue requirement. Then PG&E allocated incremental generation revenue on an equal percentage basis, such that each customer class and schedule receives the same percentage change based on its share of the adjusted present rate revenue. The proposed generation revenue for generation rate design is the sum of the adjusted present rate revenue, non-allocated revenue, and the incremental revenue.

PG&E proposed to implement the change in generation revenue for each schedule in rates as an equal percentage change to each bundled service generation demand charge component for that rate schedule. That is, the

137 Exhibit PG&E-2.

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. The change in generation energy charge-related revenue for each schedule would be implemented in rates either as: (1) an equal-cent per kWh change to each bundled service generation energy charge component for that rate schedule, or (2) as an equal-percentage change to the generation energy rate.[138]

Table 7 presents the proposed total average generation rates for bundled customers.[139] Bundled generation rates do not include bundled PCIA rates, which are shown separately in PG&E's rate schedule tariffs.[140]

Table 7: Proposed 2025 Average Total Generation Rates for Bundled Customers ($/kWh)

Residential	$0.17638
Small Commercial	$0.16681
Medium Commercial	$0.17507
Large Commercial	$0.16574
Streetlights	$0.14106
Standby	$0.11860
Agriculture	$0.15683
B20/E20 T	$0.14106
B20/E20 P	$0.15076
B20/E20 S	$0.15745
BEV1	$0.14505
BEV2	$0.16012

138 D.21-11-016.

139 Exhibit PG&E-2.

140 Pursuant to D.21-11-016.

8.2.3. Ongoing CTC

PG&E stated that, pursuant to D.18-10-019, Ongoing CTC revenue requirements are allocated to each customer class using the same generation allocation methodology used to design bundled generation rates. Eligible departed load customers pay the same class-differentiated ongoing CTC rates as bundled, DA, and CCA customers. PG&E calculated rates by dividing the allocated revenue for the class by the corresponding 2025 forecast sales. Table 8 shows PG&E's proposed Ongoing CTC rates for bundled, DA, CCA, and eligible departed load customers.[141]

Table 8: Proposed 2025 Ongoing Competition Transition Charge Rates ($/kWh)

Residential	$0.00066
Small Commercial	$0.00062
Medium Commercial	$0.00065
Large Commercial	$0.00062
Streetlights	$0.00052
Standby	$0.00044
Agriculture	$0.00058
B20/E20 T	$0.00052
B20/E20 P	$0.00056
B20/E20 S	$0.00058
BEV1	$0.00062
BEV2	$0.00062

8.2.4. New System Generation Charge

The NSGC is a non-bypassable charge to recover the net capacity costs of Combined Heat and Power contracts.[142] NSGC rates are based on the 12-month

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141 Exhibit PG&E-2.

142 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. PG&E subsequently labeled this non-bypassable charge the NSGC in AL 3896-E-B.

coincident peak methodology.[143] To determine the rates, PG&E allocated the proposed revenue requirement to each customer class using each customer class's contribution to 12-month coincident peak load. Proposed rates are based on 2023 recorded data.

Rates for each customer class are calculated by dividing the allocated revenue by each customer class's forecast usage. Proposed NSGC rates are shown in Table 9.[144]

Table 9: Proposed 2025 New System Generation Charge Rates ($/kWh)

Residential	$0.00520
Small Commercial	$0.00357
Medium Commercial	$0.00322
Large Commercial	$0.00322
Streetlights	$0.00356
Standby	$0.00359
Agriculture	$0.00344
B20/E20 T	$0.00275
B20/E20 P	$0.00275
B20/E20 S	$0.00275
BEV1	$0.00357
BEV2	$0.00322

8.2.5. Tree Mortality Non-Bypassable Charge

To determine TMNBC rates, PG&E first allocated the TMNBC revenue requirement determined in Table 1 to each customer class using the same 12-month coincident peak allocation factors used to design NSGC rates. PG&E then calculated rates for each customer class by dividing the allocated revenue by each customer class's forecast usage. TMNBC rates are embedded in total public

[143] D.11-12-013, D.15-08-005.

[144] Exhibit PG&E-2.

purpose program rates for billing. Proposed TMNBC rates are shown in Table 10.[145]

Table 10: Proposed 2025 Tree Mortality Non Bypassable Charge Rates ($/kWh)

Residential	$0.00528
Small Commercial	$0.00363
Medium Commercial	$0.00327
Large Commercial	$0.00327
Streetlights	$0.00362
Standby	$0.00365
Agriculture	$0.00349
B20/E20 T	$0.00280
B20/E20 P	$0.00280
B20/E20 S	$0.00280
BEV1	$0.00363
BEV2	$0.00327

