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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2023. (U39M)	Application No. 21-06-021 (Filed June 30, 2021)

OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON PROPOSED DECISION AND ALTERNATE PROPOSED DECISION ON TEST YEAR 2023 GENERAL RATE CASE FOR PACIFIC GAS AND ELECTRIC COMPANY

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On behalf of the Joint CCAs

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SUMMARY OF RECOMMENDATIONS

With respect to Pacific Gas and Electric Company's ("PG&E") twelve hydroelectric asset life extension requests at issue in this proceeding, the Commission should revise the Proposed Decision to: (1) find that these extensions constitute new generation commitments, (2) find that these new commitments were made on behalf of PG&E's bundled customers, and (3) order PG&E to effectuate the Joint CCAs' re-vintaging recommendations for these new commitments such that when each asset reaches its original end of life date, the resource's full revenue requirement shifts to a new vintage assignment corresponding to the year the Commission approved the decision to extend the resource's life. The specific re-vintaging orders recommended by the Joint CCAs are included in Appendix A hereto.

The Proposed Decision should be revised to clarify that, in its testimony concerning any proposed new investments in utility-owned generation ("UOG") resources in its future general rate cases ("GRCs"), PG&E must include a separate forecast of the incremental costs associated with the new investment in UOG.

The Proposed Decision should be revised to order that, in future GRCs, to the extent that PG&E is seeking cost recovery for battery-related costs, it must provide testimony on the functions that it proposes the batteries serve, and functionalize the associated costs according to the principles of cost causation.

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Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2023. (U39M)	Application No. 21-06-021 (Filed June 30, 2021)

OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON PROPOSED DECISION AND ALTERNATE PROPOSED DECISION ON TEST YEAR 2023 GENERAL RATE CASE FOR PACIFIC GAS AND ELECTRIC COMPANY

Pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the City and County of San Francisco ("CleanPowerSF"), East Bay Community Energy ("EBCE"), Marin Clean Energy ("MCE"), Peninsula Clean Energy Authority ("PCE"), Pioneer Community Energy, San José Clean Energy ("SJCE"), Silicon Valley Clean Energy Authority ("SVCE"), and Sonoma Clean Power Authority ("SCP") (collectively, the "Joint CCAs") hereby submit these Opening Comments on Administrative Law Judges DeAngelis and Larsen's *Proposed Decision on Test Year 2023 General Rate Case for Pacific Gas and Electric Company* ("Proposed Decision" or "PD")[1] and Commissioner Reynolds' *Alternate Proposed Decision on Test Year 2023 General Rate Case for Pacific Gas and Electric Company* ("APD").[2]

Assigning costs to customers in line with cost causation—*i.e.*, such that customers only pay for the costs incurred on their behalf—is a fundamental tenet of ratemaking. The Commission

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[1] Application ("A.") 21-06-021, *Proposed Decision on Test Year 2023 General Rate Case for Pacific Gas and Electric Company* (Sept. 13, 2023) ("Proposed Decision").

[2] A.21-06-021, *Alternate Proposed Decision on Test Year 2023 General Rate Case for Pacific Gas and Electric Company* (Sept. 13, 2023) ("APD"). As the PD and the APD's discussions of the Joint CCAs' issues are identical, the Joint CCAs' discussion herein regarding the PD's treatment of these issues should be understood to apply equally to the APD.

recently highlighted, in Pacific Gas and Electric Company's ("PG&E") most recent Phase I general rate case ("GRC"), the importance of ensuring that PG&E's cost assignment proposals are consistent with the principles of cost causation.[3] Throughout this proceeding, the Joint CCAs have built a detailed record on the specific cost assignment issues in this case that will determine whether community choice aggregators ("CCAs") are able to fairly compete with PG&E as alternative generation providers.

Specifically, the Joint CCAs have focused on cost causation issues that arise in: (1) assigning generation costs to the appropriate Power Charge Indifference Adjustment ("PCIA") vintage year, and (2) functionalizing battery asset costs between the utility's distribution and generation functions. While the focus of many stakeholders and decision makers in this proceeding may understandably be drawn to newsworthy undergrounding proposals and substantial rate increases, this GRC is also the only available venue for ensuring that these considerable rate increases are assigned in accordance with the principles of cost causation.

For years, CCA parties have raised concerns in various proceedings about investor-owned utilities ("IOUs") assigning the costs associated with new generation commitments to unbundled customers by simply re-investing in older generation assets.[4] In response, the Commission has explicitly recognized that such concerns are well founded and should be addressed with regard to specific assets in utility-specific GRCs.[5] If these issues are not addressed here, current CCA ratepayers—who comprise the majority of ratepayers in PG&E's service territory—will be on the hook for new costs associated with PG&E's new investments in older utility-owned generation ("UOG") resources in perpetuity. This will occur despite the fact that these customers already

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3 Decision ("D.") 20-12-005, p. 316, Finding of Fact 356, and Conclusion of Law 119.
4 Exh. JCCA-01 at 15 and n. 29; D.21-07-013, p. 21; D.18-10-019, p. 135.
5 D.18-10-019, p. 135.

departed PG&E's bundled service well before PG&E proposed these new generation resource commitments. These vintaging issues are inextricably tied to affordability concerns; if PG&E can keep assigning the costs of its massive re-investments in older assets to all customers, unbundled customers will continue to experience unjustified cost increases in violation of state law.[6]

Similarly, if asset cost functionalization issues are not addressed here, PG&E will continue to propose that its new investments in battery resources be functionalized entirely to the distribution function, even if those resources will be used to serve both the distribution and the generation functions. If the Commission fails to address these concerns here, CCA customers will continue to subsidize bundled customers for costs that are not being incurred to serve them, in violation of state law.[7]

In the Proposed Decision, the Commission largely declines to take on these issues to ensure that PG&E's costs are assigned in line with cost causation. With respect to the Joint CCAs' re-vintaging proposals for the 12 hydroelectric asset life extensions at issue in this case, the PD's primary reason articulated for this quick dismissal is that there is not "sufficient record" to address this proposal.[8] However, this hasty conclusion is in error and does not accurately reflect the record. In fact, the Joint CCAs have demonstrated on the record that these extensions constitute new generation resource commitments made on behalf of bundled customers; that the energy and capacity benefits of these asset life extensions will flow entirely to bundled customers; that the Joint CCAs' re-vintaging proposals would not interfere with the goal of ensuring that CCA customers pay their fair share of decommissioning costs; that the Commission can easily effectuate these recommendations simply by adopting the Joint CCAs' pre-drafted ordering paragraphs that

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6 *See* Cal. Pub. Util. Code § 366.2(a), (f); Cal. Pub. Util. Code §§ 365.2, 366.3.

7 *See* Cal. Pub. Util. Code § 366.2(a), (f); Cal. Pub. Util. Code §§ 365.2, 366.3.

8 Proposed Decision, p. 499.

explain in detail how each asset should be re-vintaged; and that these issues must be addressed in this case because PG&E has made clear they *cannot* be deferred to the Energy Resource Recovery Account ("ERRA") proceedings.

While the PD declines to fully adopt the Joint CCAs' broader vintaging framework for future GRCs, it does recognize the importance of adopting a requirement that PG&E provide detailed information in its future GRCs regarding its proposed new investments in UOG. This is an important first step forward in holding PG&E accountable for its new generation investments. Instead of maintaining the default assumption that all new investments in UOG should be placed in the existing PCIA vintage and thus paid for by all customers, this new filing requirement will ensure PG&E submits testimony justifying its assignment of costs to PCIA vintages for any significant new investment proposals that may constitute new commitments at existing UOG facilities. While this new requirement represents some progress on this longstanding issue, the current language in the PD does not describe in sufficient detail what information PG&E must include in this testimony.[9] The Commission should revise this portion of the PD to ensure that PG&E has adequate direction from the Commission as to precisely what this new testimony obligation entails.

Finally, with respect to battery functionalization, the PD errs in concluding these issues can or should be taken up in a rate design proceeding.[10] Functionalization is the process of assigning costs to a particular utility function, like generation or distribution, and then ensuring those costs are assigned to the proper functional revenue requirement. Since a Phase I GRC is where the Commission approves PG&E's functionalized revenue requirements, these issues must be addressed in Phase I GRCs. As such, the Commission should revise the PD to make clear that,

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[9] *Id.*, p. 500.
[10] *Id.*, p. 424.

consistent with the PD's new testimony requirement for UOG investments, PG&E must also submit testimony in its future GRCs justifying its proposed cost functionalization for new battery resources.

As reflected in the Joint CCAs' advocacy on these cost assignment issues in this proceeding, the Joint CCAs are deeply committed to maintaining affordability in the transition to a clean energy economy. On this point, on a broader level, the substantial rate increases of both the PD and the APD are concerning. The Joint CCAs urge the Commission to reconsider certain elements of the PD and APD that contribute significantly to these massive rate increases. First, the PD's adoption of an $842 million inflation adder is unreasonable, and should be reduced to 25 percent of the requested increase.[11] While the APD does in fact limit the inflation adder to 25 percent of PG&E's request,[12] these savings are more than offset by its $4.27 billion increase in capital spending[13]—an increase that would substantially impair affordability in the decades to come. The Commission should do everything in its power to shield ratepayers from drastic rate impacts, and specifically, should adopt a modified version of the PD that reduces the inflation adder to 25 percent of PG&E's request to ensure the rate increases coming out of this proceeding are just and reasonable.

I. The PD Errs in Concluding There Is Not Sufficient Record To Address the Joint CCAs' Re-Vintaging Recommendations

The Proposed Decision declines to adopt the Joint CCAs' re-vintaging recommendations for the 12 hydro asset life extensions at issue in this case on the basis that there is not "sufficient record" to do so.[14] It is unclear from the brief discussion in the PD precisely how or why the

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11 *See* Proposed Decision, pp. 720-721.
12 APD, pp. 735-737.
13 *Id.*, Conclusion of Law 83.
14 Proposed Decision, p. 499.

Commission came to this conclusion that the record is lacking, or what additional information or evidence would be needed for the Commission to act on the Joint CCAs' proposals. However, the Commission does reference one specific item raised by PG&E—the treatment of decommissioning costs—in its recommendation that, as a next step, the Joint CCAs "propose a specific approach for re-vintaging the 12 hydro resources that addresses whether and how to ensure departed customers pay a share of decommissioning those resources in another proceeding, such as . . . PG&E's [ERRA forecast proceedings.]"[15]

The PD errs in concluding there is not sufficient record basis for adopting the Joint CCAs' re-vintaging recommendations, and also errs to the extent that it concludes that the record is incomplete because of a failure to fully address the issue of decommissioning cost recovery. Further, the PD errs in concluding that this issue can be effectively addressed in future ERRA proceedings. PG&E proposed in this GRC to significantly extend the lives of these facilities to allow them to continue to produce energy and capacity for many years in the future at a time when its bundled load is sharply declining. In response to PG&E's proposals, the Joint CCAs built a detailed record demonstrating why re-vintaging issues must be taken up in this proceeding where these asset extensions are at issue. The Joint CCAs also provided specific recommendations for how the Commission can effectuate the Joint CCAs' re-vintaging recommendations for each asset. The Commission should revise the PD to accurately reflect the record on these issues.

A. The Joint CCAs Have Thoroughly Demonstrated On the Record Why the 12 Hydro Assets Must Be Re-Vintaged and How to Effectuate These Recommendations

The record in this proceeding reflects that (1) PG&E's current vintaging policy surrounding asset life extensions for UOG violates state law, (2) the hydro asset life extensions at issue in this

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15 *Id.*, pp. 499-500.

case constitute new "commitments" for purposes of PCIA vintaging, (3) PG&E is proposing these hydro asset life extensions on behalf of its bundled customers, and (4) the Commission can ensure that the costs associated with these assets are recovered in accordance with the principles of cost causation by adopting the Joint CCAs' re-vintaging recommendations set forth in Appendix A to the Joint CCAs' Opening Brief (and reproduced in Appendix A hereto). The PD errs in concluding—without any supporting references or discussion—that there is not "sufficient record" to adopt these recommendations.[16]

1. PG&E's Current Vintaging Policy Surrounding Asset Life Extensions for UOG Violates State Law

The Commission's foundational policies on PCIA vintaging evolved out of the Legislature's clear statutory directives prohibiting cost shifts between bundled and unbundled customers and requiring compliance with the indifference principle.[17] State law requires the Commission to ensure that bundled customers do not experience any cost increases as a result of other customers electing to receive service from other providers, and 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."[18] The PCIA rate mechanism is designed to effectuate these statutory requirements; it ensures that when customers depart an IOU's bundled service, they remain responsible for costs—and only those costs—previously incurred on their behalf.[19] The

16 *Id*.
17 Cal. Pub. Util. Code § 366.2(a), (f); Cal. Pub. Util. Code §§ 365.2, 366.3.
18 Cal. Pub. Util. Code § 365.2 (emphasis added). *See also id.* § 366.3.
19 Cal. Pub. Util. Code §§ 366.2, 366.3; D.18-10-019, p. 3.

Commission has confirmed that departed customers "should bear *no* cost responsibility for . . . commitments the IOU makes after their departure."[20]

The Joint CCAs have shown clearly on the record how PG&E's current vintaging policies violate these statutory mandates by failing to recognize certain new investments in existing generation assets as new resource commitments triggering vintaging reconsideration.[21] Specifically, under the current methodology, when PG&E decides to expand the capacity of its facilities to serve bundled customers, change its facilities' operations to achieve different objectives for bundled customers, or extend the facilities' lives to serve bundled customers' needs in the future, all costs associated with these new investments go to the resource's original vintage and are thus paid by both bundled and unbundled customers.[22] Given that such costs were not actually incurred on behalf of departed load—*i.e.*, they are new spending commitments made on behalf of bundled customers—state law requires that departed load does not experience any cost increases as a result of these investments.[23]

To be clear, not *all* investments in existing UOG would constitute a "new commitment." The Joint CCAs acknowledge that reasonable ongoing operations and maintenance ("O&M") and capital investments are needed to keep a resource operational through its expected useful life. The Joint CCAs further acknowledge that unbundled customers bear responsibility for such reasonable ongoing costs, even if they no longer receive the generation or resource adequacy ("RA") benefits from the facility.

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20 D.08-09-012, p. 59 (emphasis added).

21 A.21-06-021, *Opening Brief of the Joint Community Choice Aggregators*, pp. 11-23 (Nov. 4, 2022) ("Joint CCAs Opening Brief"); A.21-06-021, *Reply Brief of the Joint Community Choice Aggregators*, pp. 3-4 (Dec. 9, 2022) ("Joint CCAs Reply Brief").

22 Exh. JCCA-01 at 3:15 to 4:2.

23 Cal. Pub. Util. Code § 365.2.

But when PG&E extends any UOG plant's end of life date—either through life-extending capital investments, or via an administrative process (*e.g.*, an updated depreciation study, like in the instant proceeding)—that triggers the need for new and distinct capital and O&M investments beyond those contemplated when PG&E initially committed to the resource. Nevertheless, in these scenarios, PG&E does not propose to adjust the vintaging of the associated plant.[24] All costs associated with extensions of the lives of those resources remain in the "Legacy UOG vintage,"[25] a vintage for which virtually all unbundled customers pay.[26] Again, this policy violates the indifference principle because the costs associated with these extensions are not being incurred on unbundled customers' behalf, yet unbundled customers remain responsible for these costs for as long as the utility continues to re-invest in this asset.[27]

The need to reconsider the IOUs' default vintaging policy on UOG is not solely a concern among the CCAs. The Commission and the Legislature have both acknowledged the need to re-vintage assets in certain circumstances. For instance, the Commission has recognized CCAs' concerns regarding the treatment of ongoing costs of UOG, and the need to evolve the current policy framework to ensure that such costs are equitably allocated.[28] It has also found, in certain circumstances, that modifications to existing vintaging treatment should occur—for instance, in the context of utility power purchase agreement renewals/extensions and amendments.[29] The Legislature has also recently recognized, in the context of the Diablo Canyon plant extension, that

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24 Exh. JCCA-01, Attachment AMG-3, DR 13 Q5.

25 *Id.*; 11 Tr. 2022:22-28 (PG&E – Witnesses Rybka, Barry, and Doidge).

26 11 Tr. 2023:7-11 (PG&E – Witnesses Rybka, Barry, and Doidge).

27 Joint CCAs Opening Brief, pp. 20-22.

28 D.18-10-019, p. 135.

29 *See* Joint CCAs Opening Brief, pp. 17-19.

the extension justified removing the asset from the PCIA as of the originally anticipated retirement date and creating a new cost recovery mechanism for the costs associated with the extension.[30]

Thus, not only does the record of this proceeding show that the current approach for asset life extensions violates the indifference principle, but it also demonstrates that the Commission and the Legislature have ordered modifications to vintaging treatment in similar situations in the past when an IOU's default vintaging approach would violate the indifference principle.

2. The Hydro Asset Life Extensions At Issue In This Case Constitute New "Commitments" For Purposes of PCIA Vintaging

In this proceeding, PG&E sought Commission approval of its depreciation study in Exhibit PG&E-10, which proposed to extend the useful lives of nine of PG&E's hydro plants. It also sought continued cost recovery from three other hydro facilities for which PG&E adopted changes to end of life date assumptions in recent GRCs. If these requests are approved in this GRC without adoption of the Joint CCAs' re-vintaging recommendations, PG&E will use the newly adopted end of life dates to extend the period (beyond the original end of life date) during which PG&E can charge unbundled customers for all associated asset costs, including new capital and O&M costs incurred after that original end of life date.

The Joint CCAs demonstrated in this proceeding that these 12 asset life extensions should constitute new generation "commitments" for purposes of PCIA ratemaking.[31] Specifically, the record shows that (1) asset end of life dates included in PG&E's depreciation studies are the best available estimates—made by PG&E's own experts—of the expected life of the asset at the time of the initial asset investment,[32] (2) PG&E uses these end of life assumptions to make significant

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30 Cal. Pub. Util. Code § 712.8(f), (g), (h).

31 Joint CCAs Opening Brief, pp. 23-25.

32 PG&E has admitted on the record that these end of life dates are PG&E's own estimates, "based on [the] best professional judgement" of their experts, of the "specific or probable retirement dates [of the assets]" which it "use[s] for purposes of ratemaking." 11 Tr. 2021:4-12 (PG&E – Witnesses Rybka,

ratemaking decisions: based on these assumptions, PG&E sets depreciation rates such that it is able to recover the asset revenue requirement, including decommissioning costs, by the original end of life date,[33] and (3) any extension to these end of life dates in PG&E's depreciation study is a direct result of a new, voluntary decision by PG&E to invest in existing UOG resources instead of pursuing other alternatives, including retirements or asset sales.[34]

Thus, the record reflects that PG&E's own end of life estimates included in its depreciation studies provide the best available estimate of the cost recovery period that should be associated with generation asset commitments, and that the asset life extensions at issue in this case should be treated as new commitments.

3. PG&E is Proposing These Asset Life Extensions on Behalf of Its Bundled Customers

The record also reflects that PG&E is pursuing these new generation resource commitments *on behalf of* its bundled customers.[35] The Joint CCAs have shown both that PG&E makes these new investments in light of and to serve bundled customers' energy and compliance

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Barry, and Doidge). PG&E therefore acknowledges that these dates are its *own best estimate* of how long it expects a resource to last for purposes of establishing depreciation rates, yet it offers no logical reason why these same PG&E estimates should not serve this same purpose in the context of PCIA ratemaking. The Joint CCAs established on the record that, contrary to PG&E's assertions, end of life date assumptions in PG&E's depreciation studies are not "arbitrary." *See* Joint CCAs Reply Brief, pp. 4-7.

[33] PG&E has confirmed that it uses these estimates to calculate the asset's remaining life, which it then uses to calculate depreciation rates. Exh. PG&E-10 at 11-12; Exh. JCCA-01 at 31:21 to 32:7. This is a well-established ratemaking approach; the Commission has made clear that in approving a utility depreciation study, it is approving the "basis for establishing the authorized depreciation expense[,]" and that adjustments to end of life estimates and other depreciation parameters allow the utility to "recover the remaining service value by the time the asset is retired from service." D.19-09-025, p. 245; D.04-07-022, p. 262; D.19-09-025, p. 245.

[34] PG&E has conceded that these decisions to extend the life of these hydro assets are *voluntary* decisions to invest new capital in these older resources, instead of pursuing other available alternatives. Exh. JCCA-32 (subpart (b)); 11 Tr. 2024:4-7 (PG&E – Witnesses Rybka, Barry, and Doidge); Exh. JCCA-18 (subpart (f)); 11 Tr. 2024:8-14 (PG&E – Witnesses Rybka, Barry, and Doidge).

[35] Joint CCAs Opening Brief, pp. 25-33.

needs, and that any unquantified public benefits or reduction in PCIA rates resulting from these new investments are irrelevant to the question of cost responsibility.[36]

As an initial matter, since PG&E only has energy and capacity obligations on behalf of its bundled customers,[37] and the two largest benefits associated with these asset life extensions are energy value and capacity value,[38] it is logical to conclude that PG&E is pursuing these extensions on behalf of its bundled customers. PG&E nonetheless denied this fact throughout the proceeding.

In its testimony and in discovery responses, PG&E heavily relied on the claim that its relicensing decisions do *not* take into account bundled customers' energy or compliance needs[39] to support its position that these decisions are made on behalf of *all* customers. The Joint CCAs demonstrated during evidentiary hearings that this is not the case, presenting PG&E's witnesses with PG&E testimony and a Commission decision that make clear that bundled customer energy needs are in fact *central* to these hydro relicensing decisions.[40] Subsequently, PG&E abandoned these arguments.[41] With respect to the other primary benefit associated with these hydro extensions—RA capacity value—PG&E similarly confirmed during hearings how these benefits flow to just its bundled customers. PG&E affirmed that, in each of the last five years, PG&E has generally used all or almost all of the units associated with the twelve hydro facilities at issue in this proceeding toward its RA requirements.[42] These admissions during hearings confirmed that these asset life extensions represent investment decisions made on behalf of bundled customers.

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36 *Id*.
37 11 Tr. 2025:18 to 2026:8 (PG&E – Witnesses Rybka, Barry, and Doidge).
38 11 Tr. 2026:9-19 (PG&E – Witnesses Rybka, Barry, and Doidge); Exh. JCCA-03 (subpart (c)).
39 Exh. PG&E-18 at 9-6:1-15; Exh. JCCA-18.
40 *See* Joint CCAs Opening Brief, pp. 26-29.
41 *See* A.21-06-021, *PG&E's Opening Brief*, pp. 624-631 (Nov. 4, 2022) ("PG&E Opening Brief").
42 11 Tr. 2030:8-24 (PG&E – Witnesses Rybka, Barry, and Doidge).

