BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company For Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	Application No. 23-05-012 (Filed May 15, 2023)
Expedited Application of Pacific Gas and Electric Company Pursuant to the Commission's Approved Energy Resource Recovery (ERRA) Trigger Mechanism. (U 39 E)	Application No. 23-07-012 (Filed July 28, 2023)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING BRIEF

PUBLIC VERSION

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- The Commission should approve Pacific Gas and Electric Company's (PG&E) proposal to apply excess Renewable Energy Credits (RECs) from prior years to meet its Minimum Retained Renewable Portfolio Standard (RPS) obligations for the 2024 forecast year; its proposal to charge bundled customers for those RECs in 2024; and its proposal to credit applicable Portfolio Allocation Balancing Account (PABA) vintages for those RECs at the 2024 RPS Adder;

- The Commission should direct PG&E to apply banked RECs towards its 2024 Minimum Retained RPS requirement on a "first-in first-out" basis consistent with the California Community Choice Association's (CalCCA) proposed methodology, and to make correcting entries to the 2023 PABA to reflect that methodology;

- The Commission should approve PG&E's proposal to extend the Power Charge Indifference Adjustment (PCIA) Undercollection Balancing Account (PUBA) rate adder in 2024, and find that it is reasonable for PG&E to close the PUBA rate adder once the balance in that account reaches $1 million, or at the end of 2024, whichever is sooner, via a Tier 1 Advice Letter;

- The Commission should adjust PG&E's PCIA revenue requirement to (1) reduce the General Rate Case revenue requirement to reflect the sale of PG&E's San Francisco headquarters (SFGO), and (2) adjust the market value of capacity to remove Diablo Canyon Unit 1 November 2024 Resource Adequacy (RA);

- The Commission should apply the legal standard discussed in this Opening Brief to the October Update; and

- The Commission should defer making any findings, conclusions or orders with respect to PG&E's proposal to modify its methodology for allocating Electric Supply Administration (ESA) costs until after the Commission decision targeted for the December 14, 2023 meeting, consistent with the Administrative Law Judge's Ruling Regarding Fixed Generation Costs issued on October 9, 2023, but should direct PG&E to revert to its existing methodology for allocating ESA costs (based on net authorized revenue requirements) for the purpose of 2024 ratemaking.

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING BRIEF

Pursuant to Rule 13.12 of the Rules of Practice and Procedure of the California Public Utilities Commission and the schedule adopted in the Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo),[1] the California Community Choice Association[2] (CalCCA) hereby submits this opening brief in the above-captioned *Application of Pacific Gas and Electric*

[1] Scoping Memo at 6 (Aug. 3, 2023).

[2] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy (EBCE), Energy for Palmdale's Independent Choice, Lancaster Choice Energy, Marin Clean Energy (MCE), Orange County Power Authority, Peninsula Clean Energy (PCE), Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy (SJCE), Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

Company (PG&E) for Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (Application).

The key disputed issue remaining between CalCCA and PG&E in this case concerns Scoping Issue 1c, which is PG&E's proposed methodology to "include pre-2024 renewable energy credits (RECs) toward the 2024 Power Charge Indifference Adjustment (PCIA) revenue requirement calculation and to allocate the value of such RECs to benefit bundled and departing load customers responsible for applicable Portfolio Allocation Balancing Account (PABA) vintage costs."[3] PG&E's forecasted shortfall in RECs necessary to meet its 2024 Minimum Retained Renewable Portfolio Standard (RPS) requirement (as a result of the voluntary allocation and market offer (VAMO) process ordered in Decision 21-05-030) drives its proposal.

This is a familiar issue. PG&E forecasted a similar REC shortfall due to VAMO in 2023.[4] To cover that shortfall, PG&E proposed to apply excess "banked" RECs from prior years towards its 2023 Minimum Retained RPS requirement, and to credit bundled and unbundled customers responsible for applicable PABA vintage costs at the 2023 RPS benchmark.[5] CalCCA supported PG&E's proposal, and the Commission approved PG&E's 2023 methodology in D.22-12-044.[6]

PG&E now proposes modifications to its 2023 methodology. Whereas PG&E's 2023 methodology relied exclusively on banked RECs from within its *current* RPS compliance period (2021 through 2024), it now proposes to reach back into prior compliance periods (*i.e.*, to use banked RECs generated in 2018 and 2020, in addition to banked RECs generated in 2021 and

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3 Scoping Memo at 2 (Issue 1c.).

4 PG&E-01 at 9-18:22-25.

5 *Id*. at 9-20:12 – 9-21:2.

6 D.22-12-044 at 25, Ordering Paragraph 1.

2022) in order to cover its 2024 shortfall. Importantly, PG&E proposes to apply banked RECs from prior compliance periods in a "Last-In/First-Out" (LIFO) manner. That means PG&E will apply banked RECs generated (and paid for by customers) most recently before PG&E uses older banked RECs and credits the customers who paid for those older RECs.

The Commission should approve PG&E's proposal to apply banked RECs (including RECs from prior RPS compliance periods) towards its 2024 Minimum Retained RPS requirement, and should approve PG&E's proposal to credit applicable PABA vintages at the 2024 RPS adder. However, the Commission should not approve PG&E's illogical LIFO approach. Instead, the Commission should direct PG&E to apply banked RECs towards its forecast shortfall in a "First-In/First-Out" (FIFO) manner. A FIFO approach is more reasonable, logical, and fair than a LIFO approach because a FIFO approach credits customers for banked RECs in the order in which they paid for those banked RECs. Under a FIFO approach, customers across PCIA vintages would wait an approximately equal amount of time to receive a credit for the excess RECs for which they previously paid (customers who paid first are credited first, customers who paid second are credited second, and so on). In contrast, a LIFO method favors more recent PCIA vintages, while requiring customers who paid for RECs in earlier years to wait longer to receive a credit—a fundamentally unfair result.