8.2.6. BioMAT Non-bypassable Charge

To determine BioMAT non-bypassable charge rates, PG&E first allocated the BioMAT non-bypassable charge revenue requirement to each customer class using the same 12-month coincident peak allocation factors used to design NSGC rates. Then PG&E set rates for each customer class by dividing the allocated revenue by each customer class forecast usage. Like the TMNBC, BioMAT non-bypassable charge rates are embedded in total public purpose program rates for billing. Proposed BioMAT non-bypassable charge rates are shown in Table 11.[146]

145 Exhibit PG&E-2.

146 Exhibit PG&E-2.

Table 11: Proposed 2025 BioMAT Rates ($/kWh)

Residential	$0.00007
Small Commercial	$0.00005
Medium Commercial	$0.00004
Large Commercial	$0.00004
Streetlights	$0.00005
Standby	$0.00005
Agriculture	$0.00005
B20/E20 T	$0.00003
B20/E20 P	$0.00003
B20/E20 S	$0.00003
BEV1	$0.00005
BEV2	$0.00004

8.2.7. 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 public purpose program rates.[147]

PG&E allocated the total PPCP revenue requirement of $2.7 million using the equal percent of total revenue allocation method, consistent with the allocation methodology that applies to all other subaccounts included in the PPCBA. PPCP rates are embedded in total public purpose program rates for billing. Proposed PPCP rates are shown in Table 12.

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

Table 12: Proposed 2025 Public Policy Charge Procurement Rates ($/kWh)

Residential	$0.00003
Small Commercial	$0.00003
Medium Commercial	$0.00002
Large Commercial	$0.00002
Streetlights	$0.00003
Standby	$0.00001
Agriculture	$0.00002
B20/E20 T	$0.00002
B20/E20 P	$0.00002
B20/E20 S	$0.00002
BEV1	$0.00003
BEV2	$0.00002

8.3. Green Tariff Shared Renewables Rates

PG&E has two electric rate schedules associated with the GTSR program: (1) electric rate schedule Green Tariff (Solar Choice Program or E-GT tariff) and (2) the Enhanced Community Renewables rate schedule (E-ECR).

In the instant application, PG&E requested to update the GTSR Program rate components for rates effective January 1, 2025.[148] The GTSR Program bill credit and charges that make up the E-GT and E-ECR rates are: (1) Solar Rate (E-GT rate schedule only); (2) PCIA Program Charge; (3) Other Program Charge components:

a. RA Charge;
b. CAISO Grid Management Charge (GMC);
c. Western Renewable Energy Generation Information System (WREGIS) Fees;
d. Renewable Integration Charges;

[148] Pursuant to D.15-01-051, the renewable power rate and other components of GTSR rates should be updated annually.

e. Solar Value Adjustment (Time of Day and RA);

f. Administrative and Marketing Costs; and

g. Class Average Generation Rate credit.

The RA charge is calculated using the 2024 RA MPB issued by Energy Division. The forecast MPBs are multiplied by the current portfolio's NQC to determine the portfolio value, then divided by sales to determine the applicable rate.

The costs for CAISO GMC are based on a three-year rolling average of recorded data as presented in Federal Energy Regulatory Commission Form 1. The WREGIS fee and administrative and marketing expenses are based on PG&E's current forecast of sales and expected administrative and marketing expenditures.

PG&E presented calculations of its GTSR rates for applicable rate classes in its Application[149] and Fall Update.[150] No party disputed the calculation of PG&E's GTSR rates. We have reviewed PG&E's proposed GTSR rates and find them reasonable.

8.4. Changes to Total Rates

Appendix B Tables 13 and 14 present revenues and average rates, which include the GHG revenue return. Appendix B Tables 15 and 16 present revenues and average rates excluding the GHG revenue return. Total rates are determined by adding the current rate components that are not changing in this proceeding (e.g., nuclear decommissioning, distribution, and transmission) and proposed rates for PCIA, Generation, Ongoing CTC, NSGC, TMNBC, BioMAT non-bypassable charge, and PPCP. The TMNBC, BioMAT non-bypassable charge,

[149] Exhibit PG&E-2, Chapter 14, Tables 14-3 to 14-3.

[150] Exhibit PG&E-4, Tables 14-3, 14-5 to 14-13.

and PPCP rates proposed in this application are embedded in the average public purpose program rate in both the bundled and the DA/CCA customer average rate tables.

Illustrative non-ERRA rate components do not reflect the cost recovery (i.e., total 2025 revenue requirements) subject to Commission approval through PG&E's 2025 Annual Electric True-Up for year-end balancing account adjustments. Any revenue requirement component changes approved in this proceeding will be implemented in the 2025 Annual Electric True-Up and will be consolidated with other changes approved for implementation at that time. As a result, rates shown in Appendix B only illustrate the rate impact of this application.

9. Summary of Public Comment

Rule 1.18 of the Rules of Practice and Procedure (Rules) allows any member of the public to submit written comment in any Commission proceeding using the "Public Comment" tab of the online Docket Card for that proceeding on the Commission's website. Rule 1.18(b) requires that relevant written comment submitted in a proceeding be summarized in the final decision issued in that proceeding.