Similarly, PG&E had originally justified its position with claims in testimony and discovery that certain benefits—unmonetized public benefits and the possibility of a financial benefit via a reduction in the PCIA[43]—flow to all customers from these resource extensions.[44] As an initial matter, the relevant question is not whether unbundled customers *benefit* from asset life extensions, but rather whether these new investments in UOG assets were *incurred on their behalf*.[45] Nevertheless, the Joint CCAs demonstrated during evidentiary hearings that (1) the public benefits claimed by PG&E cannot be quantified, and CCA resources are also capable of providing the same benefits to all customers, yet CCAs are unable to recover associated costs from bundled customers, and (2) net credits to the PCIA from Legacy UOG resources are rare, and new investments in these assets expose unbundled customers to financial risk, as they may very well result in *higher* PCIA rates.[46]

The record in this proceeding therefore clearly shows that PG&E is undertaking these new resource commitments on behalf of its bundled customers, and that bundled customers are the beneficiaries of these investments. To ensure these significant and unknown future costs of these new commitments are not improperly foisted on unbundled customers, the Commission should

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[43] Notably, while PG&E argued in this proceeding that potential net credits via the PCIA constitute a benefit to CCA customers that justifies continued cost recovery for UOG assets from these customers, it advanced arguments undermining this position in its most recent ERRA forecast proceeding, A.22-05-029. There, PG&E urged the Commission *not* to forecast a negative indifference amount that could flow through to CCA customers via a forecast rate credit, highlighting that the purpose of the PCIA rate is "to ensure equitable allocation of *above-market* portfolio costs", that the Commission has placed restrictions on potentially negative PCIA rates, and that there are many reasons why such forecast credits may not be likely to actually materialize. *See* A.22-05-029, *Opening Brief of PG&E*, pp. 32-36 (Oct. 14, 2022) (emphasis in original). It is notable that PG&E touted negative PCIA rates as a substantial benefit to CCA customers in one case while it argued *against* ratemaking policy to forecast and expeditiously disburse this benefit to CCA customers in another.

[44] Exh. PG&E-18 at 9-5:18-25; Exh. JCCA-03 (subpart (d)); Exh. JCCA-27; Exh. PG&E-18 at 9-5:25-30; Exh. JCCA-03 (subpart (b)); 11 Tr. 2042:7-14 (PG&E – Witnesses Rybka, Barry, and Doidge).

[45] D.08-09-012, Findings of Fact 2-3.

[46] *See* Joint CCAs Opening Brief, pp. 29-33.

find in this proceeding, before approving the asset life extensions, that these new commitments are being made on behalf of PG&E's bundled customers.

4. The Commission Can Ensure That the Costs Associated With These Assets Are Recovered In Accordance With the Principles of Cost Causation By Adopting the Joint CCAs' Re-Vintaging Recommendations Set Forth in Appendix A to the Joint CCAs' Opening Brief

The Joint CCAs also demonstrated on the record precisely how the Commission can ensure that cost causation ratemaking principles are maintained for these asset life extensions. Specifically, the Commission can order PG&E to assign new PCIA vintages to these resources, to be effectuated when each asset reaches its original[47] end of life date. When each UOG asset reaches that original end of life date, the resource's full revenue requirement would be shifted to a new vintage assignment, as determined by the year the Commission approved the decision to extend the resource's life.[48]

The Joint CCAs provided these re-vintaging recommendations for each of the 12 hydro assets in two formats: (1) in a table in the Joint CCAs' Direct Testimony (showing the timing of the changes in vintage assignments and the ultimate end date for recovery via the PCIA for each asset),[49] and (2) in Appendix A of the Joint CCAs' Opening Brief (providing draft ordering paragraphs that the Commission could adopt in a final decision in this case to effectuate each of

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[47] The Joint CCAs have recommended that the "original end of life date" be determined by the end of life date set for the resource in the 2014 GRC, as that year provides the most recent and clear starting point to initially define the end of life dates for UOG generation plants on a going forward basis given that there were almost no unbundled customers in 2014. *See* Exh. JCCA-01, Section II.

[48] These new end dates do not impact the revenue requirement for any generating plants in this GRC; rather, they create new end dates after which the facilities' revenue requirements would no longer be applied to their original vintage assignments.

[49] Exh. JCCA-01 at 41, Table 5. *See also id.*, Attachment AMG-2 (providing additional details regarding the plants shown in this table, and a full list of hydroelectric plants that have seen extensions in their end of life dates since 2014).

these re-vintaging recommendations).[50] In this proceeding, all the Commission needs to do to effectuate these changes is to adopt these ordering paragraphs; PG&E will then be able to implement the appropriate tracking and categorization for these asset revenue requirements in an ERRA proceeding.[51]

The record on these re-vintaging recommendations for PG&E's hydro assets is clear, thorough, and detailed. It contains both the full justification for these vintaging changes and a clear methodology to effectuate them. The PD errs in concluding that there is not "sufficient record" to adopt these recommendations in this proceeding.[52]

B. The Joint CCAs Have Thoroughly Demonstrated On the Record How Their Re-Vintaging Recommendations Will Ensure That CCA Customers Pay Their Fair Share of Decommissioning Costs

While the PD does not explain why the Commission has concluded the record is not sufficient in this proceeding to adopt the Joint CCAs' re-vintaging proposals, it does mention one specific issue raised by PG&E: recovery of decommissioning costs.[53] Specifically, the PD indicates that, in a future proposal, the Joint CCAs should address "whether and how to ensure departed customers pay a share of decommissioning those resources."[54] To the extent this statement is suggesting that the Joint CCAs failed to address decommissioning costs in this case, it is in error.

In fact, the Joint CCAs demonstrated in briefing why PG&E's concerns[55] regarding the recovery of decommissioning costs are unfounded.[56] While it is *possible* this issue could arise in

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50 Joint CCAs Opening Brief, Appendix A.
51 *See* Joint CCAs Opening Brief, pp. 16-17.
52 Proposed Decision, p. 499.
53 *Id.*, pp. 499-500.
54 *Id.*
55 *See* PG&E Opening Brief, pp. 630-631.
56 Joint CCAs Reply Brief, pp. 15-17.

the context of re-vintaging other types of generation resources, it is not at all relevant in the context of PG&E's hydro assets. PG&E has established a separate decommissioning reserve for its hydro assets.[57] This reserve is recovered separately via PG&E's generation revenue requirement,[58] and it can be used to cover the decommissioning costs of *any* of PG&E's hydro assets.[59] Therefore, re-vintaging of a hydro asset's revenue requirement would not at all impact PG&E's ability to recover the asset's decommissioning costs from all responsible customers.[60] As PG&E tracks these decommissioning funds separately from each asset's individual revenue requirement, these decommissioning funds would not be re-vintaged under the Joint CCAs' proposal.

Moreover, even if these decommissioning costs were *not* recovered via a separate reserve, and even if, for some reason, PG&E had not recovered sufficient decommissioning costs from unbundled customers during the original depreciable life of the asset,[61] there is no reason why re-vintaging an asset's revenue requirement would prevent PG&E from recovering decommissioning costs from all responsible customers. In adopting re-vintaging orders, the Commission can easily make clear in its ordering paragraphs that decommissioning costs must be recovered equitably from both bundled and unbundled customers. Specifically, the Commission could order that, in the ERRA proceeding effectuating a particular re-vintaging recommendation, PG&E must implement a cost recovery method that recovers the asset's decommissioning costs equitably from all responsible customers—both bundled and unbundled. When an asset's vintaging treatment

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[57] *See* Exh. PG&E-5 at 8-12:7-17; Exh. PG&E-10 at 11-34:22 to 11-35:24.

[58] Exh. PG&E-10 at 11-32:1 to 11-35:24.

[59] *See* Exh. PG&E-5 at 8-12:7-17.

[60] *See id.*; Exh. PG&E-10 at 11-34:22 to 11-35:24.

[61] Note that as a general practice, PG&E adopts rates that collect decommissioning costs throughout the depreciation life of the asset, with annual accruals generally based on forecast retirement dates (*i.e.*, the end of life dates included in PG&E's depreciation studies). *See* Exh. PG&E-5 at 8-13:14-18. Under this cost recovery approach, unbundled customers generally pay their pro rata share of decommissioning costs during the original depreciation life of the asset.

changes, associated decommissioning costs can simply be recovered separately from the asset's re-vintaged revenue requirement, if needed.

The Joint CCAs have made clear on the record that they fully agree that unbundled customers should pay their fair share of decommissioning costs associated with assets procured on their behalf.[62] But in light of PG&E's current cost recovery methodology for hydro decommissioning costs, the Joint CCAs' recommendations will not at all impact PG&E's ability to recover decommissioning costs from unbundled customers. Further, even assuming PG&E did not have a separate cost recovery method for these assets, adopting the Joint CCAs' re-vintaging recommendations would not limit the Commission's ability to ensure decommissioning costs are equitably allocated. The PD should be revised to reflect that the Joint CCAs have thoroughly addressed this issue on the record, and that this is not a basis for deferring consideration of these re-vintaging proposals.

C. The Joint CCAs Have Thoroughly Demonstrated On the Record Why These Re-Vintaging Issues Should Be Resolved in This GRC

The PD's suggested path forward on these issues—that the Joint CCAs propose their re-vintaging recommendations in a future ERRA proceeding[63]—is inconsistent with the record in this proceeding and with recent Commission precedent. The PD ignores the Joint CCAs' extensive discussions on the record explaining why these re-vintaging issues *cannot* be raised in ERRA proceedings.[64] The Commission should not allow PG&E to continue to punt these issues from proceeding to proceeding so that it may avoid fixing these critical asset vintaging issues.

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62 Joint CCAs Reply Brief, pp. 15-17.

63 Proposed Decision, pp. 499-500.

64 Joint CCAs Opening Brief, pp. 16-17; Exh. JCCA-01 at 14:1 to 17:24, and 22:4-27.

PG&E's own admissions in discovery[65] make clear that Phase I GRCs—rather than ERRA forecast or other proceedings—are the appropriate venue for reviewing and approving changes to the vintaging treatment for UOG asset revenue requirements. The Joint CCAs have already attempted to raise re-vintaging issues in ERRA forecast proceedings, only to be informed by PG&E that the ERRA cases are not the appropriate venue for investigating issues surrounding reinvestments in UOG.[66] According to PG&E, once GRC revenue requirements are adopted, there is no way in the ERRA forecast proceedings to adjust the asset-specific revenue requirements or to delineate with respect to specific assets the costs attributable to the original investment versus new investments.[67] Therefore, if these costs are not analyzed and appropriately categorized in the adopted GRC revenue requirements, there simply will not be sufficient detail available in the subsequent ERRA proceeding to decipher what incremental generation costs should be re-vintaged.[68]

This back-and-forth via discovery with PG&E across various proceedings reveals that the only way for the Commission to address UOG re-vintaging issues in ERRA forecast proceedings would be for the Commission to approve specific vintaging recommendations associated with asset-level UOG revenue requirements in a prior GRC proceeding. Approved revenue requirements and associated vintaging orders from a GRC can subsequently be utilized by PG&E

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65 *See* Exh. JCCA-01 at 14:1 to 16:3.

66 *Id*. at 15 and n. 29.

67 *See id*. at 14:1 to 17:24. For purposes of generation ratemaking in its ERRA forecast proceedings, PG&E relies on the output of its Results of Operations model prepared in the GRC to divide the approved UOG revenue requirement into vintages to establish generation rates for a particular year. *Id*. at 18:1 to 19:8. The Joint CCAs requested PG&E provide a detailed description of its methodology for assigning the total Electric Generation revenue requirement from the GRC to cost recovery mechanisms determined via the utility's ERRA proceedings. PG&E objected to the request and declined to provide a description of the process. *See id*. at 14:3-9. However, PG&E made clear in its 2022 ERRA forecast Application, A.21-06-001, that the UOG costs included in the PCIA rates proposed in that docket had already been approved by the Commission in GRCs or other separate proceedings, and the details surrounding these costs could not be revisited in the ERRA proceeding. *See id*. at 14:1 to 16:3.

68 *Id*. at 22:6-17.

in an ERRA forecast proceeding to ensure appropriate vintage treatment for new investments in UOG.

Not only would it be practically impossible to take up these re-vintaging issues in ERRA proceedings absent such an order in the GRC, but it would also be inconsistent with recent Commission precedent. As the PD acknowledges,[69] in a 2018 decision coming out of the Order Instituting Rulemaking ("OIR") concerning PCIA policy issues, the Commission recognized the need to ensure that ongoing investments in UOG are equitably allocated, and directed the CCAs to take these issues up in GRCs.[70] Specifically, the Commission found:

> It is possible that new investments in an old power plant may represent such a significant overhaul of the facility as to justify a "re vintaging" of the facility. Likewise, it is possible that plant investments for certain upgrades may justify a different vintage treatment for those investments than for the underlying facility. But any such analysis must be fact-specific to the plants and spending in question, <u>***and is better suited to a GRC evaluating such spending***</u>.[71]

The Joint CCAs' vintaging recommendations in this proceeding are responsive to the Commission's specific directive here to address necessary modifications to UOG vintaging treatment within each utility's respective GRC proceeding.

In sum, the CCAs have raised re-vintaging issues in ERRA forecast proceedings, only to be rebuffed by PG&E on the grounds that it is not practically feasible to make these vintaging adjustments in the ERRA *after* these generation revenue requirements have been approved in GRCs.[72] The CCAs have also raised these issues in ERRA compliance proceedings, only to be directed to take these concerns to the then-active OIR setting policy across the IOUs on PCIA

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69 Proposed Decision, p. 499 ("While the Joint CCAs are correct that the Commission found in D.18-10-019 that in general these fact-specific vintaging considerations should be addressed in the relevant GRC . . .").

70 D.18-10-019, p. 135.

71 *Id*. (emphasis added).

72 Exh. JCCA-01 at 15 and n. 29.

matters.[73] However, the CCAs had in fact *already raised* re-vintaging issues in that OIR, and were directed by the Commission to take up these issues in utility-specific GRC proceedings.[74] The CCAs have now raised this issue in a GRC proceeding—as directed by both PG&E and the Commission—only to have the Commission now suggest that the CCAs return to the ERRA venue.

This issue cannot continue to be punted between various regulatory proceedings. The current vintaging policy for new investments in UOG violates state law, and the Commission recently directed the CCAs to address this issue in GRC proceedings. The Joint CCAs have built a detailed record in this proceeding on the new commitments at issue in this case that necessitate re-vintaging and have provided detailed draft ordering paragraphs that, if adopted, would allow these changes to be effectuated in a subsequent ERRA proceeding.

The Commission should revise the PD to acknowledge that it cannot dispose of these re-vintaging issues by simply punting them back to the ERRA proceedings. In recognition of the fact that this GRC proceeding has been established as the appropriate venue for these concerns, and that the Joint CCAs have built a detailed record in this proceeding, the Commission should also revise the PD to adopt the Joint CCAs' re-vintaging recommendations concerning the 12 hydro assets at issue in this case.

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[73] D.21-07-013, p. 21 ("The issue of how the Commission should prospectively address contract vintages is outside the scope of the instant proceeding. The record has not been developed to address this issue. Furthermore, this issue may affect the vintaging processes for all the investor-owned energy utilities in the State, who are not parties. For these reasons, the Commission's currently open proceeding, Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment, R.17-06-026, is more appropriate for considering how the Commission should address contract vintages for the utilities in the future, and we intend to explore these matters in that proceeding").

[74] D.18-10-019, p. 135.

II. The PD Should Be Revised To Give Clear Direction on the Specific Informational Requirements of the Testimony PG&E Must Submit On Its New Investments in UOG in Future GRCs

The PD does take one incremental step forward in addressing these UOG vintaging issues: it directs PG&E to submit testimony in its future GRCs when it is proposing certain new investments in its existing UOG assets, like asset life extensions, incremental capacity additions, and changes to the function of the asset.[75] Thus, in future testimony, PG&E will finally be required to justify its requested vintaging treatment for these kinds of new investments in UOG.

This new requirement is critical. Absent this order requiring PG&E to submit this kind of testimony in future GRCs, PG&E will continue to offer GRC and ERRA testimony that does not contend with these vintaging issues and that fails to provide key information critical to conducting the case-by-case re-vintaging reviews that the Commission has indicated should occur in GRCs.[76]

To ensure this new requirement is effective in establishing a record off of which the Commission and stakeholders can effectively assess vintaging issues in future GRCs, the Commission should clarify precisely what "details" concerning the proposal should be included in these future submissions.[77] Specifically, the PD should be revised to clarify that this testimony must include a forecast of the costs associated with the new investment in UOG—whether that new investment is in the form of an asset life extension, capacity addition, or changed UOG plant function. The Commission should require PG&E to separate out these incremental costs from the remainder of the costs associated with the relevant asset-specific revenue requirement. This type of detailed testimony will allow the Commission and stakeholders to assess these new investments more efficiently.

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75 Proposed Decision, p. 500.

76 *See* Exh. JCCA-01 at 14:1 to 16:3.

77 Proposed Decision, p. 500.

A separate forecast of the costs associated with these new investments is especially critical given that PG&E has confirmed that, unless these costs are identified and categorized appropriately in a GRC proceeding, it will be unable to effectuate vintaging modifications for these costs in a subsequent ERRA proceeding.[78] The Commission should proactively require PG&E to identify these incremental costs upfront so that the Commission and stakeholders can efficiently evaluate these proposals, and if appropriate, provide re-vintaging proposals for those segregated costs without excessive administrative burden and cost.

III. The PD Errs in Concluding That Battery Functionalization Issues Should Be Addressed in Rate Design Proceedings

The PD also errs in quickly dismissing the Joint CCAs' battery functionalization issues by concluding that the Commission should instead "consider this issue in a rate design proceeding."[79] Functionalization issues are addressed in Phase I GRCs where functionalized revenue requirements are presented and approved, not rate design proceedings. The PD should be revised to remove this error and to adopt the Joint CCAs' recommended ordering paragraph on battery functionalization issues.

The Joint CCAs originally argued in this case that certain costs associated with PG&E's proposed Renz Energy Storage Project should be reallocated to more accurately reflect cost causation. PG&E initially proposed that this battery storage system—which would at times provide distribution reliability services, and at other times be used to capture energy market value—be fully assigned to the electric distribution function for purposes of cost recovery.[80] The Joint CCAs argued that the proportion of the Renz revenue requirement associated with the planned generation-related operations should be reallocated to the generation

78 Joint CCAs Opening Brief, pp. 16-17.
79 Proposed Decision, p. 424.
80 Exh. JCCA-01 at 56:21 to 57:8.

function. Specifically, the Joint CCAs recommended that the revenue requirements be split between generation and distribution based on the expected amount of time the project would be used for these different functions.[81]

While PG&E has since terminated the contract for this project and removed the Renz revenue requirement from its request in this GRC, and therefore these specific costs are no longer at issue in this case,[82] the broader concept of the proper functionalization of battery-related costs is still a contested issue.[83] To ensure these cost functionalization issues are addressed properly going forward, the Joint CCAs recommended that in future GRCs, to the extent that PG&E is seeking cost recovery for battery-related costs, it should provide testimony on the functions that it proposes the batteries serve, and functionalize the associated costs into the proper revenue requirements according to the principles of cost causation.

Notably, this proposal is similar to the Joint CCAs' other proposal—which has since been endorsed in the PD—to establish a new requirement that PG&E submit testimony justifying its proposed vintage treatment for its new investments in UOG. Both proposals seek to ensure that GRC costs are assigned in line with the principle of cost causation, *i.e.*, that costs are assigned to the customers that caused PG&E to incur those costs.

The PD's quick dismissal of this issue seems to conflate functionalization issues with rate design issues. Functionalization of utility revenue requirements (*i.e.*, assigning costs to a particular utility function, like the generation or distribution function) occurs in Phase I GRCs,[84] while rate

81 *Id*. at 58:23 to 59:24.
82 Exh. PG&E-17 at 17-9:23-26.
83 Joint CCAs Opening Brief, pp. 9-11.
84 For example, in PG&E's 2020 Phase I GRC, the Commission affirmed the relevance and importance of cost functionalization issues to the GRC. *See* D.20-12-005, pp. 292-293, 316 ("In this decision, we will refer to the process by which PG&E allocates costs across its various functions as the 'functionalization' of costs, or PG&E's cost allocation methodology . . . The Commission has a longstanding policy of allocating costs to customers based on the costs the utilities incur on behalf of

design (*i.e.*, designing rates to recover those revenue requirements approved and functionalized in Phase I GRCs) occurs in Phase II GRCs or other rate design proceedings.[85] In PG&E's last Phase I GRC, in fact, the Commission specifically highlighted the importance of cost functionalization issues to Phase I GRC proceedings, finding:

> An appropriate functionalization methodology is important to ensure that costs are appropriately allocated to its electric generation function, which only bundled customers pay, and electric distribution function, which both bundled and unbundled customers pay. Without an appropriate cost functionalization process, costs may be misappropriated between electric generation and distribution functions, possibly causing cost shifts between bundled and unbundled customers. ***<u>To prevent possible cost subsidies between the bundled and unbundled customers, we direct PG&E to provide in its next GRC a better showing of its cost functionalization process</u>***. Specifically, we direct PG&E to provide in its next GRC detailed testimony showing and justifying how it allocates costs across its various utility functions, including how it derives its functional allocations.[86]

There is therefore significant precedent for addressing cost functionalization issues in Phase I GRCs, while there is no such precedent for scoping functionalization issues into rate design proceedings, as the PD suggests.[87] The PD should be revised to remove this error and to adopt an ordering paragraph requiring PG&E to (1) provide testimony in its future GRCs on the functions it proposes any new battery investments serve, and (2) functionalize the associated costs accordingly.

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those customers. Consistent with previous decisions, we use this policy as a guiding principle in our review and resolution of the cost allocation issues . . . An appropriate functionalization methodology is important to ensure that costs are appropriately allocated to its electric generation function, which only bundled customers pay, and electric distribution function, which both bundled and unbundled customers pay. Without an appropriate cost functionalization process, costs may be misappropriated between electric generation and distribution functions, possibly causing cost shifts between bundled and unbundled customers. To prevent possible cost subsidies between the bundled and unbundled customers, we direct PG&E to provide in its next GRC a better showing of its cost functionalization process. Specifically, we direct PG&E to provide in its next GRC detailed testimony showing and justifying how it allocates costs across its various utility functions, including how it derives its functional allocations."). *See also* D.19-10-036, pp. 51-52 ("questions of working cash development and functionalization belong in a GRC I case").

85 *See, e.g.*, D.18-08-013, p. 50.

86 D.20-12-005, p. 316.

87 Proposed Decision, p. 424.

IV. Conclusion

The Joint CCAs appreciate the opportunity to submit these comments on the Proposed Decision and APD, and urge the Commission to adopt the recommendations herein and in Appendix A hereto.

Respectfully submitted,

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On behalf of the Joint CCAs

Dated: October 3, 2023

Appendix A

Revisions to Findings of Fact, Conclusions of Law, and Ordering Paragraphs

Findings of Fact

211. It is reasonable to conclude that, in future GRCs, to the extent that PG&E is seeking cost recovery for battery-related costs, PG&E should provide testimony on the functions that it proposes the batteries serve, and functionalize the associated costs according to the principles of cost causation.