This brief also addresses Scoping Issues 6, 9a and 9c:

6. The correct determination of the calculation of the revenue requirement and rates for the Power Charge Indifference Amount (PCIA), the Competition Transition Charge (CTC), and the Cost Allocation Mechanism (CAM);

9a. Whether PG&E's proposal to change the approved methodology for allocating Electric Supply Administration (ESA) costs, and allocate those costs based on gross generation authorized costs (as opposed to allocation on net authorized revenue requirements), is reasonable and in compliance with all applicable rules, regulations, resolutions and decisions;

9c. Whether PG&E's proposal to amortize any year-end 2023 residual balance in the PCIA Undercollection Balancing Account (PUBA) in 2024 rates (through PUBA rate adders) is reasonable.[7]

With respect to Scoping Issue 6, the Commission should adopt CalCCA's uncontested recommendations to adjust PG&E's PCIA revenue requirement to (1) reduce the General Rate Case revenue requirement to reflect the sale of PG&E's San Francisco headquarters (SFGO), and (2) adjust the market value of capacity to remove Diablo Canyon Unit 1 November 2024 Resource Adequacy (RA).

With respect to Scoping Issue 9c, the Commission should approve PG&E's proposal to extend the PUBA rate adder in 2024, and find that it is reasonable for PG&E to close the PUBA once the balance in that account reaches $1 million, or at the end of 2024, whichever is sooner, via a Tier 1 Advice Letter.

Finally, with respect to Scoping Issue 9a, the Administrative Law Judge's October 9 Ruling Regarding Fixed Generation Costs clarifies that PG&E's proposal to change the methodology for allocating ESA costs is a fixed generation cost issue that will not be addressed in the decision targeted for the Commission's December 14, 2023 voting meeting, and will instead be addressed in a prehearing conference in January 2024. Accordingly, the Commission should not make any findings, conclusions or orders with respect to PG&E's proposal to modify its methodology for allocating ESA costs in its decision targeted for the Commission's December 14, 2023 voting meeting.

I. LEGAL STANDARD

The magnitude of the impact of PG&E's application on both departed and bundled customers requires cautious and careful consideration under the applicable standards of proof. As

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[7] Scoping Memo at 3-4.

the ratemaking applicant, PG&E has the burden of affirmatively establishing the reasonableness of all aspects of its application.[8] That burden of proof generally is measured based upon a preponderance of the evidence.[9]

The Scoping Ruling categorized this proceeding as ratesetting.[10] The Commission has previously determined that Section 1757 of the Public Utilities Code applies to ratesetting,[11] which means the final decision must be "supported by the findings," and those findings must be "supported by substantial evidence in light of the whole record," *i.e.*, they must be based on the record or inferences reasonably drawn from the record.[12] As a result, the Commission cannot grant the relief in PG&E's Application without substantial evidence to support the rates requested.[13] California courts will overturn Commission decisions that lack substantial evidence.[14] Mere

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[8] Application (A.) 21-09-008, *Decision Approving Partial* Settlement, p. 15 (Aug. 10, 2023) (D.23-08-027).

[9] *See, e.g.*, A.17-06-005, *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*, pp. 9-10 (Jan. 16, 2018) (D.18-01-009); R.11-02-019, *Order Modifying Decision (D.) 12-12-030 and Denying Rehearing, as Modified*, p. 29 (Jul. 27, 2015) (D.15-07-044) (observing that the Commission has discretion to apply either the preponderance of evidence or clear and convincing standard in a ratesetting proceeding, but noting that the preponderance of evidence is the "default standard to be used unless a more stringent burden is specified by statute or the Courts.")

[10] Scoping Ruling at 8.

[11] Cal. Pub. Util. Code § 1757; *see, e.g.* R.14-07-002, *et al.*, *Order Denying Rehearing of D.18-06-027*, pp. 5-6 (May 8, 2020) (D.20-05-027) (stating "As an initial matter, SDG&E cites to the wrong statute, because Public Utilities Code section 1757.1 does not set forth the applicable standards for a ratesetting proceeding like this one. Rather, section 1757 provides the appropriate standard and requires a finding as to whether the Commission's findings are not supported by substantial evidence in light of the whole record.").

[12] *See, e.g.*, D.20-05-027 at 6.

[13] Cal. Pub. Util. Code § 1757(a)(4). *See, e.g. The Utility Reform Network v. Pub. Util. Comm'n*, 223 Cal. App. 4th 945, 958-59 (Feb. 5, 2014).

[14] Cal. Pub. Util. Code § 1757(a)(4). *See, e.g. The Utility Reform Network v. Pub. Util. Comm'n*, 223 Cal. App. 4th 945, 958-59 (Feb. 5, 2014).

rubber-stamping of uncorroborated, disputed evidence does not meet this standard.[15] The Commission, therefore, must require PG&E to support its assertions with sufficient evidence or reject the components of PG&E's Application that are unsupported by substantial evidence.

In addition, pursuant to Public Utilities Code Section 451:

> All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful.[16]

This foundational "just and reasonable" statutory requirement is applicable to all rates and charges, including those that will be established by this ERRA Forecast proceeding. Commission precedent supports cost-causation principles in setting "just and reasonable" rates, whereby customers are responsible for the costs incurred on their behalf.[17] The Public Utilities Code also requires rates to be non-discriminatory. Public utilities are prohibited from establishing "any unreasonable difference as to rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service."[18]

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[15] Cal. Pub. Util. Code § 1757(a)(4). *See, e.g. The Utility Reform Network v. Pub. Util. Comm'n*, 223 Cal. App. 4th 945, 958-59 (Feb. 5, 2014).

[16] Cal. Pub. Util. Code § 451.

