~~STATE OF CALIFORNIA~~ ~~GAVIN NEWSOM, *Governor*~~

~~PUBLIC UTILITIES COMMISSION~~

~~505 VAN NESS AVENUE~~
~~SAN FRANCISCO, CA 94102-3298~~

~~November 21, 2025~~ **~~Agenda ID #23880~~**
~~Ratesetting~~

~~TO PARTIES OF RECORD IN APPLICATION 25-05-011 ET AL.:~~

~~This is the proposed decision of Administrative Law Judge Elizabeth Fox. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's~~ **~~12/18/2025~~** ~~Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.~~

~~Pursuant to Rule 14.6(b), comments on the proposed decision must be filed within four (business) days of its mailing and reply comments must be filed within seven (business) days of its mailing.~~

~~The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled,~~ ~~*ex parte*~~ ~~communications are prohibited pursuant to Rule 8.2(c)(4).~~

~~/s/ MICHELLE COOKE~~

~~Michelle Cooke~~
~~Chief Administrative Law Judge~~

~~MLC: smt~~
~~Attachment~~

Decision **PROPOSED DECISION OF ALJ FOX** (Mailed 11/21/2025)

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 2026 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation.	Application 25-05-011
Expedited Application of Pacific Gas and Electric Company Pursuant to the Commissions Approved Energy Resource Recovery Account (ERRA) Trigger Mechanism. (U39E.)	Application 25-09-015

DECISION APPROVING PACIFIC GAS AND ELECTRIC COMPANY'S 2026 ENERGY RESOURCE RECOVERY ACCOUNT RELATED FORECAST REVENUE REQUIREMENT AND 2026 ELECTRIC SALES FORECAST

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DECISION APPROVING PACIFIC GAS AND ELECTRIC COMPANY'S 2026 ENERGY RESOURCE RECOVERY ACCOUNT RELATED FORECAST REVENUE REQUIREMENT AND 2026 ELECTRIC SALES FORECAST

Summary

This decision adopts the 2026 Energy Resource Recovery Account (ERRA) and related forecasted energy costs and the 2026 electric sales forecast for Pacific Gas and Electric Company (PG&E). The decision also adopts PG&E's 2026 forecast revenue requirements for greenhouse gas and climate-related costs.

The estimated 12-month gross revenue requirement for 2026 is approximately $4.511 billion, 6.1 percent higher than the adopted 12-month gross revenue requirement for 2025. As a result of this decision and including the impact of the Greenhouse Gas allowance auction proceeds return, bundled residential customers' rates will decrease by approximately 11.0 percent or 3.9 cents per kilowatt-hour (cents/kWh) to a total rate of 31.3 cents/kWh. For residential Direct Access (DA) and Community Choice Aggregator (CCA) customers, generation rates will increase by about 14.6 percent or 2.9 cents/kWh to a total rate of 22.6 cents/kWh.[1]

PG&E forecasted an overcollection of $700 million in ERRA-Main balancing account at the end of 2025. This decision authorizes PG&E to amortize this overcollection in the annual electric true-up advice letter and requires PG&E

[1] Rates for DA and CCA customers do not include the cost of electricity generation, which is not procured by the utility.

to submit an advice letter that separately documents the rate changes made as a result of the ERRA trigger.

PG&E forecasts an energy load requirement of 27,101 gigawatt-hours (GWh) for 2026. This forecast is about 5.4 percent lower than the forecast adopted in PG&E's 2025 ERRA Forecast Application. PG&E's 2026 system peak forecast is about 2.0 percent higher than the 2025 peak forecast adopted in the 2024 ERRA Forecast proceeding.

This decision also adopts a 2026 California Climate Credit of $36.18, a $22.05 decrease compared to 2025.

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[2] 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

[2] 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.

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."[3]

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 D.06-07-030 (as modified by D.07-01-030, D.11-12-018, D.14-10-045, D.18-10-019, and D.25-06-049 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

[3] D.02-10-062.

process.[4] 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.[5]

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, 2025, Pacific Gas and Electric Company (PG&E) filed the instant application requesting Commission approval of its 2026 ERRA forecast revenue requirement (Application). On June 18, 2025, Direct Access Customer Coalition (DACC) and Small Business Utility Advocates (SBUA) filed timely responses to the Application. On the same date, the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) and California Community Choice Association (CalCCA) filed timely protests to the Application. On June 30, 2025, PG&E filed a reply to parties' responses and protests.

A prehearing conference (PHC) was held on July 8, 2025, to discuss the issues of law and fact and determine the need for hearing and schedule for

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

[5] D.14-10-033.

resolving the matter. The assigned Commissioner issued a Scoping Memo and Ruling on July 31, 2025.

On September 2, 2025, CalCCA and SBUA served intervenor testimony. On September 23, 2025, PG&E served rebuttal testimony.

On September 9, 2025, the assigned ALJ issued a ruling requiring additional information regarding PG&E's data center demand forecasts (Data Center Demand Ruling). PG&E responded to this ruling on September 23, 2025.

On September 30, 2025, PG&E filed a trigger application, Application (A.) 25-09-015, to address overcollection of its main ERRA account, pursuant to Pub. Util. Code Section 454.5(d)(3) and Decisions (D.) 02-10-062, D.04-12-048, D.08-08-011, and D.22-01-023.

On October 7, 2025, an evidentiary hearing was held.

On October 20, 2025, a PHC was held in A.25-09-015. An October 29, 2025 Assigned Commissioner's Scoping Memo and Ruling consolidated A.25-05-011 and A.25-09-015.

Pursuant to D.22-01-023, the Commission issued 2025 Resource Adequacy Market Price Benchmark (RA MPB) calculations on October 1, 2025, with figures used to calculate the 2026 PCIA.

On October 6, 2025, the assigned ALJ issued a second ruling requiring additional information regarding PG&E's data center demand forecasts (Second Data Center Demand Ruling). PG&E responded to this ruling on October 15, 2025.

PG&E served the Fall Update on October 15, 2025, concurrent with a motion to file the Fall Update (Confidential Version) under seal.

On October 24, 2025, PG&E, CalCCA, DACC, and SBUA 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 November 3, 2025, CalCCA, PG&E, and SBUA filed reply briefs.

On November 6, 2025, PG&E filed its ERRA 2026 Forecast Fall Update Errata (Fall Update Errata). On November 10, 2025, CalCCA filed comments on the Fall Update Errata.

On November 10, 2025, CalCCA filed its comments on the Fall Update and Fall Update Errata (Fall Update Comments).

1.3. Submission Date

This matter was submitted on November 10, 2025, upon submission of comments on the Fall Update.

2. Issues Before the Commission

The issues to be determined or otherwise considered are:

1. Should the Commission adopt PG&E's request to approve 2026 ERRA Forecast revenue requirements for 2026 ratesetting purposes, all as initially forecast in PG&E's Application and as may be updated through the course of this proceeding, including:
    a. Disposition of PG&E's forecast December 31, 2025 year-end balancing account balances, subject to adjustments for recorded balances through the Annual Electric True-up process, and

   b. Disposition of recorded Voluntary Allocation and Market Offer Memorandum Account (VAMOMA) balances?

2. Did D.19-10-001 establish a methodology for treatment of pre-2019 banked RECs? If not, how should PG&E value pre-2019 banked RECs for the purpose of calculating the Power Change Indifference Adjustment (PCIA)?

3. Is PG&E's proposal to modify its Resource Adequacy (RA) valuation methodology for PCIA ratemaking purposes to account for the Slice-of-Day (SoD) methodology reasonable? If not, is there another methodology that should be applied instead on an interim basis?

4. Should the Commission adopt PG&E's 2026 electric sales forecast?

5. Should the Commission adopt the GHG-related forecasts for 2026 described in the Application?

6. Were PG&E's recorded 2024 administrative and outreach expenses of $708,000 reasonable?

7. Should the Commission approve PG&E's rate proposals associated with its proposed total electric procurement related revenue requirements, including its Green Tariff Shared Renewables (GTSR) proposal, to be effective in rates on January 1, 2026?

8. Should the Commission approve following requests from PG&E?

   a. To acknowledge the overcollection of the ERRA balancing account, and

   b. To state that PG&E has complied with the requirements of D.02-10-062 to file an expedited ERRA trigger application as a result of the ERRA overcollection being greater than 5 percent.

3. Revenue Requirement

PG&E forecasts a 2026 total net revenue requirement of approximately $3.044 billion. In Table 1,[6] PG&E summarized its revenue requirement request as the sum of eight accounts with positive values, reduced by negative values of two accounts for which PG&E expects to recover costs in other proceedings.

Table 1: 2026 Revenue Requirement (in thousands)

	Application	Fall Update[7]
Cost Allocation Mechanism (CAM) and New System Generation Charge	$217,427	$372,790
Voluntary Allocation Market Offer Memorandum Account	$320	$654
Power Charge Indifference Adjustment (PCIA)	$815,274	$1,098,402
Ongoing Competition Transition Charge (CTC)	($26,941)	$33,736
Energy Resource Recovery Account (ERRA) – Main	$2,958,889	$2,951,883
Public Policy Charge Procurement	($2,546)	($1,723)
Tree Mortality Non-bypassable Charge	$41,412	$41,579
Bioenergy Market Adjusting Tariff	$10,873	$13,763
Gross Revenue Requirement	**$4,014,709**	**$ 4,511,083**
Adjustments for Revenue Requirements Authorized in Other Proceedings		
Utility-Owned Generation – Related Costs	($1,303,065)	($1,231,267)
Residential Uncollectibles Balancing Account (RUBA-E)	($6,517)	($19,119)

[6] Exhibit PGE-01 and Exhibit PGE-06, Table 1-1.

[7] As amended in Fall Update Errata.

	Application	Fall Update[7]
Subtotal of Adjustments	($1,309,582)	($1,250,386)
Net Revenue Requirement Requested in Application	**$2,705,127**	**$3,260,698**

Section 3 of this decision addresses the eight accounts with positive values, which total $4.29 billion. Section 4 addresses the remaining accounts, with negative values that total about ($1.25 billion), that are to be authorized in other proceedings.

Nearly $500 million in gross revenue requirement was added between the original filing in May and the Fall Update errata in November, with most costs increases accruing in the CAM/New System Generation Charge and PCIA. PG&E provided no narrative explanation for the $155.363 million increase in the CAM and the reason for this change was not evident from review of the associated tables.[8] Although there is sufficient foundation to find these increases reasonable for the purpose of an ERRA forecast decision, given the true-up that will occur in next year's ERRA compliance proceeding, we require additional information from PG&E in its 2026 ERRA compliance application. PG&E is therefore directed to provide a narrative describing the reasons for the increase in the CAM/New System Generation Charge as part of its next ERRA compliance filing.