~~260. Regarding the Joint CCAs' framework proposal, it is reasonable to find that such a review would best take place in a broader proceeding in which other utilities and stakeholder positions may be considered~~ ~~and because consideration of the Joint CCAs' proposal in this proceeding would require a thorough examination of the complexities involving the current vintaging framework and how costs are allocated as part of the PCIA~~.

260. Regarding the Joint CCAs' re-vintaging proposals for the twelve hydroelectric generation assets at issue in this proceeding, it is reasonable to find that: (1) these extensions constitute new generation commitments, (2) these new commitments were made on behalf of PG&E's bundled customers, and (3) it is appropriate to order PG&E to effectuate these re-vintaging recommendations for these new commitments such that when each asset reaches its original end of life date, the resource's full revenue requirement shifts to a new vintage assignment corresponding to the year the Commission approved the decision to extend the resource's life.

261. The Joint CCAs' request for PG&E to provide specific information about its resources in future GRCs is reasonable, as this information will be helpful to our consideration of proposed changes to assets regardless of whether any broader framework is adopted. Accordingly PG&E is directed to include in its future GRC filings its position and any supporting evidence concerning (1) the details of any PG&E proposal for new asset life extensions, incremental capacity additions, or changed functions for any of its UOG assets and why it is undertaking these changes, (2) on whose behalf it is making these new investments, and (3) the appropriate vintaging treatment for each asset in light of this testimony along with any future GRC proposals. Specifically, in this testimony, PG&E should include a separate forecast of the incremental costs associated with the new investment in UOG.

Conclusions of Law

144. In future GRCs, to the extent that PG&E is seeking cost recovery for battery-related costs, PG&E is directed to provide testimony on the functions that it proposes the batteries serve, and functionalize the associated costs according to the principles of cost causation.

176. Regarding the Joint CCAs' re-vintaging proposals for the twelve hydroelectric generation assets at issue in this proceeding, the Commission finds: (1) these extensions constitute new generation commitments, (2) these new commitments were made on behalf of PG&E's bundled

customers, and (3) it is appropriate to order PG&E to effectuate these re-vintaging recommendations for these new commitments such that when each asset reaches its original end of life date, the resource's full revenue requirement shifts to a new vintage assignment corresponding to the year the Commission approved the decision to extend the resource's life.

177. The Joint CCAs' request for PG&E to provide specific information about its resources in future GRCs should be adopted, as this information will be helpful to our consideration of proposed changes to assets regardless of whether any broader framework is adopted, and, accordingly, PG&E is directed to include in its future GRC filings its position and any supporting evidence concerning (1) the details of any PG&E proposal for new asset life extensions, incremental capacity additions, or changed functions for any of its UOG assets and why it is undertaking these changes, (2) on whose behalf it is making these new investments, and (3) the appropriate vintaging treatment for each asset in light of this testimony along with any future GRC proposals. Specifically, in this testimony, PG&E is directed to include a separate forecast of the incremental costs associated with the new investment in UOG.

Ordering Paragraphs

17. In future GRCs, to the extent that PG&E is seeking cost recovery for battery-related costs, PG&E shall provide testimony on the functions that it proposes the batteries serve, and shall functionalize the associated costs according to the principles of cost causation.

33. Pacific Gas and Electric Company (PG&E) shall provide specific information about its resources in future general rate cases (GRCs) ~~is reasonable~~, as this information will be helpful to our consideration of proposed changes to assets regardless of whether any broader framework is adopted. Accordingly PG&E is directed to include in all future GRC filings the following: (1) the details of any PG&E proposal for new asset life extensions, incremental capacity additions, or changed functions for any of its Utility Owned Generation assets and why it is undertaking these changes, (2) on whose behalf it is making these new investments, and (3) the appropriate vintaging treatment for each asset in light of this testimony along with any future GRC proposals. Specifically, in this testimony, PG&E shall include a separate forecast of the incremental costs associated with the new investment in its Utility Owned Generation.

34. Because the asset life extensions associated with the following hydroelectric assets constitute new generation commitments made on behalf of bundled customers, PG&E must effectuate the following changes to its asset vintaging in its next Energy Resource Recovery Account forecast proceeding:

> a. With respect to the Kerckhoff #1 hydroelectric asset revenue requirement: in 2023 the asset vintage changes to 2020, and the asset revenue requirement is then applied to 2020 PCIA rates until 2057.
>
> b. With respect to the Kerckhoff #2 hydroelectric asset revenue requirement: in 2023 the asset vintage changes to 2020, and the asset revenue requirement is then applied to 2020

PCIA rates until 2057. In 2057 the asset vintage changes to 2023, and the asset revenue requirement is then applied to 2023 PCIA rates until 2065.

c. With respect to the Balch #1 and #2 hydroelectric asset revenue requirement: in 2026 the asset vintage changes to 2023, and the asset revenue requirement is then applied to 2023 PCIA rates until 2069.

d. With respect to the Kilarc-Cow Creek hydroelectric asset revenue requirement: as the end of life date for this asset has passed as of the date of this decision, as soon as practicable after the issuance of this decision, the asset revenue requirement will be removed from the UOG Legacy vintage PCIA rate and all subsequent PCIA rates.

e. With respect to the Bucks Creek hydroelectric asset revenue requirement: in 2023 the asset vintage changes to 2017, and the asset revenue requirement is then applied to 2017 PCIA rates until 2055. In 2055 the asset vintage changes to 2020, and the asset revenue requirement is then applied to 2020 PCIA rates until 2056. In 2056 the asset vintage changes to 2023, and the asset revenue requirement is then applied to 2023 PCIA rates until 2062.

f. With respect to the Narrows hydroelectric asset revenue requirement: in 2023 the asset vintage changes to 2020, and the asset revenue requirement is then applied to 2020 PCIA rates until 2026.

g. With respect to the Upper NF Feather River hydroelectric asset revenue requirement: in 2047 the asset vintage changes to 2017, and the asset revenue requirement is then applied to 2017 PCIA rates until 2051. In 2051 the asset vintage changes to 2020, and the asset revenue requirement is then applied to 2020 PCIA rates until 2055. In 2055 the asset vintage changes to 2023, and the asset revenue requirement is then applied to 2023 PCIA rates until 2061.

h. With respect to the McCloud-Pit hydroelectric asset revenue requirement: in 2048 the asset vintage changes to 2017, and the asset revenue requirement is then applied to 2017 PCIA rates until 2053. In 2053 the asset vintage changes to 2020, and the asset revenue requirement is then applied to 2020 PCIA rates until 2055. In 2055 the asset vintage changes to 2023, and the asset revenue requirement is then applied to 2023 PCIA rates until 2061.

i. With respect to the Poe hydroelectric asset revenue requirement: in 2047 the asset vintage changes to 2017, and the asset revenue requirement is then applied to 2017 PCIA rates until 2051. In 2051 the asset vintage changes to 2020, and the asset revenue requirement is then applied to 2020 PCIA rates until 2053. In 2053 the asset vintage changes to 2023, and the asset revenue requirement is then applied to 2023 PCIA rates until 2068.

j. With respect to the Chili Bar hydroelectric asset revenue requirement: in 2047 the asset vintage changes to 2017, and the asset revenue requirement is then applied to 2017 PCIA rates until 2064.

k. With respect to the Upper Drum hydroelectric asset revenue requirement: in 2051 the asset vintage changes to 2017, and the asset revenue requirement is then applied to 2017 PCIA rates until 2053. In 2053 the asset vintage changes to 2020, and the asset revenue requirement is then applied to 2020 PCIA rates until 2057. In 2057 the asset vintage changes to 2023, and the asset revenue requirement is then applied to 2023 PCIA rates until 2063.

l. With respect to the Helms hydroelectric asset revenue requirement: in 2026 the asset vintage changes to 2023, and the asset revenue requirement is then applied to 2023 PCIA rates until 2069.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates.	R.22-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING BRIEF

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October 6, 2023

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SUMMARY OF RECOMMENDATIONS

California Community Choice Association (CalCCA) recommends that the California Public Utilities Commission:

- Reject proposals to collect the Power Charge Indifference Adjustment (PCIA) through the Income-based Fixed Charge (IGFC) because it would require unnecessarily overhauling the PCIA and would be administratively complex and burdensome.
- Reject proposals to collect the Competition Transition Charge (CTC) through the IGFC given Public Utilities Code section 371(a)'s requirement that the CTC be collected on a volumetric basis and Assembly Bill 205's prohibition on the inclusion of costs based on the volume of electricity consumed.
- Require the investor-owned utilities to include community choice aggregators (CCAs) in IGFC implementation-related working groups, notify CCAs on an ongoing basis of changes to implementation plans, and adopt CalCCA's proposals to ensure consistent messaging regarding the IGFC to both bundled and unbundled customers.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates.	R.22-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
OPENING BRIEF

Pursuant to Rule 13.12 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure,[1] *Assigned Commissioner's Phase 1 Scoping Memo and Ruling,*[2] *Administrative Law Judge's Ruling Addressing the Track A Procedural Schedule, Opening Briefs Guidance, and Exhibits*[3] (Ruling) and *Email Ruling Clarifying ALJ Ruling on Track A Briefs, Opening Briefs, and Exhibits,*[4] California Community Choice Association[5] (CalCCA) submits this opening brief.

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[1] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021): https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/rules-of-practice-and-procedure-may-2021.pdf.

[2] *Assigned Commissioner's Phase 1 Scoping Memo and Ruling*, Rulemaking (R.) 22-07-005 (Nov. 2, 2022): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M498/K072/498072273.PDF.

[3] *Administrative Law Judge's Ruling Addressing the Track A Procedural Schedule, Opening Briefs Guidance, and Exhibits*, R.22-07-005 (Aug. 22, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M517/K847/517847523.PDF.

[4] *Email Ruling Clarifying ALJ Ruling on Track A Briefs, Opening Briefs, and Exhibits*, R.22-07-005 (Aug.24, 2023); https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M518/K155/518155583.PDF.

[5] 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, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, 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, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

I. INTRODUCTION

Assembly Bill (AB) 205 requires the Commission to authorize an income-graduated fixed charge (IGFC) by July 1, 2024 for default residential rates of the investor-owned utilities (IOUs).[6] CalCCA's opening brief addresses the following two limited issues raised in party IGFC Proposals: (1) whether the Power Charge Indifference Adjustment (PCIA) and the Competitive Transition Charge (CTC) should be among the "costs" incorporated into the IGFC, and (2) how should the IGFC be implemented?

First, the Commission should reject requests to include the PCIA or CTC in the IGFC. AB 205 defines a "fixed charge" as "any fixed customer charge, basic service fee, demand differentiated basic service fee, demand charge, or other charge not based on the volume of electricity consumed."[7] Despite generation costs necessarily being charged on a volumetric basis (i.e., customers charged for the electricity they consume), parties including the National Resource Defense Council (NRDC), The Utility Reform Network (TURN), and the Coalition of Utility Employees (CUE) have advocated including the PCIA in the IGFC.[8] As set forth in CalCCA's Reply on the June 19th ALJ Ruling on IGFC Implementation,[9] the PCIA is a charge that includes some fixed costs, but also includes variable generation costs.[10] Extracting the fixed costs from the

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6 Stats. 2022, Ch. 61 (codified at California Public Utilities Code § 739.9). All section references herein are to the California Public Utilities Code, unless otherwise stated.

7 Pub. Util. Code § 739.9(a) (emphasis added).

8 *See* R.22-07-005, *Factual Excerpts from Comments of the Natural Resources Defense Council and The Utility Reform Network on Administrative Law Judge's Ruling on the Implementation Pathway for Income-Graduated Fixed Charges, Filed July 31, 2023,* Exhibit NRDC-TURN-03 (Sept. 6, 2023) (NRDC-TURN-03 Testimony), at 12; R.22-07-05, *Comments of the Coalition of California Utility Employees on the Implementation Pathway for Income-Graduated Fixed Charges* (July 31, 2023) (CUE Implementation Pathway Ruling Comments), at 5.

9 *See* R.22-07-005, *Administrative Law Judge's Ruling on The Implementation Pathway for Income-Graduated Fixed Charges* (June 19, 2023) (June 19 Ruling).

10 R.22-07-005, *California Community Choice Association's Reply Comments on Administrative Law Judge's Ruling on the Implementation Pathway for Income-Graduated Fixed Charges* (Aug. 21, 2023), at 3-6.

PCIA would not only be administratively burdensome, but it would also require reversal of the complex and time-consuming work by the Commission and many parties in the years-long proceedings to establish the PCIA.

Second, Sierra Club's/California Environmental Justice Alliance (CEJA)'s argument to include the Competition Transition Charge (CTC), in the IGFC must be rejected given Public Utilities Code section 371(a)'s requirement that the CTC be recovered volumetrically. Therefore, by definition, the CTC cannot be included in the IGFC, and the Commission should reject Sierra Club/CEJA's argument.

Finally, once the IGFC is established, the Commission should require the IOUs to establish working groups to allow stakeholder involvement (including CCAs) in IGFC implementation. In addition, the Commission should require the IOUs to communicate any changes to implementation plans even after the working group process ends.[11] Finally, the Commission should adopt CalCCA's proposals set forth in its Concurrent Reply Testimony to ensure consistent messaging regarding the IGFC to both bundled and unbundled customers.

As set forth more fully below, CalCCA recommends that the Commission:

- Reject proposals to collect the PCIA through the IGFC because it would require unnecessarily overhauling the PCIA and would be administratively complex and burdensome.
- Reject proposals to collect the CTC through the IGFC given Public Utilities Code Section 371(a)'s requirement that the CTC be collected on a volumetric basis and AB 205's prohibition on the inclusion of costs based on the volume of electricity consumed.
- Require the IOUs to include CCAs in IGFC implementation-related working groups, notify CCAs on an ongoing basis of changes to implementation plans, and

[11] *See* June 19 Ruling (Question 15b: Should the Commission establish a working group and authorize funding for a third-party contractor to develop an ME&O proposal for consideration in this proceeding?, and Question 15d: Should the Commission establish a working group to discuss IGFC implementation issues and recommend improvements?)

adopt CalCCA's proposals to ensure consistent messaging regarding the IGFC to both bundled and unbundled customers.

II. THE PCIA CHARGE, COMPOSED OF BOTH FIXED AND VARIABLE GENERATION COSTS, SHOULD BE EXCLUDED FROM THE IGFC

CalCCA provides the answer below in response to the Ruling's guidance for parties to "focus their briefs on issues necessary to authorize the first version of IGFCs, which will reduce volumetric rates."[12]

The Commission should reject party proposals to collect the PCIA through the IGFC given the administrative burden and the need to unnecessarily unravel the Commission established combination of fixed and variable costs that make up the PCIA. CalCCA established in its opening brief on statutory interpretation of AB 205, as well as its Concurrent Reply Testimony of Brian Dickman, that generation charges are necessarily based on the volume of electricity consumed and therefore should not be included in the IGFC.[13] The IGFC is required to include "fixed charges" defined as "any fixed customer charge, basic service fee, demand differentiated basic service fee, demand charge, or other charge <u>not based on the volume of electricity consumed</u>."[14] Despite this distinction, NRDC/TURN and CUE have both proposed that the PCIA should be included in the IGFC.[15]

The Commission should exclude collecting PCIA portfolio costs through the IGFC because doing so would require an unraveling or overhaul of the PCIA. The PCIA is a <u>charge</u> that collects both fixed <u>and</u> variable costs. While the fixed costs of the PCIA portfolio would

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12 Ruling, at 4.

13 R.22-07-005, *California Community Choice Association's Opening Brief*, at 3-5 (Jan. 23, 2023); *Errata to Concurrent Reply Testimony of Brian Dickman and Justin Kudo on Behalf of California Community Choice Association,* Exhibit CALCCA-01-E (Sept. 1, 2023) (CalCCA-01-E Testimony), at 3-4.

14 Pub. Util. Code § 739.9(a) (emphasis added)

15 *See* NRDC-TURN-03 Testimony, at 3; CUE Implementation Pathways Ruling Comments, at 5.

theoretically be eligible based on AB 205's requirements for the IGFC, the PCIA portfolio's variable costs would not be eligible. Separating the fixed costs from variable costs that make up the PCIA portfolio would require fundamentally restructuring the PCIA. This approach is unworkable for several reasons. First, the PCIA proceeding recently closed in June of 2023[16] so there is currently no proceeding in which to determine how to accomplish this separation of costs and restructuring of the PCIA. Second, a significant amount of time and resources from many stakeholders went into establishing the PCIA.[17] A complete restructuring would also require significant time and resources for all stakeholders to reach another consensus. Third, assuming fixed PCIA costs are separated, integrating those fixed costs by PCIA vintage into the adopted income tiers of the IGFC on an annual basis represents a considerable administrative burden.

The Commission provided opportunities for parties to comment on what eligible fixed costs should be included in the IGFC and parties failed to provide sufficient rationale for why PCIA costs should be included in the IGFC. For example, Questions 5 and 6 of the June 19 Ruling asked parties what costs are eligible for inclusion in the IGFC and whether any of those eligible costs should be excluded, respectively.[18] Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) (collectively, the Joint IOUs), NRDC/TURN, Sierra Club/CEJA, and CUE responded to Question 5 that the PCIA is eligible for the IGFC but only NRDC/TURN and CUE responded to Question 6 that the PCIA should be

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[16] *See* 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 13, 2023), at 50 (closing the PCIA proceeding).

[17] *See generally,* R.17-06-026 (PCIA proceeding).

[18] *See* June 19 Ruling, at 5 (Question 5 of the Ruling asks, "What type of fixed costs should be eligible to be included in any given IGFC (Eligible Fixed Costs)?; Question 6 of the Ruling asked: "Are there certain Eligible Fixed Costs that should be excluded from recovery through the first version of the IGFCs?").

included.[19] The only rationale provided by parties to demonstrate the eligibility to collect PCIA costs through the IGFC was a common, but inaccurate, description that the PCIA is a set of fixed costs.[20] In fact, NRDC/TURN even stated that including the PCIA in the IGFC would be administratively complex.[21] No other parties of the many involved in this proceeding advocated for collecting PCIA costs through the IGFC. Notably, while the Joint IOUs consider PCIA costs eligible for collection through the IGFC, they recommend excluding PCIA costs in the IGFC.[22]

III. THE COMMISSION SHOULD EXCLUDE CTC COSTS FROM THE IGFC GIVEN SECTION 371(A)'S REQUIREMENT THAT THE CTC BE RECOVERED VOLUMETRICALLY

CalCCA provides the answer below in response to the Ruling's guidance for parties to "focus their briefs on issues necessary to authorize the first version of IGFCs, which will reduce volumetric rates."[23]

The Commission should reject Sierra Club/CEJA's proposal to collect the CTC through the IGFC.[24] Public Utilities Code section 371(a) prohibits such recovery by requiring the CTC to be collected from customers on a volumetric basis.[25] Therefore, by definition, the CTC cannot be included among the non-volumetric costs eligible for recovery under the IGFC.

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19 Parties proposing to incorporate the PCIA in the IGFC include TURN/NRDC and CUE. TURN/NRDC Opening Comments at 25-27; CUE Opening Comments at 4-5. Parties characterizing the PCIA as "eligible" for inclusion in the IGFC (but not recommending including the PCIA in the IGFC) include the Joint IOUs and Sierra Club/CEJA. Joint IOU Opening Comments at 34; Sierra Club/CEJA Opening Comments at 17.

20 *Ibid.*

21 See NRDC-TURN-03 Testimony, at 12 (recommending recovery of the PCIA through the IGFC but recognizing that such recovery could be "administratively complex" given the way PCIA costs are currently recovered as "a function of the difference between the annual costs of these resources and their annual market value," and collected based on customer vintage).

22 *Joint IOU Implementation Pathway Opening Comments*, at 34 (recommending the Commission include PCIA in its list of eligible fixed costs, but not to recover PCIA costs through the IGFC).

23 Ruling, at 4.

24 *Sierra Club/CEJA Implementation Pathway Opening Comments,* at 17.

25 Pub. Util. Code § 371(a) (requiring that the CTC "be applied to each customer based on the amount of electricity purchased by the customer from an electrical corporation or alternate supplier of electricity, subject to changes in usage occurring in the normal course of business").

IV. THE COMMISSION SHOULD REQUIRE THE IOUS TO COORDINATE WITH CCAS IN THE IGFC TRANSITION AND IMPLEMENTATION

CalCCA provides the answer below in response to the following Ruling Questions:

- Question 1 – "What directions should the Commission provide for the development of an ME&O plan for the first IGFCs?"; and
- Question 1.d. – "If the Commission authorizes an ME&O working group, what should be the scope of work for this working group (e.g., should it include ME&O for small and multijurisdictional utilities (SMJUs), development of messages about IGFCs, and/or propose ME&O budgets)? When should the working group proposal be due?".

The Commission should require the IOUs to coordinate with the CCAs on the IGFC transition and implementation, including allowing CCAs to participate in working groups related to implementation and marketing, education, and outreach ("ME&O") for the IGFC. CalCCA appreciates the commitment of the IOUs set forth in their Concurrent Opening Testimony to coordinate with CCAs on IOU transition plans related to the IGFC for the benefit of customer communication.[26] The June 19 ALJ Ruling also asks questions regarding the establishment of working groups to address implementation and ME&O.[27] The Commission should ensure that CCAs can participate in the working group process as CCA input and participation in IOU planning for IGFC implementation is critical to maximizing customer acceptance and understanding. In addition, the Commission should adopt the proposals set forth in CalCCA's Concurrent Reply Testimony to ensure consistent messaging regarding the IGFC among bundled and unbundled customers.

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26 *See Joint Testimony of Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company (the Joint IOUs) Describing Income-Graduated Fixed Charge Proposals*, Exhibit Joint-IOUs-01-E2 (Apr. 7, 2023, revised May 3, 302, revised June 20, 2023), at 104.

27 *See* June 19 Ruling (Question 15b: Should the Commission establish a working group and authorize funding for a third-party contractor to develop an ME&O proposal for consideration in this proceeding? Question 15d: Should the Commission establish a working group to discuss IGFC implementation issues and recommend improvements?).

A. The Commission Should Allow CCA Participation in the IGFC Transition and Implementation Working Groups

Given the potentially significant changes in customer bills that will likely result from the IGFC, CCA participation in workings groups on the IGFC transition and implementation is crucial. As established in CalCCA's Concurrent Reply Testimony, most CCA customer service interactions are due to reasons unrelated to CCA service, and instead address issues relevant to IOU service, such as IOU rate transitions, unusually high usage, high gas bills, Net Energy Metering (NEM) true-ups, and expiration of CARE/FERA eligibility.[28] Clear and consistent messaging regarding the IGFC, including in bill presentation and among bundled and unbundled customers, is necessary to minimize the risk of customer confusion.[29] CCAs can contribute their knowledge and experience with their customers during the working group process to ensure such clear and consistent messaging is developed and implemented.

