Docket No.: A.25-05-011

Exhibit No.: CalCCA-01

Date: September 2, 2025

Witness: Brian Dickman

PREPARED DIRECT TESTIMONY OF BRIAN DICKMAN
ON BEHALF OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION
IN PACIFIC GAS AND ELECTRIC COMPANY'S
2026 ERRA FORECAST PROCEEDING

PUBLIC

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Attachments

I. INTRODUCTION AND SUMMARY OF TESTIMONY

The California Community Choice Association (**CalCCA**) presents this direct testimony in the *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2026 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation* (**Application**). This testimony has been prepared on behalf of CalCCA by Brian Dickman, Partner, NewGen Strategies and Solutions, LLC. Mr. Dickman's qualifications are set forth in Attachment A.

CalCCA has a particular interest in the Power Charge Indifference Adjustment (**PCIA**) and the Portfolio Allocation Balancing Account (**PABA**), both of which are charged to customers of the eleven community choice aggregators (**CCAs**) that CalCCA represents through the PCIA rates for which Pacific Gas and Electric Company (**PG&E**) seeks approval in this proceeding. This testimony focuses on the following issues in Commissioner Reynolds' July 31, 2025, Scoping Ruling:[1]

1. Should the Commission adopt PG&E's request to approve the 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 Market Offer Memorandum Account (**VAMOMA**) balances?

2. Did Decision (**D.**)19-10-001[2] establish a methodology for treatment of pre-2019 banked RECs? If not, how should PG&E value pre-2019 banked RECs

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[1] *See Assigned Commissioner's Scoping Memo and Ruling*, Application (**A.**) 25-05-011 (July 31, 2025) (**2025 Scoping Ruling**), at 2-3. Internal citations omitted.

[2] D.19-10-001, *Decision Refining the Method to Develop and True Up Market Price Benchmarks*, Rulemaking (**R.**) 17-06-026 (Oct. 10, 2019).

for the purpose of calculating the 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?

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

Based on my review of PG&E's application, supporting workpapers, and responses to discovery, I make the following recommendations to bring PG&E's request in line with prior Commission rules, regulations, resolutions, decisions, and with just and reasonable ratemaking:

- The Commission should reject PG&E's SOD RA proposal which practically eliminates all battery storage capacity value and direct that the issue of how to reflect the impact of SOD on the value of RA in the PCIA should be evaluated in a rulemaking proceeding, *i.e.*, Track 2 of R.25-02-005 (**PCIA Rulemaking Proceeding**).
- If PG&E's SOD RA proposal is adopted, 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.
- The Commission should reject PG&E's proposal to credit ERRA Forecast year vintage customers (e.g., vintage 2026 for the 2026 ERRA Forecast) for PG&E's use of RECs generated prior to 2019 (**Pre-2019 Banked RECs**). To properly credit departed load customers for the value of RECs they originally paid for, the value of banked RECs used to satisfy bundled customer compliance

requirements must be applied as a credit to the PCIA, with the credit recorded to the vintage matching the year the RECs were generated and paid for.

Table 1 provides the impact of the above recommendations on PG&E's proposed PCIA revenue requirement. Adjustment impacts are calculated relative to PG&E's initial filing and the impact will vary after PG&E files its October Update with new market price benchmarks for 2026.

Table 1: Recommended Adjustments to PCIA Revenue Requirement

Description	Impact ($ millions)
Slice of Day Storage RA	[redacted]
Modified CAM RA Error	($0.7)
Pre-2019 Banked RECs[3]	[redacted]
Total Adjustments	($792.4)

At the end of my testimony, I provide an update on the status of the final 2025 PCIA revenue requirement based on the true-up of forecasted above-market costs with actual above-market costs recorded to date and the market factors driving those changes. This change to the 2025 PCIA revenue requirement manifests in the forecasted year-end PABA balance, which will be updated with additional actual monthly activity in PG&E's October Update.

3 Pre-2019 Banked REC impact reflects the value that should be credited to Pre-2019 PCIA vintages rather than vintage 2026 as proposed by PG&E.

II. BACKGROUND ON THE PCIA AND PABA

As mentioned above, this testimony focuses on two proposals in PG&E's Application: its SOD RA proposal and its banked REC proposal. Both proposals directly impact CCAs' interests because those proposals, if adopted, would have the effect of increasing the PCIA revenue requirement, and, all else equal, increasing the PCIA rates customers pay. In this section of my testimony, I provide background on the PCIA, the calculation of the PCIA revenue requirement, and the allocation of the PCIA revenue requirement to customer vintages, because that background provides the context necessary to understand the impact of PG&E's proposals on customers.

A. Background on the PCIA

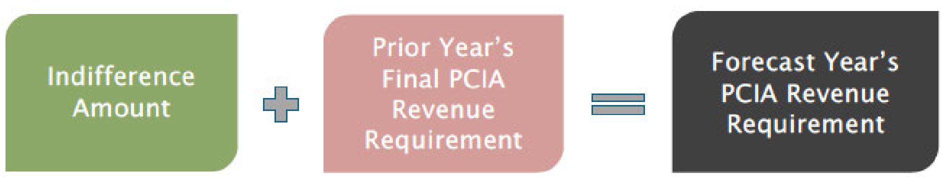
CCA customers receive generation services from their local CCA, and receive transmission, distribution, billing, and other services from the incumbent for-profit utility. CCA customers pay CCA-specific generation rates. CCA rates vary and are partially influenced by local mandates to procure and maintain clean electricity portfolios that, in many cases, exceed state requirements for renewable generation. In addition, CCA and other unbundled customers are subject to several non-bypassable charges (**NBCs**), including the PCIA and the Cost Allocation Method (**CAM**) surcharge, the 2026 levels of which will be determined in this proceeding.

The Commission has an obligation to ensure "indifference," meaning when customers of IOUs depart from bundled service and receive their electricity from a non-IOU provider, such as a CCA, "those customers remain responsible for costs previously incurred on their behalf by the IOUs — but only those costs."[4] The PCIA is the tool the Commission adopted "intend[ing] to equalize cost sharing" between these two groups of customers.[5]

B. Calculation of the PCIA revenue requirement

The PCIA revenue requirement is derived from two sources in each utility's ERRA forecast case, as demonstrated in Figure 1. The first is the Indifference Amount forecasted for the year *for which* rates are being set, *i.e.*, the Indifference Amount forecasted for 2026 in the instant proceeding. The second is the final PCIA revenue requirement for the year *in which* rates are being set, *i.e.*, the final 2025 PCIA revenue requirement in the instant proceeding, which is derived from the balance in the PABA the utility anticipates seeing at the end of the year:

FIGURE 1



The Indifference Amount is the difference between the forecasted cost of the IOU's supply portfolio and the forecasted market value of the IOU's supply portfolio as demonstrated in Figure 2:

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[4] *Scoping Memo and Ruling of Assigned Commissioner*, R.17-06-026 (Sept. 25, 2017), at 2; *see also* D.18-10-029, *Decision Modifying the Power Charge Indifference Adjustment Methodology*, R.17-06-026 (Oct. 11, 2018), at 3.

[5] *See* D.18-10-019, at 3.

FIGURE 2

Total Utility Portfolio Cost includes:

(i) the cost for Utility-Owned Generation (**UOG**) (*i.e.*, the capital investment recovery and fixed maintenance costs the Commission sets in a General Rate Case (**GRC**)),

(ii) purchased power such as that from power purchase agreements (**PPAs**),

(iii) fuel costs for UOG and PPAs with tolling agreements, and

(iv) California Independent System Operator (**CAISO**) grid charges and revenues, net of any sales.[6]

The forecasted Portfolio Market Value is derived from total eligible resource output multiplied by the Market Price Benchmarks (**MPBs**), an administratively determined set of proxy values that is intended to estimate the market value of the IOU's resource portfolio.[7] Portfolio Market Value consists of three principal components: Energy Value, Renewable Portfolio Standard (**RPS**) Value, and Resource Adequacy (**RA**) Value.

- Energy Value is the estimated financial value, measured in dollars, that is attributed to the generation component of a utility portfolio for a given year.[8]

- RPS Value is the estimated financial value, measured in dollars, that is attributed to the renewable energy component of a utility portfolio for a given year above and beyond the Energy Value.[9]

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[6] D.11-12-018, *Decision Adopting Direct Access Reforms*, R.07-05-025 (Dec. 1, 2011), at 8-9.

[7] D.19-10-001, at 6 ("Market Value is the estimated financial value, measured in dollars, that is attributed to a utility portfolio of energy resources for the purpose of calculating the Power Charge Indifference Adjustment for a given year.")

[8] *Ibid*.

[9] *Ibid*.

- RA Value is the estimated financial value, measured in dollars, that is attributed to the resource adequacy component of a utility portfolio for a given year.[10]

MPBs are estimates of the value per unit (not total portfolio value) associated with the three principal sources of value in utility portfolios (non-RPS energy, RPS, and RA capacity).[11] Each MPB must be multiplied by the relevant portfolio volume as part of the overall calculation of Portfolio Market Value:[12]

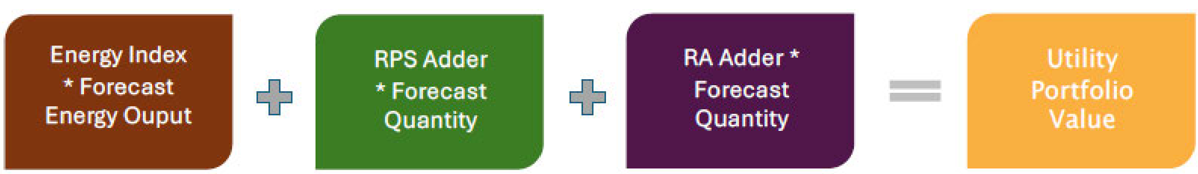
- Energy Index is the MPB that reflects the estimated market value of each unit of energy in a utility portfolio, in dollar value per megawatt hour (**$/MWh**). It is sometimes referred to as "Brown Power Index," "Brown Power component," "Brown Power Adder," or "Brown Power benchmark."[13]

- RPS Adder is the MPB that reflects the estimated incremental value of each unit of RPS-eligible energy in $/MWh.[14]

- RA Adder is the MPB that reflects the estimated value of each unit of capacity in a utility portfolio that can be used to satisfy Resource Adequacy obligations, in dollar value per kilowatt (**$/kW-month**).

The forecast utility portfolio value calculation is shown in Figure 3 below:

FIGURE 3



The forward-looking, forecasted ingredients of total portfolio cost and value are netted to produce the Indifference Amount portion of the PCIA revenue requirement.

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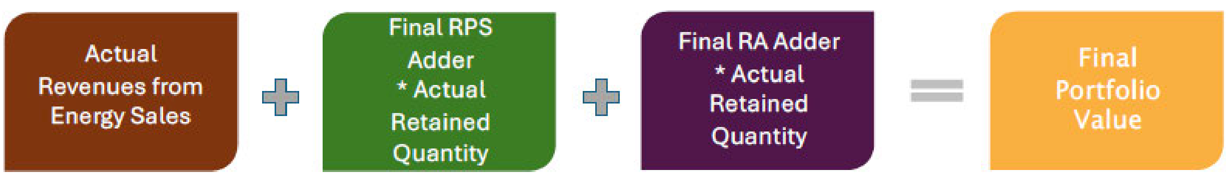
10 *Ibid*.
11 *Ibid*.
12 *Ibid*.
13 *Id*., p. 7.
14 *Ibid*.

The second portion of the PCIA revenue requirement is the "true up." The "true up" modifies the forecasted PCIA revenue requirement from the prior year to reflect, among other things, actual revenues received for products sold from the portfolio and to reflect a zero-dollar value for products left unsold from the portfolio. The revenue requirement modification also updates the proxy market values for products the utilities used to serve bundled customers, changing the *forecast* energy, RPS, and RA MPBs to *final* energy, RPS, and RA MPBs. This "true-up" relies on the same methodology used for the forecast and determines the final portfolio value, as shown in Figure 4 below:[15]

FIGURE 4



Prior to D.18-10-019, the PCIA rate was set only on a forecast basis with no after-the-fact adjustment to the forecasted PCIA revenue requirement for unbundled customers. Decision 18-10-019 approved such an adjustment via the PABA, a rolling balancing account tracking the difference between costs and revenues used to determine the forecasted PCIA revenue requirement and the actual costs and revenues PG&E realizes during the year related to its PCIA-eligible resource portfolio.

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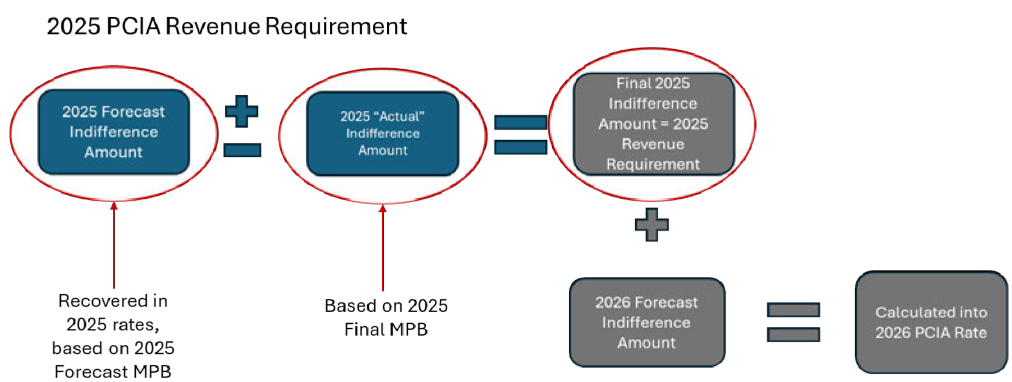
15 Because the true-up for 2025 occurs during 2025, this true-up is developed using (1) actual values that are available to date and (2) a forecast of actual values for the remainder of the year. PG&E's Application includes an estimate of the 2025 year-end PABA balance comprising a combination of actual entries from January through March 2025 and a projection of activity from April through December 2025. PG&E's October Update should include an estimate of the 2025 year-end PABA balance comprising a combination of actual entries from January through August 2025 and a projection of activity from September through December 2025. The final December 31, 2025, advice letter implementing the proceeding will include actual entries.

PG&E calculates this final 2025 portfolio value, uses it as an input to the actual 2025 indifference amount, and finalizes the 2025 revenue requirement in this case, as shown below in Figure 5.

FIGURE 5



To summarize, PG&E's PCIA rates for 2025 will be set in this proceeding based on these two components: (1) the forecasted Indifference Amount, *i.e.*, the difference between the forecasted cost of PG&E's generation portfolio in 2026 and the forecasted market value of PG&E's generation portfolio in 2026; and (2) the final 2025 PCIA revenue requirement based on the year-end balance in the PABA. The Indifference Amount and the final 2025 PCIA revenue requirement are added together to form the 2026 PCIA revenue requirement recovered through rates from bundled and unbundled customers.

C. Customer vintaging and allocation

Each generation resource and customer is assigned a "vintage." A distinct portfolio of generation resources is identified for each vintage year based on when a commitment to procure each resource was made. Customers are assigned to vintage years according to the date the customer departed bundled IOU service.[16] Customers continuing to receive bundled service from the IOU are included in the latest vintage (e.g., vintage 2026 in the current application). Each vintage is assigned both a separate Indifference Amount and a separate final 2025 revenue requirement[17] and customers are responsible for the cumulative Indifference Amount for years prior to and including their vintage. The PCIA revenue requirement is allocated among both bundled and unbundled customers based on their vintage[18] and their rate class using the allocation factors from PG&E's most recently approved GRC.[19]

III. THE COMMISSION SHOULD REJECT PG&E'S RA SOD PROPOSAL

As discussed above, PG&E must calculate the value of its capacity portfolio to determine the PCIA revenue requirement. Under the Commission-approved PCIA methodology, and as shown in Figure 3 above, a single RA Adder (*i.e.*, price) is multiplied by the amount of Retained RA capacity (*i.e.*, quantity) used for bundled customer RA compliance to determine the value of the capacity retained by the IOU (*i.e.*, price * quantity = value). Currently, the RA Adder and Retained RA capacity are each a single number representing the average price and quantity of RA across the entire year.

In D.22-06-050,[20] the Commission adopted a 24-hour SOD framework that transitions the RA program from a single Net Qualifying Capacity (**NQC**) requirement in the peak hour each month to a framework where each load serving entity (**LSE**) must

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16 Unlike portfolio resources, customers are assigned to vintages using a July to June calendar period. For example, customers departing bundled service between July 2019 and June 2020 are assigned to the 2019 vintage.

17 D.11-12-018, at 9.

18 *Ibid*.

19 D.18-10-019, at 122 and Ordering Paragraph (**OP**) 4.

20 D.22-06-050, *Decision Adopting Local Capacity Obligations for 2023 - 2025, Flexible Capacity Obligations for 2023, and Reform Track Framework*, R.21-10-002 (June 23, 2022).

demonstrate sufficient capacity to satisfy its specific gross load profile, including the planning reserve margin, in all 24 hours on the CAISO's "worst day" in each month. In D.23-04-010,[21] the Commission approved additional implementation details for the SOD framework and affirmed that it intended to move forward with SOD compliance in 2025. In D.24-06-004,[22] the Commission confirmed the start of the SOD framework would be in 2025. However, to date, the Commission has not issued any decisions or determinations regarding whether, or the manner in which, the PCIA template and framework should change in response to the new SOD framework.

Following these changes to the Commission's RA program, PG&E proposes to significantly change its approach to calculating the value of its capacity portfolio. Specifically, PG&E proposes to change the calculation of the Retained RA quantity by translating hourly SOD RA volumes into monthly values, which are then averaged across all months to produce a single average RA quantity to which the RA MPB is applied.[23] This change reduces the "quantity" of RA capacity in the PCIA calculation, thereby reducing the value of the capacity portfolio and increasing the Indifference Amount and requiring unbundled customers to pay a larger portion of the portfolio costs.