[17] R.12-06-013, *Decision on Residential Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company and Transition to Time-of-Use Rates*, p.2 (Jul. 13, 2015) (D.15-07-001) (citing *K N Energy, Inc. v. F.E.R.C.*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) ("[I]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."); *Alabama Elec. Co-op., Inc. v. F.E.R.C.*, 684 F.2d 20, 27 (D.C. Cir. 1982) ('[I]t has come to be well established that electrical rates should be based on the costs of providing service to the utility's customers, plus a just and fair return on equity."); *So. Cal. Edison Authorized to Increase Rates for California Intrastate Electric Services*, 75 CPUC 641 (1973) (recognizing the desirability of each group's bearing its fair share of the cost of service, as such share is measured by the cost of service study); A.09-11-015, *Decision Approving Settlement Agreement* (D.10-09-010) (Sept. 2, 2010). The decision further notes; "For this reason a cost of service study is part of each general rate case for establishing electricity rates." D.15-07-001 at 2-3 n.3.

[18] Cal. Pub. Util. Code § 453(c).

Section 365.2 of the California Public Utilities Code mandates indifference for departed customers, requiring the Commission to "ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load."[19] Under Section 366.2, unbundled customers are responsible solely for "estimated net unavoidable electricity costs" when determining indifference, and those costs must be reduced by the benefits in the investor-owned utilities' (IOUs) portfolios that accrue to bundled customers.[20]

In the Commission's unique ERRA Forecast applications, where policymaking is largely forbidden,[21] the utility rarely requests the recovery of costs that have not already been approved via a prior decision, and the allocation of costs among different customer groups and classes is pre-determined via the utility's general rate case (GRC). Here, PG&E's requested revenue requirement, rate proposals, and issue-specific requests—such as its request to include pre-2024 RECs towards the 2024 PCIA revenue requirement calculation and to allocate the value of such RECs to benefit bundled and departing load customers responsible for applicable PABA vintage costs[22]—must be reasonable.[23]

PG&E's October Update will modify its currently requested 2024 ERRA forecast revenue requirement of $4.147 billion.[24] The same standards enumerated in this Opening Brief will apply equally to the calculation of PG&E's 2024 rates included in that October Update, including, but not limited to, the reasonableness of PG&E's proposed treatment of (a) RA resources and

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[19] Cal. Pub. Util. Code § 365.2.

[20] Cal. Pub. Util. Code § 366.2(f)(2), (g).

[21] D.18-01-009 at 10 (finding that policy issues and other industry-wide practices such as changes to the PCIA methodology are properly addressed in rulemaking dockets, such as R.17-06-026).

[22] *See* Scoping Ruling at 2 (Scoping Issue (1)(c)).

[23] *See id*. at 3.

[24] Application at 4.

associated costs in the PCIA, (b) the treatment of RPS resources with excess RPS value and allocation of RPS sales across vintages, (c) the calculation of the 2024 indifference amount, (d) the calculation of the 2023 year-end PABA balance, and (e) the allocation of indifference charges among vintages and customer classes.

II. CONTESTED ISSUES

A. Scoping Issue 1c and 9b: PG&E should apply banked RECs towards its Minimum Retained RPS requirement in a "First-In/First-Out" manner

1. PG&E's proposal to apply banked RECs from prior years toward its 2024 REC shortfall on a Last-In/First-Out basis is not reasonable

PG&E forecasts that due to the RPS energy allocation and/or sale expected to take place through the VAMO process directed by D.21-05-030, its 2024 net RPS position (forecast RPS-eligible generation less allocation and/or market offer activity) will be lower than its annual RPS compliance target for 2024.[25] That compliance target sets the utility's Minimum Retained RPS requirement for PCIA-ratemaking purposes.[26] PG&E proposes to make up for its Minimum Retained RPS shortfall in 2024 by applying RECs generated in prior years but in excess of annual RPS targets (banked RECs) towards its 2024 requirement.

PG&E's banked REC application proposal in this year's Forecast proceeding resembles its 2023 methodology, but includes some important differences that expand that methodology. This year, PG&E proposes not only to use banked RECs from its current RPS compliance period (2021-2024), but also to reach back to banked RECs from *prior* compliance periods in order to cover its forecasted shortfall in 2024.[27] PG&E proposes to first apply banked RECs from the current RPS compliance period toward its forecasted 2024 shortfall (specifically, 2021 and 2022 RECs), and to

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[25] PG&E-01 at 9-17:15-20.

[26] D.20-12-047 at 13-14.

[27] PG&E-01 at 9-21:4-7.

then apply banked RECs from prior years (2020 and 2018) in a Last-in/First-out (LIFO) manner.[28] That means PG&E would first apply 2022 and 2021 RECs toward its forecasted 2024 shortfall, then apply 2020 RECs, and then apply 2018 RECs until it covers its forecasted shortfall.[29]

Recognizing that some of the bundled customer base that paid for banked RECs in prior years may now be unbundled customers, PG&E proposes to credit PCIA vintages 2022, 2021, 2020, and 2018 for the value of the RECs it applies towards its 2024 Minimum Retained RPS requirement, and to charge current bundled customers (debit ERRA) for those RECs in 2024.[30] PG&E will price the REC transfer at the RPS Adder for 2024 consistent with D.19-10-001 and D.23-06-006. PG&E's initial filing is based on the 2023 Forecast RPS Adder of $12.63/MWh[31] as a placeholder, but that adder will be updated to reflect the recently released 2024 Forecast Market Price Benchmarks in the October Update.[32]

The table below details the REC quantities involved with PG&E's proposal. Based on PG&E's initial filing, PG&E needs 5,416 GWh of banked RECs to eliminate its forecasted REC shortfall in 2024.

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28 *Id*. at 9-21:4-8.

29 *Id*. at 9-21:4-7.

30 *Id*. at 9-23:16 – 9-24:16.

31 *Id*. at 9-28:1-3.

32 According to Energy Division's Calculation of the Market Price Benchmark for the PCIA Forecast and True-up, the 2024 Forecast RPS adder is $31.73/MWh.