In addition to messaging and bill presentation, the working groups can discuss: (1) streamlining of CARE/FERA and other income qualified program enrollment with income verification for the IGFC, (2) income bracket restructuring, (3) ensuring low-income customers realize savings as required by AB 205, (3) community engagement, and (4) consideration of input from equity experts and California community-based organizations. These topics, among others, can inform implementation and ME&O strategies for the first version IGFC as well as inform improvements to subsequent IGFC versions.

Finally, in response to the June 19 Ruling, the Joint IOUs opposed holding working groups on an on-going basis after initial implementation due to the differing timelines of

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28 *See* CALCCA-01-E Testimony, at 5.

29 *Ibid.*

implementation among the IOUs.[30] Indeed, on-going working groups from each IOU after initial implementation of the IGFC may not be necessary and may lead to additional, unnecessary costs; however, the IOUs should be required to continually inform CCAs of any changes to IGFC implementation plans so CCAs can continue providing accurate information to customers.

B. The Commission Should Adopt CalCCA's Proposals to Ensure Consistent IGFC Messaging to Bundled and Unbundled Customers

In addition to including CCAs in the working groups, CalCCA provides proposals in its Concurrent Reply Testimony for other IOU/CCA implementation coordination that will ensure the necessary consistent messaging to customers.[31] First, the Commission should require the IOUs to solicit CCA input on any planned changes to bill presentation.[32] Second, the Commission should require the IOUs to share and solicit input on education and outreach materials on the IGFC with CCAs so that CCAs are aware of the IOUs' strategy to communicate the new system of fixed charges and lower volumetric rates to customers.[33] Such coordination is necessary to allow the CCAs and IOUs to use consistent explanatory language.[34] Third, the IOUs should augment their weekly customer database updates and billing transactions provided to CCAs to include the IGFC income tier and charge for each customer.[35] Similar to how CARE program data are currently shared to CCAs for unbundled customers, the IGFC income tier data

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30 *See* Joint IOUs' Opening Comments, at 61 (supporting initial working group meetings around ME&O however, "given that the IOUs' respective implementation timelines are not aligned, the Joint IOUs do not support on-going working group meetings that continue through the duration of each IOU's implementation").

31 *See* CALCCA-01-E Testimony, at 5-6.

32 *Id.* at 5.

33 *Id.* at 5-6.

34 *Ibid.*

35 *Id.* at 6.

will provide information to allow CCA staff to accurately answer customer questions about the IGFC and educate customers about their rate options and other bill assistance programs.[36]

V. CONCLUSION

CalCCA appreciates the Commission's consideration of the recommendations set forth herein.

Respectfully submitted,

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October 6, 2023

[36] *Ibid.*

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2023. (U39M)	Application No. 21-06-021 (Filed June 30, 2021)

REPLY COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON PROPOSED DECISION AND ALTERNATE PROPOSED DECISION ON TEST YEAR 2023 GENERAL RATE CASE FOR PACIFIC GAS AND ELECTRIC COMPANY

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On behalf of the Joint CCAs

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SUMMARY OF RECOMMENDATIONS

With respect to Pacific Gas and Electric Company's ("PG&E") twelve hydroelectric asset life extension requests at issue in this proceeding, the Commission should revise the Proposed Decision to: (1) find that these extensions constitute new generation commitments, (2) find that these new commitments were made on behalf of PG&E's bundled customers, and (3) order PG&E to effectuate the Joint CCAs' re-vintaging recommendations for these new commitments such that when each asset reaches its original end of life date, the resource's full revenue requirement shifts to a new vintage assignment corresponding to the year the Commission approved the decision to extend the resource's life. The specific re-vintaging orders recommended by the Joint CCAs are included in Appendix A to the Joint CCAs' Opening Comments.

The Proposed Decision should be revised to clarify that, in its testimony concerning any proposed new investments in utility-owned generation ("UOG") resources in its future general rate cases ("GRCs"), PG&E must include a separate forecast of the incremental costs associated with the new investment in UOG.

The Proposed Decision should be revised to order that, in future GRCs, to the extent that PG&E is seeking cost recovery for battery-related costs, it must provide testimony on the functions that it proposes the batteries serve, and functionalize the associated costs according to the principles of cost causation

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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REPLY COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON PROPOSED DECISION AND ALTERNATE PROPOSED DECISION ON TEST YEAR 2023 GENERAL RATE CASE FOR PACIFIC GAS AND ELECTRIC COMPANY

Pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the City and County of San Francisco ("CleanPowerSF"), East Bay Community Energy ("EBCE"), Marin Clean Energy ("MCE"), Peninsula Clean Energy Authority ("PCE"), Pioneer Community Energy, San José Clean Energy ("SJCE"), Silicon Valley Clean Energy Authority ("SVCE"), and Sonoma Clean Power Authority ("SCP") (collectively, the "Joint CCAs") hereby submit these Reply Comments on Administrative Law Judges DeAngelis and Larsen's *Proposed Decision on Test Year 2023 General Rate Case for Pacific Gas and Electric Company* ("Proposed Decision" or "PD")[1] and Commissioner Reynolds' *Alternate Proposed Decision on Test Year 2023 General Rate Case for Pacific Gas and Electric Company* ("APD").[2]

For the reasons set forth below, the Commission should set aside Southern California Gas Company ("SoCalGas") and San Diego Gas & Electric Company's ("SDG&E") (together,

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1 Application ("A.") 21-06-021, *Proposed Decision on Test Year 2023 General Rate Case for Pacific Gas and Electric Company* (Sept. 13, 2023) ("Proposed Decision" or "PD").

2 A.21-06-021, *Alternate Proposed Decision on Test Year 2023 General Rate Case for Pacific Gas and Electric Company* (Sept. 13, 2023) ("APD"). As the PD and the APD's discussions of the Joint CCAs' issues are identical, the Joint CCAs' discussion herein regarding the PD's treatment of these issues should be understood to apply equally to the APD.

"Sempra") comments regarding the requirement that Pacific Gas & Electric Company ("PG&E") submit testimony in future general rate cases ("GRCs") on vintaging issues. Sempra entirely misrepresents and misunderstands the Joint CCAs' basic issue in this proceeding and the Commission's direction in the PD and APD and therefore its comments should be afforded no weight.

I. Sempra Mischaracterizes the Joint CCAs' Position on Utility Owned Generation Vintaging

Sempra takes issue with the Commission's order requiring PG&E to provide more information in future GRC proceedings on the proper vintaging of new investments in utility owned generation ("UOG") which may—or may not—constitute new resource commitments. However, in its comments, Sempra grossly mischaracterizes the Joint CCAs' position on the issue of UOG vintaging. Sempra's opening comments incorrectly imply that the Joint CCAs seek to avoid *all* "future costs associated with prudent maintenance and/or upgrades" of vintaged UOG resources.[3] Sempra goes on to argue that such a position would violate the indifference principle and defeat the very purpose of the Power Charge Indifference Adjustment ("PCIA"). Fortunately, that is *not* the Joint CCAs' position in this (or any other) proceeding, and it is not the subject of the PD or the APD.

Indeed, it is undisputed that the purpose of the PCIA charge is to ensure that unbundled customers continue to pay for costs that were reasonably incurred to serve them *before* they departed investor-owned utility ("IOU") generation service.[4] The Joint CCAs acknowledge that these costs generally include reasonable ongoing (or future) operations and maintenance ("O&M")

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[3] A.21-06-021, *Opening Comments of SDG&E and Southern California Gas Company on the Proposed and Alternate Proposed Decisions on Test Year 2023 General Rate Case for PG&E*, p. 12 (Oct. 3, 2023) ("Sempra Opening Comments").

[4] *See* Rulemaking ("R.") 17-06-026, *Scoping Memo and Ruling of Assigned Commissioner*, p. 2 (Sept. 25, 2017); Decision ("D.") 18-10-019, p. 8.

and capital investments needed to keep a resource operational through its expected useful life. This is true even if the resource no longer serves unbundled customers' energy or capacity needs because the PCIA is intended to ensure that when customers of IOUs depart bundled service and receive their electricity supply from a non-IOU provider, such as a community choice aggregator ("CCA"), "those customers remain responsible for costs previously incurred on their behalf by the IOUs — but only those costs."[5] The Joint CCAs do not dispute their obligation to pay these ongoing (or future) costs to operate legacy UOG through their anticipated end of life dates because such costs were reasonably foreseeable at the time of the initial generation commitment—which PG&E made on behalf of now-unbundled customers.

The Joint CCAs have raised concerns, however, regarding PG&E's proposals in this proceeding to extend the lives of 12 hydroelectric facilities—in some cases by several decades.[6] If approved by the Commission without further direction on vintaging, PG&E will essentially have approval to invest in re-licensing and upgrading these 12 hydro facilities to serve its future bundled customers' energy and capacity needs. In these types of instances, the Commission should consider whether PG&E is making new generation resource commitments beyond those that it made to originally serve customers who have since departed bundled service.

The Joint CCAs have also advocated that the Commission should consider whether a new commitment is made at existing UOG when a utility expands its current net capacity output by making certain significant upgrades, secures future generation resource availability though asset life extensions, or essentially adds a new type of generator to its fleet by overhauling a facility to

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5 *See* R.17-06-026, *Scoping Memo and Ruling of Assigned Commissioner*, p. 2 (Sept. 25, 2017); D.18-10-019, p. 3.

6 *See* A.21-06-021, *Opening Comments of the Joint CCAs on Proposed Decision and Alternate Proposed Decision on Test Year 2023 General Rate Case for PG&E*, pp. 5-20 (Oct. 3, 2023) ("Joint CCAs Opening Comments").

change its basic function. In these specific scenarios, the Joint CCAs have argued for years that re-vintaging must be considered to maintain customer indifference.[7]

As noted throughout this proceeding, the Commission has also recognized that, in certain scenarios, it should reconsider the utilities' default vintaging treatment. Specifically, it has found:

> It is possible that new investments in an old power plant may represent such a significant overhaul of the facility as to justify a "re-vintaging" of the facility. Likewise, it is possible that plant investments for certain upgrades may justify a different vintage treatment for those investments than for the underlying facility.[8]

These are the scenarios that the Joint CCAs have worked for many years to address, and which are partially addressed by the PD. Sempra's claims that the Joint CCAs seek to avoid all future capital and O&M costs necessary to maintain vintaged UOG are simply false and do not accurately identify the matter at issue in this proceeding.

Sempra incorrectly describes the PD's directive as requiring PG&E "to indicate in future GRCs 'on whose behalf' it seeks to make ***proposed investments*** in UOG resources."[9] The PD's direction is far more specific and only requires such a showing when PG&E proposes "new asset life extensions, incremental capacity additions, or changed functions for any of its UOG assets…"[10] In these cases, more information is necessary for the Commission and parties to properly evaluate whether a new investment in an old power plant, or an extension of the plant's useful life, actually does represent a new commitment that justifies re-vintaging, or whether certain upgrades may justify a different vintage treatment for those new investments than for the underlying facility. The PD does not require a showing of "on whose behalf" PG&E seeks to make

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7 *See id*., pp. 17-20.

8 D.18-10-019, p. 135.

9 Sempra Opening Comments, p. 10 (emphasis added).

10 PD, p. 500; APD, p. 508.

any proposed investments in UOG resources—only those enumerated above.[11] This specificity renders many of Sempra's arguments in its opening comments moot.

For example, Sempra is incorrect that re-vintaging UOG assets, or assigning a new vintage to certain upgrades "would create a perverse incentive to avoid reasonable UOG maintenance and upgrade activity and would cause harm to remaining bundled service customers (either through improper shifting of maintenance/upgrade costs to them or through non-optimized resource management)."[12] As noted above, the Joint CCAs do not seek to avoid their obligation to pay for reasonable UOG maintenance, including upgrades that may be necessary to keep a plant operational through its expected useful life. Keeping a plant operational through its expected useful life is part of the "commitment" that the utility makes when it decides to invest in UOG in the first place.

The PD and APD would not require PG&E to submit testimony justifying its proposed vintage treatment when it proposes those kinds of ongoing maintenance investments. The PD's and the APD's limited direction for PG&E to provide testimony justifying its proposed vintage treatment only applies to certain specific types of UOG investments: those that increase the capacity of the plant, change the purpose or function of the plant, or extend the life of the plant. In those situations, the testimony requirement will allow the Commission to assess whether or not that investment constitutes a new commitment. Importantly, the direction also enables the utility to present evidence to show that any such investments are necessary maintenance/upgrade costs which should be considered part of its original commitment. So long as the Commission does not

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11 PD, p. 500; APD, p. 508.

12 Sempra Opening Comments, p. 12.

find the investment to constitute a new commitment, the costs would remain in the UOG's original vintage.

II. Sempra's Comments Misstate the Commission's Vintaging Policies

Sempra's comments also continuously misstate the Commission's vintaging polices. While not central to its argument in this proceeding, Sempra repeats its tortured interpretation of the Commission's vintaging policy from its own current GRC, stating that "D.08-09-012 is properly understood as establishing a presumption that reasonable ongoing capital investment costs undertaken to properly maintain ***and upgrade*** a UOG resource in a particular vintage must *also* be included in that same vintage."[13] Again, some upgrades are reasonably necessary to keep a plant running through its expected life, but not *all* upgrades fall into this category. Indeed, as the Commission stated in D.18-10-019, "certain upgrades may justify a different vintage treatment for those investments than for the underlying facility." Throughout its comments, Sempra continually ignores the Commission's direction on this issue and seeks to establish a new and unsupported standard.[14]

III. Sempra's Comments Misconstrue the PD's Order

Sempra's comments also misconstrue the PD's direction that, in future GRCs, PG&E must explain "on whose behalf" certain specific types of new investments in UOG would be made.[15] Sempra asserts that this inquiry of "on whose behalf" the investment is being made somehow equates to an examination of whether or not unbundled customers "will directly benefit," and then

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13 *Id*. Note that Sempra made this identical statement in its recent brief in its own GRC. *See* A.22-05-015 et al., *Opening Brief of Southern California Gas Company and SDG&E in the Test Year 2024 General Rate Case*, p. 339 (Aug. 14, 2023).

14 Sempra Opening Comments, p. 13 (stating without support that "re-vintaging is appropriate only in the rare situation where the capital investment in question represents such a significant overhaul of the UOG resource that it effectively creates a *new* resource.").

15 *Id*.

argues this standard does not exist.[16] However, examining "on whose behalf" the investment is being made is not the same as examining who will directly benefit. For example, a CCA may choose to invest in a solar plus storage facility *on behalf of* its CCA customers. However, non-CCA customers may directly benefit in the forms of jobs, local tax revenue, decreased air pollution, and increased local reliability. But the costs of the resource are properly assigned to CCA customers because the resource was purchased to serve their energy and capacity needs. The fact that other customers may benefit from this investment is irrelevant to the vintaging determination under the Commission's established framework.

Indeed, the question of "on whose behalf" an investment is made is central to both the Legislature's and the Commission's direction on vintaging. California Public Utilities Code section 365.2 mandates that the Commission ensure both that bundled customers do not experience any cost increases as a result of other customers electing to receive service from other providers, and 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."[17] Commission Decision 08-09-012 further clarifies that "departing customers should bear *no* cost responsibility for . . . commitments the IOU makes after their departure."[18] This directive helps ensure that each customer will "pay its fair share of the costs the IOU incurred ***on [its] behalf[,]"*** which "is an integral part of the principles of bundled customer indifference and prevention of cost-shifting."[19] Even PG&E's own witnesses explained during hearings that PG&E's primary justification for its vintaging policy position is to

16 *Id*.

17 Cal. Pub. Util. Code § 365.2 (emphasis added). *See also id.* § 366.3.

18 D.08-09-012, p. 59 (emphasis added).

19 *Id*., Finding of Fact 2 (emphasis added).

preserve indifference by ensuring costs and revenues are equitably allocated to the customers ***on whose behalf*** the resources were originally procured.[20]

As such, the PD requires that, in future GRCs, PG&E provide testimony for certain types of investments in existing UOG so that the Commission can determine whether the investment is part of the commitment PG&E made on behalf of unbundled customers before they departed, or whether it is a new commitment being made on behalf of then-bundled customers. Such an inquiry is entirely consistent with state law and the Commission's longstanding indifference principle.

IV. Sempra's Suggestion That Vintaging Issues Be Punted to Another Proceeding Is Inconsistent with Commission Precedent and the Long History of the CCAs' Advocacy on These Issues

Finally, Sempra's suggestion that the Commission address all vintaging issues in a statewide proceeding is contrary to Commission precedent and ignores the long history of the CCAs' advocacy on this issue. Currently, no such statewide proceeding exists; the Commission closed the PCIA Order Instituting Rulemaking ("OIR") in June of this year.[21] Further, when the CCAs previously raised re-vintaging issues in that OIR, they were directed by the Commission to take up these issues in utility-specific GRC proceedings.[22] This issue cannot continue to be punted between various regulatory proceedings. The current vintaging policy for new investments in UOG violates state law, and the Commission recently directed the CCAs to address this issue in GRC proceedings.

The Joint CCAs have built a detailed record in this proceeding on the new commitments at issue in this case that necessitate re-vintaging and have provided detailed draft ordering paragraphs that, if adopted, would allow these changes to be effectuated in a subsequent Energy Resource

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20 11 Tr. 2062:3 to 2063:23 (PG&E – Witnesses Rybka, Barry, and Doidge).

21 *See* D.23-06-006.

22 D.18-10-019, p. 135.

Recovery Account proceeding where specific PCIA revenue requirements will be identified and approved.[23] The limited direction for PG&E to provide testimony in future proceedings regarding specific types of new investments in UOG, to which Sempra objects, is also necessary to ensure that the Commission has access to information in future GRCs that will allow it to assess these investments and ensure the associated costs are assigned to the customers who caused the utility to incur them.

V. Conclusion

The Joint CCAs appreciate the opportunity to submit these reply comments on the Proposed Decision and APD, and urge the Commission to adopt the recommendations in the Joint CCAs' opening comments and in Appendix A thereto.

Respectfully submitted,

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On behalf of the Joint CCAs

Dated: October 9, 2023

[23] *See* A.23-05-012, *Scoping Memo and Ruling of Assigned Commissioner*, p. 2 (Aug. 3, 2023) (identifying PCIA revenue requirements as an issue within scope of PG&E's 2024 ERRA Forecast proceeding).

California Community Choice Association

SUBMITTED 10/11/2023, 12:50 PM

Contact
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1. Working Group Session - Are there any outstanding questions on BAA-Level Market Power Mitigation as it exists today?

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (CAISO) Price Formation Enhancements Working Group Session #5. As described in CalCCA's comments to working group #4,[1] with respect to balancing authority areas (BAA) -level market power mitigation, this initiative can now focus on how to group BAAs when performing the dynamic competitive path assessments to improve the existing BAA-level market power mitigation approach and developing a BAA-level market power mitigation methodology that includes both the CAISO and other BAAs participating in the Western Energy Imbalance Market (WEIM) or the Extended Day-Ahead Market (EDAM).

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[1] https://stakeholdercenter.caiso.com/Comments/AllComments/969b55a3-402f-435b-a97f-270ab94c2beb#org-163889a3-9f08-49f8-8adf-32c5edbd441d.

2. Working Group Session - Please share your organization's feedback on the PFE Working Group's draft problem statements formulation exercise. Do you have any problem statements or scope items you would like to propose for further discussion in the process.

Problem statements should be developed using analysis to support the existence of a problem.

For BAA-level market power, one of the problem statements can be defined as: The CAISO Department of Market Monitoring's (DMM) annual report consistently shows there are hours when the CAISO market is not structurally competitive,[1] but the CAISO BAA does not have market power mitigation in place at the BAA level during those uncompetitive hours.

Before defining scarcity pricing problem statements, the CAISO should demonstrate with analysis that problems exist. This should include how frequently the problem occurs, under what conditions, and what impacts it has on the market. That is, the CAISO should demonstrate the existing Scarcity Pricing mechanisms are insufficient to send the right price signals during periods of scarcity to incent resource availability. Solutions can then be tailored to the problems identified via this analysis.

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[1] 2022 Annual Report on Market Issues and Performance at 55: http://www.caiso.com/Documents/2022-Annual-Report-on-Market-Issues-and-Performance-Jul-11-2023.pdf.

3. Working Group Session – Please share your organization's feedback on the topics/themes presented in the discussion paper in order of most to least important.

CalCCA's comments to working group #4 submitted on September 28, 2023 reflect CalCCA's current feedback on the topics/themes in the discussion paper and CalCCA's ranking from most to least important.

4. Working Group Session - Provide your organization's feedback on the PFE Working Group process and any suggestions you have for improvement.

CalCCA has no comments on the PFE Working Group Process at this time.

5. Discussion Paper - Provide your organization's feedback on the guiding principles outlines in the PFE Discussion Paper. Please provide any additional PFE guiding principles for further consideration in the Working Group process.

The guiding principles of Efficiency, Simplicity, Feasibility, Transparency, Accuracy, Effectiveness, and Competition are reasonable guiding principles for price formation. Proposed policy solutions should be developed with the goal of maximizing adherence to these principles. CAISO and stakeholders will likely find, however, that most solutions will meet some of the guiding principles but not others (e.g., a proposed policy solution could be simple and feasible but not transparent, another could be transparent and simple but not accurate, etc.). The challenge during the policy development phase will be how to balance all of these guiding principles that may be at times contradictory to one another.

6. Discussion Paper – Provide your organization's feedback on the Working Group Process and Deliverables (Discussion goals, process, evolution of the Discussion Paper, Action Plan)?

CalCCA has no comments on the working group process and deliverables at this time.

7. Discussion Paper – Provide your organization's feedback on the overarching themes/topics presented for problem statement formulation. Are there any additional themes or scope items which should be further explored?

CalCCA's comments to working group #4 submitted on September 28, 2023 reflect CalCCA's current feedback on the topics/themes in the discussion paper.

8. Is your organization interested in presenting its experience or area of expertise at a future working group? If yes, which topic area or theme will your presentation address or support? Does your presentation introduce a problem statement, help illustrate a problem statement, or provide a scope item for a draft problem statement under discussion?

CalCCA is not interested in presenting at this time.

9. Please provide any additional feedback.

CalCCA has no additional comments at this time.

California Community Choice Association

SUBMITTED 10/12/2023, 12:33 PM

Contact
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1. Please provide feedback on the proposal to provide data to stakeholders to enable the zonal approach to interconnection:

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (CAISO) Interconnection Process Enhancements 2023 Straw Proposal. CalCCA applauds the CAISO for making significant positive steps toward a more durable interconnection process that can accommodate the growing number of interconnection requests.

To aid in load serving entities (LSEs') evaluation of projects in the interconnection queue, the CAISO should provide regularly updated information about existing projects in the queue that do not require any network upgrades, as the CAISO did in its May 22, 2023 presentation.[1] This information can help guide LSEs toward projects that require no (or minimal) upgrades.