In my experience, sound ratesetting methodologies are best evaluated in a proceeding with all affected stakeholders present so the Commission has a full sense of their impacts, are consistently applied across utility service territories to ensure all ratepayers are treated equally, are crafted based on available data, and are grounded in

[21] D.23-04-010, *Decision on Phase 2 of the Resource Adequacy Reform Track*, R.21-10-002 (Apr. 6, 2023).

[22] D.24-06-004, *Decision Adopting Local Capacity Obligations for 2025-2027, Flexible Capacity Obligations for 2025, and Program Refinements*, R.23-10-011 (June 20, 2024).

[23] PG&E Prepared Testimony, at 8-14, lines 2-6.

theory and practice such that they produce results that are intuitive with people's real-world experiences. PG&E's proposed methodology does not meet these goals:

- It has been raised in a proceeding where many stakeholders are absent;
- It will result in inconsistent treatment of ratepayers in different service territories;
- It is premature, being proposed well in advance of the work needed to gather the data necessary to understand the impacts of SOD on the market;
- It only considers one half of the question of how SOD has changed the value of capacity (quantity) while ignoring the other (price);
- It is not sound in theory as it ignores the value proposition storage capacity provides;
- It is not sound in practice as it produces nonsensical results that suggest:
    - Battery storage has ***negative*** RA capacity value during certain months, meaning unbundled customers should pay for bundled customers' RA compliance costs;
    - Battery storage can be obtained without cost in the market, *i.e.*, if PG&E needed to go the market to procure storage, it could procure it at zero cost; and
    - Battery storage produces no benefit for bundled customers, *i.e.*, because PG&E could obtain storage resources for free in the market, storage resources impart little to no benefit to bundled customers for which they owe unbundled customers a credit in the PCIA indifference calculation.

For these reasons, I recommend the Commission reject PG&E's proposal and allow the PCIA Rulemaking to run its course before changing how RA capacity is quantified in

PG&E's service territory. If the Commission is compelled to adopt an interim approach in this case, I recommend that it adopt the approach from Southern California Edison's (**SCE**) 2025 ERRA Forecast proceeding.

A. PG&E's proposed methodology in a nutshell

PG&E proposes to calculate a weighted average of its hourly RA position with different treatments for different resource types. Baseload resources are assigned a flat profile, meaning the same amount of capacity (i.e., NQC) is counted in every hour (varying by month). PG&E's baseload treatment applies to natural gas, hydro, geothermal, biomas, biogas, and long-duration energy storage including pumped storage.[24] Wind and solar resources are assigned capacity values that vary by hour and month based on an "exceedance" methodology.[25] For battery storage resources, PG&E proposes to develop an optimized hourly charging and discharging profile and then average all hours together.

PG&E explains in testimony that it develops an hourly bundled system RA position before factoring in energy storage and then determines the optimal charge and discharge profile to meet RA compliance needs while satisfying the SOD charging sufficiency requirement.[26] PG&E compares its bundled customer load profile to the RA available from its generation resources and develops charging and discharging profiles of its storage resources to determine what non-storage resources can be used to charge its storage resources at different times of the day and which hours are projected to have excess supply that will either be sold to third parties or remain as Unsold RA.[27] PG&E proposes to determine the average annual Retained RA quantity by summing up the storage-adjusted

[24] *Id*., at 4-11, lines 18-24.
[25] *Id*., at 4-11, lines 25-27.
[26] *Id*., at 5-8, lines 10-28.
[27] *Id*., at 5-8, lines 18-28.

hourly RA position, applying hourly weighting factors from the California Energy Commission's (**CEC**) hourly system load forecast, for each month, and then averaging the monthly values across the year.[28]

PG&E's approach to battery storage resources forms the core of my concerns—and, as a result, my testimony—regarding PG&E's RA SOD proposal. Because PG&E represents charging as a negative quantity and discharging as a positive, taking the average of all hours results in ***a near-zero RA quantity*** for storage.[29]

B. PG&E's proposal treats capacity like energy and ignores the value storage provides.

PG&E's proposed adjustment to offset every hour of storage discharge RA with the hours required to charge battery storage conflates capacity and energy concepts and improperly values the RA capacity in the PCIA. PG&E explains in testimony that storage resources can be counted as RA during any hourly provided that the LSE can demonstrate that its portfolio contains sufficient excess charging capacity to support that level of discharge.[30] Because battery storage is not perfectly efficient, more energy is required to charge the battery than can be discharged over a period of time. Despite this inefficiency, battery storage has value in addressing one of the key issues facing California as it seeks to meet its clean energy goals: it can move capacity from a period of excess capacity (typically when solar resources are generating) to a different period when the capacity is needed (typically when solar resources have stopped generating). The value proposition for battery storage resources should reflect the value of its ability to provide capacity in

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28 *Id.*, at 5-11, line 26 through page 5-12 line 11.
29 *Id.*, at 4-12, lines 1-12, and pages 5-11 to 5-12.
30 *Id.*, at 4-12, lines 1-4.

any hour (when it is charged and available), in addition to the net energy value from charging and discharging.[31]

In the PCIA context, to the extent PG&E has energy settlement rights, the cost of energy to charge the battery and the revenue earned from energy discharge are already included as net revenue that is credited against the contract payments.[32] The value of RA retained by PG&E and used to count toward its bundled customer compliance obligation must also be recognized. PG&E's current methodology fails to do this because it only captures the capacity value of the resources charging the battery storage and fails to capture the value of the storage itself.

In its Reply to Protests in this case, PG&E explains that under its proposed SOD methodology, it retains an amount of non-storage capacity for the sole purpose of charging the energy storage resources used for compliance. PG&E argues that the Retained RA from battery storage is valued "by valuing the non-storage capacity that is being used to 'charge' an energy storage resource."[33] Under that rationale, however, PG&E's methodology only accounts for one part of the storage RA equation. If Retained RA is viewed as a transaction wherein bundled customers purchase RA from the PCIA portfolio, as PG&E confirmed in its prior testimony, then bundled customers must be required to purchase the battery storage RA *and* the capacity required to charge it, not offset the value of battery discharge by its hourly charging. PG&E's methodology misses the key value storage provides: taking excess capacity during one part of the day and moving it to where it is needed most.

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[31] PG&E recognizes value streams for energy and capacity separately in its quantitative evaluation of new storage resources, as shown in Appendix E to AL 7602-E.

[32] PG&E response to CalCCA data request 2.03.

[33] A.25-05-011, PG&E Reply to Protests, at 12.

PG&E's proposal to offset the RA capacity provided by battery storage with the hours required to charge the battery resources unfairly and inaccurately discounts the value of storage despite PG&E having capacity available to charge the storage resources. PG&E has [redacted] capacity available [redacted] Confidential Attachment B to my testimony includes a chart for each month comparing the quantity of resources available to provide RA with PG&E's hourly RA requirement, including the impact of charging and discharging battery storage. Figure 6 and Figure 7 below show two of those months, [redacted] As PG&E describes in testimony, storage resources are optimized to minimize the SOD RA open position across all hours. In the figures below, any shaded area above the "RA Requirement" line, before and after accounting for storage resources, constitutes resources in excess of PG&E's SOD RA requirements. [redacted]

Figure 6: PG&E RA Position [redacted]

[redacted]

Figure 7: PG&E RA Position [redacted]

[redacted]

C. PG&E's methodology pretends battery storage has little to no cost in the market and provides little to no benefit to bundled customers.

PG&E's proposed treatment of battery storage RA seems to be premised on the idea that the Commission's SOD framework requires a showing that LSEs have sufficient capacity available to charge the battery storage before it can be counted as providing RA. PG&E translates that requirement into its proposal to fully offset the RA capacity provided by batteries and the capacity required to charge the batteries. When applied to the PCIA framework, PG&E's proposal results in little to no value from battery storage recognized in the PCIA even though PG&E plans to use the storage capacity as Retained RA for bundled customers. This proposal misconstrues the RA value proposition and does not reflect PG&E's own interpretation of RA value.

The question of how to determine the value of RA capacity the IOUs retain for their own use was determined by the Commission in D.18-10-019. The cornerstone of that approach is to value an attribute at the price at which it can be bought and sold.[34] In its 2025 ERRA Forecast testimony, PG&E further explained that the concept of Retained RA is equivalent to bundled customers purchasing RA products from PCIA resources:

> PG&E uses some of the RA in its PCIA-eligible portfolio to meet bundled service customers' RA compliance obligations. When PG&E uses or "retains" this RA for compliance, bundled service customers effectively "purchase" the RA from its PCIA-eligible portfolio at the applicable RA MPB. This "purchase" occurs not via a contract but wholly within rates via (1) a cost to bundled service customers in their generation rate and (2) an equal credit to or reduction in the PCIA rate. Because both departed load and bundled service customers pay the PCIA, part of the credit from retaining or "purchasing" RA products for bundled service customers' compliance goes to departing load customers and part of the credit goes back to bundled service customers. Since PG&E bundled service customers are currently a minority of customers in its service area, those customers are purchasing a

[34] *See* D.18-10-019, at 73.

> significant portion, 48 percent in 2023, of the RA retained for their compliance from departed load customers at the applicable RA MPBs.[35]

Applying this PG&E analogy—that using a PCIA-eligible resource to meet a bundled customer compliance requirement is the same as purchasing that attribute in the market at the MPB—to the instant question demonstrates the inadequacy of PG&E's proposal. If PG&E were to procure RA from battery storage in the market it would be required to pay the market price for the storage RA regardless of whether it already had capacity available to charge the battery. In fact, if PG&E does not already have excess charging capacity available, under the SOD framework, PG&E must procure both the battery storage resource *and* the capacity to charge the battery. The same should hold true for RA retained from PCIA-eligible resources. Bundled customers should be required to pay for the battery storage RA they need for compliance as well as the capacity required to charge the battery. Contrary to that reality, PG&E's SOD proposal treats the cost of charging capacity as an offset to the price of storage RA. PG&E's proposal essentially takes RA from PCIA-eligible battery storage resources without paying unbundled customers for it. In other words, the utility's proposal pretends battery storage capacity can be purchased at almost no cost in the market and, therefore, PG&E owes unbundled customers nothing for the resources used for bundled customer compliance.

PG&E's SOD proposal further implies that the seller of the storage RA would be willing to discount the price to $0 because the buyer must also procure charging capacity elsewhere. No seller would agree to those terms, as PG&E's own transaction data demonstrates. In discovery, PG&E provided a list of RA-only sales contracts it has

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[35] A.24-05-009, PG&E Prepared Testimony, at 2-10, lines 6-20. Internal citations omitted.

executed [redacted] for delivery during 2025.[36] PG&E summarized the transactions based on the type of resource providing the RA and the prices realized for each. As shown in Table 2 below, the average price paid for RA from baseload resources with a flat NQC profile was [redacted]. Over a similar period, the average price paid for RA from standalone storage resources was [redacted]. When selling RA to other LSEs in the market, PG&E clearly did not give buyers a [redacted]. Yet, it proposes to do so when calculating the PCIA for storage it effectively purchases from unbundled customers. This demonstrates that PG&E's proposal is out of alignment with the value of RA attributes bought and sold in the market, which is a fundamental flaw in the proposal.

Table 2: PG&E Average RA Sales Prices by Resource Type

[redacted]

[36] PG&E supplemental response to CalCCA data request 1.48.

D. PG&E's SOD proposal is not consistent with how it values storage RA when evaluating procurement opportunities for its bundled customers.

In Advice Letter (**AL**) 7602-E, filed on May 21, 2025, PG&E sought Commission approval of a power purchase agreement for long-term RA with energy settlement provided by an 80 MW, four-hour duration standalone battery storage facility.[37] PG&E undertook the procurement pursuant to the Mid-term Reliability (**MTR**) requirements of D.23-02-040, so the costs of the contract, including for the RA capacity, will be assigned to PCIA vintage 2023. PG&E indicates that cost recovery will be net of any CASIO charges and market revenue, and net of any retained RA capacity value for bundled customers.[38] Appendix E of AL 7602-E details PG&E's quantitative evaluation method for new resource procurement as applied to the proposed RA purchase. According to PG&E, new resources are quantitatively assessed based on Net Market Value, which is the present value of benefits (i.e., the value of energy, capacity, ancillary services, and RECs) minus costs (i.e., fixed costs, variable costs, metered contract costs, and transmission network upgrade costs). PG&E defines capacity value as follows:

> Capacity Value is applicable for all Agreement Types. It is the net present value of monthly capacity values across all months during the delivery period. The monthly Capacity value (C) is computed as the sum of two components: 1) the monthly Net Qualifying Capacity multiplied by the Local or System capacity price, and 2) the monthly Effective Flexible Capacity (EFC in MWs) provided by the project multiplied by the flexible RA price. These values are then discounted back by the discount factor for the month.[39]

When evaluating the value of battery storage RA needed for bundled customers, PG&E *uses the resource's **NQC** and the capacity price*. PG&E does not apply a [redacted] to

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[37] PG&E response to CalCCA data request 3.01, Advice Letter 7602-E.

[38] Advice Letter 7602-E, at 9.

[39] *Id.*, Appendix E, at E-3.

the quantity of RA it must purchase, as it proposes to do for the storage it effectively purchases from unbundled customers through the PCIA. In fact, PG&E's quantitative evaluation of new procurement is consistent with the existing PCIA method (not PG&E's SOD proposal)—the method I believe PG&E should apply until the PCIA Rulemaking determines otherwise.

E. PG&E's proposal produces nonsensical results in the PCIA.

CalCCA agrees that a storage-adjusted RA position is needed to forecast residual capacity purchases and sales, as well as the hourly RA capacity needed to meet bundled customer compliance requirements.[40] However, PG&E's proposed aggregation of the hourly RA position for the PCIA produces a nonsensical result for battery storage resources. Specifically, by summing up an hourly RA profile that includes offsetting charging (reflected as a negative) and discharging (reflected as a positive) energy from battery storage resources, PG&E effectively eliminates the MW capacity from battery storage that would receive a value credit in the PCIA. Multiplying PG&E's proposed near-zero battery storage capacity by the RA Adder results in a *de minimis* value for Retained RA from battery storage being included in the Indifference Amount.

Table 3 below lists each battery storage resource included in PG&E's PCIA-eligible resource portfolio, which is projected to provide Retained RA for bundled customers.[41] As shown in the table, PG&E's 2026 Indifference Amount forecast includes 32 of these battery storage resources with a total NQC of 3,050 MW. However, under PG&E's aggregation proposal, these resources only count as providing [redacted] of Retained RA – just [redacted] of the resources' NQC.

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[40] PG&E Prepared Testimony, at 5-9, lines 4-11.

[41] PG&E Response to CalCCA data request 1.41.

Table 3: Battery Storage NQC Versus PG&E SOD Average RA

Contract Log Number	Contract Capacity /NQC (MW)	PG&E Proposed Average RA (MW)	PG&E SOD Discount
40S008	10.0	[redacted]	
40S009	25.0		
40S011	50.0		
40S015	50.0		
40S016	50.0		
40S017	50.0		
40S018	60.0		
40S020	50.0		
40S021	63.0		
40S022	46.0		
40S023	15.0		
40S024	40.0		
40S025	132.0		
40S027	127.0		
40S029	150.0		
40S030	63.0		
40S031	47.0		
40S032	350.0		
40S033	50.0		
40S034-AR	99.7		
40S035	275.0		
40S037	300.0		
40S038	100.0		
40S039	80.0		
40S040	169.0		
40S041	12.0		
40S042	23.5		
40S043	230.0		
40S044-H01	92.0		
40S045	112.5		
40S048	69.0		
40S049	59.7		
Total	**3,050.4**		

As described earlier, the Commission-approved method for determining the value of Retained RA provided by PCIA-eligible resources is to multiply the published RA Adder by the average annual quantity of PCIA-eligible RA used to meet bundled customer compliance needs. Battery storage resources have historically been included in Retained RA using NQC because they are able to provide RA capacity during system peak hours. Consistent with the current PCIA method, applying the RA Adder to the battery storage NQC would value the Retained RA at more than $574.3 million in 2026, or an effective price of $15.69/kW-month.[42] Under PG&E's SOD proposal, that same Retained RA would be valued at only [redacted], an effective price of just [redacted] as shown in Table 4.