To date, there are fourteen comments on the "Public Comment" tab on the Docket Card for this proceeding. All opposed rate increases associated with this application.

10. Procedural Matters

We find good cause to grant, with modification:

a. CalCCA's October 21, 2024 motion to file under seal a confidential version of its opening briefs,

b. CalCCA's November 5, 2024 motion to file under seal a confidential version of its reply briefs, and

c. CalCCA's November 12, 2024 motion to file under seal a confidential version of its comments on the Fall Update.

These filings shall be given the requested confidential treatment for a period of three years. At any point from six months from the date of this motion to the conclusion of the three-year period of confidentiality, CalCCA or PG&E may move to seek a furtherance of the confidentiality treatment on the basis of whether additional good cause is shown.

Finding good cause, we grant PG&E's October 23, 2024 motion to file the Fall Update (Confidential Version) under seal, with modification. We mark and identify the Fall Update as Exhibit PG&E-4C. This exhibit shall be admitted to the evidentiary record of this proceeding and given the requested confidential treatment for a period of three years. At any point from six months from the date of this motion to the conclusion of the three-year period of confidentiality, PG&E may move to seek a furtherance of the confidentiality treatment on the basis of whether additional good cause is shown.

This decision affirms all rulings made by the Administrative Law Judge and assigned Commissioner in this proceeding. All motions not ruled on are deemed denied.

11. Reduction of Comment Period and Party Comments

The proposed decision of ALJ Elizabeth Fox in this matter was mailed to the parties in accordance with Pub. Util. Code Section 311 and comments were allowed under Rule 14.3. Pursuant to Rule 14.6(b), all parties stipulated to reduce the 30-day public review and comment period required by Pub. Util. Code Section 311 to five days for opening comments and five days for reply comments.

Comments were filed on _________by _________, and reply comments were filed on _________by _________. .

12. Assignment of Proceeding

John Reynolds is the assigned Commissioner and Elizabeth Fox is the assigned Administrative Law Judge and Presiding Officer in this proceeding.

Findings of Fact

1. PG&E presented a complete 2025 ERRA forecast in its Fall Update.

2. The estimated net revenue requirement is $2,248,901,000.

3. PG&E identified a cost shift associated with the methodology it uses to allocate Common Costs.

4. This cost shift associated with PG&E's Common Cost allocation methodology would be remedied by the adoption of the PG&E Revised Proposal.

5. PG&E incurred $382,000 in 2023 GHG administrative and customer outreach costs.

Conclusions of Law

1. It is reasonable to approve a gross revenue requirement for 2025 of $4,253,101,000, composed of the following balances in balancing accounts, subject to adjustments in the Annual Electric True-Up process.

Balancing Account	**Balance (Thousands)**
Cost Allocation Mechanism and New System Generation Charge	$294,748
Modified Cost Allocation Mechanism Balancing Account	$2,823
Voluntary Allocation Market Offer Memorandum Account	$635
Power Charge Indifference Adjustment	-$381,617
Ongoing Competition Transition Charge	-$47,114
Energy Resource Recovery Account – Main	$4,342,049
Public Policy Charge Procurement	-$1,896
Tree Mortality Non-bypassable Charge	$47,367
Bioenergy Market Adjusting Tariff	-$3,896
Gross Revenue Requirement	**$4,253,101**

2. It is reasonable to adopt PG&E's Revised Proposal for a Common Cost allocation methodology beginning with January 1, 2025 rates.

3. It is reasonable to adopt PG&E's forecasted energy load requirement of 28,655 GWh for 2025, calculated as the residual of the total system sales forecast (77,873 GWh), forecasted departing load (-49,777 GWh) and unaccounted for energy/losses (2,451 GWh).

4. It is reasonable to adopt PG&E's forecast of:

   (a) GHG administrative and outreach expenses of $817,000 for 2025.

   (b) Clean energy and energy efficiency programs totaling $38,303,000 for 2025. This includes: (1) $34,626,000 for the PG&E's SOMAH program, including true-ups; (2) $4,370,000 for the PG&E's DDAC-SASH program; (3) $5,664,000 for PG&E's DAC-GT CS-GT programs, including true-ups; (4) $9,667,000 for CCA DAC-GT and CS-GT programs, including true-ups; (5) $34,000 for CCA Disbursement Reconciliation to PG&E; and (6) -$16,059,000 in funding from public purpose programs.

   (c) Net GHG revenue return of $720,909,000 for 2025.

   (d) A semi-annual California Climate Credit value of $58.23 for 2025.

5. It is reasonable to adopt PG&E's 2023 recorded GHG administrative and customer outreach costs of $382,000.

6. It is reasonable to adopt PG&E's rate design proposals and revenue allocation proposals as detailed in Section 8 of this decision.