Table 1: Proposed Excess REC Transfer

	2018	2019	2020	2021	2022	2023	2024
PG&E Bundled Sales (MWh)	48,832,111	35,956,100	35,838,070	33,149,379	28,776,746	30,544,937	28,831,236
Annual RPS Compliance Target	29.0%	31.0%	33.0%	35.8%	38.5%	41.3%	44.0%
RPS Compliance Requirement (MWh)	14,161,312	11,146,391	11,826,563	11,850,903	11,079,047	12,599,787	12,685,744
Retained RPS (MWh)	18,934,717	10,444,565	12,271,881	17,250,635	13,737,610	10,003,832	7,269,735
Unsold RPS	-	-	-	-	-	4,090,485	-
Excess/(Defecit)	4,773,405	(701,826)	445,318	5,399,732	2,658,563	(6,686,439)	(5,416,009)
REC Transfer (MWh) 2023				(4,480,474)	(2,205,965)	6,686,439	
REC Transfer (MWh) 2024	(3,598,835)		(445,318)	(919,258)	(452,598)		5,416,009
Remaining Excess/(Defecit)	1,174,570	(701,826)	-	-	-	-	-

The table below[33] details the calculation of the proposed dollar credit applied to PCIA vintages 2022, 2021, 2020, and 2018, with an offsetting charge included in bundled generation rates for 2024. Again, the table below is based on the 2023 Forecast RPS Adder, and will be updated to reflect the 2024 Forecast RPS Adder in PG&E's October Update.

Table 2: Proposed REC Transfer Value

	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	2023 Vintage	2024 Bundled Customers
REC Transfer (MWh)	(3,598,835)	-	(445,318)	(919,258)	(452,598)	-	5,416,009
2024 RPS Adder ($/MWh)							$12.63
Transfer Value ($)	($45,453,286)	$0	($5,624,366)	($11,610,229)	($5,716,313)	$0	$68,404,194

The Commission should approve PG&E's proposal to use banked RECs to meet its minimum Retained RPS requirements in 2024 or future years. PG&E's proposal to apply banked RECs to meet its Minimum Retained RPS requirement is reasonable and consistent with Commission decisions, rules, resolutions and regulations.[34] The Commission should, however, direct PG&E to modify its banked REC application methodology such that PG&E applies banked

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33 CalCCA-01 at 11:14.

34 *See* D.19-10-001, Attachment B (requiring IOUs value Retained RPS at the benchmark); D.20-02-047 at 13-14 (establishing the annual RPS target quantities provided in D.11-12-020 for calculating RPS compliance period requirement serves as appropriate minimum quantities for PG&E to consider for its annual retained RPS volumes as part of the PABA true-up); D.20-12-012 at 5 (reinforcing D.20-02-047); D.19-06-023 at 11, Ordering Paragraph 1 (establishing minimum quantities for 2021-2024 RPS compliance period); D.23-06-006 at 44 (clarifying that per D.19-10-001, IOUs should apply the benchmark for the year in which they use the banked REC).

RECs on a FIFO basis rather than a LIFO basis. A FIFO approach is more logical, reasonable and fair to customers than a LIFO approach because, under a FIFO approach, customers across PCIA vintages would wait an approximately equal amount of time to receive a credit for the excess RECs for which they previously paid. In contrast, a LIFO method favors more recent PCIA vintages, while requiring customers who paid for RECs in earlier years to wait longer to receive a credit[35]—a fundamentally unfair result.

To illustrate this unfair result, consider vintage 2013 customers. Under PG&E's proposed methodology, vintage 2013 customers—who paid for excess RECs ten years ago—would receive no credit for PG&E's use of those RECs until PG&E has exhausted all excess RECs from years 2014 through the present. That means customers who paid for excess RECs in 2020 (for example) would receive a credit for those payments far before vintage 2013 customers receive a payment for the excess RECs they purchased seven years prior. In contrast, under a FIFO methodology, vintage 2013 customers, who paid for RECs before vintage 2014-and-later customers, would appropriately receive a credit for PG&E's use of banked RECs *before* vintage 2014-and-later customers receive a similar credit.[36] That credit would flow through to 2020 customers, as well, since those customers are also responsible for 2013 costs. The result is both sets of customers receive a credit at the same time.

PG&E's LIFO proposal is also internally inconsistent with its proposed treatment of Unsold RPS recorded in 2023. In 2023, PG&E will be left with 4,090 GWh of Unsold RPS[37] due to a delay in the approval and initial delivery dates of the Short-Term and Long-Term Market Offer

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35 CalCCA-01 at 12:3-5.

36 *Id*. at 12:8-12.

37 PG&E Prepared Testimony, Chapter 9, Table 9-4.

contracts.[38] PG&E will use that quantity of Unsold RPS to count towards its Minimum Retained RPS requirement only once all of its past, previously retained excess RPS volumes have been exhausted.[39] While it may be appropriate for PG&E to wait to use Unsold RPS towards compliance until after it exhausts its banked RECs, PG&E's proposal to delay using the 2023 Unsold RPS until prior years' banked RECs are used up is not consistent with a <u>LIFO</u> method, because Unsold RPS amounts would be applied only *after* RECs previously generated were applied.[40]

Finally, a FIFO approach is consistent with Southern California Edison's (SCE) proposed banked REC application methodology. SCE, like PG&E, proposes to apply banked RECs from prior years to cover a forecasted Retained RPS shortfall in 2024—but unlike PG&E, proposes to apply those RECs on a FIFO basis.[41] This aspect of SCE's proposed methodology is reasonable.[42] The Commission should direct PG&E to adopt the same approach.

In response to CalCCA discovery, PG&E provided an inventory of banked RECs quantifying excess RECs by year going back to 2011, the beginning of RPS Compliance Period 1 (PG&E confirmed in discovery it does not have any net available RPS generation prior to 2011).[43] At the end of 2022, PG&E had a net excess REC balance of 31.1 million MWh. See Table 3 below which summarizes the REC balance by year.[44]

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38 CalCCA-02, Attachment B (PG&E's response to CalCCA data request 2.21).

39 *Id.*, Attachment B (PG&E's response to CalCCA data request 2.22).

40 CalCCA-01 at 12:19-13:1.

41 CalCCA-03 (SCE testimony from its 2024 ERRA Forecast proceeding, A.23-06-001, describing its banked REC application methodology).