Table 4: RA Value Using NQC Versus PG&E's Proposed SOD Average RA

Contract Log Number	Contract Capacity /NQC (MW)	PG&E Proposed Average RA (MW)	RA Type	RA MPB ($/kW-month)	NQC Value ($000)	PG&E Proposed Value ($000)
40S008	10.0	[redacted]	Local (PG&E)	$ 13.29	$ 1,595	[redacted]
40S009	25.0	[redacted]	Flex	$ 16.97	$ 5,091	[redacted]
40S011	50.0	[redacted]	Local (PG&E)	$ 13.29	$ 7,974	[redacted]
40S015	50.0	[redacted]	Local (PG&E)	$ 13.29	$ 7,974	[redacted]
40S016	50.0	[redacted]	Local (PG&E)	$ 13.29	$ 7,974	[redacted]
40S017	50.0	[redacted]	Local (PG&E)	$ 13.29	$ 7,974	[redacted]
40S018	60.0	[redacted]	Flex	$ 16.97	$ 12,218	[redacted]
40S020	50.0	[redacted]	Local (SDG&E)	$ 9.99	$ 5,994	[redacted]
40S021	63.0	[redacted]	Flex	$ 16.97	$ 12,829	[redacted]
40S022	46.0	[redacted]	Flex	$ 16.97	$ 9,367	[redacted]
40S023	15.0	[redacted]	Flex	$ 16.97	$ 3,055	[redacted]
40S024	40.0	[redacted]	Local (SDG&E)	$ 9.99	$ 4,795	[redacted]
40S025	132.0	[redacted]	Local (PG&E)	$ 13.29	$ 21,051	[redacted]
40S027	127.0	[redacted]	Local (SCE)	$ 11.23	$ 17,115	[redacted]
40S029	150.0	[redacted]	Flex	$ 16.97	$ 30,546	[redacted]
40S030	63.0	[redacted]	Flex	$ 16.97	$ 12,829	[redacted]
40S031	47.0	[redacted]	Flex	$ 16.97	$ 9,571	[redacted]
40S032	350.0	[redacted]	Local (PG&E)	$ 13.29	$ 55,818	[redacted]
40S033	50.0	[redacted]	Flex	$ 16.97	$ 10,182	[redacted]
40S034-AR	99.7	[redacted]	Flex	$ 16.97	$ 20,303	[redacted]
40S035	275.0	[redacted]	Flex	$ 16.97	$ 56,001	[redacted]
40S037	300.0	[redacted]	Flex	$ 16.97	$ 61,092	[redacted]
40S038	100.0	[redacted]	Flex	$ 16.97	$ 20,364	[redacted]
40S039	80.0	[redacted]	Flex	$ 16.97	$ 16,291	[redacted]
40S040	169.0	[redacted]	Flex	$ 16.97	$ 34,415	[redacted]
40S041	12.0	[redacted]	Flex	$ 16.97	$ 2,444	[redacted]
40S042	23.5	[redacted]	Flex	$ 16.97	$ 4,786	[redacted]
40S043	230.0	[redacted]	Flex	$ 16.97	$ 46,837	[redacted]
40S044-H01	92.0	[redacted]	Flex	$ 16.97	$ 18,735	[redacted]
40S045	112.5	[redacted]	Flex	$ 16.97	$ 22,910	[redacted]
40S048	69.0	[redacted]	Flex	$ 16.97	$ 14,051	[redacted]
40S049	59.7	[redacted]	Flex	$ 16.97	$ 12,157	[redacted]
Total	**3,050.4**	[redacted]			**$ 574,339**	[redacted]
Effective RA Price ($/kW-mont		[redacted]			**$ 15.69**	[redacted]

[42] Calculated using the 2025 Forecast RA Adders for Local and Flex RA, as included in PG&E's initial filing. The value will change when the 2026 Forecast RA Adder is updated in PG&E's October Update filing.

If PG&E's annual average battery storage RA is shown on a monthly basis, it reveals that PG&E's proposal actually results in ***negative*** Retained RA attributed to battery storage in certain months. Table 5 details PG&E's proposed monthly RA from battery storage and the proposed annual average that ties to the data in Table 4.

Table 5: PG&E Monthly Battery Storage RA

Contract Log Number	Contract Capacity /NQC (MW)	PG&E Proposed Monthly RA Counting (MW)												
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
40S008	10.0	[redacted]												
40S009	25.0													
40S011	50.0													
40S015	50.0													
40S016	50.0													
40S017	50.0													
40S018	60.0													
40S020	50.0													
40S021	63.0													
40S022	46.0													
40S023	15.0													
40S024	40.0													
40S025	132.0													
40S027	127.0													
40S029	150.0													
40S030	63.0													
40S031	47.0													
40S032	350.0													
40S033	50.0													
40S034-AR	99.7													
40S035	275.0													
40S037	300.0													
40S038	100.0													
40S039	80.0													
40S040	169.0													
40S041	12.0													
40S042	23.5													
40S043	230.0													
40S044-H01	92.0													
40S045	112.5													
40S048	69.0													
40S049	59.7													
	3,050.4													

Negative Retained RA makes no sense in a PCIA context. Applying a negative quantity to the RA MPB results in a negative RA value, meaning that under PG&E's proposal departed load customers would be ***required to pay for RA retained by PG&E*** to meet its bundled customer compliance requirements. That is, CCA customers would end up paying not only for their own RA compliance obligations but those for bundled customers.

PG&E's proposal to impose an extra charge on departed load customers and keep the RA for bundled customers does not maintain indifference for bundled or unbundled customers. A customer who has departed PG&E's service is owed a credit for its share of the benefits that are provided by the resources for which the departed customer continues to pay. PG&E's methodology suggests that the benefit can be negative, essentially imposing an extra charge on departed customers. Doing so, while PG&E keeps the RA capacity to meet its own bundled customers' procurement obligations, is a clear violation of the Commission's indifference standard.

F. SOD should be fully evaluated in the PCIA Rulemaking Proceeding so that it can be applied consistently for all three IOUs.

PG&E's proposal is premature and made in the wrong proceeding. It comes at a time when the full impact of SOD on RA value, and how it should be reflected in the PCIA, is still unknown. The Commission and stakeholders spent considerable time and effort evaluating the SOD framework and preparing for binding implementation in 2025. However, again, the Commission has not addressed how—or if—the SOD framework should impact the PCIA framework. While the Commission has approved SOD implementation for RA compliance purposes, it has not provided direction regarding changes that may be required to incorporate RA compliance changes into the PCIA template for all IOUs to ensure RA continues to be valued correctly and consistently under SOD.

When Energy Division publishes its 2026 MPBs in October 2025, for example, the RA Adder will be calculated as the average $/kW price for RA from any resource technology and for the entire forecast year. Consistent with D.25-06-049,[43] the RA Adder will be based on transactions executed from September 2022 through August 2025 for delivery in 2026. Because SOD compliance was not effective until 2025, it is not clear how the market prices for RA reflect the transition from the prior single-peak RA framework to the SOD model. Energy Division will likely need to gather more transactional data than it currently collects to understand and quantify the impact of SOD in the market, including whether RA prices vary based on the underlying resource technologies. However, that work has not yet begun, and it is unclear what, if any, changes are needed to ensure that the calculation of Retained RA accurately reflects the value these resources provide to bundled customers and, in turn, whether that calculation results in indifference for unbundled customers.

In my experience, the Commission generally does not allow policymaking in ERRA Forecast cases.[44] Proposals to change the PCIA ratemaking framework are first reviewed in other proceedings, such as the PCIA Rulemaking Proceeding initiated this year, so that all interested parties have an opportunity to evaluate and respond to those proposals.[45] Because SOD RA compliance applies equally to PG&E, Southern California

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43 D.25-06-049, *Decision Adopting Changes to the Calculation of the Resource Adequacy Market Price Benchmark*, R.25-02-005 (June 26, 2025).

44 *See, e.g.,* D.18-01-009, *Decision Adopting Pacific Gas and Electric Company's 2018 Energy Resource Recovery Account Forecast and Generation Non-Bypassable Charges and Greenhouse Gas Forecast Revenue and Reconciliation*, A.17-06-005 (Jan. 11, 2018), at 10 (finding that policy issues are properly addressed in other dockets); *see also id.* at 14, Conclusion of Law (**COL**) 2 and OP 2 (denying PG&E's request to modify its line loss calculation).

45 *See Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Process*, R.25-02-005 (Feb. 26, 2025) (PCIA OIR), at

Edison Company (**SCE**), and San Diego Gas & Electric Company (**SDG&E**), changes to the PCIA framework must be applied consistently to all three. The simplest way to ensure consistent application will be to adopt the same methodology for all three IOUs in the PCIA Rulemaking Proceeding, where all three IOUs can participate and demonstrate the impact of SOD on RA value. SCE and SDG&E have signaled in their ERRA Forecasts that they believe SOD will impact how RA value should be calculated for the PCIA, but the three IOUs, including PG&E, are not on the same page regarding how or when it should be implemented.

SCE argues that under the SOD framework, a resource's RA quantity should reflect the reliable capacity provided by the resource over a full 24-hour period. Therefore, SCE proposes to represent RA as the "baseload equivalent" RA for each resource type based on how the resource contributes to SCE's hourly compliance requirements. This baseload equivalent results in monthly RA quantities in the Indifference Amount that, for some resource types, are modified from NQC using an "SOD RA Effectiveness Factor."[46] The Commission adopted SCE's SOD proposal on an *interim* basis in that utility's 2025 ERRA Forecast case but stated, "[t]he issues of whether hourly RA MPB prices are needed and how to achieve proper accounting for storage and hybrid resources under SOD are both ripe for consideration in a rulemaking proceeding."[47]

10-11 ("[T]he ERRA process itself is intended to function as an individual electric IOU's annual forecast and accounting review, not as a forum for evaluating or setting policy. A certain amount of policy decision-making is inherent within a thorough consideration of customer programs and procurement obligations, even in streamlined proceedings focused on ratemaking. But a range of policy issues arising in recent ERRA proceedings and other ratemaking cases have demonstrably strained the limits of individual cases.")

[46] *Application of Southern California Edison Company (U338E) for Approval of its 2026 ERRA Forecast Proceeding Revenue Requirement,* A.25-05-008 (May 15, 2025), SCE-01 at 131:8-17.

[47] D.24-12-039, *Decision Approving Southern California Edison Company's 2025 Energy Resource Recovery Account-Related Forecast Revenue Requirement*, A.24-05-007 (Dec. 19, 2024), at 75.

SDG&E acknowledges in its testimony that SOD RA compliance has been adopted by the Commission but that no changes to the PCIA methodology have been approved. SDG&E's testimony states:

> D.22-06-050 adopted a 24-hour slice of day ("SOD") approach to RA program requirements. At the time of this May filing, **<u>no changes to the PCIA RA methodology for SOD have been approved by the Commission</u>**. SDG&E is therefore making no such changes to the PCIA methodology for RA in this filing, and the methodology is consistent with prior years' filings.[48]

Addressing SOD in individual ERRA Forecasts will inevitably lead to inconsistent changes to the common PCIA framework, decreasing the transparency of the PCIA rate calculation and reducing the comparability of PCIA rates between IOUs.

I recommend the Commission use the PCIA Rulemaking Proceeding to evaluate the impact of SOD RA compliance on the PCIA framework as applicable to SCE, PG&E, and SDG&E. The final answer to the question of what impacts SOD will have on the PCIA framework may be a combination of modifications to RA quantity and price, but the Commission, the three IOUs, and other interested parties, including CalCCA, should conduct further analysis in the PCIA Rulemaking Proceeding before reaching a conclusion. Indeed, the preliminary scope of Track 2 of the PCIA Rulemaking Proceeding specifically includes the following issue: "Consideration of the need for ERRA-specific implementation guidance for RA program changes, including those related to the implementation of the Slice of Day framework, as was raised in the 2025 ERRA forecast."[49] After completing that evaluation, each IOU should consistently implement the resulting Commission directives in their individual ERRA Forecast proceedings. In the

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48 SDG&E Prepared Direct Testimony of Sheri Miller, A.25-05-012, at SM-5 lines 7-11 (emphasis added).

49 *See* PCIA OIR at 24.

meantime, the Commission should direct PG&E to calculate Retained RA in its 2026 ERRA Forecast the same way it has in past ERRA Forecast cases.

G. If the Commission applies an interim method to account for SOD, it should use the interim method approved for SCE.

SCE first proposed its interim approach to reflect the SOD framework in the PCIA template in Supplemental Testimony filed in its 2025 ERRA Forecast (**SCE Interim SOD Method**). SCE revised its proposal in response to issues raised by CalCCA in that proceeding, and in D.24-12-039, the Commission approved SCE's proposal "for the purposes of the 2025 ERRA forecast."[50] SCE also applied its updated interim SOD proposal in its 2026 ERRA Forecast.[51]

According to the SCE Interim SOD Method, baseload resources that deliver consistent output throughout the day continue to count up to their NQC for the month.[52] For intermittent resources (e.g., wind, solar), the RA quantity is the average of their hourly exceedance values, which vary depending on the region and technology.[53] Stand-alone battery storage resources are calculated as the storage NQC minus an estimate of the RA capacity needed for charging.[54] SCE's formula for calculating the RA quantity from storage resources is: NQC – NQC * 4 / 24 / Round Trip Efficiency.[55] In its 2026 ERRA Forecast testimony, SCE describes its treatment of energy storage as follows:

> In the SOD framework, storage resources are not assigned specific pre-determined hourly quantities for the hourly capacity determination. Instead, storage resources are optimized to address RA shortfalls during any hour of the day. Furthermore, the CPUC's QC methodology for energy storage has not changed. It is still based on the capacity (MW) level at which the storage

50 D.24-12-039, at 75.
51 A.25-05-008, SCE-01 at 129:20 – 130:2.
52 *Id.*, at 131:19-22.
53 *Id.*, at 131:24-132:8.
54 *Id.*, at 132:10-22.
55 *Id.*, at 132:26.

> resource is capable of discharging for four or more consecutive hours. Under the previous RA framework, storage resources with a duration of four hours or more are deemed equivalent to baseload for RA counting, underscoring their ability to provide capacity during the peak period. Therefore, their RA quantity can still be based on their NQC value. However, the SOD rules introduced an additional requirement: storage resources can only be counted towards RA if there is sufficient charging capacity. The combination of storage resources and the charging RA capacity provides a solution equivalent to baseload. Therefore, the effective contribution from storage is calculated as the storage NQC minus the RA capacity needed for charging.[56]

PG&E's SOD proposal in the current case has some similarities to the SCE Interim SOD Method for baseload and intermittent resources, but PG&E's proposed treatment of battery storage is markedly different than SCE's method. SCE's approach reflects that storage is not available in all 24 hours like a baseload resource but also reflects that storage is similar to baseload resources in that it can be used to provide RA in any hour as long as it can be charged, *i.e.*, SCE's approach recognizes the capacity value storage has in shifting excess capacity from one part of the day to another part of the day when capacity is needed. And under SCE's approach, similar to PG&E's, the charging capacity provided by other resources is also valued as Retained RA in the PCIA. Table 6 below shows that applying SCE's interim method for energy storage to the PCIA-eligible storage resources in PG&E's case increases the RA value from [redacted] as proposed by PG&E to $458.2 million.

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[56] *Id.*, at 132:10-21.

Table 6: SCE Interim SOD Method Applied to PG&E Storage Resources

Contract Log Number	Contract Capacity /NQC (MW)	PG&E Proposed Average RA [redacted]	RA Type	PG&E Proposed Value ($000)	Round Trip Efficiency	SCE RA Effectiveness Factor - Storage	SCE Method RA Value ($000)
40S008	10.0	[redacted]	Local (PG&E)	[redacted]	85%	8.0	$ 1,282
40S009	25.0	[redacted]	Flex	[redacted]	80%	19.8	$ 4,030
40S011	50.0	[redacted]	Local (PG&E)	[redacted]	80%	39.6	$ 6,313
40S015	50.0	[redacted]	Local (PG&E)	[redacted]	80%	39.6	$ 6,313
40S016	50.0	[redacted]	Local (PG&E)	[redacted]	80%	39.6	$ 6,313
40S017	50.0	[redacted]	Local (PG&E)	[redacted]	80%	39.6	$ 6,313
40S018	60.0	[redacted]	Flex	[redacted]	80%	47.5	$ 9,673
40S020	50.0	[redacted]	Local (SDG&E)	[redacted]	80%	39.6	$ 4,745
40S021	63.0	[redacted]	Flex	[redacted]	85%	50.6	$ 10,314
40S022	46.0	[redacted]	Flex	[redacted]	80%	36.4	$ 7,416
40S023	15.0	[redacted]	Flex	[redacted]	87%	12.1	$ 2,469
40S024	40.0	[redacted]	Local (SDG&E)	[redacted]	80%	31.7	$ 3,796
40S025	132.0	[redacted]	Local (PG&E)	[redacted]	87%	106.7	$ 17,019
40S027	127.0	[redacted]	Local (SCE)	[redacted]	80%	100.5	$ 13,549
40S029	150.0	[redacted]	Flex	[redacted]	80%	118.8	$ 24,182
40S030	63.0	[redacted]	Flex	[redacted]	87%	50.9	$ 10,372
40S031	47.0	[redacted]	Flex	[redacted]	88%	38.1	$ 7,758
40S032	350.0	[redacted]	Local (PG&E)	[redacted]	80%	277.1	$ 44,189
40S033	50.0	[redacted]	Flex	[redacted]	80%	39.6	$ 8,061
40S034-AR	99.7	[redacted]	Flex	[redacted]	80%	78.9	$ 16,073
40S035	275.0	[redacted]	Flex	[redacted]	85%	221.1	$ 45,020
40S037	300.0	[redacted]	Flex	[redacted]	87%	242.5	$ 49,389
40S038	100.0	[redacted]	Flex	[redacted]	80%	79.2	$ 16,122
40S039	80.0	[redacted]	Flex	[redacted]	80%	63.3	$ 12,897
40S040	169.0	[redacted]	Flex	[redacted]	80%	133.8	$ 27,245
40S041	12.0	[redacted]	Flex	[redacted]	80%	9.5	$ 1,935
40S042	23.5	[redacted]	Flex	[redacted]	80%	18.6	$ 3,789
40S043	230.0	[redacted]	Flex	[redacted]	83%	183.8	$ 37,432
40S044-H01	92.0	[redacted]	Flex	[redacted]	80%	72.8	$ 14,832
40S045	112.5	[redacted]	Flex	[redacted]	83%	89.9	$ 18,309
40S048	69.0	[redacted]	Flex	[redacted]	85%	55.5	$ 11,296
40S049	59.7	[redacted]	Flex	[redacted]	85%	48.0	$ 9,774
Total	**3,050.4**	[redacted]		[redacted]		**2,432.8**	**$ 458,219**

While SCE's Interim SOD Method includes a more reasonable approach to battery storage RA relative to PG&E's proposal, SCE's proposed framework is not flawless. SCE explains in testimony that it does not assume any changes to the MPB price used to value RA for SOD compared to the current single-hour RA compliance framework.[57] Therefore, SCE's proposal creates a 'Baseload Equivalent' RA quantity and applies that to the existing RA Adder. Applying the RA Adder to a Baseload Equivalent quantity from different

57 *Id.*, at 130:18-24.

resource technologies implies that the RA Adder is also a baseload equivalent market price, but, to date, SCE has provided no analysis to support that assumption. If different resources have different values under a SOD framework, and the RA Adder is the average price of all transactions for all resource types, the MPB, as currently calculated, must *not* be a baseload equivalent price.