3.1. Cost Allocation Mechanism

PG&E forecasts a 2026 CAM revenue requirement of $372.79 million. The purpose of the CAM is to allocate certain costs and benefits, including Resource

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[8] Exhibit PGE-06, Tables 4-5, 6-1, 7-1, 13-1.

Adequacy (RA) benefits, among all Load-Serving Entities (LSEs)[9] 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[10] 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.[11] 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.

We have reviewed PG&E's CAM revenue requirement and find that it is reasonable.

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[9] 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.

[10] Approved November 9, 2018.

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

3.2. Voluntary Allocation Market Offer Memorandum Account

For 2026, PG&E forecasted its Voluntary Allocation Market Offer (VAMO) Memorandum Account (VAMOMA) revenue requirement at $654,000. PG&E requested disposition of the VAMOMA balance through PCIA rates.[12] No party protested this revenue requirement request. We have reviewed this forecast and find that it is reasonable.

The purpose of the VAMOMA[13] 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. The Commission adopted the VAMO process for PCIA eligible Renewable Portfolio Standard (RPS) resources in D.21-05-030.

3.3. Power Charge Indifference Adjustment

PG&E's proposed forecast for its 2026 PCIA revenue requirement is $1.098 billion. We have reviewed this forecast and find that it is reasonable.

3.3.1. 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

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[12] Exhibit PGE-01 at 1-2.

[13] 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.

adopted a PCIA to preserve bundled customer "indifference"[14] 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.[15]

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.

The current rulemaking that addresses matters related to the PCIA is Rulemaking (R.) 25-02-005. In this rulemaking, D.25-06-049 implemented revisions to the methodology the Commission uses when calculating the RA MPB used to calculate the PCIA. The two revisions made in D.25-06-049 were made to ensure that the movement of customers from bundled electric services to unbundled service does not shift costs to either customer class. Since D.25-06-049 was issued after the filing of the instant application and before the Fall Update,

[14] 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.

[15] D.06-07-030.

the Fall Update includes some significant revisions to balancing accounts with calculations that use RA MPBs.

R.25-02-005 is open and the two applications for rehearing of D.25-06-049 were denied on October 30, 2025.[16]

3.3.2. PABA

The Commission established the PABA in 2019[17] 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 the vintage portfolio for each year 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.

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

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[16] San Jose Clean Energy and Ava Community Energy Authority Joint Application for Rehearing of D.25-06-049, July 28, 2025 *and* California Community Choice Association Application for Rehearing of Decision 25-06-049, July 28, 2025.

[17] D.19-10-001.

customers through PCIA rates to recover such above-market costs. Any over- or under-collection in the PABA vintage subaccounts in a given year is rolled into the next year's ERRA Forecast filing.[18] The PABA revenue requirement is calculated using Market Price Benchmarks (MPBs) that the Commission calculates and publishes each year.[19] In its 2025 Fall Update Errata, PG&E forecasted the PABA to be under-collected by $2.240 billion.[20] PG&E described the primary drivers for the under-collection as shown in Table 2.

Table 2: Primary Drivers for PABA Under-collection (Millions)[21]

Lower Expected CAISO Revenues	
Lower Market Electricity Prices	$430
Less Generation from PCIA-eligible Resources	$105
	$535
Greater Net Procurement Costs	
Lower Net RA Transaction Revenues	$545
Higher Energy Storage Contract Costs	$80
Lower Natural Gas Fired Generator Costs	$(85)
Procurement Related Credits not in the Forecast	$ (110)
	$430
Lower Retained RPS Value	
Lower 2025 final RPS adder	$65
Lower Retained RPS quantity	$120
	$185
Lower Retained RA Value	
Lower 2025 final RA adder	$630
Lower Retained RA quantity	$415

[18] D.19-10-001.

[19] The Commission issued Final 2025 MPBs on October 1, 2025.

[20] Exhibit PGE-06 at 18.

[21] Fall Update Errata, Table 12-3.

	$1,045
Recorded balances brought forward from 2024	
PABA	$80
ERRA	$ (70)
	$10
Balancing Account Interest	$40
Other	**$(6)**
Forecast 2025 year-end PABA balance, before Balance Transfers	**$2,240**

The PABA undercollection can be attributed to several factors as demonstrated in the table above. First, CAISO revenues were approximately 25 percent lower than the Energy Benchmark forecast due to lower-than-expected natural gas prices, and less generation from PCIA eligible Solar resources than had been expected.[22] Second, RA sales revenues were roughly $545 million lower than expected, due to lower RA sale prices than forecasted. Third, lower final RPS and RA benchmarks for 2025, combined with less retained RA than forecasted lead to an additional $1.23 billion of undercollection in the PABA.[23]

3.3.3. MPBs

MPBs are estimates of the value per unit (not total portfolio value) associated with three principal sources of value in IOU portfolios: energy, resource adequacy, and renewable energy."[24] MPBs are multiplied by the relevant portfolio volume as part of the overall calculation of market value. The

[22] Fall Update Errata at 20.

[23] Fall Update Errata at 22.

[24] D.19-10-001 at 6.

forecast adders prospectively predict the market value and the true up adders retrospectively update market value.

The Energy Index is the MPB that reflects the estimated market value of each unit of energy in an IOU's PCIA-eligible portfolio, in dollars per megawatt hour ($/MWh). The 2025 Energy Index was calculated using Platts-ICE Forward Curve-Electricity market data. Energy Division received a Platts on-peak and off-peak forward price for each month of 2026 and each electrical zone (NP15 and SP15), as calculated on each individual non-holiday weekday from September 1, 2025 through September 30, 2025 (inclusive). Using this data, Energy Division calculated a 2026 monthly average price for each peak period and each electrical zone. PG&E uses weighted averages of these values in the Fall Update.

The RA Adder calculates the estimated value of each unit of capacity in an IOU's PCIA-eligible portfolio that can be used to satisfy Resource Adequacy obligations, in dollars per kilowatt-month ($/kW-month).

D.25-06-049 modified the RA MPB methodology adopted in D.19-10-001 to calculate a single unified RA MPB rather than calculate a separate system, local, and flexible value. The RA Forecast MPB and RA Final MPB are calculated as ordered in D.25-06-049.[25]

The RPS Adder is the MPB that reflects the estimated value, incremental to the Energy Index, of each unit of RPS-eligible energy that is attributable to its RPS eligibility, in $/MWh.

[25] D.25-06-059 at OP 1.

The GHG-free Energy Adder reflects the estimated value of the GHG-free, non-RPS resources that is attributable to verifiable added market value of the GHG-free energy attribute, for the purpose of counting toward the LSEs' Portfolio Content Label.

3.4. Ongoing Competition Transition Charge

PG&E forecasts that its Ongoing Competition Transition Charge (CTC) revenue requirement for 2026 will be $33.736 million. 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.

3.5. Energy Resource Recovery Account – Main and Trigger Application

PG&E forecasted that its 2026 main ERRA revenue requirement would be $2.951 billion. According to the Fall Update Errata, ERRA – Main was overcollected by 13.6 percent, compared with the 6.3 percent over-collection forecast in PG&E's expedited ERRA Trigger Application.[26] Pursuant to D.22-01-023, PG&E proposed to transfer the over-collected ERRA balance to the PABA Vintage 2025 Subaccount for consolidation with the balance of the PABA vintages for recovery in the bundled PCIA rates.[27]

We have reviewed this forecast and find it reasonable to (1) acknowledge the overcollection of the ERRA balancing account, and (2) state that PG&E has complied with the requirements of D.02-10-062 to file an expedited ERRA trigger

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[26] Fall Update Errata Table 12-4, Exhibit PGE-06 at 25, A.25-09-015.

[27] ERRA Trigger Application at 7.

application as a result of the ERRA overcollection being greater than 5 percent. We find it reasonable to authorize PG&E to amortize this overcollection in the annual electric true-up advice letter. But given potential rate impacts that cannot be assessed in this expedited application, we require PG&E to file an information-only advice letter that separately documents the rate changes made as a result of the ERRA trigger.

3.5.1. ERRA-Main Background

The ERRA-Main balancing account records market-based energy procurement costs associated with serving bundled customers.[28] These costs include contracted resource costs, fuel costs for PG&E-owned and contracted generation, Qualifying Facility (QF) and purchased power costs, and other electric procurement costs such as natural gas hedging and collateral costs and certain GHG compliance costs associated with the Assembly Bill (AB) 32 cap-and-trade program.[29]

3.5.2. Trigger Background

On September 30, 2025, PG&E filed a trigger application that stated that the ERRA Trigger Balance, based on the August 2025 accounting close, was at $273 million, or 5.3 percent overcollected.[30] PG&E also stated that it forecast its overcollection to persist throughout 2025.[31] According to PG&E, the primary cause of its forecasted overcollection is that wholesale power prices remained

[28] Application at 21.

[29] Application at 21.

[30] ERRA Trigger Application at 2, Exhibit A.

[31] ERRA Trigger Application at 2.

low through the summer months of 2025, resulting in lower wholesale net costs for bundled load.[32]

PG&E's Fall Update refreshed the ERRA-Main Trigger Balance using the newly issued MPBs[33] and PG&E subsequently updated the ERRA-Main Trigger Balance in Fall Update Errata.[34]

Table 3: Primary Drivers for ERRA-Main Overcollection (millions)[35]

Lower Customer Revenues	**$105**
Lower Expected CAISO Costs	
Lower Market Electricity Prices	$(385)
Lower Bundled Load Requirement	$(275)
	$(660)
Greater Net Procurement Costs	**$125**
Retained RPS and RA	
Lower Retained RPS Value	$(190)
Lower Retained RA Value	$(1,200)
	(1,390)
Balancing Account Interest	**$(30)**
Other	**$(3)**
Forecast 2025 year-end ERRA-Main balance, before Balance Transfers	**$(1,853)**

According to PG&E, disposition of the ERRA-Main trigger balance for amortization in 2026 rates is consistent with D.14-12-053, D.20-03-012, and D.23-05-010, which confirmed the disposition of ERRA-Main triggers through the annual ERRA Forecast decisions. PG&E argued that amortization through the

[32] ERRA Trigger Application at 2, A-3.

[33] Exhibit PGE-06 at 25.