7. It is reasonable to grant CalCCA confidential treatment of its Opening Brief (Confidential Version) for three years.

8. It is reasonable to mark the Fall Update for identification and admit into evidence as Exhibit PG&E-4.

9. It is reasonable to mark the Fall Update (Confidential Version) for identification and admit into evidence as Exhibit PG&E-4C.

10. It is reasonable to grant PG&E confidential treatment of its Fall Update (Confidential Version) for three years.

O R D E R

IT IS ORDERED that:

1. Within 30 days of this decision's issuance date, Pacific Gas and Electric Company shall file a Tier 1 advice letter with tariffs to implement the rates authorized by this decision, effective on the date of the filing of the advice letter.

2. Within 30 days of this decision's issuance date, Pacific Gas and Electric Company shall file a Tier 2 advice letter that updates Advice Letter 5440-E to modify the Common Cost methodology in accordance with this decision.

3. California Community Choice Association's Opening Brief (Confidential Version), filed October 21, 2024, is granted confidential treatment for three years.

4. California Community Choice Association's Reply Brief (Confidential Version), filed November 5, 2024, is granted confidential treatment for three years.

5. California Community Choice Association's comments on Pacific Gas and Electric Company's 2025 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation Fall Update Testimony, filed November 12, 2024, is granted confidential treatment for three years.

6. Pacific Gas and Electric Company's 2025 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation Fall Update Testimony, filed

October 23, 2024, is marked for identification as Exhibit PG&E-4 and admitted into evidence on the effective date of this decision.

7. Pacific Gas and Electric Company's 2025 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation Fall Update Testimony (Confidential Version), filed October 23, 2024, is marked for identification as Exhibit PG&E-4C and admitted into evidence on the effective date of this decision.

8. Pacific Gas and Electric Company's 2025 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation Fall Update Testimony (Confidential Version), filed October 23, 2024, is granted confidential treatment for three years.

9. Application 24-05-009 is closed.

This order is effective today.

Dated ____________________________, at San Francisco, California

APPENDIX A

Appendix A: Commonly Used Terms

Term	Definition
AL	Advice Letter
BA	Balancing Account
CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
Bundled customer	Customer who receives both electricity generation and distribution services from PG&E
CCA	Community Choice Aggregator
CDWR	California Department of Water Resources
COL	Conclusion of Law
CTC	Competition Transition Charge
DA	Direct Access
Departed load	Also known as unbundled electric service customers, departing load customers, receive electricity generation and distribution services from separate entities. Examples of departing load customers are customers of CCAs or DA providers.
EITE	Emissions-intensive trade-exposed customers
ERRA	Energy Resource Recovery Account
ESA	Electric Supply Administration
GHG	Greenhouse gas
GTSR	Green Tariff Shared Renewables
GWh	Gigawatt-hours
LSEs	Load serving entities
MCAMBA	Modified Cost Allocation Mechanism Balancing Account
MW	Megawatt
OP	Ordering Paragraph
PCIA	Power Charge Indifference Adjustment
PUBA	PCIA Undercollection Balancing Account
PURPA	Public Utility Regulatory Policies Act
PV	Solar photovoltaic
QF	Qualifying generation facilities under the Public Utility Regulatory Policies Act of 1978
RPS	Renewable Portfolio Standard

Term	Definition
Unbundled customer	A customer that receives energy delivery services from PG&E but take energy from another supplier. Unbundled customers include CCA and Direct Access customers.
UOG	Utility-owned generation
VAMO	Voluntary Allocation Market Offer
VAMOMA	Voluntary Allocation Market Offer Memorandum Account

(END OF APPENDIX A)

APPENDIX B

Appendix B: Illustrative Rate Changes

Table 13: Revenue and Average Rate Summary with GHG Revenue Return, Bundled Customers[1]