CalCCA supports the CAISO's proposal to provide data to stakeholders to enable the zonal approach to interconnection. The existing datasets demonstrated in the workshop combined with the heat map the CAISO will develop to comply with the Federal Energy Regulatory Commission (FERC) Order 2023 should provide stakeholders with the information needed to best focus interconnection requests and procurement, subject to the clarifications described below:

First, prior to implementing the zonal approach, the CAISO should clearly define how it will establish the zones and calculate the existing and planned transmission capacity that will be used to limit the number of interconnection requests studied. The CAISO should publicize information about available interconnection capacity at the same granularity that the CAISO will use to set the 150 percent limit on the amount of capacity it will study.

Second, to allow interconnection customers and LSEs to make the best use of the data, the CAISO should provide this data in a single consolidated report or database so that all the information needed is consistent and can be found in one place.

Finally, the final proposal should provide clear information on the following: 1) Is available capacity equivalent to available transmission plan deliverability (TPD) or does it include all unused capacity (which may include projects in the queue that already secured TPD)?; 2) will projects be counted using their maximum capacity (Pmax) at the interconnection or using a methodology consistent with the generator interconnection and deliverability allocation process (GIDAP) (e.g. solar and wind exceedance adjustments); and 3) are "zones" equivalent to the TPD constraint zones or the broader "transmission areas" depicted in Figure 1 in the straw proposal?

The CAISO should aim to publish a draft of the information described above based on assumptions it will use in the forthcoming 2024 GIDAP process. This will provide much-needed clarity on the format of data and calibrate the magnitude of interconnection capacity the CAISO will study within its proposed 150 percent threshold.

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[1]
http://www.caiso.com/Documents/Briefing-ResourcesAvailable-NearTermInterconnection.pdf.

2. Please provide feedback on proposed interconnection request requirements and interconnection request review

a. Please provide suggestions for how to appropriately incorporate LSE interests and commercial procurement activities earlier in the process to support the objectives of the MOU. b. Please share your thoughts on the relationship and potential trade-offs between the scoring criteria and auction elements. c. Please share specific feedback on and recommendations for scoring criteria that are both reasonable at the interconnection request stage and easily validated by the ISO. i. Please indicate interest in participating in a workgroup to refine scoring criteria. d. Please provide feedback on auction design and use of auction revenues.

Incorporating LSE Interest and Commercial Procurement Activities

CalCCA thanks the CAISO for including LSE interest and procurement activities in the scoring criteria. Because the CAISO will not be studying all interconnection requests under the zonal approach, it will be very important for LSEs to have a say in what projects are studied so that the study process provides LSEs with a sufficient collection of projects that reflect LSEs' desired resource characteristics and diversity.

The scoring criteria for LSE interest and commercial procurement activities should be designed in a manner that:

- Meaningfully differentiates between projects, rather than assigning the same amount of points to all projects that receive LSE interest (CalCCA believes the binary letter of interest scoring is not sufficiently granular).
- Requires an appropriate level of commitment considering when scoring will take place relative to the determination of cost estimates and upgrade timelines.

With these considerations in mind, CalCCA makes the following recommendations on how to incorporate LSE interest and commercial procurement activities into the scoring criteria.

CalCCA continues to support the Sonoma Clean Power (SCP) proposed remaining import capability (RIC)-type mechanism for scoring projects based upon LSE interest. SCP's proposal would allow LSEs to provide meaningful input into which projects are studied informed by their own IRPs and preferences for technologies and locations. SCP's proposal also recognizes that the commercial readiness criteria proposed in the straw proposal, including an executed term sheet for a power purchase agreement (PPA) or an executed PPA for at least five years, may not be feasible for most projects to have at the time of scoring. LSE interest through the assignment of points is more appropriate, especially if there is uncertainty around deliverability status, network upgrade costs, and network upgrade timelines at the time of point assignment.

Using the SCP approach, the CAISO should allocate points such that the LSE interest portion can make up to 30 percent of the total score. This aligns with the LSE letter of interest points plus commercial readiness points in the straw proposal and puts sufficient weight on the LSE interest portion of the score.

The CAISO expressed concerns about the potential time the SCP proposal would add to the interconnection request intake and scoring processes. CalCCA understands the CAISO's desire to limit potential steps that could extend the time it takes to conduct these processes. However, it is more prudent for the CAISO to take the time upfront to use more robust scoring criteria to rank projects' viability on a more granular level as opposed to taking more time at the back end to conduct an auction. More granular scoring criteria could eliminate the need to have an auction mechanism, which would also be a time-consuming endeavor but reveal less in terms of projects' viability.

Additionally, the current RIC process is very efficient and should be used for interconnection scoring. In the RIC process, LSEs have less than two weeks to make their election, and a similar turnaround could be instituted for interconnection scoring. It is also very likely that LSEs can assign their points in parallel with the CAISO's processes to validate interconnection requests and assign points for the other scoring criteria. This would likely eliminate any delay in the process caused by LSE scoring.

The CAISO could also consider simplified alternatives to SCP's original RIC proposal: instead of using capacity, 1) have LSEs score each project on a 1-10 scale and take a load-weighted average for each project or 2) ask LSEs to score interest in various project, technology, and COD combinations ahead of accepting interconnection applications that could then be applied to submitted applications.

Scoring Criteria Recommendations

Recommendation 1: The CAISO proposes to "automatically include any project that a non-CPUC jurisdictional LSE demonstrates is a preferred resource in its resource plan that has been approved by its Local Regulatory Authority."[1] As CalCCA understands the proposal, this would allow projects that are identified in non-CPUC jurisdictional LSE plans to bypass the scoring criteria and automatically be included in the proposed 150 percent cap on capacity that the CAISO studies. CalCCA disagrees with this approach because it creates an unlevel playing field for CPUC versus non-CPUC jurisdictional LSEs procuring projects to meet their integrated resource plans (IRPs) and procurement mandates. The CAISO's proposal would create incentives for developers to contract with non-CPUC jurisdictional LSEs over CPUC jurisdictional LSEs because they would automatically be studied. The CAISO should instead ensure projects that support CPUC *and* non-CPUC jurisdiction resource plans are studied in the Transmission Planning Process (TPP), inform the TPP zones, and can compete on an equal playing field to be studied in the interconnection criteria by demonstrating comparable viability criteria. To accomplish this, the CAISO should (1) coordinate with LRAs and non-CPUC jurisdictional entities to include their approved resources in their IRPs, in addition to the CPUC portfolios, in the TPP (which the CAISO already indicates in the Straw Proposal that it will do) and (2) revise its proposal to have comparable scoring criteria among projects identified in CPUC and non-CPUC jurisdictional resource plans.

Recommendation 2 and 3: The CAISO proposes two limits on interconnection requests. The first would limit the number of requests a developer may submit in a cluster window to 25 percent of available transmission capacity across the CAISO footprint. The second would limit the amount of interconnection requests the CAISO studies to 150 percent of available transmission within each zone using scoring criteria to select the most viable projects. The first limit attempts to resolve the CAISO's concern around reduced competition among developers competing for contracts with LSEs if only a small number of developers are selected to be studied. CalCCA shares this concern. However, the second criteria (studying up to 150 percent of available transmission) could potentially create reduced competition by limiting the number of projects studied in each zone.

CalCCA supports a zonal approach where the CAISO selects the most viable projects to study within each zone. However, CalCCA remains concerned that only studying 150 percent of the planned or existing transmission capacity is too little, considering the transmission system is planned based upon projected resource portfolios that LSEs will procure. If the CAISO only studies 1.5X the amount of capacity needed to support reliability and policy goals, LSEs would experience significantly reduced bids in their request for offers (RFOs) relative to their procurement needs. Past experience also shows that many projects do not ultimately proceed in the development process and may drop out after it submits its interconnection request but before the contracting process. While some projects may offer to multiple LSEs, multiple LSEs may have interest in the same project, too. CalCCA instead recommends the CAISO increase the limitation on the number of projects studied in each zone cap from 150 percent to at least 200 percent.

CalCCA supports the intent of the 25 percent cap for a single developer, which is to prevent one or a few developers from having the ability to exert market power when contracting with LSEs for capacity within the transmission zones. In the stakeholder call, however, developers expressed concern with the 25 percent cap given its potential to restrict the amount of interconnection requests they could have studied by the CAISO. In addition, a cap on the number of requests *a developer can submit* may not necessarily mean a diverse set of *developers is selected* to be studied through the scoring criteria.

To balance the concerns of the developers on the restrictiveness of the proposal and the concerns of CalCCA and the CAISO regarding the potential ability for limited competition among developers selected to be studied, CalCCA recommends the CAISO assess its total transmission capacity (plus an adder that aligns with the amount of capacity the CAISO will study in the interconnection study process) and the developer make-up of cluster 15 requests to determine what level of cap would obviate a pivotal supplier issue. The CAISO could then modify the cap based on that assessment. The right level to set the cap for individual developer requests will depend on the cap chosen for the number of interconnection requests to study. The CAISO may find that the 25 percent cap is necessary to prevent the potential for too few developers' requests studied or it may find that the cap could be raised and still provide for adequate competition. Either way, CalCCA supports setting the cap at the right level to ensure adequate competition.

Because the developer cap the CAISO proposes is on the interconnection requests a developer *submits* and not the interconnection requests a developer has *studied* there is still a potential for uncompetitive outcomes where a few developers have their projects studied. To remedy this, the CAISO could introduce a resource diversity score into the scoring criteria, which could help in both ensuring the diversity of developers and ensuring a pathway for long lead time resources or technologies needed to support policy and reliability objectives.

Relationship and Trade-Offs Between Scoring Criteria and Auction

The CAISO should focus its efforts on developing scoring criteria that rank projects based on their viability at a granular enough level to limit the amount of tie scores. If there are a few instances of tie scores, the CAISO should accept each of the projects that are tied, rather than putting them through the auction. As described in the next section, this approach will avoid the shortcomings associated with an auction mechanism and focus administrative efforts on identifying the most viable projects, rather than identifying projects that can put up the most money in an auction.

Auction Design and Use of Auction Revenues

In previous comments, CalCCA expressed various concerns with the auction mechanism. CalCCA was concerned that an auction would:

1. Result in increased costs to ratepayers because the costs associated with bidding into the auction will ultimately flow to them;
2. Result in the highest bidders being studied rather than the most ready being studied;
3. Incent speculative projects to enter the queue by creating a secondary market where those projects can sell their queue position later; and
4. Limit competition among developers by favoring larger developers with deeper pockets over small developers.[2]

The CAISO's design of the auction partially addresses some of CalCCA's concerns by using auction revenues to fund offset network upgrades that ultimately get paid by ratepayers and by only using the auction in the event projects have equal viability. Still, the auction could increase costs to LSEs contracting with projects selected by the auction because the financing costs associated with the posting the auction funds would likely be recovered through the contract. The auction process could also still favor developers with deeper pockets, rather than allowing all developers with equal viability to compete for contracts. In addition, the auction process seems to introduce a significant amount of administrative burden for minimal benefit. CalCCA recommends that instead of developing an auction, the CAISO focus on developing scoring criteria robust enough to rank projects' viability and minimize occurrences of equal viability scores among projects. If projects do receive the same viability score, the CAISO should study all tied projects (or study none of the tied projects if they have a viability score of zero).

Workgroup to Refine Scoring Criteria

CalCCA supports a workgroup to further refine the scoring criteria and very interested in participating in this workgroup. The perspective of LSEs will be necessary within the workgroup to ensure scoring criteria align with LSE procurement activity.

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[1] 2023 Interconnection Process Enhancements Track 2 Straw Proposal (Sept. 21, 2023) at 26.

[2] https://stakeholdercenter.caiso.com/Comments/AllComments/1198f707-8b68-4560-bb9a-7dd64ea2b57d#org-d8462b15-4465-49d6-a464-9df1f71ab2ce.

3. Please provide feedback on the study process elements of the straw proposal

a. Please provide feedback on the modifications to the Option B process.

The CAISO proposes that only projects interconnecting in areas with no available or planned TPD capacity would be eligible to use Option B. Option B would not be available for projects that did not score enough to be studied in the transmission zones with planned or available capacity. CalCCA recommends the CAISO modify this proposal to allow projects within transmission zones that did not score high enough to be studied to elect to move forward as Option B. If projects in transmission zones that do not score high enough would like to fund their own area network upgrades rather than receive reimbursement, they should be able to do so. While the CAISO suggests that allowing projects in transmission zones to proceed under Option B would be counterproductive to solving the issue of studying capacity levels so high that the study results lose accuracy, it is not certain this would be the result. Option B is not used today under the current rules, and it is unclear whether the proposed changes to the Option B rules would result in an influx of Option B projects. If upon implementation of this initiative, the CAISO does see an influx of Option B projects, the CAISO could consider requiring Option B projects within transmission zones to elect Option B upfront (rather than being scored) or limiting Option B projects within transmission zones using the same scoring criteria.

4. Please provide feedback on proposed modifications to Transmission Plan Deliverability (TPD) and Interim Deliverability

a. TPD allocation b. Interim Deliverability

CalCCA supports the CAISO's plan to develop a TPD allocation after details of the scoring criteria are finalized. The TPD allocation process should be updated to align with the scoring criteria that will be used to rank projects for study so that the projects that are determined to be the most viable in the study process are first in line to receive deliverability. CCAs often require a project to have a deliverability allocation in order to move forward with contracting with the project. Aligning the scoring criteria and the TPD allocation process will provide more certainty to developers and LSEs about the likelihood of a project receiving a TPD allocation.

It is worthwhile for the CAISO to consider a multi-year interim deliverability allocation process to bridge the gap between the in-service date of any required LDNUs and the project's requested COD. The CAISO should also consider a multi-year interim deliverability allocation process for ADNUs considering the large volume of upgrades resulting from the Transmission Planning Process over the last several years.

5. Please provide comments and feedback on Contract and Queue Management elements of the straw proposal

a. Does the one-time withdrawal opportunity sufficiently address the assignment of costs of withdrawn projects? b. Are the updates to the Limited Operation Study sufficient? c. Comments on adding asynchronous generating facility requirements in the SGIA d. Comments on removal of suspension rights e. Comments on TPD Transferability proposal f. Comments on viability criteria and time-in-queue limit g. Comments on project Modification updates h. Comments on postings for shared network upgrades i. Comments on timing of incorporating MMAs into the GIA j. Comments on timing on starting network upgrades

CalCCA supports the CAISO's contract and queue management proposals. In particular, CalCCA supports the proposal to offer a one-time withdrawal opportunity and the proposal to enforce time-in-queue requirements for projects in the queue without executed GIAs. These proposals will incentivize lingering projects to withdrawal or move froward in the development process.

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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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October 13, 2023

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Commission Rules of Practice and Procedure

Rule 13.12 1

SUMMARY OF RECOMMENDATIONS

- 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.

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

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*

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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 LIFO 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

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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

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.

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.

Dated: October 13, 2023

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Compliance Review of Utility Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility Owned Generation Fuel Procurement, and Other Activities for the Record Period January 1 through December 31, 2022

U 39 E

Application 23-02-018

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO PACIFIC GAS AND ELECTRIC COMPANY'S MOTION TO STRIKE

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October 23, 2023

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Compliance Review of Utility Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility Owned Generation Fuel Procurement, and Other Activities for the Record Period January 1 through December 31, 2022 U 39 E	Application 23-02-018

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO PACIFIC GAS AND ELECTRIC COMPANY'S MOTION TO STRIKE

Pursuant to Rule 11.1(e) of the California Public Utilities Commission's Rules of Practice and Procedure, California Community Choice Association[1] (CalCCA) hereby submits this response to Pacific Gas and Electric Company's (PG&E) *Motion to Strike Portions of the Prepared Testimony of Brian Shuey on behalf of the California Community Choice Association* (Motion) in the above-captioned proceeding.

During the summer of 2022, PG&E transferred nearly a gigawatt of excess resource adequacy (RA) capacity from its Power Charge Indifference Adjustment (PCIA) resource portfolio to the System Reliability Incremental Procurement subaccount of its New System Generation Balancing Account (NSGBA).[2] PG&E's prepared testimony identifies and discusses that excess

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1 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, Energy for Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, 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, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 PG&E Prepared Testimony at 12-15.

RA capacity[3] and CalCCA witness Shuey's prepared testimony probes that excess RA capacity.[4] In so doing, witness Shuey identifies a substantial and troubling gulf between the excess RA capacity PG&E identifies in its testimony, and PG&E's 2022 RA position reports.[5] As witness Shuey explains, that gulf suggests that while PG&E may technically be releasing RA solicitations consistent with Appendix S of its Bundled Procurement Plan (BPP), it is doing so before it identifies excess RA, which means load serving entities may not have had a reasonable opportunity to purchase PG&E's excess RA during the summer of 2022.[6] That practice violates the Commission's directive that PG&E make reasonable attempts to sell its excess capacity,[7] and may have had important implications for all LSEs, who pay fines if they fail to meet RA compliance requirements.

Based on those observations, witness Shuey recommends the Commission update processes to scrutinize PG&E's RA sales practices, among other recommendations.[8] Far from being outside the bounds of this proceeding, Mr. Shuey's testimony *must be submitted* in this proceeding—there simply is no other proceeding in which the Commission might scrutinize whether PG&E's inadequate attempts to sell its excess RA capacity, during a time of significant capacity scarcity, harmed ratepayers.

PG&E's Motion seeks to prevent that scrutiny, based largely on PG&E's legal position that the Commission's review of its RA practices in this proceeding is limited to an evaluation of PG&E's compliance with Appendix S. The Commission should deny the Motion because it takes an unduly narrow view of the scope of this proceeding, PG&E's obligations, and the Commission's

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3 *Id*.
4 *See generally* Prepared Direct Testimony of Brian Shuey on behalf of CalCCA.
5 *Id.* at 5-7.
6 *Id*. at 7-11.
7 D.21-12-015 at 183-184.
8 Prepared Direct Testimony of Brian Shuey on behalf of CalCCA at 18.

authority. Moreover, the Motion is premature, because CalCCA has not yet offered any testimony or accompanying exhibits in evidence. Further, the Commission need not and should not curtail parties' efforts to develop the record based on PG&E's procedural motion; PG&E will have the opportunity to make arguments opposing CalCCA witness Shuey's recommendations in legal briefing following the close of the evidentiary record.

I. COMPLIANCE WITH APPENDIX S DOES NOT EXCUSE PG&E FROM COMPLIANCE WITH COMMISSION DECISIONS

The thrust of PG&E's Motion is its legal position that Appendix S is an "upfront reasonableness standard," compliance with which excuses PG&E from complying with the Commission's directive in D.21-12-015 that PG&E make reasonable attempts to sell its excess capacity prior to using that capacity for summer reliability purposes.[9] PG&E asserts "D.21-12-015 does not create a separate or additional requirement beyond Appendix S",[10] and in support of its position, cites the Commission's disposition of PG&E's Advice Letters (AL) 6306-E and 6306-E-A (Appendix S Justification ALs).

PG&E overstates the effect of the Commission's disposition of the Appendix S Justification ALs. The Commission's disposition did not conclude that compliance with Appendix S *supplants* or *is equivalent to* compliance with the Commission directives in D.21-12-015. Rather, the disposition concluded that as a general matter, PG&E's efforts to sell excess RA to the market, prior to using that excess capacity to meet its minimum effective planning reserve margin (PRM), were consistent with the requirements in D.21-03-056 (the Phase 1 Emergency Reliability OIR decision).[11]

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9 D.21-12-015 at 183-184.

10 Motion at 4.

11 Disposition of Advice Letters 6306-E and 6306-E-A at 4-5.

In this case, however, the Commission is faced with a different set of facts. PG&E reports 923 MW of excess RA capacity during the summer of 2022, and CalCCA witness Shuey's testimony demonstrates LSEs did not have a reasonable opportunity to purchase that capacity in 2022, notwithstanding the RA solicitations PG&E released. Based on the set of facts presented in this proceeding—including the specific facts surrounding the timing of PG&E's solicitations, developed through testimony, discovery, and cross examination—the Commission may find that PG&E did not comply with the directives in D.21-12-015 (notwithstanding its compliance with Appendix S). Nothing in the Commission's disposition of the Appendix S Justification ALs would preclude that result.

II. PG&E'S COMPLIANCE WITH D.21-12-015 IS WITHIN THE SCOPE OF THIS PROCEEDING

PG&E notes Scoping Issue 5 in the Assigned Commissioner's Scoping Memo and Ruling asks "Whether PG&E administered resource adequacy and sales consistent with its Bundled Procurement Plan."[12] On that basis, PG&E suggests any review of PG&E's RA practices beyond the utility's compliance with Appendix S, including whether PG&E made reasonable attempts to sell its excess RA in compliance with D.21-12-015, is outside the scope of this proceeding.[13]

PG&E takes an unreasonably narrow view of this proceeding's scope. While CalCCA does not dispute that one of the purposes of this proceeding is to review whether PG&E's RA procurement and sales practices during the record period were consistent with its BPP, Scoping Issue 5 does not establish the outer bounds of the Commission's review of PG&E's RA practices in this proceeding. Indeed, the reasonableness of PG&E's attempts to sell excess RA during the

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12 Motion at 3 (citing *Assigned Commissioner's Scoping Memo and Ruling* at 3 (Jun. 2, 2023)).

13 *Id*. at 4 (stating "the relevant inquiry within the scope of this proceeding with respect to RA is "Whether PG&E administered resource adequacy procurement and sales consistent with its Bundled Procurement Plan," not whether PG&E complied with D.21-12-015." (citations omitted)).

summer of 2022—notwithstanding the utility's compliance with Appendix S—is well-within the scope of this proceeding because that issue ultimately impacts the entries PG&E made to its balancing accounts, including the Portfolio Allocation Balancing Account (PABA) during the 2022 record period. Scoping Issue 3 concerns the reasonableness and appropriateness of those entries, giving the Commission broad latitude to consider, in this proceeding, PG&E's activities impacting those entries.

III. THE COMMISSION CAN, IN THIS PROCEEDING, ORDER FURTHER INVESTIGATION INTO PG&E'S BUNDLED PROCUREMENT PLAN IN OTHER PROCEEDINGS

PG&E argues certain sections of witness Shuey's testimony must be stricken because they seek to "amend or relitigate the BPP[.]"[14] PG&E asserts the structure of the BPP can and should be litigated in the Integrated Resources Plan (IRP) proceeding, or in the investor-owned utilities' BPP-related advice letter filings.[15]

CalCCA agrees that ERRA Compliance proceedings are not aimed at rewriting the structure of the BPP. However, again, PG&E takes an unduly restrictive view of the potential outcomes of this proceeding. For instance, should the Commission determine that PG&E's RA-related actions warrant further scrutiny, it might direct or suggest—in this proceeding—further investigation into the BPP to occur in a separate proceeding (which is the type of determination the Commission frequently makes in ERRA proceedings).[16] The Administrative Law Judge should not close that door by granting PG&E's Motion.

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14 *Id*. at 7-8.

15 *Id*. at 7.