[34] Fall Update Errata, Table 12-4.

[35] Fall Update Errata, Table 12-4.

annual electric true-up advice letter would minimize the number of rate changes in 2026 and provide a smoother customer rate experience.[36] PG&E requested that amortization of the ERRA-Main Trigger Balance occur through the PCIA, including the transfer of the overcollected ERRA balance in the Vintage 2025 PCIA subaccount for consolidation with the balance of the PABA vintages in the bundled PCIA rates.[37]

3.5.3. Trigger Party Comments

No party protested PG&E's proposed treatment of the ERRA-Main trigger balance.

3.5.3. Trigger Discussion

Given the submission and revision of the ERRA-Main trigger balance within weeks of the proposed decision, the Commission was unable to fully assess the impact of amortizing this overcollection on rates. In addition, the cost recovery approved in this application is trued up in the annual electric true-up advice letter, which consolidates various rate changes, so the Commission will not otherwise have an opportunity to consider the rate impacts of this request. Given potential rate impacts that cannot be assessed in this expedited application, we require PG&E to file an information-only advice letter that separately documents the rate changes made as a result of the ERRA trigger. That advice letter shall update the rate impacts demonstrated in Tables 13-3, 13-5 to 13-10 of its Testimony, Fall Update and Fall Update Errata.

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[36] Exhibit PGE-06 at 26.

[37] Exhibit PGE-06 at 26; PG&E Opening Brief at 22.

3.6. Public Policy Charge Procurement

PG&E forecasts that its 2026 Public Policy Charge Procurement (PPCP) revenue requirement would be -$1.72 million. No party protested this forecast. 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.[38] The PPCP subaccount was established to record the recovery of the above-market costs associated with: (1) 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.

3.7. Tree Mortality Non-bypassable Charge

PG&E forecasts its Tree Mortality Non-bypassable Charge (TMNBC) revenue requirement at $41.579 million for 2026.

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.[39] Senate Bill (SB) 859, Statutes 2016, Chapter 368,[40] 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.

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

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

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

Res. E-4805, which implemented the requirements of SB 859,[41] 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.[42]

PG&E calculated its 2026 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.[43] 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.[44]

No party protested the forecasted revenue requirement for the TMNBC. We have reviewed this forecast and find that it is reasonable.

3.8. Bioenergy Market Adjusting Tariff

For 2026, PG&E forecasts that its Bioenergy Market Adjustment Tariff (BioMAT) revenue requirement will be $13.763 million. 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

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

[42] Exhibit PGE-01 at 9-2.

[43] Exhibit PGE-01 at 9-2.

[44] Exhibit PGE-01 at 9-2.

each IOU and establishing the pricing mechanism and other rules for the BioMAT Program.

No party protested this forecasted revenue requirement. We reviewed this forecast and find that it is reasonable.

4. Revenue Requirement Adjustments Authorized in Other Proceedings

PG&E proposed to reduce its 2025 revenue requirement by $1.25 billion to account for revenue requirements authorized in other proceedings. Therefore, the two 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 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 -$1.231 billion for 2026.

For reference, these costs are as follows:

Table 4: UOG-Related Costs[45]

	Authorization	Revenue Requirement (Thousands)
Authorized UOG-Related Costs		
2023 GRC + 2024 to 2026 Attrition	D.23-11-069	$1,205,338
Cost of Capital and Debt Adjustment	Advice Letter (AL) 5042-G/7535-E	$19,893
Hydro Sales	AL 5042-G/7535-E	$(8,866)
Pension	AL 5042-G/7535-E	$30,252
Gain on Sale of San Francisco General Office	D.21-08-027	$(21,028)
Purchase of Oakland General Office	D.24-08-009	$9,286
Non-Wildfire Self Insurance Adjustment	D.25-03-008	$(8,350)
2022 WMCE	D.25-09-008	$4,742
Total		**$1,231,267**
Recovery of Authorized UOG-Related Costs		
PCIA		$1,185,531
ERRA		$(737)
CAM		$46,474
Total		**$1,231,267**

4.2. 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

[45] Exhibit PGE-06, Table 8-1.

uncollectibles.[46] 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 -$19.119 million in its RUBA-E generation subaccount.

5. Pre-2019 Banked Renewable Energy Credits

PG&E proposed to use certain banked renewable energy credits (REC) to meet its RPS compliance target and CalCCA and DACC opposed the proposal on grounds that it violated the Commission's principles of customer indifference. We find that PG&E's proposal is reasonable on an interim basis while awaiting a more comprehensive decision on use of banked RECs in a rulemaking.

5.1. Background

PG&E forecasted a short RPS position in 2026 and stated that it expected to use banked RECs to meet the RPS compliance target.[47] PG&E noted that the Commission determined in D.23-12-022, modified by D.24-08-004, that RECs generated and banked in and after 2019 (Post-2019 Banked RECs) are first applied to meet the minimum retained RPS requirement.[48] PG&E stated that

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[46] AL 6001-E-A.

[47] Exhibit PGE-01 at 8-19.

[48] Exhibit PGE-01 at 8-19, PG&E Opening Brief at 18.

once these retained volumes had been exhausted, it would then utilize RECs generated and retained before January 1, 2019 (Pre-2019 Banked RECs) to meet the compliance target.[49] If the Pre-2019 Banked REC volumes were exhausted, PG&E would then look to retain previously Unsold RPS volumes, if available, to meet its minimum retained RPS requirement.[50]

PG&E stated that, as ordered in D.19-10-001, it would apply the applicable current RPS Adder when crediting customers based on their PCIA vintage for any Post-2019 Banked RECs utilized towards meeting PG&E's minimum retained RPS requirement.[51] For any utilized Pre-2019 Banked RECs, PG&E stated that it would credit applicable ERRA Forecast year vintage customers (e.g., vintage 2026 for the 2026 ERRA Forecast), regardless of delivery year, as D.19-10-001 excluded these RECs from receiving any additional ratemaking treatment associated with bundled RPS compliance.[52]

5.2. Party Comments

5.2.1. CalCCA

CalCCA argued that, to the extent a REC was previously purchased by bundled customers at the time it was generated, the value of that REC should be credited to the PCIA vintage corresponding to the year it was generated to ensure both bundled and unbundled customers are treated fairly.[53] According to

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[49] Exhibit PGE-01 at 8-19.

[50] Exhibit PGE-01 at 8-19.

[51] Exhibit PGE-01 at 8-19.

[52] Exhibit PGE-01 at 8-19.

[53] CalCCA Opening Brief at 20.

CalCCA, PG&E's banked REC proposal in this proceeding fails to comport with Pub. Util. Code Section 366.2(g), Commission precedent implementing the indifference framework established in California law (including D.19-10-001 and its predecessors), "and basic logic."[54] According to CalCCA, PG&E's proposal would denying departed load its fair share of the value of those RECs.[55]

CalCCA argued that the Commission should therefore reject PG&E's Banked REC proposal, since (1) PG&E's current bundled customers in 2026 should be responsible for the cost of RPS compliance on their behalf in 2026, and (2) unbundled customers who were customers at the time that the RECs were paid for should receive credit for the value of RPS attributes that are now being used for bundled customer RPS compliance, now that they have departed from CCA service.

CalCCA also stated in its Fall Update Comments that PG&E's proposal (1) "violates Section 366.2(g) of the Public Utilities Code and the Commission's settled indifference framework," and (2) exacerbates the PCIA rate increases that occurred, in part, as a result of MPB changes approved in D.25-06-049.[56] CalCCA argued that, if the Commission does not address the pre-2019 Banked RECs methodology, "the impact on departed customers will balloon to over a billion dollars."[57]

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[54] CalCCA Opening Brief at 20.

[55] CalCCA Opening Brief at 20.

[56] CalCCA Fall Update Comments at 6.

[57] CalCCA Fall Update Comments at 11.

5.2.2. DACC

DACC also opposed PG&E's proposal.[58] DACC noted that in R.25-02-005, the Commission stated in D.25-06-049 that,

> The departed customer is also entitled to any residual procurement benefits enjoyed by the incumbent IOU attributable to the departed customer. The Public Utilities Code and existing policy mandate processes and mechanisms that ensure these costs and benefits are retained by the departing customers, promoting fairness and indifference to all customers.[59]

DACC argued that PG&E had disregarded this finding in its Fall Update by continuing to propose that bundled customers be allowed to use pre-2019 banked RECs without compensation to departed load. According to DACC, this is "inequitable, unfair and counter to the Commission's historical indifference principles and the manner in which the PCIA is to be calculated."[60]

5.2.3. PG&E

In reply briefs, PG&E argued that CalCCA's interpretation of D.19-10-001 is "unsupported" and that CalCCA erroneously attempted to retroactively apply findings of D.19-10-001.[61] According to PG&E, there is no basis to compensate now departing load customers for Pre-2019 Banked RECs.[62]

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[58] DACC Opening Brief at 2-3.

[59] DACC Opening Brief at 2 citing D.25-06-049 at 4.

[60] DACC Opening Brief at 3.

[61] PG&E Reply Brief at 4-7.

[62] PG&E Reply Brief at 4.

PG&E stated that CalCCA cites to D.19-10-001 "but fails to identify with any specificity how D.19-10-001 applies to pre-2019 RECs."[63] According to PG&E, CalCCA "simply asserts that Section 366.2(g) and a long line of Commission decisions implementing the indifference principle require PG&E to value all RECs used for bundled customer compliance – including 'pre-2019' banked REC – at the RPS Adder applicable in the year those RECs are used."[64]

PG&E noted that D.19-10-001, Finding of Fact 8 states that the methods approved in the decision apply to RECs generated commencing January 1, 2019 and going forward and does not mention RECs generated before this time.[65] PG&E further stated that CalCCA's argument in an attachment to D.19-10-001 applies to "all RECs" is unpersuasive.[66] According to PG&E, the Commission "unambiguously states in its findings that the methods are prospective for RECs generated commencing January 1, 2019 and going forward. The methods in D.19-10-001 are clearly prospective and exclude pre-2019 RECs from its requirements."[67]

5.3. Discussion

D.19-10-001 stated in Finding of Fact 8 that "[t]he methods adopted in this Decision apply to RECs generated commencing January 1, 2019 and going

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[63] PG&E Reply Brief at 4.

[64] PG&E Reply Brief at 4-5.

[65] PG&E Reply Brief at 5, emphasis added.

[66] PG&E Reply Brief at 5.