	Total Proposed Revenue (cents/kWh)	Total Sales (kWh)	Revenue at Present Rates	Total Proposed Rates	Percent Change
Residential					
Non-CARE	$2,644,175,194	6,335,565,412	$0.42605	$0.41735	-2.0%
CARE	$970,165,228	3,758,009,155	$0.26449	$0.25816	-2.4%
Total Residential	$3,614,340,422	10,093,574,567	$0.36590	$0.35808	-2.1%
Small L&P					
B-1	$750,424,283	1,786,706,393	$0.42607	$0.42000	-1.4%
B-6	$247,513,777	593,843,975	$0.42502	$0.41680	-1.9%
A-15	$136,520	277,413	$0.49156	$0.49212	0.1%
TC-1	$4,173,752	10,134,384	$0.42155	$0.41184	-2.3%
Total Small	$1,002,248,332	2,390,962,165	$0.42580	$0.41918	-1.6%
Medium L&P					
B-10 T	$210,327	962,378	$0.23165	$0.21855	-5.7%
B-10 S	$9,025,520	26,514,098	$0.35321	$0.34040	-3.6%
B-10 P	$783,103,926	2,064,951,472	$0.38630	$0.37924	-1.8%
Total Medium	$792,339,773	2,092,427,948	$0.38581	$0.37867	-1.8%
B-19 Class					
B-19 Firm T	$1,254,909	4,503,500	$0.28830	$0.27865	-3.3%
B-19 V T	$1,572,695	7,051,673	$0.23208	$0.22302	-3.9%
Total B-19 T	$2,827,605	11,555,173	$0.25399	$0.24470	-3.7%
B-19 Firm P	$84,849,408	299,396,687	$0.29319	$0.28340	-3.3%
B-19 V P	$41,290,148	151,890,436	$0.28192	$0.27184	-3.6%
Total B-19 P	$126,139,557	451,287,123	$0.28939	$0.27951	-3.4%
B-19 Firm S	$338,240,029	840,715,969	$0.40815	$0.40232	-1.4%
B-19 V S	$645,758,558	2,029,504,056	$0.32593	$0.31819	-2.4%
Total B-19 S	$983,998,586	2,870,220,025	$0.35002	$0.34283	-2.1%
B-19 T	$2,827,605	11,555,173	$0.25399	$0.24470	-3.7%
B-19 P	$126,139,557	451,287,123	$0.28939	$0.27951	-3.4%
B-19 S	$983,998,586	2,870,220,025	$0.35002	$0.34283	-2.1%
Total B-19	$1,112,965,748	3,333,062,322	$0.34148	$0.33392	-2.2%
Streetlights	$34,580,541	75,210,025	$0.46450	$0.45979	-1.0%
Standby					
Standby T	$72,024,358	416,555,851	$0.18359	$0.17290	-5.8%

[1] Exhibit PG&E-4, Attachment B-2.

	Total Proposed Revenue (cents/kWh)	Total Sales (kWh)	Revenue at Present Rates	Total Proposed Rates	Percent Change
Standby P	$5,630,567	6,370,007	$0.36027	$0.88392	145.4%
Standby S	$1,079,679	1,990,716	$0.53775	$0.54236	0.9%
Total Standby	$78,734,605	424,916,574	$0.18790	$0.18529	-1.4%
Agriculture					
AG-A1	$104,462,588	206,383,738	$0.51018	$0.50616	-0.8%
AG-A2	$50,506,653	125,604,108	$0.40934	$0.40211	-1.8%
AG B	$386,002,215	728,236,669	$0.53348	$0.53005	-0.6%
AG C	$1,089,067,350	3,228,972,407	$0.34514	$0.33728	-2.3%
Total Agriculture	$1,630,038,806	4,289,196,921	$0.38694	$0.38003	-1.8%
B-20 Class					
B-20 Firm T	$378,447,751	1,986,186,889	$0.19701	$0.19054	-3.3%
FPP T					
Total	$378,447,751	1,986,186,889	$0.19701	$0.19054	-3.3%
B-20 Firm P	$350,611,351	1,310,236,573	$0.27336	$0.26759	-2.1%
FPP P					
Total	$350,611,351	1,310,236,573	$0.27336	$0.26759	-2.1%
B-20 Firm S	$64,479,846	208,282,246	$0.31629	$0.30958	-2.1%
FPP S					
Total	$64,479,846	208,282,246	$0.31629	$0.30958	-2.1%
B-20 T	$378,447,751	1,986,186,889	$0.19701	$0.19054	-3.3%
B-20 P	$350,611,351	1,310,236,573	$0.27336	$0.26759	-2.1%
B-20 S	$64,479,846	208,282,246	$0.31629	$0.30958	-2.1%
Total B-20	$793,538,949	3,504,705,708	$0.23265	$0.22642	-2.7%
SYSTEM	$9,058,787,174	26,204,056,231	$0.35287	$0.34570	-2.0%

Table 14: Revenue and Average Rate Summary with GHG Revenue Return, DA/CCA Customers[2]