42 SCE's proposal to avoid applying the RPS Adder for 2024 to these banked RECs is unreasonable and in dispute in that proceeding.

43 CalCCA-02, Attachment B (PG&E's response to CalCCA's data request 5.01).

44 CalCCA-01 at 15:1.

Table 3: PG&E Banked REC Balance by Year

Year	Annual Surplus/ (Deficit) MWh	Cumulative Balance MWh
2011	(139,673)	(139,673)
2012	(727,915)	(867,588)
2013	1,928,480	1,060,892
2014	3,980,017	5,040,909
2015	4,482,478	9,523,387
2016	5,379,424	14,902,811
2017	3,704,274	18,607,085
2018	4,773,405	23,380,490
2019	(701,826)	22,678,664
2020	445,318	23,123,982
2021	5,399,732	28,523,714
2022	2,658,563	31,182,277
2023	(6,686,440)	24,495,837
2024	(5,416,009)	19,079,828

Based on PG&E's banked REC inventory, and using the FIFO methodology CalCCA proposes, PG&E should begin by crediting customers who paid for excess RECs in 2013 to meet the minimum Retained RPS targets in later years. That would require PG&E to (1) apply banked RECs from years 2013, 2014, and 2015 to cover its entire 2023 shortfall,[45] and (2) apply banked RECs from 2015 and 2016 to cover its 5,416 GWh shortfall in 2024. Table 4 below details the REC quantities required if PG&E were to switch to a FIFO model as CalCCA recommends.[46]

45 Doing so will require PG&E to make a correcting entry to the 2023 PABA to move the value of banked RECs needed for 2023 out of the 2021 and 2022 vintages (used under a LIFO method) and into the 2013, 2014 and 2015 vintages (used under a FIFO method). This correcting entry is required before determining the vintages that should be credited for the 2024 REC transfers.

46 CalCCA-01 at 2.

Table 4: REC Quantities – FIFO Method

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Compliance Period 1			Compliance Period 2			Compliance Period 3							
PG&E Bundled Sales (MWh)	74,863,941	76,205,120	75,705,039	74,546,865	72,112,848	68,440,794	61,397,214	48,832,111	35,956,100	35,838,070	33,149,379	28,776,746	30,544,937	28,831,236
Annual RPS Compliance Target	20.0%	20.0%	20.0%	21.7%	23.3%	25.0%	27.0%	29.0%	31.0%	33.0%	35.8%	38.5%	41.3%	44.0%
RPS Compliance Requirement (MWh)	14,972,788	15,241,024	15,141,008	16,176,670	16,802,294	17,110,199	16,577,248	14,161,312	11,146,391	11,826,563	11,850,903	11,079,047	12,599,787	12,685,744
Retained RPS (MWh)	14,833,115	14,513,109	17,069,488	20,156,687	21,284,772	22,489,623	20,281,522	18,934,717	10,444,565	12,271,881	17,250,635	13,737,610	10,003,832	7,269,735
Unsold RPS	-	-	-	-	-	-	-	-	-	-	-	-	4,090,485	-
Excess/(Defecit) Before Portfolio Compliance	(139,673)	(727,915)	1,928,480	3,980,017	4,482,478	5,379,424	3,704,274	4,773,405	(701,826)	445,318	5,399,732	2,658,563	(6,686,440)	(5,416,009)
Retained for Compliance (MWh)	139,673	727,915	(867,588)					(701,826)	701,826					
Excess/(Defecit) Available For Use	-	-	1,060,892	3,980,017	4,482,478	5,379,424	3,704,274	4,071,579	-	445,318	5,399,732	2,658,563	(6,686,440)	(5,416,009)
REC Transfer (MWh) 2023			(1,060,892)	(3,980,017)	(1,645,531)								6,686,440	
REC Transfer (MWh) 2024					(2,836,947)	(2,579,062)								5,416,009
Net Excess/(Defecit)	-	-	-	-	-	2,800,362	3,704,274	4,071,579	-	445,318	5,399,732	2,658,563	-	-

To be clear, utilizing the FIFO method CalCCA recommends, rather than the LIFO method PG&E proposes, would not affect the total *value* of banked RECs PG&E needs to cover its 2024 Retained RPS shortfall—in either scenario, the banked RECs would be valued using the 2024 RPS Adder. The change to PG&E's proposal would simply alter the PCIA vintages that receive the credit for the use of banked RECs. Table 5 below details the application of the proposed dollar credits to PCIA vintages 2013-2016. Separate columns are used to summarize the 2023 REC transfer (in the PABA) and 2024 REC transfer (in the PCIA forecast).

Table 5: REC Transfer Value – FIFO Method

PCIA Vintage	2023 REC Transfer (MWh)	2023 RPS Adder ($/MWh)	2023 Transfer Value ($)	2024 REC Transfer (MWh)	2024 RPS Adder ($/MWh)	2024 Transfer Value ($)
2011	-	-	$ -	-	-	$ -
2012	-	-	$ -	-	-	$ -
2013	(1,060,892)	$ 12.63	$ (13,399,066)	-	-	$ -
2014	(3,980,017)	$ 12.63	$ (50,267,615)	-	-	$ -
2015	(1,645,531)	$ 12.63	$ (20,783,057)	(2,836,947)	$ 12.63	$ (35,830,641)
2016	-	-	$ -	(2,579,062)	$ 12.63	$ (32,573,553)
2017	-	-	$ -	-	-	$ -
2018	-	-	$ -	-	-	$ -
2019	-	-	$ -	-	-	$ -
2020	-	-	$ -	-	-	$ -
2021	-	-	$ -	-	-	$ -
2022	-	-	$ -	-	-	$ -
2023	6,686,440	$ 12.63	$ 84,449,737	-	-	$ -
2024	-	-	$ -	5,416,009	$ 12.63	$ 68,404,194

2. Contrary to PG&E's assertion, applying banked RECs to PG&E's forecasted REC shortfall on a FIFO basis would not violate any RPS rules

In rebuttal, PG&E makes two main criticisms of CalCCA's proposed FIFO methodology. First, PG&E asserts CalCCA's proposal is inconsistent with the banked REC application methodology that was adopted by the Commission for ratesetting in PG&E's 2023 ERRA Forecast proceeding.[47] That criticism ignores that PG&E's proposal is itself inconsistent with the banked REC application methodology the Commission adopted in last year's 2023 ERRA Forecast proceeding. PG&E's 2024 proposal is significantly more expansive than its 2023 methodology in that it seeks to reach back into prior RPS compliance periods to satisfy the utility's forecasted REC shortfall. CalCCA's proposal appropriately responds to PG&E's expanded approach, and recommends modifications aimed at ensuring that expanded approach is reasonable.