[67] PG&E Reply Brief at 5.

forward."[68] We agree with PG&E that the methodology established in D.19-10-001 applies to post-2019 banked RECs. However, the decision did not conclusively resolve how to value pre-2019 RECs. Given the expedited nature of ERRA Forecast proceedings, it would not be possible at this time to consider whether and how to apply pre-banked RECs to the specific vintages of customers that were bundled customers at the time the REC was procured but have since departed from IOU service for rates effective January 1, 2026. We therefore find it reasonable to adopt PG&E's Pre-2019 Banked RECs methodology on an interim basis for the purpose of this decision.

The proposal to address conflicting understandings regarding the valuation of Pre-2019 Banked RECs is appropriate for consideration in a rulemaking. PG&E is directed to file a Tier 2 advice letter by February 1, 2026 to propose how they will track and report the quantity of pre-2019 banked RECs used to meet 2026 compliance and the year those RECs were generated. The advice letter shall explain how PG&E intends to track the quantity and generation year of all Pre-2019 Banked RECs it will use to meet 2026 compliance requirements until further Commission guidance is put into place. The advice letter shall also explain how PG&E intends to forecast how many and which RECs PG&E intends to use for bundled customer compliance from October 1, 2026, through December 31, 2026.

This information will allow any updated guidance from the Commission regarding the treatment of Pre-2019 Banked RECs to apply to Pre-2019 Banked

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[68] D.19-10-001, FOF 8.

RECs used for bundled compliance in 2026. Should the Commission issue updated guidance on the appropriate valuation of Pre-2019 Banked RECs prior to September 1, 2026, PG&E will be required to incorporate that guidance into its 2027 ERRA forecast Fall Update, filed in 2026.

6. ~~Slice of Day~~Slice-of-Day Resource Adequacy Counting Methodology

PG&E proposed a methodology to comply with recently adopted RA Slice-of-Day (SoD) requirements. We have reviewed PG&E's proposal[69] and revised proposal,[70] and well as party comments[71] and remarks on the two proposals in hearing.[72] We find that PG&E shall adopt on an interim basis the methodology used by Southern California Edison (SCE) awaiting a more comprehensive decision on SoD compliance in a rulemaking.

6.1. Background

Pursuant to D.22-06-050, the Commission's Resource Adequacy (RA) compliance program now requires meeting 24 hourly requirement positions for each month instead of one hourly requirement. PG&E stated that adjustments are necessary to reflect the Commission's compliance program's impact on its Retained RA quantities used for the purpose of ratesetting.[73]

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[69] Exhibit PGE-01 at 4-10 to 4-12, 5-7 to 5-12.

[70] Exhibit PGE-04 at 1-2, 3-1 to 3-14.

[71] Exhibit CalCCA-01 at 10-33, CalCCA Opening Brief at 47-74, PG&E Opening Brief at 38-46, PG&E Reply Brief at 11-15.

[72] October 7, 2025 Hearing Transcript at 21-76.

[73] PG&E Opening Brief at 18.

6.2. PG&E Proposal

PG&E initially requested to use average hourly battery discharge and charging to calculate capacity value; this methodology resulted in nearly a zero capacity value for PCIA-eligible batteries. Following protest from CalCCA,[74] PG&E revised its proposal.[75] In the updated proposal, PG&E applied a 100 percent weight on its SoD position during the CAISO peak hour. According to PG&E, this revision would make its forecast RA retention obligations consistent with requirements for Retained RA set forth in D.19-10-001.

The Revised Proposal contains a weighting scheme that places 100 percent of the portfolio's SoD position during the CAISO peak hour (peak hour), and 0 percent on the other 23 SoD hours.[76] According to PG&E, the amount of solar retained in the peak hour is no different than under the status quo, and the only exception between the status quo and the Revised Proposal is that PG&E's retained battery storage quantities reflect those that are forecast to be discharged in the peak hour. According to PG&E, the 100 percent peak hour weighting captures the SoD volumes for all of the other 23 SoD positions in each month since the resources being retained in the peak hour deliver across all hours.[77] PG&E states that its PGE forecast Retained RA in each hour of the month that is effectively set at the level of Retained RA derived in the peak hour. The peak

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[74] CalCCA Protest at 21-27.

[75] Exhibit PG&E-04 at Chapter 3.

[76] PG&E Reply Brief at 13.

[77] PG&E Reply Brief at 13.

hour requirement in each month is either the maximum or close to the maximum hourly requirement in each month.

PG&E argued that the Revised Proposal, adopted on an interim basis, is reasonable for ratemaking purposes.[78]

6.3. CalCCA Comments

CalCCA asked the Commission to reject PG&E's SoD RA proposal and instead consider the matter in a rulemaking proceeding such as R.25-02-005.[79] CalCCA stated that if the Commission adopts PG&E's SoD RA proposal, PG&E should "correct an error that understates the Retained RA provided by storage resources procured pursuant to D.19-11-016 and recovered through a Modified CAM allocation."[80]

Alternatively, CalCCA asked the Commission to adopt for PG&E the methodology approved last year in the SCE ERRA forecast proceeding.[81] In SCE's methodology, the capacity value for stand-alone storage resources is calculated as the storage Net Qualifying Capacity (NQC) minus an estimate of the RA capacity needed for charging. SCE's formula for calculating the RA quantity from storage resources is: NQC – NQC * 4 / 24 / Round Trip Efficiency.[82]

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[78] PG&E Reply Brief at 13.

[79] CalCCA Protest at 26-27, Exhibit CalCCA-01 at 2, 12-13.

[80] Exhibit CalCCA-01 at 2, 34-35.

[81] CalCCA Opening Brief at 48, 51, 70-75. *See* also Exhibit CalCCA-01C at 30, referencing A.25-05-008, SCE-01 at 129-130.

[82] CalCCA Opening Brief at 72.

According to CalCCA, SCE's methodology is more reasonable than PG&E's revised proposal because it (1) produces a result that better comports with market realities, and (2) would produce a consistent discount for battery storage RA, relative to baseload, among electric utilities.[83] According to CalCCA, SCE's interim SoD method uses a formula that produces a fixed discount for a battery storage resource relative to its maximum capacity, rather than an utility-specific optimized quantity that the battery would deliver in any given hour.[84]

6.4. PG&E Response

PG&E disagreed with CalCCA's assessment that there is no compelling reason to adopt a revised SoD methodology in this proceeding and argued again that the Commission should adopt its proposed methodology on an interim basis.[85] According to PG&E, it is uncontested that the Commission has fundamentally modified its RA compliance program, and that the modifications will have an ongoing impact on resources used for RA compliance.[86]

PG&E noted that under the Commission's SoD RA program, there are significant distinctions between resources that may be used for compliance. For example, baseload resources face no hourly restrictions, but four-hour battery resources can only commit 16.7 percent of its capacity for RA compliance.[87] Therefore, battery storage resources cannot be committed to meet RA compliance

[83] CalCCA Opening Brief at 73-74.

[84] CalCCA Opening Brief at 73-74.

[85] PG&E Reply Brief at 11-15.

[86] PG&E Reply Brief at 11-15.

[87] PG&E Reply Brief at 11.

obligations in the same manner baseload resources can due to their limited hours of operation.[88] PG&E argued that the Commission should therefore consider differences between resource categorization when considering RA retained for compliance.[89]

PG&E further argued that adoption of SCE's interim methodology in this proceeding is "inappropriate," "impossible," and "unimplementable,"[90] since PG&E does not possess the information necessary to apply SCE's interim methodology to its own portfolio.[91] PG&E stated that there is no record in this proceeding addressing: how bundled customer RA requirements would be weighted, how PG&E would calculate retained RA volumes or how to calculate RA sales or unsold RA volumes.[92]

PG&E further stated that CalCCA's criticism that PG&E's Revised Proposal would produce different quantities of RA if applied to SCE or SDG&E is irrelevant in this PG&E-specific proceeding.[93]

6.5. CalCCA Response

In its Fall Update Comments, CalCCA asked the Commission not to adopt either of PG&E's SOD RA methodologies and instead should consider these

[88] PG&E Reply Brief at 11-12.

[89] PG&E Reply Brief at 12.

[90] PG&E Reply Brief at 12.

[91] PG&E Reply Brief at 12-13.

[92] PG&E Reply Brief at 13.

[93] PG&E Reply Brief at 12.

methodologies in R.25-02-005. CalCCA further noted that PG&E's proposal "further exacerbates the PCIA rate increases departed customers face in 2026."[94]

In addition, CalCCA addressed PG&E's claims that it lacks sufficient information to implement SCE's interim SoD method and stated that PG&E "overstates its inability to implement SCE's method." According to CalCCA, implementation of SCE's method for Retained RA simply requires PG&E to apply SCE's formula for calculating the RA quantity from storage resources, as included in CalCCA's testimony.[95]

6.6. Discussion

We agree with PG&E that the Commission's RA regulatory program has changed enough to warrant a response in this expedited proceeding. Nonetheless, we do not find that PG&E demonstrated that either of its proposals would result in a reasonable outcome. PG&E did not provide sufficient evidence that the original and revised proposals would reasonably discount the RA value of storage resources by conflating energy with capacity and failing to account for batteries' ability to provide capacity in any hour.

After review of PG&E's proposals and CalCCA's comments, we find that PG&E should adopt the SCE SoD methodology[96] on an interim basis while awaiting a more comprehensive decision on implementation of the SoD methodology. We disagree with PG&E's claim that SCE's methodology is

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[94] CalCCA Fall Update Comments at 14.

[95] Exhibit CalCCA-01C at 30.

[96] *See* Exhibit CalCCA-01C at 30, referencing A.25-05-008, SCE-01 at 129-130.

"inappropriate," "impossible," and "unimplementable." SCE's methodology is simply a method to discount the NQC of storage resources to account for the fact that storage is not available at its NQC value for 24 hours. PG&E has sufficient information to apply ~~PG&E's methodology; they~~SCE's current methodology for calculating the RA sales; PG&E would apply ~~their~~SCE's current methodology for calculating the RA sales, unsold and retained RA volumes for storage resources.

To ensure that PG&E's SoD methodology is consistent with SCE's SoD methodology and appropriately implemented, we direct PG&E to submit a Tier 1 advice letter that explains how it has implemented its SoD methodology pursuant to this decision for implementation in January 1, 2026 rates. This advice letter will be due within 30 days of the issuance of this decision.