The disjointed result is SCE's methodology seeks a baseload-equivalent value using a baseload-equivalent quantity, but a *non*-baseload equivalent price. Revisiting a point from earlier in testimony, good ratesetting methodologies are both sound in theory and practice, producing results that are intuitive with real-world experiences. Where PG&E's methodology fails both tests, SCE's at least passes one: while the theory underlying SCE's approach is flawed, SCE's methodology results in outcomes that better comport with how the market values capacity from technologies like battery storage.

PG&E's RA transaction data provided in discovery and summarized earlier in Table 2 show a pattern of different prices for RA from different resource types.[58] [redacted] Applying SCE's method results in storage being included at about 79% of baseload. However, as PG&E indicated in its response, PG&E's transaction data likely represents a small fraction of the broader RA market transactions and may not reflect a similar analysis that considers all RA market transactions. Clearly, more analysis needs to be done. A quantity discount approach is applicable only so long as the MPB is a baseload equivalent price. PG&E claims in discovery that the significant majority of RA transactions

[58] PG&E supplemental response to CalCCA data request 1.48.

are for baseload RA.[59] But PG&E's observation confirms that non-baseload transactions are likely included in the MPB dataset and causing the RA Adder to be [redacted] relative to a baseload equivalent price.

Currently, insufficient data is available to know what changes may be required to the RA Adder or the quantity applied to the MPB. CalCCA does not have a clear picture of what transactions are included in the RA Adder or whether the published MPBs are higher or lower than a baseload equivalent price, since Energy Division does not make the data available. The final answer to the question of what impacts SOD will have on the PCIA framework may be a combination of modifications to RA quantity and price, but the Commission, the three IOUs, and other interested parties like CalCCA should conduct further analysis in the PCIA Rulemaking Proceeding before reaching a conclusion on how best to value capacity in a post-SOD world. The Commission should not disturb PG&E's existing approach to valuing its RA capacity until that analysis occurs; however, if the Commission adopts an interim change to PG&E's existing approach, it should adopt SCE's Interim SOD Method, and not PG&E's proposal.

IV. PG&E SHOULD CORRECT ERRORS IN THE CALCULATION OF ITS ENERGY STORAGE RA FROM MODIFIED CAM RESOURCES.

Several of PG&E's energy storage contracts were procured pursuant to D.19-11-016. In that decision, the Commission directed that PG&E procure capacity on behalf of LSEs that elected not to self-provide capacity, and that the cost of such procurement be recovered from customers of those LSEs through a Modified CAM (**ModCAM**) surcharge. The portion of ModCAM procurement undertaken for PG&E's bundled customers is recovered through the PCIA. In discovery, PG&E acknowledged that it's PCIA workpapers

59 PG&E supplemental response to CalCCA data request 1.43.

erroneously included the CAM portion of Modified CAM resources rather than the PCIA share of the ModCAM resources, resulting in an understated amount of Retained RA included in the PCIA.[60] PG&E indicated in discovery that it will correct this error in its October Update to reflect the PCIA share of Retained RA from ModCAM resources.[61] If PG&E's SOD proposal is adopted by the Commission then PG&E should be required to correct the Retained RA from ModCAM storage resources. Correcting this error reduces PG&E's filed Indifference Amount by $0.7 million.

V. DEPARTED LOAD SHOULD RECEIVE A SHARE OF THE VALUE OF BANKED RECS USED AS RETAINED RPS FOR BUNDLED CUSTOMERS

When PG&E uses RPS-eligible generation from its PCIA resource portfolio to meet its bundled customer RPS compliance target, it must count that RPS-eligible generation as Retained RPS and credit the value of that generation to the PCIA using the RPS Adder. PG&E must credit the value of Retained RPS to the PCIA so that departed load customers receive an allocated share of the RPS benefits provided by the PCIA-eligible resources for which they continue to pay, consistent with the indifference principle that underpins the PCIA framework. Bundled customers pay for the RECs needed for compliance because the value is included in their generation rates, *i.e.*, Retained RPS is debited to ERRA and credited out of the PCIA.

Based on previous Commission decisions,[62] PG&E must retain a minimum volume of RPS-eligible generation corresponding to PG&E's RPS compliance period requirement. If RPS-eligible generation available to PG&E in the Forecast year (in this case, 2026) is less than its annual RPS compliance requirement for bundled customers, PG&E proposes

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[60] PG&E responses to CalCCA data request 2.05 and 2.06.

[61] PG&E response to CalCCA data request 2.06.

[62] D.20-02-047, at 13-14.

to use banked RECs to make up the difference and meet the minimum Retained RPS requirement established by the Commission. “Banked” RECs are RECs generated in previous years, in excess of PG&E’s RPS compliance period requirement, and paid for by PG&E’s bundled customers (as Retained RPS in the PCIA). When those banked RECs are eventually used, PG&E’s bundled customers will extract the value they previously paid for by using those RECs for compliance. Those customers who were bundled when the banked RECs were generated and paid for, but who have since departed PG&E generation service, should receive value for the RECs through a credit to the PCIA. PG&E’s proposal does not convey this value to these departed load customers.

In a departure from its past ERRA cases, PG&E proposes in this case that customers who paid for banked RECs prior to 2019, but have since departed PG&E’s system, should get ***no*** credit for those RECs when they are finally used to meet bundled customer compliance requirements. This essentially forces now-departed customers to subsidize RECs used by today’s bundled customers. PG&E’s approach does not comport with the indifference principle underpinning the PCIA framework, nor does it follow Commission precedent.

To properly credit departed customers for the value of RECs used for current bundled customer compliance, a credit equal to the current value of the RECs is required in the PCIA. If the RECs were previously counted as Retained RPS and paid for by customers receiving bundled service at the time the RECs were generated, the current value of the Banked RECs (i.e., using the RPS Adder) must be applied as a credit to the PCIA vintage matching the year the RECs were generated and paid for. Applying the credit to the PCIA vintage corresponding to the year the RECs were generated ensures that customers who were bundled at the time the REC was generated, but who have since departed bundled service, receive their share of the value of the RECs now being used for bundled customers. If the RECs were not previously counted as Retained RPS (i.e., Unsold RPS), the PCIA credit should be spread to all vintages based on the PCIA-eligible RPS generation in each vintage. In that way the credit is shared with all customers responsible to pay the cost of PG&E's PCIA-eligible RPS resources.

As described in detail below, the question of how to value banked RECs used to meet the minimum compliance requirement has been raised in many different proceedings, the question has been answered inconsistently across those proceedings. Because this issue affects PG&E, SCE, and SDG&E, CalCCA recommends that the Commission resolve conflicting interpretations of D.19-10-001 and the appropriate valuation of Pre-2019 Banked RECs in Track 2 of the PCIA Rulemaking Proceeding. For the purposes of PG&E's 2026 shortfall, the Commission can direct PG&E to use its Unsold RPS from 2023 and 2024 [redacted].

A. Overview of PG&E's Banked REC Proposal

PG&E explains in testimony that its forecasted RPS-eligible generation in 2026 will fall short of its annual RPS compliance requirement. Therefore, it expects to use [redacted] banked RECs to meet the minimum Retained RPS requirement.[63] According to its historical net RPS position, PG&E has RECs available that were generated and banked during the years [redacted].[64] To cover its minimum Retained RPS requirement in 2026, PG&E proposes to first use RECs generated in and after 2019 (**Post-2018 Banked RECs**). After its Post-2018 Banked RECs are exhausted PG&E proposes to then use Pre-

[63] PG&E Prepared Testimony, at 8-19, lines 2-4, and at 8-20, Table 8-4.
[64] *Id.*, at Table 8-3.

2019 Banked RECs. PG&E's proposed use of Post-2018 Banked RECs and Pre-2019 Banked RECs covers only the RECs that were counted as Retained RPS, even though they were excess, when they were generated. PG&E also has RECs that were counted as Unsold RPS in 2023 and 2024 which were valued at $0 when they were generated. According to PG&E these RECs would only be used after all of the Post-2018 Banked RECs and Pre-2019 Banked RECs are exhausted.[65]

If *Post-2018 Banked RECs* are used, PG&E proposes to apply the 2026 RPS Adder to value the RECs and apply the credit to the PCIA vintage matching the year the REC was generated. However, if *Pre-2019 Banked RECs* are used, PG&E proposes to apply the 2026 RPS Adder but argues that the credit should only be given to the most recent PCIA vintage (i.e., 2026) so that the PCIA credit and the ERRA debit fully offset each other and zero value is passed back to departed load customers.[66]

CalCCA agrees with PG&E's proposal to first use RECs generated in and after 2019 to cover its minimum Retained RPS shortfall in 2026. CalCCA also agrees with PG&E's proposal to credit the PCIA vintage corresponding to the year the REC was generated because the Post-2018 Banked REC was counted as Retained RPS when it was generated. However, CalCCA disagrees with PG&E's proposal to credit only the most recent PCIA vintage if Pre-2019 Banked RECs are used. CalCCA also disagrees with PG&E's proposal to skip over Unsold RPS from 2023 and 2024, [redacted] requiring the Commission to address the valuation of Pre-2019 Banked RECs in this case.

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65 *Id.*, at 8-19, lines 5-14.

66 *Id.*, at 8-19, lines 18-23 and footnote 32.

B. Valuing banked RECs for the PCIA has been raised in several regulatory proceedings.

Prior to D.19-10-001, all PCIA-eligible RPS generation was recognized as either being sold to third parties or retained by then-bundled customers and valued at the RPS Adder. Pursuant to D.19-10-001, effective beginning 2019, RPS-eligible generation that is not retained for compliance or sold to third parties counts as Unsold RPS and is valued at $0 in the PCIA.[67]

In D.21-05-030, the Commission adopted the voluntary allocation and market offer (**VAMO**) process for PCIA-eligible RPS resources. Under VAMO, LSEs in PG&E's service territory, including PG&E, were able to elect to receive an allocation of energy from eligible RPS resources in PG&E's portfolio. Unallocated RPS energy was then made available for sale through a market offer process. One consequence of VAMO is that PG&E has less RPS-eligible generation available in its PCIA resource portfolio to use for RPS compliance and to count toward Retained RPS requirements for its bundled customers.

The Commission determined in D.20-02-047 that the annual RPS compliance target is the minimum quantity of RPS generation that must be recognized as Retained RPS and credited to the PCIA annually.[68] If the RPS-eligible generation available to PG&E is less than its annual RPS compliance requirement for bundled customers, PG&E must use banked RECs to make up the difference and ensure that departed load customers receive their share of the REC value.

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[67] D.19-10-001, OP 2 and Attachment B, Table I.

[68] D.20-02-047, *Decision Adopted PG&E's 2020 ERRA Forecast and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation*, A.19-06-001 (Feb. 28, 2020), at 13-14.

The question of how to value banked RECs used to meet the minimum compliance requirement has a five-year-old, multi-proceeding history that includes the Commission's 2017 PCIA rulemaking proceeding (R.17-06-026), a petition to modify D.23-06-006[69] coming out of that proceeding, PG&E's past four ERRA Forecast proceedings, SCE's past three ERRA Forecast proceedings, and SDG&E's last ERRA Forecast Proceeding. The question has been answered inconsistently across those proceedings, and PG&E's latest proposal to deny departed customers the value of RECs for which they paid is itself a departure from its own Commission-approved approach in previous cases.

PG&E's ERRA Forecast Cases: PG&E has used the approach endorsed by CalCCA for valuing banked RECs in its ERRA Forecasts since 2023, including its 2023 ERRA Forecast (A.24-05-009),[70] 2024 ERRA Forecast (A.23-05-012),[71] and 2025 ERRA Forecast (A.24-05-009). [72] In each of these proceedings PG&E's forecasted RPS generation, after accounting for the VAMO process, was less than the annual RPS compliance obligation. In each proceeding PG&E used banked RECs to make up the difference and in each proceeding PG&E applied a credit to the PCIA vintage matching the year the banked RECs were generated.

In its 2023 ERRA Forecast testimony PG&E explained that in previous years its ERRA revenue requirement was calculated to recover the full RPS market value associated with its annual RPS generation volumes, even if the volume exceeded the annual RPS

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[69] D.23-06-006, *Decision Addressing Greenhouse Gas-Free Resources, Long-Term Renewable Transactions, Energy Index Calculations, and Energy Service Providers' Data Access*, R.17-06-026 (June 8, 2023).

[70] A.22-05-029, PG&E 2023 ERRA Forecast Prepared Testimony, at 11-13 through 11-21.

[71] A.23-05-012, PG&E 2024 ERRA Forecast Prepared Testimony, at 9-17 through 9-24.

[72] A.24-05-009, PG&E 2025 ERRA Forecast Fall Update Testimony, at 9.

compliance requirement.[73] As a result, all of PG&E's banked RECs through that point were paid for by customers who received bundled service in the year the RECs were generated.[74] PG&E explained, "It is precisely those customers that earlier procured surplus RPS generation who will benefit from an accounting adjustment for 2023 ratesetting."[75] Accordingly, PG&E credited the PCIA vintages corresponding to the years in which the banked RECs were generated by applying the then-current forecast RPS Adder to the quantity of banked RECs utilized.

In September 2023, while the 2024 ERRA Forecast cases were pending, SCE filed a petition for modification (**PFM**) of D.23-06-006 seeking clarification regarding the valuation of Pre-2019 Banked RECs. Because SCE's PFM was pending, the Commission adopted an interim method for valuing banked RECs in PG&E's 2024 ERRA Forecast proceeding, requiring PG&E "to use a First-In-First-Out methodology for RECs banked in or after 2019, beginning with RECs that were generated in 2018."[76] PG&E was required to apply the interim process in 2024 as well as in its 2025 ERRA Forecast application unless the Commission resolved the PFM prior a decision is reached on the PFM. As a result of D.23-12-022 PG&E used Banked RECs generated in 2018 to meet the minimum RPS requirement in its 2024 ERRA Forecast and 2025 ERRA Forecast proceedings. In

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[73] A.22-05-029, PG&E 2023 ERRA Forecast Prepared Testimony, at 11-14, lines 10-21.

[74] *Id*., at 11-16, lines 28-33.

[75] *Id*., at 11-17, lines 1-4.

[76] D.23-12-022, *Decision Adopting the Electric Revenue Requirements and Rates Associated with the 2024 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation and the 2024 Electric Sales Forecast for Pacific Gas and Electric Company as Well as the Resolution of the 2023 Trigger Application for an Undercollection of the Energy Resource Recovery Account,* A.23-05-012, et al., (Dec. 14, 2023), at 17.

both cases, PG&E used the then-current RPS Adder to calculate the credit it applied to PCIA vintage 2018.[77]

<u>SCE's ERRA Forecast Cases:</u> In its 2023 ERRA Forecast case, SCE determined that it needed to use banked RECs for Retained RPS and proposed to first use Post-2018 Banked RECs, valued at the Forecast RPS Adder, "as an interim methodology that may be subject to further refinement in future years."[78] In D.22-12-012, the Commission adopted SCE's proposal for purposes of the 2023 forecast and noted that the scope of the pending 2017 PCIA rulemaking proceeding included consideration of whether to modify the PCIA for VAMO transactions.[79]

In SCE's 2024 ERRA Forecast case the Commission adopted an interim method for valuing banked RECs that would apply "until or unless a decision is reached on the PFM."[80] That methodology broke with the methodology approved in PG&E's service territory, allowing SCE to value Pre-2019 Banked RECs at zero on an interim basis after SCE exhausted its Post-2018 Banked RECs. In D.23-11-094, the Commission agreed the issue of valuing Pre-2019 Banked RECs "would not be appropriately addressed in a single IOU's annual ERRA Forecast Application" and therefore only adopted an interim solution for that 2024 forecast.[81]

In SCE's 2025 ERRA Forecast, CalCCA recommended SCE be required to continue adhering to the directive from D.23-11-094 requiring it to first use Post-2018

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77 *See* A.23-05-012, PG&E Fall Update Testimony, at 81, Table 9-10. *See also* A.24-05-009, PG&E Fall Update Testimony, at 55, Table 10-5.

78 A.22-05-014, SCE-05, at 123:19-24 (October 10, 2022).

79 D.22-12-012, *Decision Adopting SCE's 2023 ERRA Forecast*, A.22-05-014 (Dec. 5, 2022), at 60-61.

80 D.23-11-094, *Decision Adopting SCE's 2024 ERRA Forecast*, A.23-06-001 (Dec. 1, 2023), at 53.

81 *Id.*, at 60.

Banked RECs and value those RECs at the RPS Adder. Valuing Pre-2019 Banked RECs was not an issue in that proceeding. In D.24-12-039 the Commission approved SCE's treatment of RPS resources "as proposed *for this proceeding*."[82] Here again, the question of whether to value Pre-2019 Banked RECs again was not resolved for SCE.

SDG&E's ERRA Forecast Case: In its 2025 ERRA Forecast, SDG&E filed rebuttal testimony indicating that it agreed with the Joint CCAs' recommendation to calculate the REC market value based on SDG&E's minimum RPS requirement and that banked RECs should be valued at the Forecasted RPS Adder. Like PG&E, SDG&E's bundled customers had previously paid for the banked RECs, so SDG&E proposed to credit the PCIA for the difference between the 2025 RPS Adder and the RPS Adder paid at the time the RECs were generated. In SDG&E's October Update the revised forecast for 2025 did not require the use of banked RECs, so the issue was moot for that case.

SCE's Petition for Modification: In D.24-08-004, the Commission denied SCE's PFM but modified D.23-06-006 to state simply, "The Commission provided direction for the treatment of banked RECs in D.19-10-001."[83] The Commission stated further: "While we recognize that parties have different perspectives about the direction in D.19-10-001 and its applicability to pre-2019 RECs, we do not have the record to fully evaluate them here. We may consider the issue in a future rulemaking. It is reasonable to deny [SCE's] Petition."[84]

Interpretation of D.19-10-001: PG&E's testimony in the current proceeding states that D.19-10-001 orders it to apply the current RPS Adder to any Post-2018 Banked RECs

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[82] D.24-12-039, at 68.

[83] D.24-08-004, *Decision Denying Petition for Modification of Decision 23-06-006*, R.17-06-026 (Aug. 1, 2024), at 5.