Second, PG&E asserts CalCCA's proposal is not consistent with the RPS compliance rules because those rules require the use of excess RECs from the current RPS compliance period to meet RPS compliance targets before the use of banked RECs from prior compliance periods to meet the same targets.[48] This criticism is meritless because PG&E incorrectly equates RPS compliance with the Minimum Retained RPS requirement for PCIA-ratemaking purposes. No RPS compliance rule or statute addresses the manner in which PG&E can or should use banked RECs to meet its Minimum Retained RPS requirement for PCIA-ratemaking purposes. PG&E (belatedly) acknowledged the distinction between RPS compliance and PCIA ratemaking in response to a CalCCA discovery request: "PG&E clarifies that the concept of the "Minimum Retained RPS Requirement" is an aspect of power charge indifference adjustment (PCIA) ratemaking initially

47 PG&E-03 at 21:27-28.

48 *Id*. at 21:30-33.

created for 2019 in PG&E's 2020 ERRA Forecast decision, D.20-02-047, and has not been directly addressed in RPS compliance rules or statutes."[49] PG&E also acknowledged it is not aware of any RPS compliance rule which specifically requires excess from prior period RECs be utilized according to a LIFO sequence.[50] The RPS statute and rules, therefore, do not support PG&E's proposal or its criticism of CalCCA's recommendation. The Commission should adopt CalCCA's proposed FIFO approach.

III. UNCONTESTED ISSUES AND ISSUES TO BE ADDRESSED IN THE OCTOBER UPDATE

A. <u>Scoping Issue 9c</u>: PG&E should close out its PUBA account once the balance in that account reaches $1 million or at the end of 2024, whichever comes sooner, via a Tier 1 advice letter

Decision 18-10-019 limited the change of the PCIA from one year to the next. Starting with forecast year 2020, the Commission capped the PCIA rate at $0.005/kWh more than the prior year's PCIA, differentiated by vintage.[51] The Commission established a new balancing account, the PUBA, to record the shortfall in revenue charged to departing load customers due to the new cap on annual rate changes.

Less than three years later, the Commission discontinued the annual PCIA cap.[52] Subsequently, in D.20-12-038, the Commission approved a PCIA adder to amortize the 2020 PUBA year-end balances over a three-year period beginning in 2021. Therefore, in theory, the PUBA should have been fully amortized by the end of 2023.

PG&E, however, projects approximately $7.4 million remaining unamortized in the PUBA

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[49] CalCCA-02 (*See* PG&E response to CalCCA discovery request 6.04).

[50] *Id*. (*See* PG&E response to CalCCA discovery request 6.06).

[51] D.18-10-019, Conclusions of Law 19-20, Ordering Paragraph 9(a)-(c).

[52] D.21-05-030, Ordering Paragraph 1.

at the end of 2023.[53] PG&E proposes to amortize the residual PUBA balance through 2024 rate adders. To avoid the indefinite continuation of PUBA rate adders as the balance in the account slowly approaches zero, CalCCA witness Shuey recommended PG&E close out the PUBA once its balance reaches $1 million by submitting a Tier 1 advice letter and transferring that balance to the PABA.[54] Witness Shuey further recommended that if the PUBA balance does not reach the $1 million threshold in 2024, PG&E should nevertheless close out the PUBA and dispose of its PUBA balance in its 2025 ERRA Forecast proceeding.

PG&E agreed with each of witness Shuey's recommendations. Should its PUBA balance reduce to $1 million in 2024, PG&E will file a Tier 1 advice letter proposing a methodology to transfer its PUBA balance to the PABA and setting its PUBA rate adder values to zero in the next rate change.[55] Should its PUBA balance remain above $1 million by the end of 2024, PG&E will nevertheless propose to set its PUBA rate adders to zero in 2025 by transferring the remaining PUBA balance to PABA.[56]

B. Scoping Issue 6: PG&E should reduce its PCIA revenue requirement by $17 million to reflect the sale of its SFGO headquarters

In D.21-08-027 the Commission authorized PG&E to credit customers the gain on the sale of its SFGO headquarters over a five-year period from 2022 through 2026. Because a portion of the costs to own and operate SFGO is allocated to PG&E's electric generation revenue requirement and included in the GRC-related electric generation costs recovered through PCIA rates, a portion

[53] PG&E-1 at 14-23:27-30.

[54] CalCCA-01 at 24:12-17. Witness Shuey noted that in their pending 2024 ERRA Forecast proceedings, both San Diego Gas & Electric Company and Southern California Edison have proposed to close out their respective PUBA accounts and transfer the residual balance to PABA ($1.3 million balance for SDG&E and $1.5 million balance for SCE). *Id*. at 25:1-4.

[55] PG&E-3 at 27:22-25.