16 *See, e.g.,* D.21-07-013, *Decision Resolving Phase One of Pacific Gas and Electric Company's ERRA Compliance Application for the 2019 Record Year,* A.20-02-009 (July 15, 2021), at 21 (emphasis added) (stating "The Commission's currently open proceeding, Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment, R.17-06-026, is more appropriate for considering how the Commission should address contract vintages for the utilities in the future, ***and we intend to explore these matters in that proceeding***.); D.20-12-028 at Ordering Paragraphs

IV. NOTHING IN WITNESS SHUEY'S TESTIMONY IS UNFAIRLY PREJUDICIAL

According to PG&E, Section V of CalCCA witness Shuey's testimony "impl[ies] that PG&E is responsible for 'substantial fines' incurred by Load Serving Entities", and asserts that testimony is "unfairly prejudicial to PG&E because it incorrectly implies that PG&E is a contributing cause to the LSE's RA compliance fines."[17] PG&E misrepresents Mr. Shuey's testimony. In the first sentence in Section V of his testimony, Mr. Shuey asserts that PG&E's unreasonable attempts at selling its excess RA capacity "cannibalize[] an already constrained RA market and increase costs to all customers."[18] In the remaining portion of Section V, Mr. Shuey presents a series of facts illustrating RA market constraints.[19]

PG&E read into Mr. Shuey's testimony an implication that PG&E caused LSEs' RA compliance fines, but Mr. Shuey's testimony does not actually make that allegation. Moreover, to the extent Mr. Shuey's testimony *implies* a relationship between PG&E's RA practices and fines paid by LSEs, PG&E fails to explain why that implication would be "unfairly prejudicial" to PG&E, beyond its bare assertion that such an implication is "incorrect." To the extent PG&E disagrees with Mr. Shuey's testimony, it has the opportunity to respond to that testimony in rebuttal, and the Commission will have the opportunity to resolve that disagreement via its final decision—in other words, the regulatory process would work as intended.

4, 22 ("We recognize the importance of approving a consistent method for returning balances to customers but will not adopt PG&E's going-forward proposal at this time. We will consider a long-term solution when we address PCIA framework issues in the appropriate proceeding."); D.20-02-047 at 13-16 (resolving PG&E's 2020 ERRA Forecast case and stating "A tracking framework within PABA and mechanisms to value banked RECs at the end of the compliance period may help resolve these issues. These issues are however, more appropriately addressed by the Commission in the PCIA proceeding."); D.22-12-044 at 22; and D.22-12-012 at 61-62 (stating "… the current scope of the PCIA proceeding includes consideration of whether to modify or clarify the calculation of the PCIA for VAMO transactions, so we do not address SoCal CCAs' request here.").

17 Motion at 8.

18 Prepared Direct Testimony of Brian Shuey on behalf of CalCCA at 11.

19 *Id*. at 11-14.

V. PG&E'S MOTION IS PREMATURE BECAUSE CALCCA HAS NOT OFFERED ANY TESTIMONY OR ACCOMPANYING EXHIBITS INTO EVIDENCE

CalCCA filed Mr. Shuey's prepared testimony and accompanying exhibits (including a series of PG&E's responses to CalCCA discovery requests) on September 22, 2023 consistent with the procedural schedule established in the Scoping Memo.[20] CalCCA has not yet, however, offered its prepared testimony or accompanying exhibits in evidence pursuant to Rule 13.8 of the Commission's Rules of Practice and Procedure. To the extent CalCCA seeks to offer in evidence any or all of its prepared testimony and exhibits, it would so do by making a motion prior to or during the evidentiary hearing consistent with Commission Rules 11.1 and 13.8. PG&E would have an opportunity to object to CalCCA's motion at that time, including by lodging objections to the admission of certain (or all) of PG&E's discovery responses. The Motion, therefore, is premature, and the Commission may reject it on that basis alone.

PG&E takes particular umbrage to the discovery responses attached to Mr. Shuey's testimony because PG&E asserted an objection to the underlying discovery requests and provided a response subject to and without waiving that objection.[21] PG&E asserts "[i]nclusion of data request responses in testimony when an objection has been lodged does not comport with the CPUC's general discovery customs and practice."[22] PG&E is incorrect. It is common practice for parties to attach discovery responses to their testimony, even where the responding party lodged an objection to the underlying discovery request. Moreover, nothing in the Commission's discovery rules prohibits such practice. As discussed above, PG&E would have an opportunity to renew its objection if and when CalCCA offers the relevant discovery response into evidence.

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20 Scoping Memo at 4.

21 Motion at 9.

22 *Id*.

VI. CONCLUSION

For the foregoing reasons, the Commission should reject the Motion.

Respectfully submitted,

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Dated: October 23, 2023

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**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 REPLY BRIEF

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October 23, 2023

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SUMMARY OF RECOMMENDATIONS

The Commission should direct Pacific Gas and Electric Company (PG&E) to apply banked Renewable Energy Credits towards its 2024 Minimum Retained Renewable Portfolio Standard 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 Portfolio Allocation Balancing Account to reflect that methodology;

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 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.

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
REPLY 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 reply brief in the above-captioned *Application of Pacific Gas and Electric Company*

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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.

(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 parties' Opening Briefs demonstrate CalCCA and PG&E agree on the majority of the issues in this case, reflecting the fact that five years since Decision (D.) 18-10-019, most implementation details of the Commission's revised framework for the Power Charge Indifference Adjustment (PCIA) have been settled.[3] Even on the single remaining contested issue—PG&E's proposed methodology to apply Renewable Energy Credits (RECs) generated in prior years towards its Minimum Retained Renewable Portfolio Standard (RPS) requirement in 2024—CalCCA and PG&E agree on several key details (including that the REC transfer should be priced at the benchmark for the year in which the REC is used towards bundled customer compliance). CalCCA and PG&E disagree, however, on the sequence in which PG&E should use its excess RECs from prior years; whereas PG&E proposes a Last-In/First-Out (LIFO) approach; CalCCA supports a First-In/First-Out (FIFO) approach.

No matter which method the Commission ultimately approves, the *total value* of banked RECs that PG&E would use to cover its 2024 Retained RPS shortfall would remain the same. The only difference would be the *specific vintages* of customers that receive a credit. CalCCA's proposal produces a fair result because customers would be credited in the order in which they paid for PG&E's excess RPS procurement. PG&E's proposal, in contrast, favors more recent vintages and keeps customers who paid for banked RECs in earlier years waiting longer for a

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[3] CalCCA notes parties' positions may change, and contested issues may emerge, following review of PG&E's recently filed Fall Update. CalCCA will address that Fall Update in comments on November 1, 2023, consistent with the procedural schedule adopted in the Assigned Commissioner's Scoping Memo and Ruling.

credit. Contrary to PG&E's argument, nothing in the RPS compliance rules compels this illogical result. The Commission should therefore approve CalCCA's proposal and direct PG&E to apply banked RECs towards its Minimum Retained RPS requirement on a FIFO basis.

I. CONTESTED ISSUE: PG&E ERRONEOUSLY CONFLATES THE RPS COMPLIANCE RULES WITH THE MINIMUM RETAINED RPS REQUIREMENT

PG&E forecasts it will have insufficient RECs to meet its bundled customer Minimum Retained RPS compliance requirement in 2024.[4] To cover its shortfall, PG&E proposes to apply excess "banked" RECs from prior years towards its 2024 Minimum Retained RPS requirement.[5] PG&E further proposes to compensate customers who previously paid for those banked RECs by crediting the corresponding PABA vintages at the 2024 RPS Adder.[6] CalCCA supports Commission approval of each of those proposals.

CalCCA and PG&E diverge, however, on the sequence in which PG&E should use its banked RECs. Whereas PG&E proposes to apply a LIFO methodology once it exhausts RECs from its current RPS compliance period (2021 and 2022 RECs), CalCCA recommends PG&E apply a more logical FIFO methodology such that customers are credited in the order in which they paid for PG&E's excess RPS procurements.[7]

PG&E disagrees with CalCCA's proposal because the utility believes a FIFO method "is inconsistent with RPS compliance rules."[8] PG&E erroneously conflates the RPS compliance rules with the Minimum Retained RPS requirement. The RPS compliance rules establish PG&E's

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4 PG&E Opening Brief at 22.

5 *Id*.

6 PG&E-01 at 9-28:1-3.

7 CalCCA Opening Brief at 8-16.

8 PG&E Opening Brief at 25.

obligations with respect to the RPS program, which is not at issue in this proceeding. The Minimum Retained RPS requirement is conceptually related to the RPS program—in that PG&E is required to retain RECs corresponding to its annual RPS targets[9]—but the requirement is a function of PCIA ratemaking and not governed by the RPS compliance rules. Whereas PG&E's Opening Brief ignores that distinction, the utility acknowledges that distinction in its responses to CalCCA discovery requests, where it states:

> PG&E clarifies that the concept of the "Minimum Retained RPS Requirement" is an aspect of Power Charge Indifference Adjustment (PCIA) ratemaking initially created in 2019 for PG&E's 2020 ERRA Forecast decision, D.20-02-047, and has not been directly addressed in RPS compliance rules or statutes . . . PG&E is not aware of an RPS compliance rule which specifically requires excess from prior period RECs be utilized according to a last-in/first-out sequence.[10]

Thus, while the RPS compliance rules may require that PG&E use excess RECs from its current RPS compliance period before using any accumulated RPS banked volumes to cover a current period *RPS compliance* shortfall,[11] neither the RPS rules nor Commission decisions compel such a sequence with respect to PG&E's Minimum Retained RPS compliance requirement. The Commission can adopt CalCCA's more logical FIFO approach without running afoul of the RPS rules.

PG&E also incorrectly suggests that CalCCA's proposal requires PG&E to apply Unsold RPS volumes towards its Retained RPS shortfall *prior to* using banked RECs.[12] PG&E

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9 D.20-02-047 at pp. 13-14 (establishing the annual RPS target quantities provided in D.11-12-020 for calculating the RPS compliance period requirement serve as appropriate minimum quantities for PG&E to consider for its annual retained RPS volumes as a part of the PABA true-up).

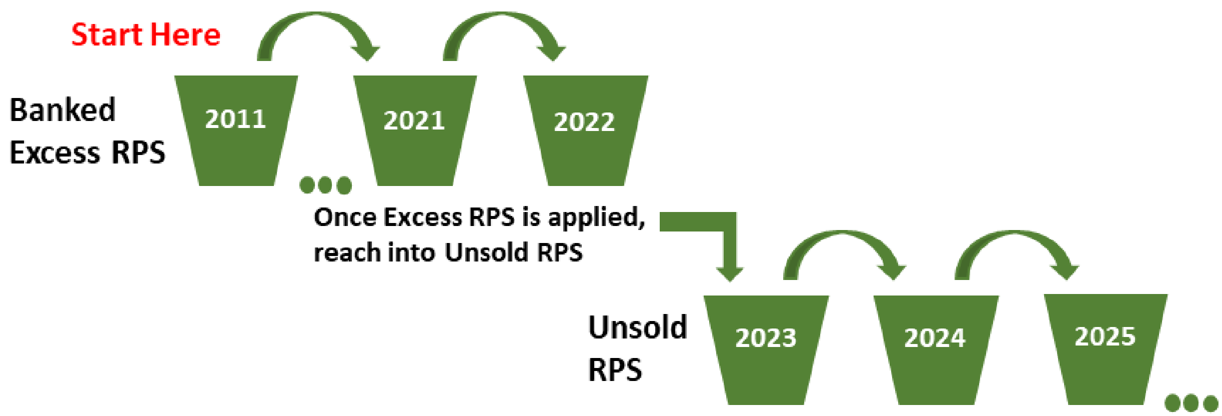
10 CalCCA-02 (PG&E response to CalCCA data request 6.06).

11 PG&E-03 at 21:30-33.

12 PG&E Opening Brief at 23-24.

misunderstands CalCCA's proposal. CalCCA does not recommend PG&E apply Unsold RPS quantities toward its 2024 Minimum Retained RPS requirement prior to applying banked RECs towards that requirement—the graphic at page 14 of CalCCA witness Shuey's testimony,[13] and reproduced below, amply reflects that fact.

Figure 1: CalCCA Banked REC application methodology proposal[14]



CalCCA observes, however, that the FIFO approach CalCCA supports "allows a more natural transition to using PG&E's 2023 Unsold RPS after all previously banked excess RECs have been applied."[15] In other words, both PG&E and CalCCA *agree* Unsold RPS can count towards the Minimum Retained RPS quantity for PCIA ratemaking purposes once previously retained excess RPS volumes have been exhausted;[16] the only difference is the sequence in which PG&E uses banked RECs before applying Unsold RPS quantities. Therefore, nothing about CalCCA's proposal compels the valuation of Unsold RECs in 2024 or is otherwise at odds with D.22-11-021, contrary to PG&E's assertions. The Commission should reject PG&E's misplaced criticisms of

13 CalCCA-01 at 14:1.

14 *Id.*

15 *Id.* at 13:11-13.

16 *See id.* at Attachment B (PG&E response to CalCCA data request 2.22 (acknowledging "Unsold RPS will be eligible to count toward the Minimum RPS quantity for the PCIA in a future period once all of the past, previously retained excess RPS volumes have been drawn upon.")).

CalCCA's proposal and adopt a FIFO approach because it would credit customers in a more logical, reasonable and fair manner than a LIFO approach.

II. UNCONTESTED ISSUE: PG&E'S OCTOBER UPDATE INDICATES IT INTENDS TO REVERT TO ITS EXISTING ESA COST ALLOCATION METHODOLOGY FOR THE PURPOSES OF 2024 RATESETTING

The Administrative Law Judge's October 9 Ruling clarified PG&E's proposal to change the methodology for allocating Electric Supply Administration (ESA) costs, identified as Issue 9a in the Scoping Memo, will not be addressed in the decision targeted for the Commission's December 14, 2023 voting meeting.[17] Accordingly, in its Opening Brief, CalCCA recommended the Commission direct PG&E to revert to its existing methodology for allocating ESA costs for the purposes of 2024 rates.[18]

In its recently filed Fall Update, PG&E states it "anticipates providing a Supplement to this Fall Update . . . to reflect revisions to ESA allocation and other common costs based on a net revenue requirement methodology."[19] CalCCA will review that testimony and address it as necessary in its comments and/or reply comments on the Fall Update. Assuming PG&E appropriately reverts to allocating ESA costs based on a net revenue requirement methodology for the purpose of 2024 rates, the Commission would no longer need to issue a directive to that effect. CalCCA maintains its recommendation that the Commission 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.

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

18 CalCCA Opening Brief at 23.

19 PG&E Fall Update Testimony at 9.

III. CONCLUSION

For the foregoing reasons, CalCCA respectfully requests the Commission adopt the recommendations in CalCCA's Opening Brief. CalCCA continues to reserve its right to modify its recommendations based on updated information presented in PG&E's recently filed October Update, and to address other issues raised therein, via comments on the October Update or any further process the Commission may adopt.

Dated: October 23, 2023

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STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

IN THE MATTER OF: Rulemaking to Amend Regulations Governing the Power Source Disclosure Program	DOCKET NO. 21-OIR-01 RE: Power Source Disclosure

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PRE-RULEMAKING PROPOSED UPDATES TO THE POWER SOURCE DISCLOSURE REGULATIONS

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STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

IN THE MATTER OF: Rulemaking to Amend Regulations Governing the Power Source Disclosure Program	DOCKET NO. 21-OIR-01 RE: Power Source Disclosure

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PRE-RULEMAKING PROPOSED UPDATES TO THE POWER SOURCE DISCLOSURE REGULATIONS

California Community Choice Association[1] (CalCCA) submits these comments to the California Energy Commission (Commission) on the "Pre-Rulemaking Draft" of Proposed Amendments to the Power Source Disclosure Program, the Staff Report on "Power Source Disclosure Proposals on Hourly and Annual Accounting,"[2] and the Commission Staff Presentation on "Proposed Updates to Power Source Disclosure Regulations" (collectively, the Proposed PSD Updates).[3]

I. INTRODUCTION

CalCCA appreciates the opportunity to comment on the Proposed PSD Updates, and to be a participant in both this pre-rulemaking and the upcoming Rulemaking to formalize the PSD

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1 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, 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, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 Clendening, Logan, and Jordan Scavo. 2023. *Power Source Disclosure Proposals on Hourly and Annual Accounting.* California Energy Commission. Publication Number: CEC-200-2023-014 (Staff Report).

3 The Proposed PSD Updates are included in Docket No. 21-OIR-01.

program modifications. As generation providers to approximately 37 percent of customers in the investor-owned utilities' (IOU) territories, community choice aggregators (CCA) as load-serving entities (LSE) serve approximately 14 million electricity customers in California. CCAs have a strong interest in ensuring the accurate portrayal of their electricity portfolios through the power source disclosure (PSD) program and the power content labels (PCL), especially given their focus on procurement of renewable and green-house gas (GHG) -free electricity to meet California's decarbonization goals.

The proposed updates are intended to advance the goals in the PSD authorizing statute to provide "reliable, accurate, timely, and consistent information regarding fuel sources for electric generation offered for retail sale in California."[4] The updates will update the existing annual reporting requirements, and add the requirement set forth in Senate Bill (SB) 1158 for retail suppliers to report data on hourly loss-adjusted load and associated emissions to the Commission starting in 2028.[5] Specifically, the updates: (1) propose rules for LSE hourly reporting to accomplish SB 1158's goals to allow California energy agencies to track progress toward statewide GHG reduction targets; (2) update the annual accounting rules; (3) implement the PCL due date changes from Assembly Bill (AB) 242 (2021); (4) streamline the attestation requirements for public agencies; (5) codify the regulatory advisory on GHG emissions reporting requirements for new CCAs; (6) incorporate the regulatory advisory on the retirement of unbundled renewable energy credits (REC); and (7) modernize the PSD's method of data collection and processing for both hourly and annual reporting.

CalCCA generally supports the proposed updates, with the requested recommendations and requests for clarification provided herein. Specifically, CalCCA recommends that the Commission:

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4 Cal. Pub. Util. Code § 398.1(a).
5 Staff Report at 1-2.

- Clarify the calculation methodology for "losses" related to unspecified power in the context of hourly reporting;

- Adopt the Proposed PSD Update allowing LSEs to specify the stacking order of resources in their hourly reporting to benefit marketing of their portfolios and/or the utilization of avoided emissions;

- Adopt hourly reporting rules for contracts with multiple buyers and/or resources, including allocations from IOUs to LSEs through the California Public Utilities Commission (CPUC) -authorized Voluntary Allocation and Market Offer (VAMO) processes;

- Provide example "use cases," opportunities for comment on proposed proxy hourly resource profiles, and template and program testing opportunities to facilitate the implementation of the hourly reporting rules;

- Establish rules to exempt small LSEs from the hourly reporting requirements in accordance with Public Utilities Code Section 398.6(1);

- Codify the existing treatment of allocations of GHG-Free resources from the IOUs to CCAs as carbon-free in the PCL; and

- Establish rules for the annual reporting of VAMO allocations.

II. THE PROPOSED HOURLY REPORTING RULES SHOULD BE ADOPTED, WITH CLARIFICATIONS AND AMENDMENTS

A. The Calculation Methodology for "Losses" Related to Unspecified Power Requires Further Clarification

The Commission should clarify its calculation methodology for "losses" related to unspecified power. Public Utilities Code section 398.6(a)(4) defines "loss-adjusted load" as "the total amount of electricity, measured at the utility-scale generation source, that a retail supplier requires in order to provide for retail sales after electrical losses in transmission and distribution."[6] The proposed regulations further specify the increases to "loss-adjusted load" to account for transmission and distribution losses for specified resources: (1) four percent of each specified resource to account for losses incurred with California; and (2) an additional two

[6] Pub. Util. Code § 398.6(a)(4).

percent of each specified import to account for losses incurred outside California.[7] The proposed regulations specify the following for unspecified power:

> Unspecified power shall increase loss-adjusted load using loss adjustment factors for each hour of the year that CEC staff shall calculate and publish hourly loss adjustment factors for unspecified power annually. The loss adjustment factors shall be based on the hourly profile of unspecified imports, unspecified in-state resources, and oversupplied resources.[8]

Additional information should be provided by the Commission to clarify how it will calculate the hourly loss adjustment factors, given the potential for such calculation to substantially impact LSE hourly reporting.

B. The Proposed Rules Allowing LSE Discretion to Specify the Stacking Order Should be Adopted

The Proposed PSD Updates allowing LSEs flexibility in specifying their stacking order in the context of the hourly reporting should be adopted. CalCCA agrees with Commission staff that retail suppliers should have the ability to assign resources to hourly load to match offerings to customers.[9] However, retail suppliers should also be able to assign GHG-intensive resources to loss-adjusted load first to accumulate greater avoided GHG emissions.[10] As noted by CEC staff, a retail supplier's reported GHG emissions or emissions' intensities will not be impacted by the stacking order chosen by the retail supplier.[11]

C. The Commission Should Adopt Rules Regarding Contracts with Multiple Parties or Resources

As noted in CalCCA's Comments in response to the Commission's Request for Information on the SB 1158 hourly reports, access to hourly data in existing and/or specific

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7 Proposed Regulations, § 1392(c)(2)(A)-(B).
8 *Id.,* § 1392(c)(2)(C).
9 *See* Staff Report at 10-11.
10 *Id.* at 11.
11 *Id.* at 10-11.

contractual situations may be challenging.[12] While SB 1158 does require sellers to provide hourly information to buyers and for that information to be made available to subsequent buyers, it does not address situations in which a single seller has sold to multiple buyers, some of whom specified hours in their contracts and others who did not. This situation is particularly problematic with respect to existing contracts that did not contemplate this granularity of reporting when the contracts were negotiated and signed.

In addition, rules must be established for situations in which a buyer purchases or receives allocations from multiple resources. For example, in the case of the VAMO processes allowing allocations to CCAs of Renewables Portfolio Standard (RPS) eligible energy from IOUs, the allocations incorporate a "slice" of the IOU portfolio from potentially hundreds of resources. Overall, the mechanisms adopted for the hourly reporting must take into account different contractual configurations, and whether and how the data necessary for the reporting can actually be obtained.

D. The Commission Should Provide Example 'Use Cases,' Opportunities for Comment on Proposed Proxy Hourly Resource Profiles, and Template and Program Testing Opportunities to Facilitate the Implementation of the Hourly Reporting Rules

Given the novelty and complexity of the new hourly reporting rules for retail sellers, the Commission should provide example "use cases" for each new accounting rule to clearly establish how the rules will be applied. In addition, if the Commission provides proxy hourly resource profiles for use when actual hourly data is not available, the Commission should provide the profiles in advance and allow stakeholders opportunity to review and comment on such profiles. Finally, to the extent new templates and programs are established to implement the

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12 *See* Docket 21-OIR-01, *California Community Choice Association's Comments on the Request for Information, Power Source Disclosure* (Apr. 14, 2023).

new rules, the Commission should allow retail suppliers adequate time to test the new templates and programs prior to going live on January 1, 2028.