7. 2026 Sales and Peak Demand Forecast

7.1. Background

PG&E forecasted an energy load requirement of 27,101 Gigawatt-hours (GWh) for 2026.[97] This forecast was calculated as the retail sales forecast (89,500 GWh) less forecasted direct access load (11,414 GWh), less CCA load (38,806 GWh), plus unaccounted for energy/losses (2,316 GWh). The departing load forecast included acceptance of all 12 of the CCA–provided 2026 monthly sales forecasts.

PG&E's bundled electricity sales forecast for 2026, as shown in the Fall Update, was about 5.4 percent lower than the forecast adopted in PG&E's 2025

[97] Exhibit PGE-06, Table 2-3.

ERRA Forecast Application, A.24-05-009.[98] The 2026 system peak forecast was about 2.0 percent higher than the 2025 peak forecast adopted in A.24-05-009.[99] PG&E attributed the changes to multiple factors, including a revision of its data center demand and lower than expected sales in the first third of 2025.[100]

7.2. Methodology

For its bundled sales forecast, PG&E first forecasted total electric sales at the "retail system" level. Then PG&E determined 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).[101] 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.[102]

PG&E's retail sales forecast is influenced by economic measures, price variables, and weather variables, and other factors such as customer-sited solar generation, energy efficiency savings, electric vehicle charging, and building electrification.[103]

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[98] Exhibit PGE-06, Table 2-3, Line 2; D.24-12-038.

[99] Exhibit PGE-06, Table 2-3, Line 32; D.24-12-038.

[100] Exhibit PGE-06 at 5-6.

[101] Exhibit PGE-01 at 2-2, Table 2-3.

[102] Exhibit PGE-01 at 2-2.

[103] Exhibit PGE-01 at 2-2 to 2-8.

For its 2026 forecast, PG&E initially included data center demand for the first time.[104] According to PG&E, its interconnection application queue served as the main source data for forecasting future data center facilities. PG&E aggregated requested load from applications in each year, then multiplied that time series by an assumed application conversion rate of 70 percent to create a forecast of data center capacity installed.[105] In the Fall Update, PG&E revised its forecasting methodology[106] and included data center demand in its Unmitigated Retail Sales and Unmitigated Retail Peak forecasts.[107]

7.2.1. Party Comments

SBUA argued that the Commission should direct PG&E to consult with outside experts regarding the ongoing shift to remote work resulting from behavioral, economic and technological change following the COVID-19 pandemic.[108]

In addition, SBUA asked the Commission to direct PG&E to discontinue use of its Bass Diffusion Model, or provide more transparent validation, for fuel cell and behind the meter solar adoption.[109] According to SBUA, PG&E uses the Bass Diffusion Model to "inform" its forecast customer adoption of fuel cells and behind the meter solar but does not clarify how the forecast is informed by the

[104] Exhibit PGE-01, Table 2-3, Lines 7 and 39.

[105] Exhibit PGE-01 at 2-11

[106] Exhibit PGE-06 at 7-11.

[107] Fall Update, Table 2-3, Lines 2 and 32.

[108] SBUA Opening Brief at 3-4 and SBUA Reply Brief at 2.

[109] SBUA Opening Brief at 8.

model or how the model functions.[110] According to SBUA, the Bass Diffusion Model "can result in highly arbitrary outcomes as the results can be dramatically influenced by small changes in assumptions or the historical period selected."[111]

7.2.2. Discussion

7.2.2.1. Post-COVID Demand Forecasts

We are not persuaded by SBUA that PG&E's demand forecasts are deficient in their analysis of the shift to remote work following the COVID-19 pandemic. As PG&E noted in testimony,[112] it conducted a Meet & Confer with a consultant for SBUA on February 21, 2025, providing historical monthly sales data by customer class in advance of the meeting and identifying post-regression adjustments. According to PG&E, PG&E solicited data and analysis from SBUA to substantiate their assertions of lasting changes in small commercial load, but received none, either in advance or at the meeting. At the meeting, PG&E stated it described its forecasting methodology and post-regression adjustments and summarized the rates calculation process showing impacts of increasing or decreasing load. SBUA, according to PG&E, reiterated its belief that long-term changes were not represented, but shared no data or analysis for PG&E to address. PG&E stated that because SBUA did not support its assertions with any forward-looking data or an illustrative forecast methodology, PG&E was unable to provide any additional responsive testimony addressing SBUA's concerns.

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110 SBUA Opening Brief at 8, citing Exhibit PGE-01 at 2-9 and Exhibit PGE-04 at 2-11.

111 SBUA Opening Brief at 8.

112 Exhibit PGE-01 at 2-4.

Subsequently, SBUA did not provide substantive material for the record of this proceeding that persuaded us to require modifications to PG&E's post-COVID demand forecasts.

Therefore, we do not direct PG&E to update its methodology regarding the shift to remote work.

7.2.2.2. Bass Diffusion Model

We acknowledge SBUA's concerns about PG&E's use of the Bass Diffusion Model. Nonetheless, there is insufficient support for SBUA's assertions that the model "can result in highly arbitrary outcomes" or that it lacks transparency. Therefore, we decline to adopt SBUA's recommendation that the Commission direct PG&E to discontinue use of its Bass Diffusion Model.

7.3. Data Center Demand Forecasting

In its Fall Update, PG&E revised its methodology for calculating data center demand. The Commission approves this demand forecast methodology for use in the instant proceeding but urges PG&E to revise its data center demand forecast methodology as new information is available.

7.3.1. Background

PG&E's demand forecasts in prepared testimony included a new line item for data centers for both energy load (in gigawatt-hours or GWh) and peak load (in MW).[~~112~~113] That calculation for data center demand was based on data in PG&E's interconnection queue, as well as a conversion factor of 70 percent.[~~113~~114]

[~~112~~113] Exhibit PGE-01, Table 2-3, Lines 7 and 39.

[~~113~~114] Exhibit PGE-01, Chapter 2.

Two rulings in this proceeding required PG&E to provide more detailed information about its data center demand forecasts, including the basis for using a 70 percent conversion factor and a list of projects in the data center interconnection queue.[~~114~~115] PG&E provided public and confidential responses to those rulings.[~~115~~116]

As part of the Fall Update, filed concurrently with the second data center ruling response, PG&E revised its demand forecast.[~~116~~117] In the revised demand forecast, PG&E removed the lines for data center demand in its Table 2-3 and incorporated data center demand in its unmitigated retail sales and unmitigated retail peak values instead.[~~117~~118] In addition, PG&E adjusted the methodology for calculating data center demand to only assume new data center load from projects identified a "Business Case Customer Required Operative Date" by year-end 2026.[~~118~~119]

As a result of this modification to the demand forecast methodology, the unmitigated retail sales forecast for 2026 decreased by 3.0 percent to 89,500

[~~114~~115] September 9, 2025 Ruling Requiring Additional Information and October 6, 2025 Second Ruling Requiring Additional Information.

[~~115~~116] *PG&E's response to ALJ Ruling*, September 23, 2025, and *Response to October 6, 2025 ALJ's Ruling Requiring Additional Information*, October 5, 2025.

[~~116~~117] Exhibit PGE-06.

[~~117~~118] Fall Update at 7-11. Among other reasons, PG&E stated that it made this change to comply with the 15/15 rule in D.97-10-031.

[~~118~~119] Fall Update at 7. The Business Case Customer Required Operative Date is the date that PG&E agreed to in the business case with the customer to put the project in service.

GWh[~~119~~120] when compared to PG&E's testimony, and the unmitigated retail peak forecast for December 2026 decreased by 0.8 percent.

7.3.2. Party Comments

SBUA argued that PG&E's methodology for its load adjustment for large data center near-term forecasting is flawed. SBUA asked the Commission to direct PG&E to adjust its 2027 ERRA forecast to:

- Treat data center additional loads like other additional loads;[~~120~~121]
- Use its own 2024-2025 historical data rather than California Energy Commission (CEC) and Silicon Valley Power long-term planning data;[~~121~~122] and
- Instruct PG&E not to assume data centers will result in downward pressure on rates in the absence of smart policies protecting consumers.[~~122~~123]

7.3.3. Discussion

Upon review of PG&E's Fall Update and responses to the two data center rulings, we are persuaded that PG&E's 2026 demand forecasts are reasonable.

8. GHG Forecast Costs, Auction Proceeds, 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

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[~~119~~120] When compared with Exhibit PGE-01E, which had a value of 90,765 GWh for unmitigated retail sales and 1,474 GWh for large data centers.

[~~120~~121] SBUA Opening Brief at 5.

[~~121~~122] SBUA Opening Brief at 5-7.

[~~122~~123] SBUA Opening Brief at 7-8.

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 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 forecasted $47,962,186 in GHG Cap-and-Trade costs for 2026.[~~123~~124] PG&E calculates the net GHG allowance proceeds available for customer return

[~~123~~124] Fall Update Errata, Table 15-1, Template D-2.

at $704,046,796[~~124~~125] and the net GHG auction proceeds return at $475,276,000.[~~125~~126] PG&E's net GHG auction proceeds and expenses consist of the following: (1) a prior balance; (2) allowance auction proceeds; (3) revenue franchise fees and uncollectibles; (4) outreach and administrative 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 $51.257 million to emissions-intensive trade-exposed (EITE) customers through the EITE customer return (CA Industry Assistance).[~~126~~127] PG&E proposes to distribute $424.019 million to residential and small commercial customers through the semi-annual residential California Climate Credit of $36.18 per eligible account.[~~127~~128]

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

A summary of PG&E's proposed GHG allowance-related proceeds and expenses, which is also the Commission's adopted GHG allowance-related proceeds and expenses, are provided in Table 5 below and explained in the following sections:

[~~124~~125] Fall Update Errata, Table 17-3.

[~~125~~126] Fall Update Errata, Fall Update Errata, Table 17-1, Template D-1, Line 17.

[~~126~~127] Fall Update Errata, Table 17-1, Template D-1, Line 19.

[~~127~~128] Fall Update Errata, Table 17-1, Template D-1, Lines 29 and 30.