[56] CalCCA-02 (PG&E response to CalCCA data request 6.11).

of the benefits related to the sale are also allocated to electric generation and included as a credit to the Indifference Amount.[57] Those benefits include the gain on sale of the SFGO headquarters and a reduction in GRC-related revenue requirement due to a lower rate base and reduced expenses such as depreciation, property taxes, and operation and maintenance costs.[58]

PG&E's Application includes a $22 million credit for the electric generation portion of the estimated net gain on sale of its SFGO headquarters, reflecting year 3 of the amortization of the gain.[59] CalCCA witness Shuey identified two errors related to PG&E's treatment of the SFGO sale included in the 2024 Indifference Amount. First, PG&E did not include Revenue Franchise Fees and Uncollectibles (RF&U) in the calculation of the credit before including the credit in the Indifference Amount calculation.[60] This error overstates the Indifference Amount. PG&E corrected this error in its supplemental testimony submitted on August 15, 2023.[61]

Second, PG&E did not remove the cost of the SFGO headquarters from the GRC-related revenue requirement included in the 2024 Indifference Amount.[62] Through discovery, PG&E confirmed that the GRC-related costs in its Application are based on the authorized 2020 GRC revenue requirement plus attrition for 2021 and 2022.[63] The cost to own and operate the SFGO was included in the 2020 GRC because, at the time, PG&E was using SFGO as their headquarters. Now that PG&E has sold SFGO, PG&E should have removed the cost of SFGO from the GRC-related costs in its Application.

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57 CalCCA-01 at 26:3-11.

58 *Id*.

59 PG&E-01 at Table 9-1.

60 CalCCA-01 at 26:16-18.

61 PG&E-02 at 2:15 – 3:5.

62 CalCCA-01 at 26:20-21.

63 *Id*., Attachment B (PG&E's response to CalCCA data request 3.04).

CalCCA identified the same issue in PG&E's 2023 ERRA Forecast proceeding. In that case, PG&E agreed that an adjustment was required to remove SFGO costs from the GRC-related revenue requirement until the pending 2023 GRC Phase 1 is implemented.[64] PG&E's 2023 GRC remains pending before the Commission, and resolution is not expected prior to finalizing the 2024 ERRA Forecast. Consequently, PG&E should again remove SFGO costs from its GRC-related costs in this Application, until the GRC is reflected in rates. Extending the GRC-related cost reductions through at least the end of 2023 results in an incremental credit of $17.4 million allocated to electric generation.[65] Of the $17.4 million credit, $17 million is allocated to the PCIA and will reduce the 2024 Indifference Amount.[66]

In rebuttal testimony, PG&E agreed with CalCCA, and committed to including a $17 million GRC-related adjustment in its PCIA revenue requirement.[67] In response to a CalCCA discovery request, PG&E further stated it will include this adjustment in its October Update.[68] CalCCA will review PG&E's October Update to confirm that adjustment has been made.

C. <u>Scoping Issue 6</u>: PG&E should adjust its PCIA revenue requirement to reflect the removal of Diablo Canyon Unit 1 from the PCIA effective November 2, 2024

The Diablo Canyon Power Plant will soon be retired or enter extended operations.[69] Diablo Canyon Unit 1 will retire or enter extended operations on November 2, 2024, and Unit 2 will retire or enter extended operations in 2025.[70] While PG&E currently recovers the above-market costs

64 *Id*. at 27:5-8.

65 *Id*. at 27:12-13.

66 *Id*. at 27:13-14.

67 PG&E-03 at 28:17.

68 CalCCA-02 (PG&E response to CalCCA data request 6.12).

69 CalCCA-01 at 27:19.

70 *Id*. at 27:20-21.

associated with Diablo Canyon through the PCIA, it will no longer recover those costs through the PCIA once each Unit retires or enters extended operations.[71]

PG&E proposes to remove Diablo Canyon Unit 1 GRC-related revenue requirement from the PCIA calculation effective November 2, 2024.[72] CalCCA witness Shuey observed that PG&E removed the fuel costs and generation output of Diablo Canyon Unit 1 for November and December of 2024; however, as demonstrated in Table 4-6 of PG&E's Prepared Testimony, PG&E only removed the RA capacity associated with Diablo Canyon Unit 1 for December 2024.[73] Given that Diablo Canyon Unit 1 will be removed from the PCIA effective November 1, 2024, PG&E should make an adjustment to remove an additional month of Diablo Canyon Unit 1 RA capacity from the calculation of the 2024 Indifference Amount. Removing an additional month of RA reduces Diablo Canyon Unit 1 annual average Retained RA by 95 MW, with a corresponding reduction of [redacted] to the market value of capacity included in the Indifference Amount.[74] This adjustment increases the 2024 Indifference Amount by [redacted], and therefore would increase PCIA rates, all else equal.[75] PG&E has agreed to make this adjustment in the October Update.[76]

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71 *Id*. at 27:21-28:2.

72 PG&E-01 at 9-12:11 – 9-13:1.

73 *Id*. at Table 4-6.

74 CalCCA-01 at 28:12-14

75 *Id*. at 28:14.

76 *Id*., Attachment B (PG&E's response to CalCCA data request 2.06).

IV. ISSUES RAISED IN THIS TRACK THAT HAVE BEEN DEFERRED TO A FUTURE TRACK

A. <u>Original Scoping Issue 9a</u>: The Commission should defer making any findings, conclusions, or orders with respect to PG&E's proposal to modify its Electric Supply Administration (ESA) cost allocation methodology

In this proceeding, PG&E proposes to modify its approved methodology for allocating ESA costs between its ERRA, PABA and New System Generation Balancing Account (NSGBA).[77] Under PG&E's existing approach, approved via Advice Letter 5440-E, PG&E offsets its authorized gross procurement costs by the market value of generation resource attributes (*i.e.*, the "net authorized revenue requirement" applicable to each balancing account) when calculating its allocation rates.[78] PG&E proposes to modify that approach and allocate ESA costs to ERRA, PABA and NSGBA based on each balancing account's *gross* authorized revenue requirement.[79] In other words, under PG&E's proposal, the utility would no longer offset authorized gross procurement costs by the market value of generation attributes when determining allocation rates.