E. The Commission Should Exempt Small LSEs from the Hourly Reporting Requirements in Accordance with Section 398.6(l)

CalCCA requests that the Commission include criteria in the Proposed PSD Updates for exempting small retail suppliers from hourly reporting requirements. Section 398.6(l) authorizes the Commission to modify or adjust the hourly reporting requirements for any electrical corporation with 60,000 or fewer customer accounts in the state or any retail supplier with an annual electrical demand of less than 1,000 gigawatt hours (GWh).[13] The Commission can exclude such LSEs if it finds that the costs to comply with the hourly reporting requirements unduly burden the LSE.[14] The Commission has in fact recently exempted small CCAs from the requirements of its Load Management Standards (LMS) for similar reasons.[15] In this Rulemaking, the Commission should consider the compliance costs and burdens of compliance and establish criteria for exempting small retail suppliers like those that the Commission used to exempt small CCAs from the LMS.

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[13] Pub. Util Code § 398.6(l).

[14] *Ibid.*

[15] In response to comments from CalCCA, the Commission exempted CCAs that provide 700 or fewer GWh of electricity to customers in any calendar year from the LMS requirements. *See* Title 20, Art. 5, § 1621(c)(10) (requiring only CCA providing in excess of 700 GWh of electricity to consumers to be subject to the LMS). In its Final Statement of Reasons, the Commission noted that this change from the LMS as initially proposed was "necessary to … minimize the burdens on CCAs that play a smaller role in the electricity market." California Energy Commission Docket 21-OIR-03, *Final Statement of Reasons for Revisions to the Load Management Standards* (Jan. 25, 2023), at 7.

III. THE PROPOSED MODIFICATIONS TO ANNUAL REPORTING ON THE PCL SHOULD BE ADOPTED, WITH AMENDMENTS

A. The Existing Treatment of GHG-Free Allocations in the PCL Should be Codified in the Updated Regulations

The Commission should continue to allow LSEs to count GHG-free resource allocations as carbon-free on their PCLs. In Decision (D.) 23-06-006, the CPUC established an allocation mechanism and a new market price benchmark (MPB) for CCAs to receive the GHG-free incremental value of large hydroelectric energy resources above the value of fossil fuel resources.[16] IOUs are able to choose whether to provide the GHG-free incremental value through a GHG-free allocation or a GHG-free MPB adder.[17] An IOU's choice of the GHG-free allocation will essentially continue the interim GHG-free resource allocations that had been allowed prior to the Decision, except that the new GHG-Free allocations only include large hydroelectric resources (with the option for the IOU to also include nuclear resources). Under the interim allocation approach, CCAs were permitted to count the interim allocations as carbon-free on their PCLs. In the event the IOU chooses to allocate the GHG-free resource value to CCAs going forward, the Commission should continue to allow CCAs to count their GHG-free allocations as carbon-free in their PCL calculations.

B. Rules Should be Established for the Annual Reporting of VAMO Allocations

As noted above, CCAs can take allocations of RPS from the IOUs through the RPS VAMO processes adopted in CPUC D.21-05-030. The first VAMO processes were conducted in 2023, with many CCAs receiving allocations of RPS through either a Voluntary Allocation or Market Offer. The Commission should establish rules governing the treatment of the VAMO

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16 D.23-06-006, *Decision Addressing Greenhouse Gas-Free Resources, Long-term Renewable Transactions, Energy Index Calculations, and Energy Service Providers' Data Access,* Rulemaking (R.) 17-06-026 (June 13, 2023).

17 *Id.*, Ordering Paragraph 3, at 48.

allocations to ensure CCAs realize the full value of RPS resources, including the ability to count the allocated resources on their PCLs. This is a logical extension of the current rules for counting the interim GHG-free allocations, which as described above allow an LSE to count a GHG-free allocation towards their PCL. There is no reason that RPS VAMO resources should not be also counted in the PCL.

In addition, the Commission should include in the Proposed PSD Updates clarification of its treatment of different Portfolio Content Category (PCC) resources in a VAMO allocation. CalCCA recommends the following treatment: (i) PCC 1 resources should be treated as "Directly Delivered Renewables" in Schedule 1 in the PSD Annual Report template; (ii) PCC 2 resources should be treated as "Firmed-and Shaped Imports" in Schedule 1; and (iii) PCC 3 resources should be treated as "Retired Unbundled RECs" in Schedule 2. In addition, as directed by the CPUC in D.22-06-034, PCC 0 resources allocated to CCAs through the Voluntary Allocation must retain their PCC 0 status and shall not be treated as a resale devaluing their PCC status.[18]

IV. CONCLUSION

CalCCA looks forward to further collaboration on this topic in the pre-rulemaking and rulemaking phases.

Respectfully submitted,

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October 24, 2023

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[18] D.22-06-034, *Decision Establishing Rules for Portfolio Content Category Classification for Voluntary Allocations of Renewables Portfolio Standard Resources*, R.18-07-003 (June 24, 2022), Conclusion of Law 6, at 23 ("[PCC 0] RECS allocated under the Voluntary Allocation process should retain PCC 0 status").

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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates.	R.22-07-005

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON EMAIL RULING DIRECTING SOUTHERN CALIFORNIA EDISON COMPANY AND PACIFIC GAS AND ELECTRIC COMPANY TO PROVIDE ADDITIONAL PILOT BUDGET INFORMATION**

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SUMMARY OF RECOMMENDATIONS

California Community Choice Association recommends that the California Public Utilities Commission:

- Reject Southern California Edison Company's proposal to recover expanded pilot costs through two separate balancing subaccounts;
- Reject the Public Advocates Office at the California Public Utilities Commission's proposal to require community choice aggregators (CCAs) to submit proof of non-ratepayer funding before being eligible to receive ratepayer funding;
- Require investor-owned utilities to share demand response enrollment data with CCAs implementing expanded pilots;
- Reject Pacific Gas and Electric Company's (PG&E's) misleading assertions that a CCA administering an expanded pilot is less cost-effective than a CCA opting into PG&E's expanded pilots; and
- Reject PG&E's proposal to prohibit a phased launch for CCAs administering their own expanded pilot in the case in which the Commission approves a phased launch framework.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates.	R.22-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON EMAIL RULING DIRECTING SOUTHERN CALIFORNIA EDISON COMPANY AND PACIFIC GAS AND ELECTRIC COMPANY TO PROVIDE ADDITIONAL PILOT BUDGET INFORMATION

California Community Choice Association[1] (CalCCA) submits these comments in response to the *Email Ruling Directing Southern California Edison Company and Pacific Gas and Electric Company to Provide Additional Pilot Budget Information*[2] (Ruling), dated October 3, 2023.

I. INTRODUCTION

CalCCA appreciates the opportunity to submit a response to Reply Comments[3] on the Staff Proposal on Existing Dynamic Rate Pilot Expansion (Staff Proposal) attached to the Commission's August 15, 2023 Ruling (August 15 Ruling) on expanding existing dynamic rate

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1 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, 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, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 Rulemaking (R.) 22-07-005, *Email Ruling Directing Southern California Edison Company and Pacific Gas and Electric Company to Provide Additional Pilot Budget Information* (Oct. 3, 2023).

3 All references herein to party Reply Comments are to the Reply Comments filed in this Rulemaking (R.) 22-07-005, on or about October 9, 2023, unless otherwise specified.

pilots.[4] Robust community choice aggregator (CCA) participation in the expanded pilots heavily depends on the Commission-approved design of the pilots. Accordingly, CalCCA recommends that the Commission:

- Reject Southern California Edison Company's (SCE's) proposal to recover expanded pilot costs through two separate balancing subaccounts;
- Reject the Public Advocates Office at the California Public Utilities Commission's (Cal Advocates') proposal to require CCAs to submit proof of non-ratepayer funding before being eligible to receive ratepayer funding;
- Require investor-owned utilities (IOU) to share demand response (DR) enrollment data with CCAs implementing expanded pilots;
- Reject Pacific Gas and Electric Company's (PG&E's) misleading assertions that a CCA administering an expanded pilot is less cost-effective than a CCA opting into PG&E's expanded pilots; and

II. REJECT PG&E'S PROPOSAL TO PROHIBIT PHASED LAUNCH FOR CCAS ADMINISTERING THEIR OWN EXPANDED PILOT, IN THE CASE WHERE THE COMMISSION APPROVES A PHASED LAUNCH FRAMEWORK. THE COMMISSION SHOULD REJECT SCE'S PROPOSAL THAT COSTS FROM EXPANDED PILOTS BE RECOVERED FROM TWO BALANCING ACCOUNTS

The Commission should reject SCE's proposal to recover the distribution and generation costs of expanded pilots through two separate balancing accounts. SCE proposes to recover the delivery portion of program costs through a distribution subaccount of SCE's BRRBA-D and the generation portion of program costs through the generation subaccount.[5] This cost recovery framework, which tracks pilot costs through two separate balancing accounts, is similar to PG&E's proposal from opening comments, which proposed to recover generation costs from

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4 R.22-07-005, *Administrative Law Judge's Ruling on Track B Staff Proposal to Expand Existing Pilots* (Aug. 15, 2023) (ALJ Ruling on Expanded Pilots).

5 *See* SCE Reply Comments, at 7-8 ("Specifically, administrative and bill credit costs associated with the delivery portion of a customer's bill would be recovered from all customers via distribution rates using the distribution subaccount of SCE's Base Revenue Requirement Balancing Account (BRRBA-D). Administrative and bill credit costs associated with the generation portion of a bundled service customer's bill would be recovered from bundled service customers via bundled generation rates using the generation subaccount of SCE's BRRBA-G").

providing shadow bill credits through the latest vintage of the Power Charge Indifference Adjustment (PCIA).[6] In response, CalCCA proposed to recover all expanded pilot costs for IOUs and CCAs through distribution rates because the expanded pilots will benefit the reliability of the grid, which benefits all customers.[7] While SCE and PG&E may have different specific subaccounts in which to track expanded pilot costs through distribution rates, the principle that all customers that benefit from the improved reliability of the expanded pilot should pay the costs of the programs still stands. The simplest and most effective way to do this is to use a single balancing account and distribution rates since all customers, bundled and unbundled, pay distribution rates. Tracking costs through a single balancing account also minimizes administrative costs relative to tracking costs through two balancing accounts. Finally, the use of distribution rates mimics the Cost Allocation Mechanism and will not necessitate relying upon the PCIA and associated complicated vintaging calculations that occur with the PCIA.

III. THE COMMISSION SHOULD REJECT CAL ADVOCATES' PROPOSAL TO REQUIRE PROOF OF ALTERNATIVE FUNDING SOURCES BEFORE RECEIVING RATEPAYER FUNDING FOR EXPANDED PILOTS

The Commission should reject Cal Advocates' proposal to require CCAs to seek funding from other sources prior to ratepayer funding because time is essential to being able to provide increased reliability for potential extreme weather events as early as the summer of 2024. Cal Advocates argues in Reply Comments that ratepayer funding should only go to a CCA after it has submitted an application to the Commission that proves the CCA has attempted and failed to

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6 *See* R.22-07-005, *Attachment to the Submission of GridX, Inc., Polaris Energy Services, Gridtractor, Inc., and Pacific Gas and Electric Company's Comments and Responses to the Administrative Law Judge's Ruling on Track B Staff Proposal to Expand Existing Pilots,* at 27 (Sept. 25, 2023) ("PG&E believes that recovery through the last PCIA vintage year of PABA for PG&E generation rate shadow billing credits is the most appropriate method of recovery for the generation component because it will recover the revenue shortfall from those customers i.e., bundled and departed load customers who left bundled service from the preceding six month period, who received the benefit of the pilot").

7 *See* CalCCA Reply Comments, at 6-7.

acquire alternative funding sources.[8] The August 15, 2023 Ruling's request for potential expanded pilot administrators to consider non-ratepayer funding sources is reasonable;[9] however, given the short timeline to launch expanded pilots in June 2024, CCAs will need to spend their available time in developing programs, identifying customers, enrolling those customers, implementing necessary technology for the customer, and implementing their own billing systems in order to have the expected load shift available by summer of 2024. Placing another task of identifying alternate sources of funding, applying for such funding, and obtaining funding is not likely to be feasible in the short time that is available to meet grid reliability needs for potential extreme weather conditions in the summer of 2024. CCAs have only recently begun to plan for an AgFIT pilot after the Commission published the Staff Proposal on August 15, 2023 proposing to expand the pilot, and Commission decisions on funding and cost recovery are still undetermined. Requiring CCAs to prove they have sought alternative funding means not only leaves little time for CCAs to apply for and receive determinations on alternative funding sources before Summer 2024, but also makes funding uncertain, which can negatively impact planning and pilot development. Additionally, Cal Advocates' proposal does not propose for IOUs to provide the same proof which constitutes inequitable and inconsistent treatment that would also hinder CCA planning of expanded pilots. Therefore, the Commission should reject

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8 *See* Cal Advocates Reply Comments, at 12-13 ("CCAs should not receive funding from bundled service customers for the Expanded Pilots until they have proven that they have utilized all other sources of non-ratepayer funds at their disposal. This should include submission of their applications with requests for funding and reporting of the outcome for each of the identified funding sources").

9 ALJ Ruling on Expanded Pilots, at 2 ("PG&E and SCE are each directed to: (a) provide estimated costs for additional administration of implementation for the Expanded Pilots (as described in the Staff Proposal), including a table with a breakdown of costs by category, and (b) comment on whether non-ratepayer sources of funds are available to provide additional automation incentives beyond those authorized in D.21-12-015 (*e.g.,* Energy Commission grants)").

Cal Advocates' proposal, which is not suitable for the short planning and implementation timeline of expanded pilots by June 2024.

IV. PG&E'S PROPOSAL TO REQUIRE CCA COMPLIANCE WITH COMMISSION REQUIREMENTS IF ACCEPTING RATEPAYER FUNDING FOR EXPANDED PILOTS IS REASONABLE

PG&E's proposal to require CCA compliance with Commission requirements if utilizing Commission-authorized ratepayer funds for implementing expanding pilots is reasonable. PG&E argues that if the Commission approves funding for CCAs to implement expanded pilots, then CCAs should have to comply with Commission oversight of those expanded pilots.[10] CCAs anticipated doing so and have experience with Commission oversight and administering ratepayer funds through the implementation of programs in other proceedings. For example, eight CCAs administer the Disadvantaged Community Green Tariff (DAC-GT) and Community Solar Green Tariff (CS-GT) programs, and operate under Commission oversight while recovering costs from ratepayers.[11] PG&E correctly supposes that the Commission cannot establish rules or funding requirements for those areas where it does not authorize ratepayer funding and "particularly those over which the Commission has no authority or oversight."[12] However, in the alternative where the Commission does authorize ratepayer funding, it can place conditions and requirements on the use of those funds. The examples provided of CCA implementation of energy efficiency and DAC-GT and CS-GT programs demonstrate that the Commission has already set the precedent for CCAs to receive ratepayer funding for programs

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10 *See* PG&E Reply Comments, at 12 ("If the Commission classifies and funds the AgFIT expansions as DRET pilots, it would rely on a regulatory program that would subject participating CCA's pilot activities to Commission oversight (as occurs with VCE in the existing pilot").

11 Clean Power Alliance of Southern California, Clean Power San Francisco, CalChoice, East Bay Community Energy (now known as Ava Community Energy), MCE, Peninsula Clean Energy, San Diego Clean Energy, and San Jose Clean Energy administer DAC-GT and/or CS-GT programs.

12 *See* PG&E Reply Comments, at 12.

and that CCAs would indeed be under Commission oversight for operating those programs. CCAs generally support the application of Commission jurisdiction over Commission-authorized ratepayer funding for pilots or programs.

V. THE COMMISSION SHOULD REQUIRE IOU DR ENROLLMENT DATA SHARING WITH CCAS PARTICIPATING IN EXPANDED PILOTS

The Commission should require PG&E and SCE to share relevant DR program enrollment data with CCAs participating in expanded pilots. CalCCA appreciates PG&E's recommendation that if the Commission prohibits dual enrollment between expanded pilots and demand response programs, the Commission should direct PG&E and SCE to provide unbundled customer specific Emergency Load Reduction Program (ELRP) data to CCAs.[13] As discussed in the Track B Working Group Report, PG&E does not currently share ELRP data with CCAs.[14] Without this data, CCAs would not be able to prevent dual enrollment with a DR program like ELRP while enrolling customers into a dynamic rate pilot, complicating enrollment for both customers and CCAs. Additionally, without this data, CCAs would not be able to gain insight into and isolate the impacts of ELRP, the expanded pilots, and other demand side programs on load, hindering load forecasting efforts and estimates of future potential for demand flexibility, CalCCA does not currently take a position on whether or to what extent dual enrollment prohibitions should apply to expanded dynamic rate pilot.

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[13] *See* PG&E Reply Comments, at 15-16 ("Solely for purposes of evaluating participation in PG&E's Expanded Pilots as a load serving entity subject to the CEC LMS standards, the Commission decision on pilot expansion might direct that unbundled customer specific ELRP information be provided to the unbundled customer's CCA or ESP under a non-disclosure agreement").

[14] *See* R.22-07-005, *Track B Working Group Report and Notice of Availability*, at 235 (listing the potential barriers to CCA participation in dynamic pricing, including CCA's lack of data on customer enrollment in ELRP) (Oct. 11, 2023).

VI. THE COMMISSION SHOULD REJECT PG&E'S ASSERTION THAT CCAS OPTING INTO AN IOU EXPANDED PILOT WOULD BE MORE COST EFFECTIVE

The Commission should reject PG&E's claim that CCAs administering the expanded pilots in their service area would increase overall pilot costs. PG&E asserts that, "It will be more efficient and less costly to implement PG&E's pilot expansion proposal overall, versus allowing separate CCA AgFIT pilot expansions."[15] This statement should be rejected because it ignores two crucial factors that are relevant to both the cost and the benefit of CCA participation through their own programs. First, PG&E claims that CCAs will save money by opting into the PG&E Expanded Pilots. However, without funding mechanisms determined at this point,[16] this claim is premature. In addition to this claim being premature, PG&E's description ignores the fact that CCAs administering the expanded pilot in their service area will allow that CCA to utilize its deep knowledge of its community, including leveraging relationships with community based organizations and local governments in its service area, to more effective and efficiently find customers for which the expanded pilots might be a good fit – thus potentially increasing the number of customers enrolled and participating. This in turn will increase the potential for load shifting resulting in further benefit to the grid, including summer reliability. Second, PG&E's position also ignores an important aspect of CCAs administering expanded pilots rather than opting into PG&E's expanded pilots: experience gained implementing dynamic rates ahead of the 2027 deadline to comply with CEC LMS. The Staff Proposal lists CCAs gaining operational

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15 *See* PG&E Reply Comments, at 11.

16 *See* PG&E Reply Comments, at 11 ("PG&E believes it would be significantly less costly for CCAs to use what will be available under PG&E's pilots, instead of each interested CCA mounting its own AgFIT extension").

experience in offering dynamic rates as a benefit of expanding the existing pilots.[17] If, instead of administering their own pilots, CCAs are required to allow PG&E to fully administer the expanded pilots in their service areas for their customers to be able to participate, those CCA's that are interested in creating their own dynamic rates as their preferred method to comply with the CEC's LMS would lose a valuable chance to gain such operational experience. Therefore, CCAs being permitted to administer the pilots, and not being required to "opt in" to an IOU expanded pilot does not represent a suboptimal pathway, instead it furthers the goals listed in the Staff Proposal for expanded pilots.

VII. THE COMMISSION SHOULD REJECT PG&E'S PROPOSAL TO PROHIBIT PHASED LAUNCH FOR CCAS THAT CHOOSE TO INDEPENDENTLY FUND EXPANDED PILOT IMPLEMENTATION

If the Commission allows CalCCA's phased launch for CCA expanded pilots, the Commission should not require CCAs to opt into PG&E's expanded pilots. In Reply Comments, PG&E acknowledges that it can accommodate CalCCA's phased launch approach, but only if CCAs are opting into its expanded pilots.[18] This condition would prohibit CCAs launching and running their own expanded pilot from having the same flexibility with launch timing, preventing CCAs from gaining operational experience with dynamic rates as set forth above in Section VI.

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17 R.22-07-005, Staff Proposal attached to *ALJ Ruling on Expanded Pilots*, at 2 ("Furthermore, staff suggests that there are additional benefits in expanding the pilots discussed in this proposal, including the following:… Enabling utilities and CCAs to gain important operational experience in offering dynamic rates to customers across different applications and capabilities, which should help advance their technical and operational readiness and deployment timelines to offer widespread hourly, marginal-cost-based dynamic rates consistent with CEC's Load Management Standards").

18 *See* PG&E Reply Comments, at 14 ("The PG&E Expanded Pilots can accommodate this CalCCA request. CCAs can join PG&E's Expanded Pilots at any point in the initial years, although there may be lead time required to get everything accomplished to roll out the pilot for any particular CCA"), and 15 ("It may not be reasonable to let a CCA start its own stand-alone AgFIT pilot later, whenever it wants since the pilot is for 2024-2027").

VIII. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the recommendations herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,

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Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates.	Rulemaking 22-07-005

REPLY COMMENTS OF MARIN CLEAN ENERGY ON ADMINISTRATIVE LAW JUDGE'S RULING ON TRACK B STAFF PROPOSAL TO EXPAND EXISTING PILOTS

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IV. THE COMMISSION SHOULD AIM TO PROVIDE CLARITY THAT ANY EXPANDED AGFIT PILOT WOULD BE COMPLIANT WITH THE CEC'S LMS. 8

V. CONCLUSION 9

SUMMARY OF RECOMMENDATIONS

- The Commission should permit any CCAs that participate in the expanded pilots to recover pilot costs in the same manner as PG&E;
- The Commission should reject PG&E's request to recover shadow bill payment costs through the PCIA; and
- The Commission should aim to provide clarity that any expanded AgFIT Pilot would be compliant with the CEC's LMS.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates.	Rulemaking 22-07-005

REPLY COMMENTS OF MARIN CLEAN ENERGY ON ADMINISTRATIVE LAW JUDGE'S RULING ON TRACK B STAFF PROPOSAL TO EXPAND EXISTING PILOTS

Marin Clean Energy[1] ("MCE") submits these Reply Comments in response to the *Administrative Law Judge's Ruling on Track B Proposal to Expand Existing Pilots* ("Ruling") Pursuant to Rule 14.3 of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure and the directives provided by the Ruling. These comments are timely filed in accordance with the Administrative Law Judge's September 13, 2023 procedural email setting October 9, 2023 as the deadline for reply comments.