	Total Proposed Revenue (cents/kWh)	Total Sales (kWh)	Revenue at Present Rates	Total Proposed Rates	Percent Change
Residential					
Non-CARE	$3,461,630,920	13,346,861,903	$0.27149	$0.25936	-4.5%
CARE	$308,009,906	3,022,634,575	$0.11174	$0.10190	-8.8%
Total Residential	$3,769,640,826	16,369,496,478	$0.24199	$0.23028	-4.8%
Small L&P					
B-1	$1,129,269,047	4,060,734,460	$0.28679	$0.27809	-3.0%
B-6	$278,946,476	1,023,773,874	$0.28217	$0.27247	-3.4%
A-15	$271,303	575,172	$0.41471	$0.47169	13.7%
TC-1	$7,955,920	28,917,077	$0.28494	$0.27513	-3.4%
Total Small	$1,416,442,747	5,114,000,583	$0.28587	$0.27697	-3.1%
Medium L&P					
B-10 T	$242,295	2,676,574	$0.10545	$0.09052	-14.2%
B-10 S	$9,999,530	51,446,413	$0.20318	$0.19437	-4.3%
B-10 P	$1,126,027,928	5,148,537,148	$0.22745	$0.21871	-3.8%
Total Medium	$1,136,269,753	5,202,660,134	$0.22715	$0.21840	-3.8%
B-19 Class					
B-19 Firm T	$1,686,366	20,166,485	$0.09371	$0.08362	-10.8%
B-19 V T	$680,950	7,439,692	$0.10023	$0.09153	-8.7%
Total B-19 T	$2,367,317	27,606,177	$0.09547	$0.08575	-10.2%
B-19 Firm P	$82,792,529	563,885,086	$0.15444	$0.14683	-4.9%
B-19 V P	$44,744,699	315,001,472	$0.15080	$0.14205	-5.8%
Total B-19 P	$127,537,228	878,886,559	$0.15313	$0.14511	-5.2%
B-19 Firm S	$597,820,910	2,872,882,560	$0.21725	$0.20809	-4.2%
B-19 V S	$1,227,520,149	7,275,014,777	$0.17684	$0.16873	-4.6%
Total B-19 S	$1,825,341,059	10,147,897,337	$0.18828	$0.17987	-4.5%
B-19 T	$2,367,317	27,606,177	$0.09547	$0.08575	-10.2%
B-19 P	$127,537,228	878,886,559	$0.15313	$0.14511	-5.2%
B-19 S	$1,825,341,059	10,147,897,337	$0.18828	$0.17987	-4.5%
Total B-19	$1,955,245,603	11,054,390,072	$0.18526	$0.17688	-4.5%
Streetlights	$48,006,848	167,420,501	$0.29381	$0.28674	-2.4%
Standby					
Standby T	$14,252,638	127,201,735	$0.12048	$0.11205	-7.0%
Standby P	$5,547,481	19,021,282	$0.26536	$0.29165	9.9%
Standby S	$1,013,166	3,967,230	$0.26065	$0.25538	-2.0%

2 Exhibit PG&E-4, Attachment B-4.

	Total Proposed Revenue (cents/kWh)	Total Sales (kWh)	Revenue at Present Rates	Total Proposed Rates	Percent Change
Total Standby	$20,813,285	150,190,248	$0.14253	$0.13858	-2.8%
Agriculture					
AG-A1	$23,209,623	63,278,965	$0.37487	$0.36678	-2.2%
AG-A2	$9,573,122	37,801,841	$0.26380	$0.25324	-4.0%
AG B	$79,908,303	234,808,728	$0.34972	$0.34031	-2.7%
AG C	$244,081,503	1,222,641,247	$0.20921	$0.19963	-4.6%
Total Agriculture	$356,772,551	1,558,530,781	$0.23843	$0.22892	-4.0%
B-20 Class					
B-20 Firm T	$248,375,539	3,568,413,811	$0.07527	$0.06960	-7.5%
FPP T	$11,902,920	291,475,444	$0.04081	$0.04084	0.1%
Total	$260,278,459	3,859,889,255	$0.07266	$0.06743	-7.2%
B-20 Firm P	$673,451,544	4,995,435,528	$0.14085	$0.13481	-4.3%
FPP P	$2,450,230	19,094,641	$0.12854	$0.12832	-0.2%
Total	$675,901,774	5,014,530,169	$0.14080	$0.13479	-4.3%
B-20 Firm S	$244,475,303	1,596,450,972	$0.16066	$0.15314	-4.7%
FPP S	$4,880,199	49,429,915	$0.09888	$0.09873	-0.1%
Total	$249,355,502	1,645,880,887	$0.15881	$0.15150	-4.6%
B-20 T	$260,278,459	3,859,889,255	$0.07266	$0.06743	-7.2%
B-20 P	$675,901,774	5,014,530,169	$0.14080	$0.13479	-4.3%
B-20 S	$249,355,502	1,645,880,887	$0.15881	$0.15150	-4.6%
Total B-20	$1,185,535,735	10,520,300,311	$0.11862	$0.11269	-5.0%
SYSTEM	$9,888,727,349	50,136,989,109	$0.20629	$0.19723	-4.4%

Table 15: Revenue and Average Rate Summary without GHG Revenue Return, Bundled Customers[3]