[84] *Ibid.*

used to meet RPS compliance and to credit customers based on their PCIA vintage so that departed load receives a share of the value.[85] PG&E then argues that "D.19-10-001 excluded [Pre-2019 Banked RECs] from receiving any additional ratemaking treatment associated with bundled RPS compliance."[86] Notwithstanding its testimony, PG&E proposes a scheme to apply the value of Pre-2019 Banked RECs to the latest PCIA vintage such that only bundled customers receive the credit as an offset to the cost Retained RPS in the ERRA.[87]

To be clear, PG&E offers no compelling policy reason for its proposal to deny unbundled customers the benefits to which they are entitled: it only points to D.19-10-001. However, D.19-10-001 requires all RECs forecasted to be used towards bundled customer compliance in any given year to be valued at the RPS benchmark and credited to the PCIA.[88] That requirement applies to <u>all</u> Forecast Retained RPS; D.19-10-001 does not draw any distinction between the treatment of Pre-2019 Banked RECs and Post-2018 Banked RECs (*i.e.*, Unsold RPS) when those RECs are eventually applied towards bundled customer compliance. That outcome is consistent with California Public Utilities Code Section 366.2(g), which requires unbundled customers receive "the value of any benefits that remain with bundled service customers;"[89] an issue CalCCA will address more extensively in briefing.

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85 PG&E Prepared Testimony, at 8-19, lines 14-18.
86 *Id.,* at 8-19, lines 18-23.
87 *Id.,* at 8-19, lines 18-23 and footnote 32.
88 D.19-10-001, at Attachment B.
89 Cal. Pub. Util. Code § 366.2(g).

C. Pre-2019 Banked RECs used for RPS compliance should be valued at the RPS Adder and credited to the Indifference Amount using a "First-in, first-out" methodology.

CalCCA agrees with PG&E's assessment in its 2026 ERRA Forecast that it does not have sufficient forecasted RPS-eligible generation in 2026 and needs to use banked RECs to ensure Retained RPS is at least equal to the annual RPS compliance target. However, CalCCA disagrees with PG&E's proposal to "credit applicable ERRA Forecast year vintage customers regardless of delivery year" if Pre-2019 Banked RECs are used.[90]

Stated simply, PG&E's current bundled customers in 2026 should be responsible for the cost of RPS compliance on their behalf in 2026. And unbundled customers should receive credit for the value of RPS attributes they previously paid for but that are now being used for bundled customer RPS compliance. If previously banked RECs are used for current bundled customer RPS compliance, then it is critical to properly value them in PG&E's Indifference Amount and resulting PCIA rates. This ensures that the cost of bundled customer compliance is not shifted to departed load customers and that the value of resources departed load customers paid for originally is received.

Customers who received bundled service when Pre-2019 Banked RECs were generated paid for the RECs as a retained resource in the PCIA. In the present day, the current group of bundled customers will extract the value they paid for by using the Pre-2019 Banked RECs for compliance. Absent a credit through the PCIA, however, customers who departed after the RECs were banked get no benefit for what they paid when the RECs were generated. This means that, to ensure departed load customers receive the value of resources they originally paid for, current bundled customers should be required to credit

[90] PG&E Prepared Testimony, at 8-19, lines 18-21.

those departed customers for the use of RECs the departed customers purchased when they were still bundled customers.

As noted earlier, PG&E proposes in testimony that Pre-2019 Banked RECs will be credited to the PCIA vintage corresponding to the current ERRA Forecast year at the value of the current applicable RPS Adder MPB. While CalCCA agrees that Pre-2019 Banked RECs should be valued at the current RPS Adder, CalCCA disagrees with that credit being applied to the current ERRA Forecast year vintage. By crediting the current year vintage rather than the vintage corresponding to the year the REC was generated, PG&E fails to acknowledge that many of the customers that paid for the RECs when they were generated have now departed PG&E bundled service. Those now-departed customers should bear no cost responsibility for PG&E's RPS compliance on behalf of today's bundled customers. It is fundamentally unfair to count RECs generated in prior years and paid for by now-departed customers toward RPS compliance for current bundled customers without a credit back to departed customers for the value of the RECs.

To properly credit now-departed load customers for the value of RECs they originally paid for, the current RPS Adder must be applied to all banked RECs used for RPS compliance, including Pre-2019 Banked RECs, as a credit to the PCIA. The PCIA credit should be recorded to the PCIA vintage corresponding to the year the RECs were generated to ensure that customers who departed bundled service after the REC was generated receive their share of the value of the RECs now being used for bundled customers.

CalCCA recommends the Commission direct PG&E to modify its proposed treatment of Pre-2019 Banked RECs in this case so that the cost of the RPS compliance for current bundled customers is not shifted to departed load customers. Specifically, CalCCA recommends the following:

- To the extent PG&E must use Pre-2019 Banked RECs to meet its minimum annual RPS compliance requirement, the Pre-2019 Banked RECs should be valued using the RPS Adder in the year the banked REC is used;
- Pre-2019 Banked RECs should be utilized on a first-in-first-out basis so that credit is provided to now-departed customers who paid for the banked RECs earliest; and
- The value of Pre-2019 Banked RECs used to meet the RPS compliance shortfall should be a credit to the PCIA with an offsetting charged to bundled customers' generation costs (i.e., ERRA). The PCIA credit should be recorded to the PCIA vintage corresponding to the year the REC was generated and banked.

D. Departed load customers paid for a portion of the Pre-2019 Banked RECs and they should receive a credit for the REC value.

Applying credit to the PCIA vintage corresponding to the year the Pre-2019 Banked REC was generated and banked results in a net payment from bundled customers to now-departed customers for the portion of the banked RECs previously paid for by now-departed load customers. After considering the net effect of charges to ERRA and credits to the PCIA, current bundled customers would be fairly compensating now-departed load customers for the portion of the Pre-2019 Banked RECs generated on their behalf and used for current bundled service compliance.

In each year since 2013, additional customer load in PG&E's service territory has departed bundled service. Table 7 uses the sales forecast in the current proceeding to distinguish PG&E's system sales by bundled vs unbundled service and customer vintage.

According to PG&E's vintage sales data, roughly 87 percent of PG&E's system received bundled service in 2013. In 2026 PG&E projects approximately 32 percent of its system will receive bundled service.

Table 7: PG&E 2026 System Sales by Customer Vintage (MWh)

PCIA Vintage	Bundled	Departed	Total System	% Bundled
2013	68,447,069	10,039,076	78,486,145	87%
2014	67,534,534	10,951,611	78,486,145	86%
2015	65,639,298	12,846,847	78,486,145	84%
2016	65,393,001	13,093,144	78,486,145	83%
2017	58,758,778	19,727,367	78,486,145	75%
2018	46,453,885	32,032,260	78,486,145	59%
2019	36,678,603	41,807,542	78,486,145	47%
2020	34,492,530	43,993,615	78,486,145	44%
2021	31,225,581	47,260,564	78,486,145	40%
2022	29,030,908	49,455,237	78,486,145	37%
2023	28,624,970	49,861,175	78,486,145	36%
2024	28,176,001	50,310,144	78,486,145	36%
2025	28,139,821	50,346,324	78,486,145	36%
2026	25,055,466	53,430,679	78,486,145	32%

From 2013 through 2022 customers receiving bundled service at the time RECs were generated paid for the RECs through generation rates. As shown in Table 8, comparing the current bundled sales volume to the bundled sales in years going back to 2013 demonstrates that customers who received bundled service in previous years, but have since departed, paid for a significant portion of PG&E's banked RECs each year.

Table 8: Current Bundled Sales Versus Bundled Sales in Prior Years

PCIA Vintage	Current Bundled MWh	Previously Bundled/Now Departed MWh	Total Bundled MWh by Vintage Year	% Current Bundled	% Previously Bundled
2013	25,055,466	43,391,602	68,447,069	37%	63%
2014	25,055,466	42,479,067	67,534,534	37%	63%
2015	25,055,466	40,583,831	65,639,298	38%	62%
2016	25,055,466	40,337,535	65,393,001	38%	62%
2017	25,055,466	33,703,312	58,758,778	43%	57%
2018	25,055,466	21,398,419	46,453,885	54%	46%
2019	25,055,466	11,623,137	36,678,603	68%	32%
2020	25,055,466	9,437,064	34,492,530	73%	27%
2021	25,055,466	6,170,115	31,225,581	80%	20%
2022	25,055,466	3,975,441	29,030,908	86%	14%
2023	25,055,466	3,569,503	28,624,970	88%	12%
2024	25,055,466	3,120,535	28,176,001	89%	11%
2025	25,055,466	3,084,355	28,139,821	89%	11%
2026	25,055,466	-	25,055,466	100%	0%

Now-departed customers paid for the portion of RECs in each year as listed under "% Previously Bundled" in the table above. For example, now-departed customers paid 63 percent of the cost of the RECs generated in 2013, including 63 percent of the RECs that were banked and are now available to be used for compliance on behalf of current bundled customers. If the banked RECs now needed for Retained RPS requirements were already paid for by customers in previous years, the banked REC credit should be applied to the PCIA vintage corresponding to the year the RECs were generated. In this way, customers who were bundled at the time the RECs were generated, but who have since departed bundled service, would receive credit for the value of the RECs now being used for current bundled customers.

Crediting the PCIA for the value of banked RECs that were paid for by bundled customers in prior years does not result in a double charge to today's bundled customers. Rather, after considering the net effect of charges to ERRA and credits to the PCIA, current bundled customers would only be charged for the banked RECs previously paid for by now-departed customers. The now-departed customers receive credit for the value of RECs counted as Retained RPS on behalf of current bundled customers, leaving the now-departed customers indifferent relative to current bundled customers. To be clear, those departed customers do not receive *all* of the value of banked RECs that were paid for by then-bundled customers—they receive only a proportional amount. The Commission has employed this type of policy – crediting customers through the PCIA for refunds or credits for which they are owed – in numerous places in ERRA proceedings.[91]

The following figures illustrate the payments and credits that should be recognized if RECs generated and banked in 2013 in PG&E's service territory are needed to meet bundled customers' RPS compliance obligations in 2026.

Figure 8: Banked RECs are Generated and Paid For in 2013

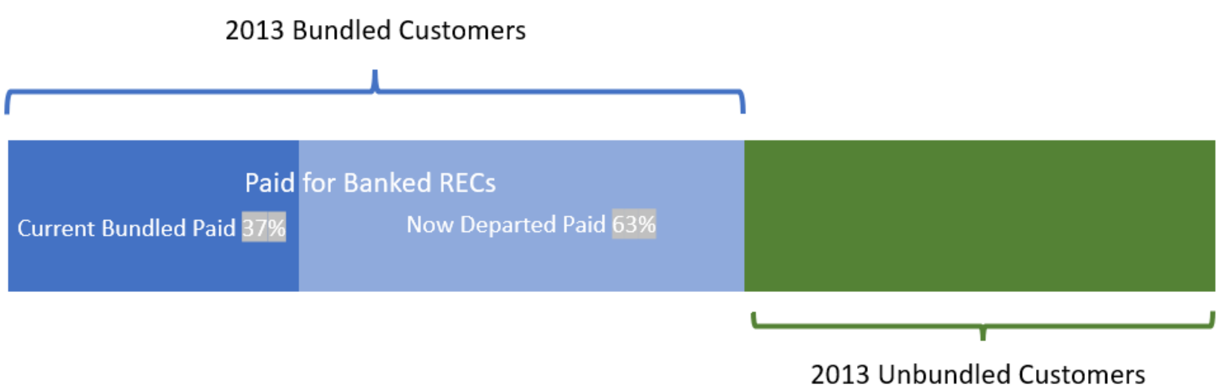
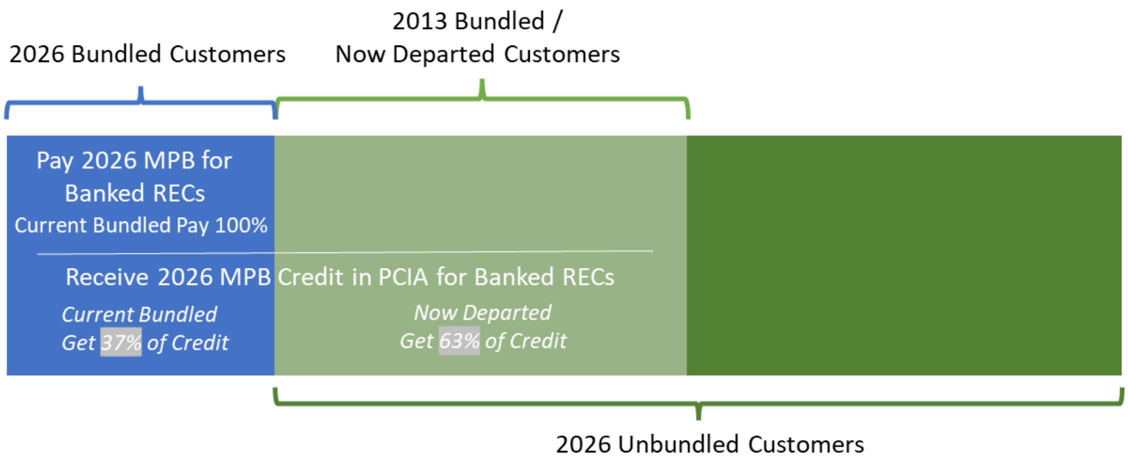


Figure 8 shows that all bundled customers in 2013, including now-departed customers that left PG&E's service after 2013 (the light blue portion above), paid a portion of the cost of the RECs that were banked in 2013. An offsetting credit was applied in the PCIA and shared between all bundled and unbundled customers.

Figure 9: Banked RECs are Used for Retained RPS in 2026



Customers who were bundled during 2013 and have since departed PG&E's bundled service can no longer use the banked RECs. Figure 9 demonstrates that if RECs banked in 2013 are used for RPS compliance in 2026, current bundled customers (the dark blue portion) should pay the MPB for those RECs, and the value of the RECs should be credited to PCIA vintage 2013. By crediting PCIA vintage 2013, the credit is shared by today's bundled customers and unbundled customers who received bundled service in 2013, but not by customers who departed prior to 2013. Customers who departed after 2013 (the light green portion) are credited at today's MPB at the current value of the RECs, and they receive the same percentage of the credit as the percentage of the total cost they paid in 2013. Bundled customers also receive a percentage of the Retained RPS credit at the current value of the RECs – the same percentage of the total cost for the RECs those

[91] For example, in D.22-01-023, *Decision Resolving Phase 2 Issues Related to Energy Resources Recovery Account Proceedings*, R.17-06-026 (Jan. 27, 2022), the Commission directed that prior year under- or over-recovery balances in IOU ERRA balancing accounts should be transferred to the most-recent vintage subaccount of PABA to facilitate recovery or refund to customers.

customers paid in 2013. None of the customers that were already departed in 2013 would receive an additional "double" credit. Those customers already received a credit in 2013 and it would not be fair to credit them again in 2025. However, for now-departed customers that were bundled customers in 2013, crediting the value of banked RECs to the PCIA using the 2026 RPS Adder ensures that those customers are indifferent to bundled customers' use of banked RECs for which now-departed customers paid for but can no longer use.

Because bundled and unbundled customers all pay a share of the PCIA revenue requirement based on their vintaged load share, credits to the PCIA are also shared between bundled and departed load customers. The following quantitative example demonstrates the net charge to bundled customers for using banked RECs, after considering their share of the PCIA credit. If PG&E needs 100 GWh of Banked RECs to count toward its 2026 RPS compliance target and those banked RECs were generated in 2013, PG&E should credit PCIA vintage 2013 for the value of the banked RECs using the 2026 RPS Adder. Applying the filed RPS Adder MPB of $71.24/MWh, the PCIA vintage 2013 credit would be $7.1 million. As shown in Table 9 below, bundled customer generation rates would include a Retained RPS charge of $7.1 million, but they would also receive a $2.6 million share of the credit to the PCIA. The resulting $4.5 million net charge represents the value paid to departed load customers in exchange for use of the banked RECs from 2013.

Table 9: Banked REC Example – Net Charge to Bundled Customers

Item	Amount
RPS Adder MPB ($/MWh)	$71.24
Banked RECs Used (GWh)	100
Banked REC Value Credit to PCIA ($000)	($7,124)
Departed Load Share ($000)	($4,539)
Bundled Load Share ($000)	($2,585)
Bundled Charge to ERRA ($000)	$7,124
Net Charge to Bundled Customers ($000)	**$4,539**

Furthermore, the credit to the PCIA should be valued using the RPS Adder in the year the RECs are used for bundled customer compliance. When the banked RECs were paid for through the PCIA, a net credit was conveyed to unbundled customers at the time. But for bundled customers, the charge and credit for their share of the RECs were offsetting and the RECs were stored for later use. When used, current bundled customers will extract the contemporaneous value of the RECs by using them for compliance. Now departed customers should also receive the contemporaneous value of the REC through the PCIA credit priced at the current RPS Adder.

E. The value of Pre-2019 Banked RECs should be credited to PCIA vintages based on the year the RECs were generated.

To ensure that customers are not double-credited for RECs generated in a prior year, the value of Pre-2019 Banked RECs should be credited to PCIA vintages based on the year the RECs were generated. Table 10 below provides details of PG&E's REC bank, showing annual deposits and withdrawals since 2013, including PG&E's projection for

2026.[92] For the 2026 ERRA Forecast, PG&E projects it will need to use banked RECs from [redacted] to meet its minimum RPS requirement.