Table 5: Summary of GHG Allowance Auction-Related Proceeds and Expenses~~[128]~~[129]

Program	PG&E Proposed 2026 (thousands)
GHG auction proceeds	
Prior Balance	-$199,666
Allowance Auction Proceeds	$704,047
Revenue Franchise Fees and Uncollectibles	$5,877
GHG Proceeds Subtotal	**$510,258**
Expenses	
Outreach and Administrative Expenses	-$934
Interest	$183
Expenses Subtotal	**-$750**
Clean Energy and Energy Efficiency Programs	
PG&E 2026 SOMAH~~[129]~~[130] Including True-Ups	$15,196
PG&E 2026 DAC-SASH~~[130]~~[131]	$4,370
PG&E 2026 DAC-GT~~[131]~~[132] and CS-GT~~[132]~~[133] Including True-Ups	$18,219
CCA DAC-GT and CS-GT Including True-Ups	$13,206
CCA Disbursement Reconciliation to PG&E	-$715
Funding from Public Purpose Programs	-$16,046
Clean Energy and Energy Efficiency Programs Subtotal	**-$34,232**
Auction Proceeds Distributed for the Climate Credit	
EITE Customer Return	-$51,257
California Climate Credit	$424,019

~~128~~129 Fall Update Errata, Table 17-1, Template D-1.

~~129~~130 Solar on Multifamily Affordable Housing program.

~~130~~131 Disadvantaged Communities – Single-Family Solar Homes.

~~131~~132 Disadvantaged Communities Green Tariff.

~~132~~133 Community Solar Green Tariff.

8.1. 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 calculated direct GHG costs by multiplying the 2026 forecast price of $30.58/metric ton (MT),[~~133~~134] which is the Intercontinental Exchange settlement price for Vintage 2026 California Carbon Allowances as of August 27, 2025, by the forecast utility-owned generation GHG emissions volume and adding any GHG costs specified in tolling agreement, qualifying facility (QF) contracts, and emissions from energy imports.[~~134~~135]

No parties opposed or commented on PG&E's GHG costs. Upon review, the Commission finds PG&E's 2026 forecast GHG costs reasonable and in compliance with applicable rules, orders and Commission decisions.

8.2. GHG Allowance Proceeds

GHG allowance proceeds come from the sale of GHG allowances allocated by the California Air Resources Board for the benefit of ratepayers, which PG&E sells on behalf of ratepayers at quarterly GHG allowance auctions. PG&E

[~~133~~134] Fall Update Errata, Table 15-1, Template D-2.

[~~134~~135] Fall Update Errata, Table 15-1, Template D-2.

forecasts its GHG allowance proceeds by multiplying a proxy GHG allowance price of $30.58/MT (the same price used to forecast GHG costs) by the total volume of allowances CARB allocated to PG&E (23,023,000 allowances) in 2026.[~~135~~136] PG&E's total forecast GHG allowance proceeds in 2026 is $704,046,796 million.[~~136~~137] PG&E adjusted this forecast to reflect: (1) a prior balance of $199.666 million; and (2) $5.877 million in revenue franchise fees and uncollectibles, for a net 2026 GHG allowance proceeds forecast of $510.258 million.[~~137~~138]

No parties opposed or commented on PG&E's GHG proceeds calculations. We reviewed PG&E's net 2026 forecast allowance proceeds amount and find it reasonable and in compliance with applicable rules, orders and Commission decisions.

8.3. 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.

[~~135~~136] Exhibit PGE-06, Table 17-1, Template D-1.

[~~136~~137] Exhibit PGE-06, Table 17-3.

[~~137~~138] Fall Update Errata, Table 17-1, Line 8.

8.3.1. 2024 Recorded Administrative and Customer Outreach Costs

PG&E's 2024 recorded administrative and customer outreach costs were recorded at $708,000.[~~138~~139] No parties opposed or commented on PG&E's 2024 recorded administrative and customer outreach costs. We find that PG&E's 2024 recorded administrative and customer outreach expense cost of $708,000 is reasonable and in compliance with applicable rules, orders, and Commission decisions.

8.3.2. 2026 Forecast GHG Administrative and Customer Outreach Costs

PG&E's 2026 forecast of administrative and customer outreach expenses is $925,000, consisting primarily of outreach efforts for the California Climate Credit and assistance for eligible CA Industry Assistance/EITE customers.[~~139~~140]

No parties opposed or commented on PG&E's 2026 forecast of administrative and customer outreach expenses. Upon consideration, the Commission finds PG&E's 2026 forecast administrative and customer outreach expense costs reasonable and in compliance with applicable rules, orders, and Commission decisions.

8.4. Clean Energy and Energy Efficiency Projects

Pursuant to 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

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[~~138~~139] Exhibit PGE-06, Table 16-5, Template D-3.

[~~139~~140] Fall Update Errata, Table 16-5, Template D-3, Line 14.

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 $34.232 million.[~~140~~141] 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).[~~141~~142]

D.24-05-065 allowed Program Administrators to discontinue the CS-GT program and transfer all remaining unprocured capacity to a Modified DAC-GT program. Therefore, PG&E closed its CS-GT program.[~~142~~143] PG&E completed its closure of the CS-GT balancing account in 2025. This included transferring a total of $9 million, comprising: (1) $3.3 million of unspent PPP funding to the DAC-GT balancing account, and (2) $5.8 million of unspent GHG auction proceeds to the GHG proceeds balancing account.[~~143~~144]

8.5. EITE Emissions Customer Return

A portion of the GHG allowance proceeds is returned to customers who qualify for CA Industry Assistance. The EITE customer return is facility-specific

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[~~140~~141] Fall Update Errata, Table 17-1, Template D-1, Line 14.

[~~141~~142] Fall Update Errata, Table 17-1, Template D-1, Lines 14(a)-(d).

[~~142~~143] PG&E AL 7554-E.

[~~143~~144] Exhibit PGE-06 at 34.

and made to qualifying customers once per year in April. PG&E's 2026 forecast EITE customer return is $51.257 million.[~~144~~145]

No parties opposed or commented on PG&E's 2026 forecast EITE customer return as proposed in the Fall Update. Upon review, the Commission finds PG&E's forecast 2026 EITE customer return reasonable and in compliance with applicable rules, orders and Commission decisions.

8.6. 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[~~145~~146] 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.

In 2025, the total recorded GHG allowance proceeds available for distribution were approximately $199.666 million less than forecast for 2025.[~~146~~147] PG&E proposed to return the 2025 balance through the total 2026 GHG allowance proceeds available for distribution through the California Climate Credit.

[~~144~~145] Fall Update Errata, Table 17-1, Template D-1, Line 19.

[~~145~~146] Res. E-5339, August 22, 2024, modified eligibility rules for small business customers.

[~~146~~147] Fall Update Errata, Table 17-1, Template D-1, Line 4.

PG&E's 2026 forecast of the total number of households and small businesses eligible for the California Climate Credit is 5,860,251 and the proposed total auction proceeds available for the California Climate Credit is $424.019 million.[~~147~~148] PG&E proposed a California Climate Credit of $36.18, to be distributed as a credit on residential and small business account customers' bills in April and October of 2026.[~~148~~149] This credit value is 37.9 percent lower than the California Climate Credit distributed in 2025.

No parties opposed or commented on PG&E's California Climate Credit in the Fall Update. The residential and small business California Climate Credit decreases to $36.18.

The Commission finds PG&E's forecast 2026 California Climate Credit reasonable and in compliance with applicable rules, orders and Commission decisions.

9. Rate Design Proposal

9.1. Background

PG&E's proposed rates would recover the revenue requirements for: (1) PCIA, (2) ERRA - Main, (3) Ongoing CTC, (4) CAM and Central Procurement Entity costs, (5) TMNBC, (6) BioMAT non-bypassable charge, and (7) VAMO.[~~149~~150]

[~~147~~148] Fall Update Errata, Table 17-1, Template D-1, Lines 28 and 30.

[~~148~~149] Fall Update Errata, Table 17-1, Template D-1, Line 29.

[~~149~~150] Exhibit PGE-01, Chapter 13.

To recover these revenue requirements, PG&E requested to change: (1) vintage PCIA rates, (2) generation rates, (3) ongoing CTC rates, (4) NSGC rates, (5) TMNBC rates, (6) BioMAT rates, and (7) PPCP rates with these rate changes going into effect on January 1, 2026.[~~150~~151]

PG&E calculated illustrative rates by applying the incremental revenue requirements requested in the instant application on top of present rates effective March 1, 2025. For the Application, PG&E used the revenue allocation and rate design methodology used to design the rates effective March 1, 2025 as adopted in D.21-11-016.[~~151~~152]

Using this methodology and proposed revenue requirements, the system average bundled rate would decrease by about 4.0 percent, or 11.4 percent, to a total rate of 31.2 cents per kWh when compared to the system average bundled rate of 35.2 cents per kWh effective at the time of the Fall Update. The system average rate for DA and CCA customers, whose average rates exclude commodity charges from third-party service providers, would increase by approximately 2.7 cents per kWh, or 13.8 percent, to a total rate of 22.4 cents per kWh, when compared to the system average rate for DA and CCA customers of 19.7 cents per kWh effective at the time of the Fall Update.[~~152~~153]

[~~150~~151] Exhibit PGE-01, Chapter 13.

[~~151~~152] Exhibit PGE-01, Chapter 13.

[~~152~~153] Exhibit PGE-06, at 4-5.

9.2. Revenue Allocation and Rate Design

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

9.2.1. 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 2026 generation rates presented in the instant application, which are designed using the 2026 forecast bundled sales by customer class.[~~153~~154] All PCIA rates include CDWR franchise fees.[~~154~~155]

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.[~~155~~156] To comply with this decision, PG&E proposed in the Fall Update to transfer the forecast 2025 year-end ERRA-Main balance to the 2025 vintage subaccount in

[~~153~~154] Exhibit PGE-01 at 13-4.

[~~154~~155] Exhibit PGE-01 at 13-4.

[~~155~~156] Application at 7, D.22-01-023 at 13-15.

PABA.[~~156~~][157] Amortizing this balance in the 2025 vintage subaccount in PABA allows the balance to be applied to both bundled customers and PCIA-eligible departed load customers that departed on or after July 1, 2025.[~~157~~][158] As of the Fall Update, PG&E forecasted an overcollection of $1.853 billion in ERRA-Main at the end of 2025.[~~158~~][159] PG&E updated this balance in the Fall Update Errata to $700 million.

Table 5 shows illustrative PCIA rates for all vintages and customer classes.[~~159~~][160] 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.

[~~156~~][157] Exhibit PGE-06 at 27.

[~~157~~][158] Exhibit PGE-01 at 13-4.

[~~158~~][159] Exhibit PGE-06, Table 12-4.

[~~159~~][160] Any revenue requirement component changes approved in this proceeding will be implemented in the 2026 Annual Electric True-Up and will be consolidated with other changes approved for implementation at that time.