	Total Proposed Revenue (cents/kWh)	Total Sales (kWh)	Revenue at Present Rates	Total Proposed Rates	Percent Change
Residential					
Non-CARE	$2,782,205,360	6,335,565,412	$0.44669	$0.43914	1.7%
CARE	$1,049,711,910	3,758,009,155	$0.28455	$0.27933	1.8%
Total Residential	$3,831,917,271	10,093,574,567	$0.38632	$0.37964	1.7%
Small L&P					
B-1	$765,785,792	1,786,706,393	$0.43535	$0.42860	1.6%
B-6	$249,544,237	593,843,975	$0.42847	$0.42022	1.9%
A-15	$138,681	277,413	$0.50666	$0.49991	1.3%
TC-1	$4,173,752	10,134,384	$0.42155	$0.41184	2.3%
Total Small	$1,019,642,462	2,390,962,165	$0.43359	$0.42646	1.6%
Medium L&P					
B-10 T	$210,327	962,378	$0.23165	$0.21855	5.7%
B-10 S	$9,120,368	26,514,098	$0.35363	$0.34398	2.7%
B-10 P	$783,740,816	2,064,951,472	$0.38659	$0.37954	1.8%
Total Medium	$793,071,511	2,092,427,948	$0.38610	$0.37902	1.8%
B-19 Class					
B-19 Firm T	$1,254,909	4,503,500	$0.28830	$0.27865	3.3%
B-19 V T	$1,572,695	7,051,673	$0.23208	$0.22302	3.9%
Total B-19 T	$2,827,605	11,555,173	$0.25399	$0.24470	3.7%
B-19 Firm P	$85,336,374	299,396,687	$0.29500	$0.28503	3.4%
B-19 V P	$41,290,148	151,890,436	$0.28192	$0.27184	3.6%
Total B-19 P	$126,626,522	451,287,123	$0.29059	$0.28059	3.4%
B-19 Firm S	$338,862,721	840,715,969	$0.40872	$0.40306	1.4%
B-19 V S	$646,051,520	2,029,504,056	$0.32593	$0.31833	2.3%
Total B-19 S	$984,914,241	2,870,220,025	$0.35018	$0.34315	2.0%
B-19 T	$2,827,605	11,555,173	$0.25399	$0.24470	3.7%
B-19 P	$126,626,522	451,287,123	$0.29059	$0.28059	3.4%
B-19 S	$984,914,241	2,870,220,025	$0.35018	$0.34315	2.0%
Total B-19	$1,114,368,367	3,333,062,322	$0.34178	$0.33434	2.2%
Streetlights	$34,580,541	75,210,025	$0.46450	$0.45979	1.0%
Standby					
Standby T	$81,364,254	416,555,851	$0.20258	$0.19533	3.6%
Standby P	$6,001,635	6,370,007	$0.94542	$0.94217	0.3%
Standby S	$1,079,679	1,990,716	$0.53827	$0.54236	-0.8%

[3] Exhibit PG&E-4, Attachment B-6.

	Total Proposed Revenue (cents/kWh)	Total Sales (kWh)	Revenue at Present Rates	Total Proposed Rates	Percent Change
Total Standby	$88,445,568	424,916,574	$0.21529	$0.20815	3.3%
Agriculture					
AG-A1	$107,163,008	206,383,738	$0.52781	$0.51924	1.6%
AG-A2	$51,098,739	125,604,108	$0.41505	$0.40682	2.0%
AG B	$386,588,684	728,236,669	$0.53458	$0.53086	0.7%
AG C	$1,089,618,305	3,228,972,407	$0.34528	$0.33745	2.3%
Total Agriculture	$1,634,468,736	4,289,196,921	$0.38825	$0.38107	1.8%
B-20 Class					
B-20 Firm T	$384,647,881	1,986,186,889	$0.19954	$0.19366	2.9%
FPP T					
Total	$384,647,881	1,986,186,889	$0.19954	$0.19366	2.9%
B-20 Firm P	$353,551,677	1,310,236,573	$0.27628	$0.26984	2.3%
FPP P					
Total	$353,551,677	1,310,236,573	$0.27628	$0.26984	2.3%
B-20 Firm S	$64,572,437	208,282,246	$0.31676	$0.31002	2.1%
FPP S					
Total	$64,572,437	208,282,246	$0.31676	$0.31002	2.1%
B-20 T	$384,647,881	1,986,186,889	$0.19954	$0.19366	2.9%
B-20 P	$353,551,677	1,310,236,573	$0.27628	$0.26984	2.3%
B-20 S	$64,572,437	208,282,246	$0.31676	$0.31002	2.1%
Total B-20	$802,771,995	3,504,705,708	$0.23519	$0.22906	2.6%
SYSTEM	$9,319,266,452	26,204,056,231	$0.36250	$0.35564	1.9%

Table 16: Selected Revenue and Average Rate Summary without GHG Revenue Return, DA/CCA Customers[4]