Table 10: Banked REC Deposits and Withdrawals by Year

	REC Bank Deposits (MWh)		REC Withdrawals by Year (MWh)					Remaining in Bank (MWh)
Year	**Pre-2019**	**Post-2018**	**2019**	**2023**	**2024**	**2025**	**2026**	**Total**
2013	1,928,480					[redacted]	[redacted]	[redacted]
2014	3,980,017					[redacted]	[redacted]	[redacted]
2015	4,482,478					[redacted]	[redacted]	[redacted]
2016	5,379,425					[redacted]	[redacted]	[redacted]
2017	3,704,274					[redacted]	[redacted]	[redacted]
2018	4,773,405				(3,020,978)	[redacted]	[redacted]	[redacted]
2019		0	(701,826)			[redacted]	[redacted]	[redacted]
2020		445,318				[redacted]	[redacted]	[redacted]
2021		5,399,732		(3,211,076)	(2,188,656)	[redacted]	[redacted]	[redacted]
2022		1,322,452		(786,427)	(536,025)	[redacted]	[redacted]	[redacted]
2023		0				[redacted]	[redacted]	[redacted]
2024		0				[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]				[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]				[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	**(701,826)**	**(3,997,503)**	**(5,745,659)**	[redacted]	[redacted]	[redacted]
RPS Adder ($/MWh)							71.24	
REC Value ($000)							[redacted]	

Based on the accounting in Table 10, a total credit of [redacted] should be included as a reduction to the 2026 Indifference Amount forecast to reflect the value of banked RECs needed in 2026. PG&E's testimony discusses applying the current RPS Adder to the Post-2018 Banked RECs generated in [redacted] and applying that credit to the [redacted] PCIA vintage. PG&E must also apply this treatment to the Pre-2019 Banked RECs from [redacted]. Table 11 below breaks down the total credit into the PCIA vintages corresponding to the banked RECs used each year and the bundled and departed load customers' share of these credits as recommended by CalCCA. As shown in Table 11, the

[92] *See* Workpaper: ERRA_2026_Forecast_WP_PGE_20250515_Tables_8-2_8-3_8-4_CONF.

[redacted] credit for 2026 would be allocated between PCIA Vintages [redacted] according to the number of RECs used from each generation year.

Table 11: CalCCA Recommended – Banked REC Credit by Vintage

	REC Bank Withdrawals by Year (MWh)		Total PCIA Credit by Vintage	Bundled Customer Share of Credit	Departed Load Customer Share of Credit
Year	**2026**	**PCIA Vintage**	**2026 PCIA Credit ($000)**	**2026 PCIA Credit ($000)**	**2026 PCIA Credit ($000)**
2013	[redacted]	2013	[redacted]		
2014		2014			
2015		2015			
2016		2016			
2017		2017			
2018		2018			
2019		2019			
2020		2020			
2021		2021			
2022		2022			
2023		2023			
2024		2024			
2025		2025			
2026		2026			
Total		**Total**			

PG&E proposes in its testimony to credit the value of the Pre-2019 Banked RECs to PCIA vintage 2026 and to credit the value of the Post-2018 Banked RECs to the PCIA vintage year in which the RECs were generated. Table 12 below shows the REC credit share by vintage under PG&E's proposal.

Table 12: PG&E Proposal – REC Credit Share by Vintage

Year	REC Bank Withdrawals by Year (MWh) 2026	PCIA Vintage	Total PCIA Credit by Vintage 2026 PCIA Credit ($000)	Bundled Customer Share of Credit 2026 PCIA Credit ($000)	Departed Load Customer Share of Credit 2026 PCIA Credit ($000)
2013	[redacted]	2013	[redacted]	[redacted]	[redacted]
2014	[redacted]	2014	[redacted]	[redacted]	[redacted]
2015	[redacted]	2015	[redacted]	[redacted]	[redacted]
2016	[redacted]	2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	2019	[redacted]	[redacted]	[redacted]
2020	[redacted]	2020	[redacted]	[redacted]	[redacted]
2021	[redacted]	2021	[redacted]	[redacted]	[redacted]
2022	[redacted]	2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	2026	[redacted]	[redacted]	[redacted]
Total	[redacted]	**Total**	[redacted]	[redacted]	[redacted]

Correcting the vintage assignment for Pre-2019 Banked RECs increases the credit to departed load customers by [redacted] compared to PG&E's proposal. PG&E should credit the PCIA vintage years in which all Banked RECs (Pre-2019 Banked RECs and Post-2018 Banked RECs) were generated, while valuing them at the RPS Adder of the year in which the RECs are used to ensure departed load customers are properly credited for resources they paid for but are used by bundled customers.

F. PG&E should use its Unsold RPS from 2023 and 2024 to meet the minimum RPS requirement in 2026.

In the 2024 ERRA Forecasts, the Commission prioritized using RECs banked from 2019 or later because there was no dispute about how to value those RECs. The Commission could follow a similar path here. As an alternative to relying on Pre-2019

Banked RECs in the current proceeding, PG&E could first use the remaining Unsold RPS it recorded in 2023 and 2024 to count toward its minimum RPS requirement in 2026.

In 2023 and 2024, some of PG&E's RPS generation offered through the VAMO process went unsold; therefore, PG&E began to track Unsold RPS as defined in D.19-10-001.[93] In testimony, PG&E proposes to use the Unsold RPS from those years only after it exhausts Pre-2019 Banked RECs and only if it does not sell the RECs to third parties.[94] PG&E indicates it will use those RECs last because it may try to sell them to benefit all customers. The RECs at issue can be seen in Table 13 below.

Table 13: PG&E Unsold RPS

Year	Unsold RPS (MWh)
2013	0
2014	0
2015	0
2016	0
2017	0
2018	0
2019	0
2020	0
2021	0
2022	0
2023	3,409,455
2024	349,104
2025	0
2026	0
Total	**3,758,559**

Consistent with the interim method adopted in PG&E's 2024 ERRA Forecast, the Commission could require PG&E to meet its 2026 compliance shortfall by using the Unsold RPS from 2023 and 2024 before relying on Pre-2019 Banked RECs. Because these RECs have not been previously paid for (i.e., they were counted as Unsold RPS in 2023 and 2024 with a $0 value applied consistent with D.19-10-001) the corresponding PCIA

93 PG&E Prepared Testimony, at 8-17, Table 8-2.
94 *Id.*, at 8-19, lines 11-14.

credit would be spread to all vintages according to the RPS generation in each vintage. In this way, counting the Unsold RPS toward PG&E's Retained RPS in 2026 would benefit all customers by including a credit in the PCIA; however, bundled customers would also be required to pay for the RECs used for compliance purposes. For these reasons, CalCCA recommends that all RECs generated in 2019 or later, including Unsold RPS from 2023 and 2024, should be counted toward PG&E's minimum RPS requirement before using Pre-2019 Banked RECs.

VI. PG&E'S ASSUMPTION THAT NEW DATA CENTER LOAD WILL BE SERVED BY CCAS IS APPROPRIATE

PG&E describes in testimony that new as of this year it is explicitly incorporating into its Sales and Peak Demand forecasts the impacts of new large data center load in its service territory.[95] While PG&E's testimony and supporting workpapers identify the data center energy and peak demand forecasts, they do not explain whether the new load will receive bundled service from PG&E, be served by a CCA, or take direct access from an energy service provider.

In discovery PG&E clarified that it identified a theoretical maximum demand of 518.5 MW in 2026 based on max load requests from new data center customer interconnection applications.[96] After applying a 70 percent application conversion rate and assumed capacity utilization and load factors, that maximum demand translates in to 1,474 GWh sales from approximately 17 data centers.[97] Generally, PG&E assumes that data centers located in CCA service territories will be served by the CCA. Specifically, PG&E assumes the new load will be served by the CCA after applying an opt-out rate of 13

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95 PG&E Prepared Testimony, at 2-11, line 12 through page 2-12, line 4.

96 PG&E response to CalCCA data request 4.03.

97 PG&E response to CalCCA data requests 4.02, 4.03 and 4.04.

percent, which it says is based on historical industrial customer opt-out rates.[98] PG&E included information about its data center forecast during the meet and confer process with CCAs,[99] and PG&E represents that it included new data center load in the individual CCAs' load forecasts in this case.[100]

CalCCA agrees with PG&E's assumption that new data center load located in CCA service territory will default to CCA service unless the customer opts out. CalCCA has also advocated in other proceedings that CCAs be made aware of new large loads, including potential data center load, in their service territory in a timely manner. For example, the interim decision in A.24-11-007, PG&E's Application for Approval of Electric Rule No. 30 for Transmission-Level Retail Electric Service, directs PG&E to share transmission interconnection applications within 20 business days of receipt.[101] CalCCA is advocating in A.24-11-007 to make that requirement permanent.

VII. REVIEW OF PG&E'S 2025 YEAR-END PABA BALANCE

The PABA is a rolling true-up of the actual above-market costs of PG&E's PCIA-eligible resource portfolio and the amount collected from customers through PCIA rates to recover such above-market costs. Any over- or under-collection in the PABA through the end of 2025 is used to modify the 2025 PCIA revenue requirement, by vintage.

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[98] PG&E response to CalCCA data request 4.05.

[99] PG&E response to CalCCA data request 4.07.

[100] PG&E response to CalCCA data request 4.08.

[101] *See* D.25-07-039, *Decision Partly Granting and Partly Denying Pacific Gas and Electric Company's Motion for Interim Implementation of Electric Rule Number 30*, (July 28, 2025), Finding of Fact 35; COL 14, Ordering Paragraph 7a; *See also* A.24-11-007, PG&E Rebuttal Testimony (August 19, 2025), at 91-92, stating, "Based on discovery responses, PG&E understands that CalCCA interprets the default provider role under California Public Utilities Code Section 366.2(c)(4) to require a CCA to offer universal service to all customers in a CCA's service territory, including both residential and non-residential (e.g. transmission-level) customers. PG&E agrees with this interpretation and understands that, unless a potential transmission-level customer located in a CCA's service area opts out of CCA service, that customer will be provided with generation service by the CCA."

Since its inception, the PABA has been a major contributor to the total PCIA revenue requirement. In addition to being a large contributor to PCIA revenue requirement, the PABA balance has proven to be unpredictable, fluctuating by hundreds of millions of dollars during the pendency of the ERRA application process. Given both the variability and importance of this final balance, CalCCA pays close attention to the monthly PABA and ERRA balance updates and supporting information PG&E is now required to provide throughout the ERRA Forecast application process.

In its Application filed in May 2025, PG&E's projection of the 2025 year-end PABA balance (based on actual results through March 2025 and projections for April through December 2025) indicated that by the end of 2025, the PABA will be under-collected by $1.2 billion.[102] If everything went exactly according to the 2025 ERRA Forecast, the PABA balance would be reduced to $0 by the end of this year. An under-collected PABA balancing account can be the result of many different factors, including lower than expected customer revenues, higher than expected procurement costs, or lower than expected market revenue from resource generation. Evaluating the reasonableness of PG&E's projection that the 2025 PABA will be under-collected by over $1.2 billion requires a comparison of the initial PCIA forecast for 2025 with the latest combination of actual results and projected activity in 2025.

Using data from the 2025 ERRA Forecast and the PABA data provided in the PG&E's Master Data Request to CalCCA, I was able to prepare Table 14 comparing the 2025 PCIA forecast to the 2025 PABA.

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[102] PG&E Prepared Testimony, Chapter 12, Table 12-3. The 2025 year-end PABA balance of $1,194 million excludes proposed transfers from other balancing accounts.

Table 14: 2025 PCIA Forecast Versus 2025 PABA

Line	Category	2025 PCIA Forecast ($000)	2025 PABA Projection ($000)	Variance ($000)	Variance %
1	UOG (GRC) Costs	1,875,656	[redacted]	[redacted]	[redacted]
2	Fuel, Purchased Power, Other Costs	2,533,448	[redacted]	[redacted]	[redacted]
3	**Total Portfolio Costs**	**4,409,104**	[redacted]	[redacted]	[redacted]
4	Brown Power Market Value[1]	[redacted]	[redacted]	[redacted]	[redacted]
5	RPS Market Value[2]	[redacted]	[redacted]	[redacted]	[redacted]
6	RA Market Value[3]	[redacted]	[redacted]	[redacted]	[redacted]
7	**Total Market Value**	**(5,379,422)**	[redacted]	[redacted]	[redacted]
8	**Indifference Amount**	**(970,318)**	[redacted]	[redacted]	[redacted]
9	Misc Adjustments		[redacted]	[redacted]	[redacted]
10	**Adjusted PCIA Revenue Requirement**	**(970,318)**	[redacted]	[redacted]	[redacted]
11	Customer Revenue	306,410	[redacted]	[redacted]	[redacted]
12	**Subtotal Under/(Over) Recovery**	**(663,908)**	[redacted]	[redacted]	[redacted]
13	2024 PABA Ending Balance	807,116			
14	2024 ERRA Ending Balance	(143,836)			
15	Miscellaneous	628			
16	**Total Under/(Over) Recovery**	**0**	**279,531**		
17	**2025 PABA**				
18	Beginning Balance		914,052		
19	Activity		279,531		
20	**Ending Balance**		**1,193,583**		

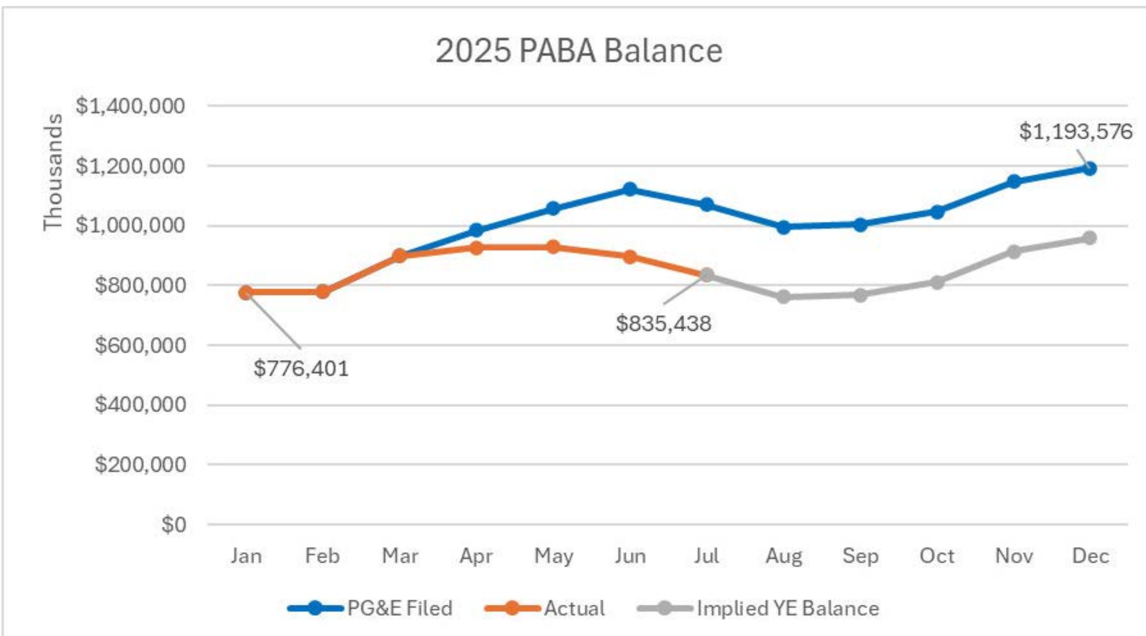
PG&E's testimony includes a description of the drivers it identified as causing the large projected overcollection in the 2025 PABA.[103] My analysis shows that the largest contributor to the undercollection is a decline in the market value of energy by over [redacted]

[103] PG&E Prepared Testimony, at 12-10, line 1 through page 12-13, line 19.

[redacted] due to lower market prices. This is offset by lower procurement costs of [redacted].

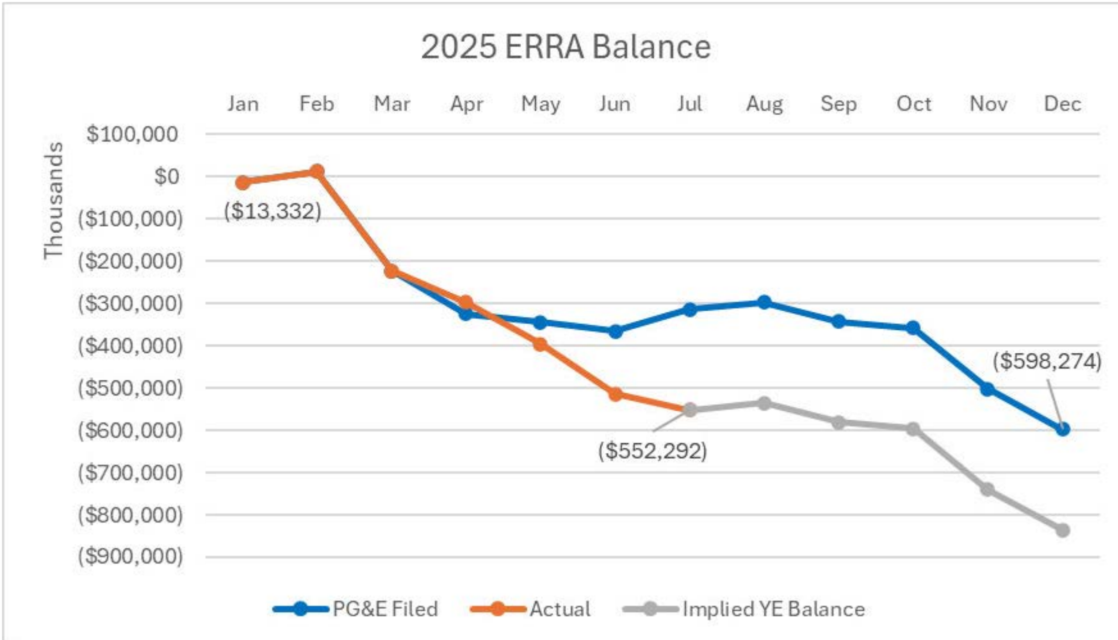
Thus far, PG&E's actual 2025 PABA balance has remained lower than expected. Actual results through July 2025 showed that the PABA balance was now under-collected by $835 million, $235 million lower than PG&E projected for June 2025. Figure 10 illustrates the variability in the monthly PABA balance in 2025 and the deviation of the actual balance from the forecast included in PG&E's Application.