PG&E's proposal to modify its ESA cost allocation methodology was originally within the scope of this phase of this proceeding as Scoping Issue 9a.[80] As such, CalCCA witness Shuey addressed that proposal in his testimony. Among other things, Mr. Shuey recommended removing two months of Diablo Canyon Power Plant (DCPP) Unit 1 costs from the calculation of common cost allocation factors,[81] to reflect the fact that DCPP Unit 1 will no longer be a PCIA-eligible

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77 PG&E-01 at 9-9 – 9-12.

78 CalCCA-01 at 19:10-14.

79 PG&E-01 at 9-10:21-29.

80 Scoping Memo at 3.

81 *See* CalCCA-02 (PG&E response to CalCCA data request 6.10) (confirming PG&E's proposed common cost allocation factors are based on the 2023 gross costs which include Diablo Canyon Power Plant in the legacy utility owned generation PCIA Vintage for a full 12 months).

resource effective on November 2, 2024.[82] This modification would reduce the allocation of ESA costs to the PCIA.[83] Should the Commission authorize extended operations at DCPP,[84] Mr. Shuey noted it would be appropriate for an allocated share of ESA costs to follow other DCPP costs for recovery from customers responsible for the cost of extended operations (*i.e.*, those costs should no longer be allocated to the PCIA, consistent with PG&E's treatment of DCPP's extended operations costs).[85]

On August 1, 2023, however, the Administrative Law Judge issued a ruling directing parties to comment on certain issues related to PG&E's "Fixed Generation Costs." [86] Administrative Law Judges in SCE and San Diego Gas & Electric Company's parallel 2024 ERRA Forecast proceedings issued substantially similar rulings. Among other things, those rulings asked the IOUs to identify their "Fixed Generation Costs" in their ERRA Forecast proceedings.[87] In response to that Ruling, PG&E identified its ESA costs as one of the utility's "Fixed Generation Costs."[88] In reply, CalCCA recommended the Commission address PG&E's allocation of ESA costs in a Phase II of this proceeding in order to ensure the Commission addresses the allocation and recovery of fixed common costs consistently and comprehensively (across common cost

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[82] CalCCA-01 at 21:22-22:3. Note PG&E confirmed it has removed Diablo Canyon Power Plant Unit 1 from the legacy utility owned generation PCIA vintage for the Indifferent Amount forecast effective November 2, 2024. *See* CalCCA-02 (PG&E response to CalCCA data request 6.09).

[83] CalCCA-01 at 22:11-12.

[84] The Commission is currently considering this issue in R.23-01-007.

[85] CalCCA-01 at 23:3-10.

[86] Administrative Law Judge's Ruling Regarding Fixed Generation Costs (Aug. 1, 2023).

[87] *Id*. at 1.

[88] PG&E Response to Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs at 2 (Aug. 16, 2023).

categories and across the three IOU service territories).[89]

On October 9, 2023, ALJ Long issued a ruling deferring consideration of the fixed generation costs issues identified in the August Fixed Generation Cost Ruling until after the Commission's decision targeted for the December 14, 2023 voting meeting.[90] Importantly, the Ruling clarifies that the issue regarding PG&E's proposal to change the methodology for allocating ESA costs, identified as Issue 9a in the Scoping Memo, is a fixed generation cost issue that will not be addressed in the decision targeted for the Commission's December 14, 2023 voting meeting.[91] The Ruling further states that PG&E's proposal will be addressed at a pre-hearing conference on January 9, 2024, in which the Commission will more broadly consider an expedited Track 2 to address fixed generation cost issues.[92] Accordingly, the Commission should not issue any findings, conclusions, or orders with respect to PG&E's proposal to modify its ESA cost allocation methodology in its Decision, but should direct PG&E to revert to its existing methodology for allocating ESA costs (based on net authorized revenue requirements) for the purpose of 2024 ratemaking, because any change to PG&E's methodology will not be addressed until after the December 14, 2023 voting meeting. CalCCA will address the allocation of DCPP-related common costs, as well as any other issue related to PG&E's proposal to modify its ESA cost allocation methodology, during the January 9 pre-hearing conference and in any future track or phase of this proceeding in which that issue is in scope.

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89 Reply Comments of CalCCA in Response to ALJ Ruling Regarding Fixed Generation Costs at 9 (Aug. 23, 2023).

90 Administrative Law Judge's Ruling Regarding Fixed Generation Costs at 2 (Oct. 9, 2023).

91 *Id*.

92 *Id*.

V. CONCLUSION

For the foregoing reasons, CalCCA requests that the Commission:

- Approve PG&E's proposal to apply excess RECs from prior years to meet its Minimum Retained RPS obligations for the 2024 forecast year; its proposal to charge bundled customers for those RECs in 2024; and its proposal to credit applicable PABA vintages for those RECs at the 2024 RPS Adder;

- Direct PG&E to apply RECs towards its 2024 Minimum Retained RPS requirement on a "first-in first-out" basis consistent with CalCCA's proposed methodology, and to make correcting entries to the 2023 PABA to reflect that methodology;

- Approve PG&E's proposal to extend the PUBA rate adder in 2024, and find that it is reasonable for PG&E to close the PUBA rate adder once the balance in that account reaches $1 million, or at the end of 2024, whichever is sooner, via a Tier 1 Advice letter;

- Adjust PG&E's PCIA revenue requirement to (1) reduce the General Rate Case revenue requirement to reflect the sale of PG&E's SFGO, and (2) adjust the market value of capacity to remove Diablo Canyon Unit 1 November 2024 RA;

- Apply the legal standard discussed in this Opening Brief to the October Update; and

- Defer making any findings, conclusions or orders with respect to PG&E's proposal to modify its methodology for allocating ESA costs until after the Commission decision targeted for the December 14, 2023 meeting, consistent with the Administrative Law Judge's Ruling Regarding Fixed Generation Costs issued on October 9, 2023, but should direct PG&E to revert to its existing methodology for allocating ESA costs (based on net authorized revenue requirements) for the purpose of 2024 ratemaking.

CalCCA reserve their right to modify these recommendations based on updated information presented in PG&E's October Update, and to address other issues raised therein, via comments on the October Update or any further process the Commission may adopt.

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Respectfully submitted,

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