Table 6: Proposed Power Charge Indifference Adjustment Rates by Class and Vintage ($/kWh)[~~160~~161]

Vintage	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential	0.0285	0.032	0.0332	0.0348	0.035	0.035	0.035	0.035	0.0348	0.0343	0.0361	0.0352	0.0557	0.0558	0.0573	0.0544	-0.0151	-0.0151
Small Light & Power	0.0278	0.0311	0.0323	0.0339	0.0341	0.0341	0.034	0.0341	0.0339	0.0334	0.0351	0.0342	0.0542	0.0543	0.0557	0.053	-0.0147	-0.0147
Medium Light & Power	0.0293	0.0328	0.0341	0.0357	0.0359	0.0359	0.0359	0.0359	0.0357	0.0352	0.037	0.036	0.0572	0.0572	0.0587	0.0558	-0.0155	-0.0155
E19	0.0278	0.0311	0.0323	0.0339	0.0341	0.0341	0.034	0.0341	0.0339	0.0334	0.0351	0.0342	0.0542	0.0543	0.0557	0.053	-0.0147	-0.0147
Streetlights	0.0233	0.0261	0.0272	0.0285	0.0286	0.0286	0.0286	0.0286	0.0284	0.028	0.0295	0.0287	0.0455	0.0456	0.0468	0.0445	-0.0124	-0.0124
Standby	0.0196	0.0219	0.0228	0.0239	0.024	0.024	0.024	0.024	0.0239	0.0235	0.0248	0.0241	0.0382	0.0383	0.0393	0.0374	-0.0104	-0.0104
Agriculture	0.0264	0.0295	0.0307	0.0322	0.0324	0.0324	0.0323	0.0324	0.0322	0.0317	0.0333	0.0325	0.0515	0.0515	0.0529	0.0503	-0.014	-0.014
B20/E20 T	0.0246	0.0275	0.0286	0.03	0.0302	0.0302	0.0302	0.0302	0.03	0.0296	0.0311	0.0303	0.048	0.0481	0.0494	0.0469	-0.013	-0.013
B20/E20 P	0.0251	0.0281	0.0292	0.0306	0.0308	0.0308	0.0308	0.0308	0.0306	0.0301	0.0317	0.0309	0.049	0.049	0.0503	0.0478	-0.0133	-0.0133
B20/E20 S	0.0259	0.029	0.0302	0.0317	0.0318	0.0318	0.0318	0.0318	0.0316	0.0312	0.0328	0.0319	0.0506	0.0507	0.052	0.0495	-0.0138	-0.0138
BEV1	0.0226	0.0253	0.0263	0.0276	0.0278	0.0278	0.0277	0.0278	0.0276	0.0272	0.0286	0.0278	0.0442	0.0442	0.0454	0.0431	-0.012	-0.012
BEV2	0.0261	0.0292	0.0304	0.0319	0.0321	0.0321	0.032	0.032	0.0319	0.0314	0.033	0.0322	0.051	0.051	0.0524	0.0498	-0.0138	-0.0138
System Average	0.0261	0.029	0.0322	0.0331	0.0341	0.0345	0.0343	0.0343	0.0336	0.0338	0.034	0.0342	0.0539	0.0534	0.0539	0.0506	-0.0148	-0.0148

[~~160~~161] Fall Update Errata, Table 13-3.

Table 7[~~161~~162] 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 7: Forecast PCIA Revenues from Proposed PCIA Rates (Thousands)

Bundled Customers	$(362,845)
DA/CCA Customers	1,461,901
Total Revenues	$1,099,056

9.2.2. 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 2026 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.

[~~161~~162] Fall Update Errata, Table 13-4.

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 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.

Table 8 presents the proposed total average generation rates for bundled customers.[~~162~~163] Bundled generation rates do not include bundled PCIA rates, which are shown separately in PG&E's rate schedule tariffs.[~~163~~164]

[~~162~~163] Fall Update Errata, Table 13-5.

[~~163~~164] Pursuant to D.21-11-016.

Table 8: Proposed 2026 Average Total Generation Rates for Bundled Customers ($/kWh)

Residential	$0.12349
Small Commercial	$0.12015
Medium Commercial	$0.12663
Large Commercial	$0.12011
Streetlights	$0.10085
Standby	$0.08469
Agriculture	$0.11403
B20/E20 T	$0.10641
B20/E20 P	$0.10849
B20/E20 S	$0.11217
BEV1	$0.09785
BEV2	$0.11296

9.2.3. 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.[~~164~~165] 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 9 shows PG&E's proposed Ongoing CTC rates for bundled, DA, CCA, and eligible departed load customers.[~~165~~166]

[~~164~~165] Exhibit PGE-06, Table 13-6.

[~~165~~166] Fall Update Errata, Table 13-6.

Table 9: Proposed 2026 Ongoing Competition Transition Charge Rates ($/kWh)

Residential	$0.00046
Small Commercial	$0.00045
Medium Commercial	$0.00047
Large Commercial	$0.00045
Streetlights	$0.00038
Standby	$0.00032
Agriculture	$0.00043
B20/E20 T	$0.00040
B20/E20 P	$0.00041
B20/E20 S	$0.00042
BEV1	$0.00045
BEV2	$0.00045

9.2.4. New System Generation Charge

The NSGC is a non-bypassable charge to recover the net capacity costs of Combined Heat and Power contracts.[~~166~~167] NSGC rates are based on the 12-month coincident peak methodology.[~~167~~168] 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.

[~~166~~167] 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.

[~~167~~168] D.11-12-013, D.15-08-005.

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 10.[~~168~~169]

Table 10: Proposed 2026 New System Generation Charge Rates ($/kWh)

Residential	$0.00685
Small Commercial	$0.00449
Medium Commercial	$0.00399
Large Commercial	$0.00399
Streetlights	$0.00391
Standby	$0.00413
Agriculture	$0.00433
B20/E20 T	$0.00341
B20/E20 P	$0.00341
B20/E20 S	$0.00341
BEV1	$0.00449
BEV2	$0.00399

9.2.5. 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 purpose program rates for billing. Proposed TMNBC rates are shown in Table 11.[~~169~~170]

[~~168~~169] Fall Update Errata, Table 13-7.

[~~169~~170] Fall Update Errata, , Table 13-8.

Table 11: Proposed 2026 Tree Mortality Non Bypassable Charge Rates ($/kWh)

Residential	$0.00076
Small Commercial	$0.00050
Medium Commercial	$0.00044
Large Commercial	$0.00044
Streetlights	$0.00043
Standby	$0.00046
Agriculture	$0.00048
B20/E20 T	$0.00034
B20/E20 P	$0.00034
B20/E20 S	$0.00034
BEV1	$0.00050
BEV2	$0.00044

9.2.6. 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 12.[~~170~~171]

[~~170~~171] Fall Update Errata, Table 13-9.

Table 12: Proposed 2026 BioMAT Rates ($/kWh)

Residential	$0.00025
Small Commercial	$0.00017
Medium Commercial	$0.00015
Large Commercial	$0.00015
Streetlights	$0.00014
Standby	$0.00015
Agriculture	$0.00016
B20/E20 T	$0.00011
B20/E20 P	$0.00011
B20/E20 S	$0.00011
BEV1	$0.00017
BEV2	$0.00015

9.2.7. 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.~~[171]~~[172]

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 13.~~[172]~~[173]

~~171~~172 PG&E established the PPCP subaccount through AL 6524-E, effective March 14, 2022.

~~172~~173 Fall Update Errata, Table 13-10.

Table 13: Proposed 2026 Public Policy Charge Procurement Rates ($/kWh)

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

9.3. 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, 2026.[~~173~~174] 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;

[~~173~~174] Pursuant to D.15-01-051, the renewable power rate and other components of GTSR rates should be updated annually.

d. Renewable Integration Charges;

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 2025 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[~~174~~175] and Fall Update.[~~175~~176] No party disputed the calculation of PG&E's GTSR rates. We have reviewed PG&E's proposed GTSR rates and find them reasonable.

9.4. Changes to Total Rates

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

[~~174~~175] Exhibit PG&E-2, Chapter 14, Tables 14-3 to 14-3.

[~~175~~176] Exhibit PG&E-4, Tables 14-3, 14-5 to 14-13.

non-bypassable charge, 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 2026 revenue requirements) subject to Commission approval through PG&E’s 2026 Annual Electric True-Up for year-end balancing account adjustments. Any revenue requirement component changes approved in this proceeding will be implemented in the 2026 Annual Electric True-Up and will be consolidated with other changes approved for implementation at that time.

10. Summary of Public Comment

Rule 1.18 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.

As of the date of the proposed decision, there were 18 public comments on the Docket Card for this proceeding. All commenters opposed approval of this application. Among the concerns that public commenters raised were:

- PG&~~E's~~E’s strong financial position and CEO compensation as evidence that rate increases are unjustified;
- The cumulative burden of rate increases;
- Outdated assistance program income thresholds that exclude struggling middle-class families; and
- Lack of transparency, accountability, and consideration of alternatives to ratepayer-funded cost recovery.

11. Procedural Matters

We find good cause to grant:

a. PG&E's November 3, 2025 Motion for Leave to File the Confidential Version of its Reply Brief Under Seal, and

b. CalCCA's November 10, 2025 Motion to File Confidential Version of Comments Under Seal.

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.

12. 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 four business days for opening comments and three days for reply comments.

On December 1, 2025, PG&E, CalCCA, and SBUA filed opening comments on the proposed decision.

PG&E requested that the Commission: (1) clarify that the interim SoD methodology applies only to energy storage resources,[177] and (2) update the proposed decision to reflect that the value of Pre-2019 Banked RECs in the PCIA is zero dollars.[178] In addition, PG&E requested that the Commission address its

[177] PG&E Comments on the Proposed Decision at 2-3.

[178] PG&E Comments on the Proposed Decision at 3-4.

confidentiality motion for its November 3, 2025 reply brief (Confidential Version).[179]

In its opening comments on the proposed decision, CalCCA argued that the Commission should:

- Reject PG&E's pre-2019 banked REC zero valuation proposal and value pre-2019 banked RECs at the applicable RPS Adder;[180]
- Direct PG&E to exhaust its post-2018 banked RECs before using any pre-2019 banked RECs towards its Minimum Retained RPS requirement;[181]
- Direct PG&E to track and report not only the Pre-2019 Banked RECs it will use to meet 2026 bundled customer compliance but also those it will use to meet 2025 compliance;[182]
- Direct PG&E to file a Tier 2 advice letter detailing its implementation of SCE's SoD method within thirty days of its final decision in this proceeding;[183] and
- "[M]emorialize CalCCA and PG&E's uncontested agreement that data center load in CCA service territory defaults to CCA service."[184]

In addition, both PG&E and CalCCA noted a typo on page 35 and PG&E noted typos on pages 24 and 50.