	Total Proposed Revenue (cents/kWh)	Total Sales (kWh)	Revenue at Present Rates	Total Proposed Rates	Percent Change
Residential					
Non-CARE	$3,798,969,223	13,346,861,903	$0.29544	$0.28463	-3.7%
CARE	$385,204,692	3,022,634,575	$0.13594	$0.12744	-6.3%
Total Residential	$4,184,173,915	16,369,496,478	$0.26599	$0.25561	-3.9%
Small L&P					
B-1	$1,148,280,127	4,060,734,460	$0.29184	$0.28278	-3.1%
B-6	$281,492,418	1,023,773,874	$0.28470	$0.27496	-3.4%
A-15	$312,788	575,172	$0.55451	$0.54382	-1.9%
TC-1	$7,955,920	28,917,077	$0.28494	$0.27513	-3.4%
Total Small	$1,438,041,253	5,114,000,583	$0.29040	$0.28120	-3.2%
Medium L&P					
B-10 T	$242,295	2,676,574	$0.10545	$0.09052	-14.2%
B-10 S	$9,999,530	51,446,413	$0.20318	$0.19437	-4.3%
B-10 P	$1,126,828,903	5,148,537,148	$0.22760	$0.21886	-3.8%
Total Medium	$1,137,070,728	5,202,660,134	$0.22730	$0.21856	-3.8%
B-19 Class					
B-19 Firm T	$1,686,366	20,166,485	$0.09371	$0.08362	-10.8%
B-19 V T	$680,950	7,439,692	$0.10023	$0.09153	-8.7%
Total B-19 T	$2,367,317	27,606,177	$0.09547	$0.08575	-10.2%
B-19 Firm P	$82,929,180	563,885,086	$0.15471	$0.14707	-4.9%
B-19 V P	$44,744,699	315,001,472	$0.15080	$0.14205	-5.8%
Total B-19 P	$127,673,879	878,886,559	$0.15331	$0.14527	-5.2%
B-19 Firm S	$598,842,898	2,872,882,560	$0.21752	$0.20845	-4.2%
B-19 V S	$1,228,006,272	7,275,014,777	$0.17684	$0.16880	-4.6%
Total B-19 S	$1,826,849,170	10,147,897,337	$0.18836	$0.18002	-4.4%
B-19 T	$2,367,317	27,606,177	$0.09547	$0.08575	-10.2%
B-19 P	$127,673,879	878,886,559	$0.15331	$0.14527	-5.2%
B-19 S	$1,826,849,170	10,147,897,337	$0.18836	$0.18002	-4.4%
Total B-19	$1,956,890,365	11,054,390,072	$0.18534	$0.17702	-4.5%
Streetlights	$48,006,848	167,420,501	$0.29381	$0.28674	-2.4%
Standby					
Standby T	$14,252,638	127,201,735	$0.12048	$0.11205	-7.0%
Standby P	$5,621,783	19,021,282	$0.30460	$0.29555	-3.0%
Standby S	$1,013,166	3,967,230	$0.26080	$0.25538	-2.1%

[4] Exhibit PG&E-4, Attachment B-8.

	Total Proposed Revenue (cents/kWh)	Total Sales (kWh)	Revenue at Present Rates	Total Proposed Rates	Percent Change
Total Standby	$20,887,587	150,190,248	$0.14751	$0.13907	-5.7%
Agriculture					
AG-A1	$23,825,639	63,278,965	$0.38797	$0.37652	-3.0%
AG-A2	$9,685,004	37,801,841	$0.26742	$0.25620	-4.2%
AG B	$80,020,264	234,808,728	$0.35040	$0.34079	-2.7%
AG C	$244,444,785	1,222,641,247	$0.20936	$0.19993	-4.5%
Total Agriculture	$357,975,693	1,558,530,781	$0.23927	$0.22969	-4.0%
B-20 Class					
B-20 Firm T	$262,351,777	3,568,413,811	$0.07843	$0.07352	-6.3%
FPP T	$11,902,920	291,475,444	$0.04081	$0.04084	0.1%
Total	$274,254,696	3,859,889,255	$0.07559	$0.07105	-6.0%
B-20 Firm P	$679,901,795	4,995,435,528	$0.14252	$0.13610	-4.5%
FPP P	$2,450,230	19,094,641	$0.12854	$0.12832	-0.2%
Total	$682,352,025	5,014,530,169	$0.14247	$0.13607	-4.5%
B-20 Firm S	$244,672,383	1,596,450,972	$0.16079	$0.15326	-4.7%
FPP S	$4,880,199	49,429,915	$0.09888	$0.09873	-0.1%
Total	$249,552,582	1,645,880,887	$0.15893	$0.15162	-4.6%
B-20 T	$274,254,696	3,859,889,255	$0.07559	$0.07105	-6.0%
B-20 P	$682,352,025	5,014,530,169	$0.14247	$0.13607	-4.5%
B-20 S	$249,552,582	1,645,880,887	$0.15893	$0.15162	-4.6%
Total B-20	$1,206,159,304	10,520,300,311	$0.12051	$0.11465	-4.9%
SYSTEM	$10,349,205,693	50,136,989,109	$0.21506	$0.20642	-4.0%

(END OF APPENDIX B)