Figure 10: PG&E Monthly PABA Balance



On the other hand, PG&E's 2025 ERRA balancing account, which tracks the difference between the market cost to serve bundled load and revenue collected through bundled generation rates, is expected to be significantly over-collected by the end of 2025 due to the lower-than-expected wholesale market prices in 2025. Figure 11 illustrates the variability in the monthly ERRA balance in 2025 and the deviation of the actual balance from the forecast included in PG&E's Application.

Figure 11: PG&E Monthly ERRA Balance



Because the actual year-end PABA balance will be rolled into PCIA rates in 2026, the large swings in the recorded PABA balance versus the projection PG&E included in its Application will put further upward pressure on the PCIA rates that bundled and unbundled customers ultimately pay. At the same time, including the year-end ERRA over-collection into rates in 2026 will put downward pressure on bundled customers' rates. It remains to be seen whether the summer months of 2025 will reduce the year-to-date under-collected PABA balance in a manner consistent with PG&E's initial expectations.

In June 2025, the Commission issued D.25-06-049, which adopted significant reforms to the RA MPB calculation. The Decision indicates the reform will be applied to the 2026 Indifference Amount as well as retroactively to the 2025 PCIA revenue requirement. On July 28, 2025, CalCCA filed an Application for Rehearing of D.25-06-049, arguing, among other things, that by applying a new methodology for calculating the RA MPB retroactively to the 2025 RA MPB, the Commission commits legal error.

CalCCA specifically argued that changing methodologies between the calculation of the Forecast and the Final 2025 PCIA revenue requirements, the Commission has engaged in unlawful retroactive ratemaking in violation of Public Utilities Code § 728.[104] CalCCA maintains the same position in this Application regarding the utilization of the modified 2025 Final RA MPB and recommends the Commission require PG&E to true-up the 2025 PABA using a 2025 Final RA MPB calculated via the same methodology as the 2025 Forecast RA MPB. CalCCA will discuss this issue in more detail in legal briefing.

This concludes my testimony.

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104 *California Community Choice Association Application for Rehearing of Decision 25-06-049*, R.25-02-005 (July 28, 2025), at 1-2.

Attachment A

Curriculum Vitae of Brian Dickman

BRIAN DICKMAN

Partner

Mr. Brian Dickman is a partner in NewGen's energy practice with over 20 years of utility industry experience. Mr. Dickman's career includes over a decade working for PacifiCorp, a vertically integrated investor-owned utility, including senior-level positions in regulatory, financial, and commercial roles. He began consulting in 2017, assisting a wide array of clients across the United States and internationally, including utilities, large consumers, and private investment firms. Mr. Dickman has extensive experience preparing and evaluating utility revenue requirements and cost allocation studies, developing utility-avoided costs, and analyzing the impact of new initiatives and transactions on a utility and its customers. In addition to his extensive technical experience, Mr. Dickman understands the regulatory governance process, and he has personally testified as an expert witness before state public utility commissions in California, Idaho, Indiana, Oregon, Utah, Washington, and Wyoming.

Mr. Dickman advises numerous Community Choice Aggregator (CCA) clients in California, focusing on regulatory and rate issues such as the state-mandated exit fee known as the Power Charge Indifference Adjustment (PCIA). He also represents California CCAs as a member of the Cost Allocation Mechanism Procurement Review Groups for PG&E and Southern California Edison, which the California Public Utility Commission established to provide an independent review of the centralized procurement of local generation capacity requirements.

CONTACT

225 Union Boulevard, Suite 450
Lakewood, CO 80228
bdickman@newgenstrategies.net
www.newgenstrategies.net

EDUCATION

Master of Business Administration, Finance Emphasis, University of Utah

Bachelor of Science, Accounting, Utah State University

KEY EXPERTISE

Cost of Service and Rates

Financial Analysis and Modeling

Power Charge Indifference Amount

Regulatory Strategy

Revenue Requirement

RELEVANT EXPERIENCE

Electric Cost of Service, Rate Design, and Regulatory Analysis

Mr. Dickman leads projects developing utility revenue requirements, preparing cost of service and rate design studies, and performing financial and regulatory analyses for electric utilities. Mr. Dickman previously held leadership positions at a multi-billion-dollar utility. He interfaced with state regulatory agencies in support of revenue requirements, cost recovery mechanisms, avoided costs, valuations of potential asset acquisitions and other commercial opportunities, and financial impacts of utility initiatives. Mr. Dickman now works with clients and stakeholders to prepare pro forma financial models to determine revenue sufficiency, evaluate the cost of service studies and rate design proposals, and support such proposals before local and state governing bodies. Mr. Dickman's experience also includes evaluating the financial and rate impact of proposed mergers and acquisitions, acquisition and divestiture of utility assets, negotiated retail service contracts, changing business models, and stranded costs due to exiting load. A sample of Mr. Dickman's utility clients includes the following:

- Abu Dhabi Distribution Company, UAE
- Central Coast Community Energy, CA
- City and County of San Francisco, CA
- Clean Power Alliance, CA
- Duke Energy, NC
- East Bay Community Energy, CA
- Hydro One, Ontario, Canada
- Liberty Utilities, CA

NewGen Strategies & Solutions

BRIAN DICKMAN

Partner

Electric Cost of Service, Rate Design, and Regulatory Analysis (cont.)

- Lubbock Power and Light, TX
- Minnesota Power, MN
- New York Power Authority, NY
- Portland General Electric, OR
- San Diego Community Power, CA
- San Jose Clean Energy, CA
- Silicon Valley Clean Energy Authority, CA
- Vermont Gas Systems, VT

Non-Utility Clients

A sample of Mr. Dickman's non-utility clients includes the following:

- Blackstone Group, NY
- California Community Choice Association, CA
- Facebook, CA
- Hemlock Semiconductor, MI
- Newmont Mining, NV
- SABIC Innovative Plastics, IN
- Tri-County Metropolitan Transportation District, OR
- Vistra Energy, TX

Expert Witness and Litigation Support

Mr. Dickman provides comprehensive expert witness testimony related to utility revenue requirements, cost of service, rate design, and other ratemaking issues before state and local regulatory bodies. He has provided litigation support in wholesale and retail jurisdictions, including California, Idaho, Indiana, Oregon, Washington, Wyoming, Utah, the Federal Energy Regulatory Commission, and Ontario Energy Board. Mr. Dickman offers expert witness testimony and litigation support in the following areas.

Revenue Requirement | Cost Allocation | Rate Design

Mr. Dickman prepared revenue requirements, inter-jurisdictional cost allocation, coincident peak allocation studies, and supporting testimony for PacifiCorp over many years. He now provides litigation support and expert testimony for clients wishing to review utility filings on revenue requirements, cost allocation, and rate design, including program-specific rate tariffs.

Power Supply Costs | Stranded Costs | Rate Adjustment Mechanisms

Mr. Dickman has prepared and evaluated variable power supply cost forecasts, power supply cost balancing accounts and other rate mechanisms, stranded costs, and exit fees for departing loads. Since 2019, Mr. Dickman has actively participated in PCIA matters in California on behalf of CCA clients.

Avoided Costs | Resource Valuation

Mr. Dickman provided expert testimony for PacifiCorp on various components included in a proposed method for valuing solar generation resources, the calculation of Public Utility Regulatory Policies Act avoided costs for large resources and support of modifications to the avoided cost calculation for small resources.

BRIAN DICKMAN

Partner

WORKSHOPS AND PRESENTATIONS

Host organizations and the topics Mr. Dickman presented are displayed below.

Advanced Workshop in Regulation and Competition, Center for Research in Regulated Industries, 2018

Customer Choice at a Vertically Integrated Utility
Advanced Workshop in Regulation and Competition, Center for Research in Regulated Industries, 2018

Record of Testimony: **Brian Dickman**

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
1. SCE	A.25-05-008	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	California Community Choice Association	2025
2. PG&E SCE SDG&E	R.25-02-005	Rebuttal testimony addressing resource adequacy market price benchmark calculation for the power charge indifference adjustment	California Public Utilities Commission	California Community Choice Association	2025
3. PG&E SCE SDG&E	A.23-05-012 A.23-07-012 A.23-06-001 A.23-05-013	Expert testimony addressing definition of fixed generation costs and recovery from bundled and unbundled customers	California Public Utilities Commission	California Community Choice Association, San Diego Community Power, Clean Energy Alliance	2024
4. PG&E	A.24-05-009	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	California Community Choice Association	2024
5. SCE	A.24-05-007	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	California Community Choice Association	2024
6. PG&E	A.24-03-018	Expert testimony evaluating allocation of generation benefits during period of extended operations at Diablo Canyon Nuclear Power Plant	California Public Utilities Commission	California Community Choice Association	2024
7. SCE	A.23-06-001	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	California Community Choice Association	2023

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
8. PG&E	A.22-09-018	Expert testimony evaluating customer benefits of a proposal to transfer generation assets to a newly created regulated utility subsidiary	California Public Utilities Commission	California Community Choice Association	2023
9. PG&E	R.23-01-007	Expert testimony proposing new rate design and allocation of generation benefits during period of extended operations at Diablo Canyon Nuclear Power Plant	California Public Utilities Commission	California Community Choice Association	2023
10. Joint IOUs	R.22-07-005	Expert testimony addressing inclusion of stranded costs in newly proposed income graduated fixed charges for residential customers	California Public Utilities Commission	California Community Choice Association	2023
11. SCE	A.12-01-008 A.12-04-020 A.14-01-007	Declaration supporting response to petition for modification of D.15-01-051, addressing changes to optional green tariff program rates	California Public Utilities Commission	Clean Power Alliance, California Choice Energy Authority	2022
12. SCE	A.22-05-014	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Clean Power Alliance, California Choice Energy Authority, and Central Coast Community Energy	2022
13. PG&E, SCE, SDG&E	A.20-02-009 A.20-04-002 A.20-06-001 (Consolidated)	Expert testimony evaluating the unrealized sales volumes and revenue due to Public Safety Power Shutoff events	California Public Utilities Commission	CCA Parties (9 individual CCAs)	2022
14. San Diego Gas & Electric	A.21-09-001	Expert testimony responding to proposed residential electrification tariff	California Public Utilities Commission	San Diego Community Power and Clean Energy Alliance	2022

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
15. San Diego Gas & Electric	R.20-05-003	Declaration supporting motion for clarification of D.19-11-016, quantifying impact to allocated incremental reliability procurement requirement due to departing load	California Public Utilities Commission	San Diego Community Power	2021
16. Southern California Edison	A.21-06-003	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Clean Power Alliance and California Choice Energy Authority	2021
17. Pacific Gas & Electric	A.21-06-001	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Joint Community Choice Aggregators	2021
18. San Diego Gas & Electric	A.21-04-010	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	San Diego Community Power and Clean Energy Alliance	2021
19. Pacific Gas & Electric	A.12-01-008 A.12-04-020 A.14-01-007	Declaration supporting petition for modification of D.15-01-051, recommending changes to optional green tariff program rates designed to avoid shifting costs of resource capacity to non-participants	California Public Utilities Commission	Joint Community Choice Aggregators	2021
20. Pacific Gas & Electric	A.19-11-019	Expert testimony (adopted) addressing use of marginal costs to determine economic development rates and responding to proposed electrification tariff for retail customers	California Public Utilities Commission	Joint Community Choice Aggregators	2021

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
21. Pacific Gas & Electric	A.20-07-002	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Joint Community Choice Aggregators	2020
22. Southern California Edison	A.20-07-004	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Clean Power Alliance and California Choice Energy Authority	2020
23. Pacific Power	Docket UE 375	Joint testimony supporting a settlement agreement resolving the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon	Facebook, Inc.	2020
24. Pacific Gas & Electric	A.20-02-009	Expert testimony evaluating the appropriateness of entries recorded to the Portfolio Allocation Balancing Account to true up the Power Charge Indifference Amount	California Public Utilities Commission	Joint Community Choice Aggregators	2020
25. Vectren Energy Delivery of Indiana	Cause No. 43354 MCRA 21 S1	Expert testimony supporting a settlement agreement regarding the calculation and use of a 4CP load study to allocate tariff rider costs among customer classes	Indiana Utility Regulatory Commission	SABIC Innovative Plastics Mt. Vernon, LLC	2020
26. PacifiCorp	Docket UE 307	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon		2016
27. PacifiCorp	Docket UM 1662	Joint testimony with Portland General Electric regarding the need for a renewable resource tracking mechanism to provide cost recovery related to the impacts of renewable resource generation	Public Utility Commission of Oregon		2015

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
28. PacifiCorp	Docket UE 296	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon		2015
29. PacifiCorp	Docket No. 20000-469-ER-15	Expert testimony regarding the annual variable power supply cost forecast and modifications to the Energy Cost Adjustment Mechanism	Public Service Commission of Wyoming		2015
30. PacifiCorp	Docket No. 15-035-03	Provided expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2015
31. PacifiCorp	Docket UM 1716	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resources	Public Utility Commission of Oregon		2015
32. PacifiCorp	Docket No. 20000-481-EA-15	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resources	Public Service Commission of Wyoming		2015
33. PacifiCorp	Docket No. 15-035-T06	Expert testimony updating standard PURPA avoided cost prices and supporting modifications to the avoided cost calculation for small resources	Public Service Commission of Utah		2015
34. PacifiCorp	Case No. PAC-E-15-03	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resource	Idaho Public Utilities Commission		2015

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
35. PacifiCorp	Docket UE-144160	Declaration supporting updates to standard PURPA avoided cost prices and supporting modifications to the avoided cost calculation for small resources	Washington Utilities and Transportation Commission		2014
36. PacifiCorp	Docket UE 287	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon		2014
37. PacifiCorp	Case No. PAC-E-14-01	Expert testimony regarding the true up of variable power supply costs in the Energy Cost Adjustment Mechanism	Idaho Public Utilities Commission		2014
38. PacifiCorp	Docket A.14-08-002	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission		2014
39. PacifiCorp	Docket No. 20000-447-EA-14	Expert testimony regarding the true up of annual variable power supply cost in the Energy Cost Adjustment Mechanism	Public Service Commission of Wyoming		2014
40. PacifiCorp	Docket No. 14-035-31	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2014
41. PacifiCorp	Case No. PAC-E-13-03	Expert testimony regarding the true up of variable power supply costs in the Energy Cost Adjustment Mechanism	Idaho Public Utilities Commission		2013

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
42. PacifiCorp	Docket A.13-08-001	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission		2013
43. PacifiCorp	Docket No. 13-035-32	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2013
44. PacifiCorp	Docket UM 1610	Expert testimony proposing changes to the calculation of PURPA avoided costs for large and small generation resources	Public Utility Commission of Oregon		2012
45. PacifiCorp	Docket A.12-08-003	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission		2012
46. PacifiCorp	Docket No. 12-035-67	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2012
47. PacifiCorp	Docket No. 20000-389-EP-11	Expert testimony regarding the collection of deferred balances accrued through previous Power Cost Adjustment Mechanisms	Public Service Commission of Wyoming		2011
48. PacifiCorp	Docket No. 20000-405-ER-11	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2011
49. PacifiCorp	Case No. GNR-E-11-03	Expert testimony proposing changes to the calculation of PURPA avoided costs for large and small generation resources	Idaho Public Utilities Commission		2011

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
50. PacifiCorp	Case No. PAC-E-06-10	Expert testimony regarding low-income customer weatherization rebates	Idaho Public Utilities Commission		2010
51. PacifiCorp	Docket No. 20000-405-ER-10	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2010
52. PacifiCorp	Docket No. 10-035-89	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Utah		2010
53. PacifiCorp	Docket No. 20000-352-ER-09	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2009
54. PacifiCorp	Case No. PAC-E-08-07	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Idaho Public Utilities Commission		2008
55. PacifiCorp	Docket No. 20000-333-ER-08	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2008

Confidential Attachment B

PG&E 2026 Hourly RA Position by Month

Attachment(s) Confidential

Attachment C

Select Responses to CalCCA Data Requests

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2026 Forecast
Application 25-05-011
Data Response

PG&E Data Request No.:	CalCCA_001-Q041
PG&E File Name:	ERRA-2026-PGE-Forecast_DR_CalCCA_001-Q041
Request Date:	June 5, 2025
Requester DR No.:	001
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	June 18, 2025
PG&E Witness(es):	George Clavier – Energy Policy and Procurement

QUESTION 041

Refer to PG&E workpaper '05.ERRA_2026_Forecast_WP_PGE_20250515_Ch05_Table 4-6- 4-17 & 5-3 - 5-17_RA Open Position_CONF', tab 'Data (New)': For each Battery Storage resource (as delineated in column G) please provide the maximum hourly discharge capacity that could be counted toward PG&E's RA compliance obligation (i.e. NQC, prior to PG&E shaping the charging and discharging).

ANSWER 041

Storage units included in 2026 ERRA forecast:

PGE_LogNum	ContractCapacity_MW
40S008	10
40S009	25
40S011	50
40S014	75
40S015	50
40S016	50
40S017	50
40S018	60
40S020	50
40S021	63
40S022	46
40S023	15
40S024	40
40S025	132
40S027	127
40S029	150
40S030	63

40S031	47
40S032	350
40S033	50
40S034-AR	99.7
40S035	275
40S037	300
40S038	100
40S039	80
40S040	169
40S041	12
40S042	23.5
40S043	230
40S044-H01	92
40S045	112.5
40S048	69
40S049	59.7
PGEMOSSLANDING	182.5

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2026 Forecast
Application 25-05-011
Data Response

PG&E Data Request No.:	CalCCA_001-Q043
PG&E File Name:	ERRA-2026-PGE-Forecast_DR_CalCCA_001-Q043Supp01
Request Date:	June 5, 2025
Requester DR No.:	001
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	(Original) June 18, 2025 (Supp01) July 17, 2025
PG&E Witness(es):	George Clavier – Energy Policy and Procurement

QUESTION 043

Referring to PG&E's prepared testimony, Chapter 4 Section C, Chapter 5 Section D, and Chapter 8 Section F.1: Does PG&E agree that RA can be purchased or sold in the bilateral market at prices that distinguish between the technology of the resource supplying the RA capacity (e.g., baseload, solar, wind, or battery storage)? If not, please explain why not.