SBUA's opening comments argued the following:

[179] PG&E Comments on the Proposed Decision at 5.

[180] CalCCA Comments on the Proposed Decision at 8-11.

[181] CalCCA Comments on the Proposed Decision at 11.

[182] CalCCA Comments on the Proposed Decision at 11-12.

[183] CalCCA Comments on the Proposed Decision at 12-13.

[184] CalCCA Comments on the Proposed Decision at 8.

- The proposed decision fails to address' SBUA's objections to PG&E's use of the Bass Diffusion Model for fuel cell and behind the meter solar adoption forecasting;[185]
- The proposed decision rejects SBUA's recommendations for improved post-COVID demand forecasting without a reasoned basis;[186]
- The proposed decision rejects SBUA's proposals regarding data center forecasting without analysis, despite PG&E largely adopting SBUA's recommendations.[187] SBUA stated that, "[i]n apparent response to SBUA's testimony, the ALJ required PG&E to provide more information on data centers."[188]

On December 4, 2025 PG&E, CalCCA, and SBUA filed reply comments.

PG&E responded that:

- If the Commission clarifies that PG&E is required to adopt SCE's SoD methodology for energy storage resources only, there would be no need for a compliance advice letter as recommended by CalCCA;[189]
- The Commission should disregard CalCCA recommendations on pre-2019 Banked RECs;[190]
- The Commission should limit the application of any findings or conclusions concerning default service provider of data centers in CCA territories to 2026; and
- The Commission should reject SBUA's recommendations that PG&E take specific actions in prospective load forecasting activities.[191]

[185] Opening Comments of Small Business Utility Advocates on the Proposed Decision at 2-3.

[186] Opening Comments of Small Business Utility Advocates on the Proposed Decision at 3-4.

[187] Opening Comments of Small Business Utility Advocates on the Proposed Decision at 4.

[188] Opening Comments of Small Business Utility Advocates on the Proposed Decision at 4.

[189] PG&E Reply Comments on the Proposed Decision at 1-3.

[190] PG&E Reply Comments on the Proposed Decision at 3-5.

[191] PG&E Reply Comments on the Proposed Decision at 5.

CalCCA's reply comments asked the Commission to reject PG&E's pre-2019 Banked REC proposal[192] and to apply SCE's interim SoD methodology to all technology types in PG&E's PCIA-eligible RA portfolio, including but not limited to battery energy storage.[193]

In its reply comments, SBUA argued that CalCCA's request to memorialize PG&E's data responses does not comply with Rule 14.3(c) and must be rejected.[194]

In response to comments on the proposed decision, we make the following changes:

- Address certain PG&E and CalCCA confidentiality motions.
- Clarify that the interim SoD methodology applies only to storage resources.
- Agree with CalCCA that it is reasonable for PG&E to file an advice letter seeking approval of its SoD implementation within thirty days of this decision and direct PG&E to file this advice letter.
- Address typos.

We decline to make substantive changes to either the Pre-2019 Banked RECs methodology or SoD methodology as detailed in the proposed decision. We were also not persuaded of the benefits of memorializing CalCCA and PG&E's "agreement that data center load in CCA service territory defaults to CCA service," given that the two parties do not appear to concur on what that agreement entails.

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[192] California Community Choice Association's Reply Comments on Proposed Decision at 2-4.

[193] California Community Choice Association's Reply Comments on Proposed Decision at 4-5.

[194] Reply Comments of Small Business Utility Advocates on the Proposed Decision at 1-3.

In response to SBUA's concerns regarding PG&E's demand forecasts, we provide additional context for why we are not persuaded by SBUA's requests regarding post-COVID demand forecasts or the Bass Diffusion Model. We further note here that the ALJ's rulings requiring additional information on data centers were not prompted by or informed by SBUA's testimony.

13. Assignment of Proceeding

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

Findings of Fact

1. PG&E presented a complete 2026 ERRA forecast in its Fall Update.
2. We have reviewed the Cost Allocation Mechanism (CAM) and New System Generation Charge balance of $372,790,000 and find that it is reasonable.
3. We find that additional information on the CAM is needed in the next ERRA compliance filing.
4. We have reviewed the Voluntary Allocation Market Offer Memorandum Account balance of $654,000 and find that it is reasonable.
5. We have reviewed the Power Charge Indifference Adjustment (PCIA) balance of $1,098,402,000 and find that it is reasonable.
6. We have reviewed the Ongoing Competition Transition Charge (CTC) balance of $33,736,000 and find that it is reasonable.
7. We have reviewed the ERRA – Main balance of $2,951,883,000 and find that it is reasonable.
8. We acknowledge the overcollection of the ERRA - Main balancing account.

9. PG&E has complied with the requirements of D.02-10-062 to file an expedited ERRA trigger application as a result of the ERRA overcollection being greater than 5 percent.

10. We find it reasonable to authorize PG&E to amortize this overcollection in the annual electric true-up advice letter.

11. We have reviewed the Public Policy Charge Procurement balance of -$1,723,000 and find that it is reasonable.

12. We have reviewed the Tree Mortality Non-bypassable Charge balance of $41,579,000 and find that it is reasonable.

13. We have reviewed the Bioenergy Market Adjusting Tariff balance of $13,763,000 and find that it is reasonable.

14. The estimated net revenue requirement is $3,260,698,000.

15. We find it reasonable to adopt PG&E's Pre-2019 Banked RECs methodology on an interim basis for the purpose of this decision.

16. The proposal to address conflicting understandings regarding the valuation of Pre-2019 Banked RECs is appropriate for consideration in a rulemaking.

17. We find it reasonable for PG&E to adopt SCE's Slice-of-Day methodology, as described herein, on an interim basis.

18. A more comprehensive decision on SoD compliance should be developed in a rulemaking.

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

20. PG&E incurred $708,000 in 2024 GHG administrative and customer outreach costs.

21. PG&E's 2026 forecast of administrative and customer outreach expenses is $925,000.

22. PG&E's 2026 forecast administrative and customer outreach expense costs reasonable and in compliance with applicable rules, orders, and Commission decisions.

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

Conclusions of Law

1. It is reasonable to approve a gross revenue requirement for 2025 of $4,511,083,000, 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 (CAM) and New System Generation Charge	$372,790
Voluntary Allocation Market Offer Memorandum Account	$654
Power Charge Indifference Adjustment (PCIA)	$1,098,402
Ongoing Competition Transition Charge (CTC)	$33,736
Energy Resource Recovery Account (ERRA) – Main	$2,951,883
Public Policy Charge Procurement	($1,723)
Tree Mortality Non-bypassable Charge	$41,579
Bioenergy Market Adjusting Tariff	$13,763
Gross Revenue Requirement	**$4,511,083**

2. It is reasonable to authorize PG&E to amortize a $700,000,000 overcollection of its ~~ERRA–Main balancing account~~ ERRA Trigger balance in the

annual electric true-up advice letter, subject to submission of a Tier 1 advice letter that documents the associated rate changes.

3. It is reasonable to update PG&E's ~~Slice of Day~~Slice-of-Day methodology on an interim basis.

4. It is reasonable to adopt PG&E's forecasted energy load requirement of 27,101 GWh for 2026, 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).

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

(a) GHG administrative and outreach expenses of $925,000 for 2026.

(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 DAC-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 allowance auction proceeds return of $475,276,000 for 2026.

(d) A semi-annual California Climate Credit value of $36.18 for 2026.

6. It is reasonable to adopt PG&E's 2024 recorded GHG administrative and customer outreach costs of $708,000.

7. It is reasonable to adopt PG&E's rate design proposals and revenue allocation proposals as detailed in Section 9 of this decision.

8. It is reasonable to allow PG&E to amortize the ERRA-Main overcollection in the annual electric true-up advice letter.

9. It is reasonable to grant PG&E's November 3, 2025 Motion for Leave to File the Confidential Version of its Reply Brief Under Seal.

10. It is reasonable to grant CalCCA's November 10, 2025 Motion to File Confidential Version of Comments Under Seal.

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. Pacific Gas and Electric Company shall provide a narrative describing all reasons for the increase in the Cost Allocation Mechanism/New System Generation Charge in its next ERRA compliance filing.

3. Within 30 days of this decision's issuance date, Pacific Gas and Electric Company shall file an information-only Advice Letter with updated rate impacts associated with the approval of Application 25-09-015, as described in Section 3.5.3.

4. Pacific Gas and Electric Company (PG&E) shall file a Tier 2 advice letter by February 1, 2026 to propose how they will track and report the quantity of pre-2019 banked RECs used to meet 2026 compliance and the year those RECs were generated. The advice letter shall explain how PG&E intends to track the quantity and generation year of all Pre-2019 ~~banked~~Banked RECs it will use to

meet 2026 compliance requirements through September 30, 2026. The advice letter shall also explain how PG&E intends to forecast how many and which RECs PG&E intends to use for bundled customer compliance from October 1, 2026, through December 31, 2026.

5. Should the Commission issue updated guidance on the appropriate valuation of Pre-2019 Banked RECs prior to September 1, 2026, PG&E shall incorporate that guidance into its 2027 ERRA forecast Fall Update.

6. Pacific Gas and Electric Company (PG&E) shall file a Tier 1 Advice Letter within 30 days of the issuance of this decision that explains how it has implemented its Slice-of-Day methodology pursuant to this decision for implementation in January 1, 2026 rates.

7. Pacific Gas and Electric Company's November 3, 2025 Motion for Leave to File the Confidential Version of its Reply Brief Under Seal is granted.

8. California Community Choice Association's November 10, 2025 Motion to File Confidential Version of Comments Under Seal is granted.

9. ~~6.~~ Application 25-05-011 and Application 25-09-015 (consolidated) are closed.

This order is effective today.

Dated _________________, at Sacramento, 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
MPBs	Market Price Benchmarks
MW	Megawatt
NQC	Net Qualifying Capacity
OP	Ordering Paragraph
PABA	Portfolio Allocation Balancing Account
PCIA	Power Charge Indifference Adjustment
PUBA	PCIA Undercollection Balancing Account
PURPA	Public Utility Regulatory Policies Act
PV	Solar photovoltaic

Term	**Definition**
QF	Qualifying generation facilities under the Public Utility Regulatory Policies Act of 1978
RPS	Renewable Portfolio Standard
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)

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