ANSWER 043

PG&E objects on the basis of scope and relevance.

ANSWER 043 SUPPLEMENTAL 01

PG&E objects on the basis of scope to the extent that CalCCA seeks to examine PG&E's Commission-approved RA sales strategies in this proceeding. Subject to and without waiving that objection, PG&E agrees, but notes that it is PG&E's observation that a significant majority of RA transactions to date are for baseload (flat 24 hour) RA product.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2026 Forecast
Application 25-05-011
Data Response

PG&E Data Request No.:	CalCCA_001-Q048
PG&E File Name:	ERRA-2026-PGE-Forecast_DR_CalCCA_001-Q048Supp01
Request Date:	June 5, 2025
Requester DR No.:	001
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	(Original) June 18, 2025 (Supp01) July 17, 2025
PG&E Witness(es):	George Clavier – Energy Policy and Procurement

QUESTION 048

Referring to PG&E's prepared testimony, Chapter 4 Section C, Chapter 5 Section D, and Chapter 8 Section F.1: Has PG&E executed any RA transactions with third parties that were priced at a premium or discount due to the underlying resource technology type (relative to RA from other generation resources)? If yes, please provide all supporting documentation demonstrating the premium or discount.

ANSWER 048

PG&E objects on the basis of scope and relevance.

ANSWER 048 SUPPLEMENTAL 01

An attachment to this response contains CONFIDENTIAL information provided pursuant to the Non-Disclosure Agreement in this proceeding.

Based on the July 14, 2025 Meet and Confer between PG&E and CalCCA, PG&E understands the intent of this question is to understand whether there is an observable difference in pricing between RA-only transactions for storage resources and RA-only transactions for baseload resources. PG&E continues to object on the basis of scope to the extent that CalCCA seeks to review PG&E's RA sales practices in this proceeding. PG&E also objects on the basis of burden to the extent that CalCCA seeks "all supporting documentation." Subject to and without waiving the foregoing objection, attached as confidential attachment *"ERRA-2026-PGE-Forecast_DR_CalCCA_001-Q048Supp01Atch01CONF.xlsx"* is a document summarizing (1) executed RA-only contracts for Delivery Period 2025; and (2) an analysis of pricing differences in that data set based on the delivery profile of the resources (i.e., "flat" vs. storage or wind). PG&E notes that this data likely represents a small fraction of broader RA market transactions and may not be reflective of similar analysis that considers all RA market transactions.

Attachment(s) Confidential

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2026 Forecast
Application 25-05-011
Data Response

PG&E Data Request No.:	CalCCA_002-Q003
PG&E File Name:	ERRA-2026-PGE-Forecast_DR_CalCCA_002-Q003
Request Date:	July 21, 2025
Requester DR No.:	002
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 4, 2025
PG&E Witness(es):	George Clavier – Energy Policy and Procurement

QUESTION 003

Referring to workpaper '08. ERRA_2026_Forecast_WP_PGE_20250515_Ch08_PCIA_CONF': Please identify any energy storage resources for which the cost of energy needed to charge the battery and revenue from energy discharged into the CAISO market is included in the 2026 Indifference Amount. For each such resource, please quantify for the 2026 forecast:

a. Charging energy volume and cost

b. Discharge energy volume and revenue

ANSWER 003

The attachment contains Confidential Information Protected Under Non-Disclosure Agreement and under D. 06-06-066, and/or Public Utilities Code Section 454.5(G)

PG&E's contracted battery resources recovered through the PCIA are a combination of RA-only contracts and RA plus CAISO wholesale energy market benefits that are referred to as 'energy settlement' within the agreements. The energy settlement benefits represent contractual energy arbitrage based on contractual terms that include elements such as operating capacity, roundtrip efficiency (RTE), and wholesale market prices. These benefits are modeled within PG&E's P^3 model that only produces the aggregated monthly net benefits as part of the modeling results, so the charging and discharging values are not available as separate data points. Attachment "ERRA-2026-PGE-Forecast_DR_CalCCA_002-Q003Atch01CONF" contains a list of the storage contracts with energy settlement provisions and the associated forecasted annual energy settlement revenues that are included within the total cost values that are presented in PG&E's workpapers for these projects.

Attachment(s) Confidential

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2026 Forecast
Application 25-05-011
Data Response

PG&E Data Request No.:	CalCCA_002-Q005
PG&E File Name:	ERRA-2026-PGE-Forecast_DR_CalCCA_002-Q005CONF
Request Date:	July 21, 2025
Requester DR No.:	002
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 4, 2025
PG&E Witness(es):	George Clavier – Energy Policy and Procurement

QUESTION 005

Referring to workpaper '05.ERRA_2026_Forecast_WP_PGE_20250515_Ch05_Table 4-6- 4-17 & 5-3 - 5-17_RA Open Position_CONF,' and tab 'CONF_CTC and PCIA' of workpaper '08. ERRA_2026_Forecast_WP_PGE_20250515_Ch08_PCIA_CONF:

For each of the contracts listed in the table below, please confirm that the weighted average annual RA shown in the table (derived using data from '05.ERRA_2026_Forecast_WP_PGE_20250515_Ch05_Table 4-6- 4-17 & 5-3 - 5-17_RA Open Position_CONF') is correct as proposed by PG&E differentiated by cost recovery mechanism. If not confirmed, please explain.

05.ERRA_2026_Forecast_WP_PGE_20250515_ Ch05_Table 4-6- 4-17 & 5-3 - 5-17_RA Open Position_CONF'

Weighted Average Annual RA Capacity

LogNumber	PCIA RA (MW)	CAM RA (MW)
40S015	[redacted]	
40S016		
40S017		
40S018		
40S020		
40S021		
40S022		
40S023		
40S024		
40S025		
40S027		

ANSWER 005

PG&E confirms that the values presented in the above table are correct.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2026 Forecast
Application 25-05-011
Data Response

PG&E Data Request No.:	CalCCA_002-Q006
PG&E File Name:	ERRA-2026-PGE-Forecast_DR_CalCCA_002-Q006CONF
Request Date:	July 21, 2025
Requester DR No.:	002
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 4, 2025
PG&E Witness(es):	George Clavier – Energy Policy and Procurement

QUESTION 006

Referring to workpaper

‘05.ERRA_2026_Forecast_WP_PGE_20250515_Ch05_Table 4-6- 4-17 & 5-3 - 5-17_RA Open Position_CONF,’ and tab ‘CONF_CTC and PCIA’ of workpaper ‘08. ERRA_2026_Forecast_WP_PGE_20250515_Ch08_PCIA_CONF’ : Please confirm that PG&E included the ModCAM-related RA capacity in the Indifference Amount calculation (tab ‘CONF_CTC and PCIA’) (see Table below) rather than the PCIA-related capacity. If not confirmed, please explain.

08. ERRA_2026_Forecast_WP_PGE_20250515_Ch0 8_PCIA_CONF

Weighted Average Annual RA Capacity	
LogNumber	PCIA RA (MW)
40S015	[redacted]
40S016	
40S017	
40S018	
40S020	
40S021	
40S022	
40S023	
40S024	
40S025	
40S027	

ANSWER 006

PG&E confirms that the weighted average RA capacities corresponding to the CAM allocation of the ModCAM resources were erroneously included as the RA quantities for the PCIA share of the ModCAM resources in 08._ERRA_2026_Forecast_WP_PGE_20250515_Ch0 8_PCIA_CONF. PG&E's Fall Update to the 2026 ERRA Forecast will correct this error and reflect the PCIA share of the retained RA quantities for the ModCAM resources.

PACIFIC GAS AND ELECTRIC COMPANY
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Application 25-05-011
Data Response

PG&E Data Request No.:	CalCCA_003-Q001
PG&E File Name:	ERRA-2026-PGE-Forecast_DR_CalCCA_003-Q001
Request Date:	July 23, 2025
Requester DR No.:	003
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 5, 2025
PG&E Witness(es):	George Clavier – Energy Policy and Procurement

QUESTION 001

Referring to PG&E's prepared testimony, page 3-9, lines 12-26: Please provide a copy of the confidential version of PG&E Advice Letter 7602-E and appendices.

ANSWER 001

The attachment provided contains confidential information protected under Non-Disclosure Agreement and under D. 06-06-066, and/or Public Utilities Code Section 454.5(G)

PG&E objects to the request for the entire confidential version of PG&E Advice Letter 7602-E on the basis of scope and relevance. Subject to and without waiving that objection, *"ERRA-2026-PGE-Forecast_DR_CalCCA_003-Q001Atch01.pdf"* provides the applicable details to forecasting the project's costs and volumes.

Attachment(s) Confidential

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2026 Forecast
Application 25-05-011
Data Response

PG&E Data Request No.:	CalCCA_004-Q002
PG&E File Name:	ERRA-2026-PGE-Forecast_DR_CalCCA_004-Q002
Request Date:	August 20, 2025
Requester DR No.:	004
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 27, 2025
PG&E Witness(es):	Daniel Nelli – Engineering, Planning and Strategy

QUESTION 002

Referring to PG&E's prepared testimony, page 2-11, line 22: Please describe how the assumed application conversion rate of 70% was determined. Please describe if this assumed conversion rate is based on any historical conversion rates for existing data centers in PG&E's service territory. To the extent that Subject Matter Expertise (SME) informs the conversion rate, please provide any sources relied on by the SMEs to develop their proposal.

ANSWER 002

The 70% application conversion rate comes from the California Energy Commission's "confidence level" assumption in its 2024 IEPR forecast of data center load. See slide four of this presentation.

PG&E's SMEs have not conducted analysis to compare this assumed conversion rate to historical conversion rates for existing data centers in PG&E's service territory.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2026 Forecast
Application 25-05-011
Data Response

PG&E Data Request No.:	CalCCA_004-Q003
PG&E File Name:	ERRA-2026-PGE-Forecast_DR_CalCCA_004-Q003CONF
Request Date:	August 20, 2025
Requester DR No.:	004
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 27, 2025
PG&E Witness(es):	Daniel Nelli – Engineering, Planning and Strategy

QUESTION 003

Referring to PG&E's prepared testimony, page 2-11, lines 14-32: Please provide electronic workpapers demonstrating PG&E's calculated new large data center load forecast including the following:

a. A list of each new data center assumed to come online in 2026.

b. The geographic location of each new data center.

c. The peak demand (total MW capacity) for each new data center.

d. The capacity utilization rate and load factor assumptions applied by PG&E to each new data center.

e. The monthly sales forecast (MWh) for each new data center as included in PG&E's 2026 forecast.

ANSWER 003

This response contains confidential information provided pursuant to the Non-Disclosure Agreement in this proceeding.

PG&E objects to production of the information requested in the manner requested in ERRA-2026-PGE-Forecast_DR_CalCCA_004-Q003 on the basis that production would violate PG&E's customer privacy obligations and contractual obligations.

Subject to and without waiving that objection, PG&E responds to CalCCA's request to certain sub-parts of ERRA-2026-PGE-Forecast_DR_CalCCA_004-Q003 with sufficiently aggregated information concerning PG&E's new large data center load forecast presented in its Prepared Testimony.

a. No sufficiently aggregated information is available to produce.

b. [redacted]

c. Note that PG&E defines capacity and peak demand as different values. PG&E's reference to capacity is associated with "max load" requests from data center customer interconnection applications and represents a theoretical maximum demand. PG&E forecasts the end of year 2026 capacity is 518.5 MW. Refer to Table 2-3 of prepared testimony, line 39 for peak demand.

d. PG&E estimates annual sales using the following method

   518.5 MW capacity * 70% application conversion rate * 58.6% capacity utilization rate * 79.1% load factor * 8760 hours / 1000 ≈ 1,474 GWh sales

   Refer to Table 2-3 for the monthly forecast of 2026 data center load.

   For clarity, PG&E is proactively providing sources of assumptions mentioned above.

   The 58.6% capacity utilization rate is based on Silicon Valley Power's 67% capacity utilization rate, as publicized in CEC DAWG and IEPR workshops leading up to the 2024 IEPR forecast (see slide 9 of this presentation, for example). The lower value PG&E assumed in the near term is due to load ramping and hourly shaping to account for seasonality of data center load.

   The 79.1% load factor assumption comes from internal subject matter expert professional expertise as well as the necessary hourly shaping to account for seasonality of data center load. This value aligns well with numerous public studies on load factors of data centers.[1,2]

e. Refer to Table 2-3, line 7.

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[1] Slide 15 of https://www.energy.ca.gov/filebrowser/download/6686?fid=6686

[2] https://www.ethree.com/wp-content/uploads/2024/07/E3-White-Paper-2024-Load-Growth-Is-Here-to-Stay-but-Are-Data-Centers-2.pdf

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2026 Forecast
Application 25-05-011
Data Response

PG&E Data Request No.:	CalCCA_004-Q004
PG&E File Name:	ERRA-2026-PGE-Forecast_DR_CalCCA_004-Q004CONF
Request Date:	August 20, 2025
Requester DR No.:	004
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 27, 2025
PG&E Witness(es):	Daniel Nelli – Engineering, Planning and Strategy

QUESTION 004

Referring to PG&E's prepared testimony, page 2-11, lines 14-32: Please respond to the following:

a. How many new data centers are included in PG&E's 2026 Forecast sales?

b. Where are the new data centers described in part a of this request located geographically?

ANSWER 004

This response contains confidential information provided pursuant to the Non-Disclosure Agreement in this proceeding.

a. Approximately seventeen customers are included in the data center forecast in PG&E's 2026 ERRA forecast. This value is approximate as it is a product of a) the total number of applicants that were in the application queue at the time of forecast development (24) and b) the application conversion rate mentioned in the responses to CalCCA_004-Q002 and CalCCA_004-Q003 (70%). Thus, 24 * 70% ≈ 17.

[redacted]

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2026 Forecast
Application 25-05-011
Data Response

PG&E Data Request No.:	CalCCA_004-Q005
PG&E File Name:	ERRA-2026-PGE-Forecast_DR_CalCCA_004-Q005
Request Date:	August 20, 2025
Requester DR No.:	004
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 27, 2025
PG&E Witness(es):	Daniel Nelli – Engineering, Planning and Strategy

QUESTION 005

Referring to PG&E's prepared testimony, page 2-11, lines 14-32: Please identify each new data center included in PG&E's 2026 sales forecast and identify whether each is assumed to take bundled service or unbundled service. For each new data center identify the load serving entity expected to provide generation service to the data center, and identify each data center's energy and capacity included in PG&E's 2026 sales forecast.

ANSWER 005

PG&E objects to CalCCA_004-Q005 on the basis that production would violate PG&E's customer privacy obligations and contractual obligations. Subject to and without waiving the foregoing objections, PG&E clarifies that aggregated data center information specific to each community choice aggregator (CCA) service territory was shared with individual CCAs during the meet and confer process described in Chapter 2 of PG&E's prepared testimony.

Generally, PG&E assumes that data centers in CCA territories will be served by CCAs. Specifically, in load forecast preparation activities, PG&E assumes an opt-out rate of 13% based on historical industrial customer opt-out rates. For aggregate energy and capacity assumed in PG&E's 2026 ERRA forecast, see response to CalCCA_004-Q003.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2026 Forecast
Application 25-05-011
Data Response

PG&E Data Request No.:	CalCCA_004-Q007
PG&E File Name:	ERRA-2026-PGE-Forecast_DR_CalCCA_004-Q007
Request Date:	August 20, 2025
Requester DR No.:	004
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 27, 2025
PG&E Witness(es):	Jorge Meraz – Engineering, Planning and Strategy

QUESTION 007

Referring to PG&E's prepared testimony, page 2-11, lines 14-32: Did PG&E meet and confer with any CCAs about the new data centers included in its 2026 sales forecast? If yes, please explain whether any CCAs identified the load as load they intended to serve? If no, please explain why not?

ANSWER 007

PG&E conducts a meet and confer process with all Community Choice Aggregators (CCAs) in its service territory concerning the 2026 sales forecast. This process is generally described in prepared testimony, page 2-18, line 10 through page 19, line 11.

For those CCAs with potential data center load, PG&E did meet and confer with such CCAs concerning the potential for new data centers. No CCA identified new data center customers or load in their forecasts. During the meet and confer process, wherein communications (e.g., exchange of forecast results and assumptions) are conducted via e-mail, the CCAs did not explicitly communicate their intention to serve the new data center load.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2026 Forecast
Application 25-05-011
Data Response

PG&E Data Request No.:	CalCCA_004-Q008
PG&E File Name:	ERRA-2026-PGE-Forecast_DR_CalCCA_004-Q008Supp01
Request Date:	August 20, 2025
Requester DR No.:	004
Requesting Party:	California Community Choice Association
Requester:	Nikhil Vijaykar
Date Sent:	August 27, 2025 Supp01: August 29, 2025
PG&E Witness(es):	Andrew Klingler / Jorge Meraz – Engineering, Planning and Strategy

QUESTION 008

Referring to PG&E's prepared testimony, page 2-11, lines 14-32: Please explain whether the sales forecast for CCAs shown in PG&E Table 2-3 (energy and peak demand) includes new data center load served by CCAs? If yes, please quantify and explain whether the data center load served by CCAs is also included in lines 7 and 39 of Table 2-3.

ANSWER 008

Yes, the sales forecast for CCAs includes new data center load served by CCAs. The data center load to be served by CCAs is also reflected in lines 7 and 39 of Table 2-3. On the basis of customer privacy, PG&E objects to providing data center load details. However, please note that aggregate data center customers and load were shared with CCAs during the meet and confer process and CalCCA can connect with the relevant CCAs to request such information.

ANSWER 008 SUPPLEMENTAL 01

For the purposes of the initial load forecast presented, PG&E further clarifies that aggregation of data center load meets an applicable aggregation standard for energy and that the associated energy sales amount to 1,182 GWh. PG&E further clarifies that Meet & Confer information is confidential under applicable NDAs with CCAs.