I. INTRODUCTION

In their Opening Comments, several parties expressed support for Energy Division's Staff Proposal on Existing Dynamic Rate Pilot Expansion, subject to additional recommendations or modifications.[2] As a general matter, MCE agrees with those supportive parties that the Valley Clean Energy ("VCE") and Pacific Gas & Electric ("PG&E") Agricultural Flexible Irrigation Technology Pilot ("AgFIT") has shown promising results with a limited sample size, and supports the Commission expanding the pilot to other customer classes throughout PG&E's service area as

[1] Marin Clean Energy is a load-serving entity supporting a 1,200 MW peak load. MCE provides electricity service to more than 540,000 customer accounts and more than one million residents and businesses in 37 member communities across four Bay Area counties. Contra Costa, Napa, Marin, and Solano.
[2] *See* Opening Comments of VCE, 3CE, PG&E, CalCCA, Sierra Club, and others.

proposed by Staff. MCE supports the expansion of AgFIT for the purposes of providing both: (1) summer grid reliability; and (2) increased testing and learning in offering dynamic rates, particularly in support of Load Serving Entities ("LSEs") efforts to prepare for the California Energy Commission's ("CEC") Load Management Standards ("LMS") requirements.

As both California Community Choice Association ("CalCCA") and Central Coast Community Energy ("3CE") highlight in their Opening Comments, any choice to participate in a Commission approved dynamic rate pilot will be determined by each individual CCA and their governing board.[3] As a Community Choice Aggregator ("CCA"), MCE's governing board maintains authority of its rate and program offerings,[4] and any decision for MCE to participate in a Commission or PG&E created rate pilot requires sufficient information about the design and scope of the pilot is available to review and make a reasonable determination. For instance, before committing to offer any pilot, including an expanded AgFIT pilot, MCE would need the ability to review sufficient implementation details (final approved rate design, funding, cost recovery, role in program administration, etc.). In addition to these considerations, MCE would also examine its current portfolio of rate and program offerings to determine whether offering an additional pilot would be an appropriate fit for MCE's individual service area and each individual customer class.

MCE notes that it does not have a strong preference for whether the Commission adopts the Staff proposal to expand AgFIT as currently offered, or the PG&E proposal to modify the design to test more CalFUSE rate elements; however, in an effort to encourage CCA participation and equity between bundled and unbundled customers, MCE offers the following recommendations in response to parties' Opening Comments on the Ruling:

[3] CalCCA Opening Comments at 2; 3CE Opening Comments at 2.
[4] California Assembly Bill No. 117, Chapter 838, Section 366.2(c), Approved by Governor September 24, 2002.

- The Commission should permit any CCAs that participate in the expanded pilots cost recovery in the same manner as PG&E;
- The Commission should reject PG&E's proposal to recover shadow-bill payment costs through the PCIA; and
- The Commission should aim to provide clarity that any expanded AgFIT pilot would be compliant with the CEC's LMS.

II. THE COMMISSION SHOULD PERMIT CCAS THAT PARTICIPATE IN THE EXPANDED AGFIT PILOTS TO RECOVER PILOT COSTS IN THE SAME MANNER AS PG&E

The Staff proposal does not make clear who would be responsible for which aspects of administering the pilots and whether, or how, costs would be eligible for cost recovery for CCAs offering the pilot to its customers. As outlined above, MCE and other CCAs need more clarity on the proposed funding sources and categories (e.g. marketing, education and outreach ("ME&O"), program administration, technology, evaluation, billing system upgrades, etc.), to assess their participation in the expanded pilots.

In their joint Opening Comments, GridX, Inc., Polaris Energy Services, Gridtractor, Inc., and PG&E ("Joint Parties") propose a modified version of the Staff proposal in which PG&E would offer two pilots: 1) the current and expanded AgFIT pilot for bundled and unbundled Agricultural customers across PG&E's service territory ("VCE/PG&E AgFIT Pilot" or "Pilot #1"), and 2) a pilot rate that the expands AgFIT to bundled and unbundled Residential, Commercial, and Industrial Customers across PG&E's service area ("PG&E CalFUSE Pilot" or "Pilot #2").

In its proposal, PG&E provides more clarity on implementation and pilot administration, proposing specific cost recovery mechanisms for its expanded pilot costs,[5] and proposing to be the

[5] Joint Parties Opening Comments at 16-22.

sole program administrator of both Pilot #1 and Pilot #2 outside of VCE's service area.[6] However, PG&E's proposal does not incorporate or consider any CCA costs.[7] MCE is concerned that neither the Staff proposal nor PG&E proposal adequately address the issue of CCA costs to participate in the pilot and CCA cost recovery.

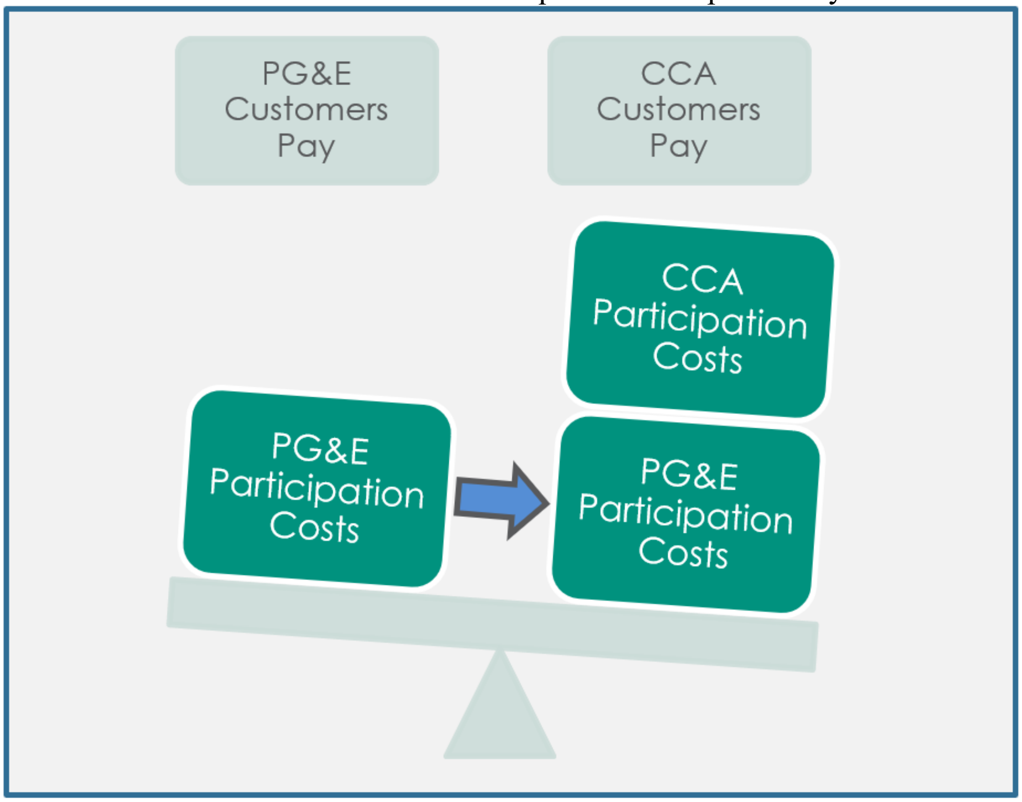
If the Commission adopts a form of PG&E's proposal, CCAs would still have significant costs to participate and many categories of costs would remain including, but not necessarily limited to: billing costs (development, testing, implementation), marketing (updating website, materials, etc.), customer support, program management, shadow bill payments, reporting and evaluation costs. In Opening Comments from 3CE and VCE, they generally propose that CCAs be able to administer the pilot in their service territory. If CCAs are permitted to administer the pilots themselves, additional cost categories for technology incentives, vendor sourcing, additional ME&O, etc. will be required, which should be eligible for cost recovery in the same manner as PG&E. Whether the Commission adopts Staff's, PG&E's, or another model for AgFIT pilot expansion, it is imperative that CCAs be permitted to recover their costs to administer and/or participate in the pilot in the same manner as PG&E.

As a general matter, if CCAs are not eligible to recover the same categories of program and pilot of costs, using the same cost recovery mechanisms or rate components as PG&E, CCA customers will be unreasonably harmed. This harm results from unequal cost responsibility where PG&E's customers can spread their participation costs across all customers in transmission and distribution ("T&D") rate components and conversely CCA customers must pay for those PG&E customers in the T&D rates and must additionally absorb all of their own participation costs,

[6] Joint Parties Opening Comments at 20.
[7] Joint Parties Opening Comments at 4 and 37.

without spreading them to all customers, in their CCA's generation rates.[8] This effect is illustrated in Table 1 below. This outcome places a disproportionate burden on participating CCA customers and, contrary to the Commission's goal, serves as a disincentive to participation for CCAs.

Table 1: Illustration of Unequal Cost Responsibility



Put another way, unequal cost recovery mechanisms result in unequal cost recovery and can unreasonably distort cost responsibility for customers.

Additionally, as it is currently unclear what the exact structure of the expanded pilots will be, MCE agrees with the parties who noted in their Opening Comments that providing an accurate budget for participation in the expanded pilots is difficult. Instead of providing a potentially inaccurate budget now, MCE proposes that once the final details of the expanded pilots are

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[8] MCE refers to both T&D rates here to illustrate a general principle of unequal cost recovery, but notes that in the instance of the expanded AgFIT pilots, PG&E is not proposing to recover costs from all customers through the transmission rate component, only the distribution rate component. However, the principle remains the same.

adopted, any interested CCAs be permitted to create and submit pilot budgets via Advice Letter to the Commission, in a similar manner to how the Commission provides consistent cost recovery mechanisms to IOUs and CCAs in the context of disadvantaged community Green Tariff ("DAC-GT") programs,[9] to ensure all customers share equally in the program costs. This is a simple solution that the Commission can apply here to avoid unreasonable harm to customers. Once the CCA budget is reviewed and approved by the Commission, that CCAs costs would be eligible for cost recovery through the same cost recovery mechanism approved for PG&E. This will ensure equitable treatment of CCA's and PG&E's costs to offer the expanded pilots and likely encourage greater CCA participation in the expanded pilots.

III. THE COMMISSION SHOULD REJECT PG&E'S PROPOSAL TO RECOVER SHADOW BILL PAYMENTS THROUGH THE PCIA

In their Opening Comments, Joint Parties propose that PG&E be allowed to recover true-up shadow bill savings payments for the generation component in the Power Charge Indifference Adjustment ("PCIA") vintage year of the Portfolio Allocation Balancing Account ("PABA").[10] MCE urges the Commission to reject PG&E's request to recover the generation revenue shortfall in the PCIA, and instead recommends that both CCAs and PG&E be permitted to recover shadow bill savings payments from all ratepayers through distribution rates in the same manner that PG&E proposes to recover the distribution component of shadow bill savings payments, through its Distribution Revenue Adjustment Mechanism ("DRAM").[11]

The PCIA is intended to recover an IOU's above market costs associated with resource commitments made in service of departed load. The PCIA was not intended to (and to MCE's

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[9] *See generally* Commission Rulemaking 14-07-002, Decision 18-06-027.
[10] Joint Parties Opening Comments at 26.
[11] Joint Parties Opening Comments at 27.

knowledge has not previously been used to) recover the costs of what are essentially demand response performance payments. Permitting PG&E to utilize the PCIA to recover costs spent on shadow bill savings payments would represent an inappropriate and unnecessary expansion of the PCIA.

As stated above, as a general principle, IOUs and CCAs should be permitted to recover pilot costs in the same manner to ensure equity and indifference in cost responsibility between bundled and unbundled customers. If PG&E is permitted to recover its shadow bill savings costs for the expanded pilots through the PCIA with the most recent vintage, but CCAs are required to recover shadow bill savings costs through their generation rates, CCAs' generation rates will go up, but PG&E's generation rates will be artificially subsidized by the PCIA carrying those pilot costs instead. This result creates inappropriate competitive issues for CCAs and potentially misleads customers by concealing the pilot cost in the PCIA, as many customers are likely to simply compare the difference between CCA and IOU generation rates when comparing service options. This distortion also makes it harder for customers to compare rates among load serving entities. In such a case, CCA pilot costs will be included in their generation rates whereas PG&E's generation rates would not include the pilot costs yet PG&E's customers would still pay them in the PCIA.

Further, the expanded AgFIT pilots are intended to benefit all customers by providing grid benefits in the form of increased reliability. As benefits are intended to flow to all customers, it is also appropriate to recover the costs from all customers in an equitable and efficient manner. Permitting both CCAs and PG&E to seek cost recovery through the same mechanism from all ratepayers, in this instance the DRAM, meets that aim. Accordingly, the Commission should reject

PG&E's proposal to recover the generation component of shadow bill savings payments through the PCIA.

IV. THE COMMISSION SHOULD AIM TO PROVIDE CLARITY THAT ANY EXPANDED AGFIT PILOT WOULD BE COMPLIANT WITH THE CEC'S LMS.

While MCE appreciates the Commission's broad goal to expand the AgFIT pilot to serve Summer reliability needs, MCE also supports the expansion of the pilot for purposes of learning and potential alignment and compliance opportunities with the California Energy Commission's ("CEC") Load Management Standards ("LMS"). The LMS state that each Large CCA shall develop and apply to its rate-approving body for approval of at least one marginal cost based rate by July 2025.[12,13] To this end, MCE would encourage the Commission and the CEC to work together to ensure that any expanded pilot meets the requirements for LMS compliance. Specifically, MCE encourages the Commission to acknowledge in a future Ruling or Proposed Decision on the expanded pilots that it believes the expanded AgFIT pilots are LMS compliant. A reasonable level of assurance that the rates are compliant with LMS direction to offer marginal cost-based rates that vary at least hourly may encourage more broad participation in the pilots by CCAs as they hope to gain increased learnings and experience in preparation for LMS compliance requirements.

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[12] CEC LMS, Section 1623.1(b)(2).

[13] MCE notes that while it does not believe that the CEC has the authority to require MCE to comply with the LMS, including Section 1623.1(b)(2) directing to develop marginal cost-based rates, MCE intends to voluntarily comply with the CEC's LMS to the extent reasonable and practicable.

V. CONCLUSION

MCE appreciates the chance to provide Reply Comments, and for all the foregoing reasons, MCE requests consideration of its recommendations and looks forward to resolution of the issues identified herein.

Respectfully submitted:

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Dated: October 9, 2023

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Assembly Bill 843 – the Bioenergy Market Adjusting Tariff Program.	R.22-10-010

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON PROPOSED DECISION IMPLEMENTING ASSEMBLY BILL 843 - SETTING RULES TO ENABLE COMMUNITY CHOICE AGGREGATORS TO PARTICIPATE IN THE BIOENERGY MARKET ADJUSTING TARIFF PROGRAM

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October 30, 2023

TABLE OF AUTHORITIES

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SUMMARY OF RECOMMENDATIONS

California Community Choice Association (CalCCA) recommends that the California Public Utilities Commission (Commission) adopt the Proposed Decision, with the following clarifications and modifications:

- ✓ Clarify that an individual community choice aggregator's (CCA's) participation in the Bioenergy Market Adjusting Tariff (BioMAT) program begins when a CCA files a Tier 1 Advice Letter incorporating the program documents already approved by Energy Division;
- ✓ Clarify the Tier 3 Advice Letter and Rule 2 Application filing requirements for a CCA that files its Tier 1 Advice Letter to participate in BioMAT after February 1 of any year, including:
    1) If Energy Division fails to approve the standard program documents submitted in the Tier 2 Advice Letter prior to February 1, 2024, no CCA can be required to file its Tier 3 Advice Letter seeking approval of forecasted costs by February 1, 2024;
    2) If a CCA files its Tier 1 Advice Letter to join BioMAT between February 1 and September 1 of any year, the CCA should be permitted to submit supplemental testimony 14 days prior to October 1 of that year to have its estimated costs incorporated into the investor-owned utility's (IOU) October Update; and
    3) A CCA's Rule 2 Application to establish compliance with the Commission's prudent manager standard should be required to be filed on September 1 of year <u>following</u> the CCA's Tier 1 Advice Letter filing for the CCA joining the BioMAT program;
- ✓ Reject the requirement that CCAs "request" the IOUs include their BioMAT cost estimates in their October update if the Commission fails to approve a CCA's Tier 3 Advice Letter filing 14 days prior to the IOU's October Update; instead, the Commission should require the IOUs to include the CCA's cost estimates in the October Update;
- ✓ Clarify the contracting processes and framework for the Accion Group and the third-party administrator to ensure CCAs have contract parity with Accion for the webpage contract and with the third-party administrator;
- ✓ Require the IOUs update their program documents, including their BioMAT Tariffs, within 30 days of the final Decision; and
- ✓ Adopt CalCCA's proposed timeline incorporating its recommendations for the BioMAT processes.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Assembly Bill 843 – the Bioenergy Market Adjusting Tariff Program.	R.22-10-010

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON PROPOSED DECISION IMPLEMENTING ASSEMBLY BILL 843 - SETTING RULES TO ENABLE COMMUNITY CHOICE AGGREGATORS TO PARTICIPATE IN THE BIOENERGY MARKET ADJUSTING TARIFF PROGRAM

California Community Choice Association[1] (CalCCA) submits these comments, pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure, on the *Proposed Decision Implementing Assembly Bill 843 - Setting Rules to Enable Community Choice Aggregators to Participate in the Bioenergy Market Adjusting Tariff Program*[2] (Proposed Decision or PD), mailed October 10, 2023.

I. INTRODUCTION

The PD is a culmination of advocacy by community choice aggregators (CCAs) for participation in the Bioenergy Market Adjusting Tariff (BioMAT) program, as authorized in 2021

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1 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, 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, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 Rulemaking (R.) 22-10-010, *Proposed Decision Implementing Assembly Bill 843 - Setting Rules To Enable Community Choice Aggregators To Participate in the Bioenergy Market Adjusting Tariff Program* (Oct. 10, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K541/520541653.PDF.

by Assembly Bill (AB) 843.[3] CalCCA appreciates the Commission's thoughtful exploration of methodologies and mechanics to incorporate CCAs into the already established program. The PD generally succeeds in its effort "to adopt CCA BioMAT rules that create an efficient, fair, and competitively neutral process for BioMAT participants to execute BioMAT PPAs."[4]

The PD strikes a reasonable balance between stakeholder positions on capacity allocation, queue management, BioMAT cost recovery, and process. CalCCA supports most of the PD's findings, including:

- ✓ The PD's rejection of the investor-owned utility's (IOU) capacity allocation proposal; instead, the PD adopts CalCCA's proposal that all available BioMAT capacity is available for contracting either by the IOUs or CCAs, and should all be managed in the same queue;
- ✓ The role of the Accion Group (Accion) in maintaining the Accion website platform on behalf of the IOUs and CCAs, the design of which will maintain user firewalls and confidentiality between the load-serving entities' (LSEs') procurement processes;
- ✓ The role of the independent third-party administrator to integrate IOU and CCA BioMAT program administration tasks, including: (a) managing BioMAT contract offer processes, including the BioMAT project queues; (2) tracking and reporting power purchase agreement (PPA) executions; (3) tracking statewide BioMAT market pricing; and (4) maintaining up-to-date feedstock megawatt allocation amounts;
- ✓ CCA BioMAT cost recovery (including PPA, Accion, and third-party administrator costs) through the IOUs' non-bypassable charge (NBC), the public purpose program (PPP) charge;
- ✓ The requirement that CCAs purchase Renewables Portfolio Standard (RPS) and Resource Adequacy (RA) attributes based on market-price benchmarks established by the Commission; and
- ✓ CCA filings, including through Tier 3 Advice Letters and Rule 2 Applications, to ensure cost effectiveness and prudent contract management.[5]

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3 Assembly Bill 843 (Aguiar), Stats. 2021, Ch. 234 (Sept. 21, 2021) (amending Pub. Util. Code § 399.20).

4 Proposed Decision at 31.

5 CalCCA provides recommended changes to the Findings of Fact, Conclusions of Law, and Ordering Paragraphs in Appendix A attached hereto. Note that CalCCA did recommend moving proposed Finding of Fact 7 ("GO 96-B Energy Industry Rule 5 does not explicitly prevent CCAs from filing advice

CalCCA's comments herein seek to further clarify and streamline the BioMAT process to ensure CCAs can expeditiously be incorporated into the program. With the sunset of the program on December 31, 2025, quickly approaching, nimble rules must be adopted while maintaining appropriate cost and contract management oversight to protect ratepayers. In addition, confidentiality with respect to IOU and CCA contracting practices must be maintained. In light of these considerations and as incorporated in the timeline set forth in Table 1 below, CalCCA recommends that the Commission:

- ✓ Clarify that an individual CCA's participation in the BioMAT program begins when a CCA files a Tier 1 Advice Letter incorporating the program documents already approved by Energy Division;
- ✓ Clarify the Tier 3 Advice Letter and Rule 2 Application filing requirements for a CCA that files its Tier 1 Advice Letter to participate in BioMAT after February 1 of any year, including:
    1) If Energy Division fails to approve the standard program documents submitted in the Tier 2 Advice Letter prior to February 1, 2024, no CCA can be required to file its Tier 3 Advice Letter seeking approval of forecasted costs by February 1, 2024;
    2) If a CCA files its Tier 1 Advice Letter to join BioMAT between February 1 and September 1 of any year, the CCA should be permitted to submit supplemental testimony 14 days prior to October 1 of that year to have its estimated costs incorporated into the IOU's October update; and
    3) A CCA's Rule 2 Application to establish compliance with the prudent manager standard should be required to be filed on September 1 of year following the CCA's Tier 1 Advice Letter filing for the CCA joining the BioMAT program;
- ✓ Reject the requirement that CCAs "request" that the IOUs include their BioMAT cost estimates in their October Update if the Commission fails to approve a CCA's Tier 3 Advice Letter filing 14 days prior to the IOU's October Update; instead, the

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letters. GO 96-B, Energy Industry Rule 9 provides a regulatory process for load-serving entities, including CCAs, to submit compliance filings") to Conclusion of Law 10 describing the advice letter process for CCA approval of BioMAT program documents and recovery of BioMAT costs. The nature of Finding of Fact 7 is not factual, but rather legal, and therefore should be listed as a Conclusion of Law rather than a Finding of Fact.

Commission should require the IOUs to include the CCA's cost estimates in the October Updates;

- ✓ Clarify the contracting processes and framework for the Accion Group and the third-party administrator to ensure CCAs have contract parity with Accion for the webpage contract and with the third-party administrator;
- ✓ Require the IOUs update their program documents, including their BioMAT Tariffs, within 30 days of the final Decision; and
- ✓ Adopt CalCCA's proposed timeline incorporating its recommendations for the BioMAT process.

II. THE COMMISSION SHOULD CLARIFY THAT A CCA'S PARTICIPATION IN BIOMAT BEGINS UPON THE FILING OF A CCA TIER 1 ADVICE LETTER INCORPORATING THE ALREADY APPROVED PROGRAM DOCUMENTS

The Commission should clarify that an individual CCA's participation in BioMAT can begin upon a Tier 1 Advice Letter adopting the already approved standard program documents (once approved by Energy Division through the joint CCA Tier 2 Advice Letter Filing[6]) for incorporating CCAs into the BioMAT program. The PD correctly finds that CCAs should not be required to provide notification of their "intent" to participate in the BioMAT program, or to begin participation in BioMAT at any particular time, as CCA participation in the program is voluntary pursuant to AB 843.[7] The PD, however, concludes that "CCA participation in BioMAT will be revealed when project applicant Program Participation Requests (PPR) are submitted to IOUs and/or CCAs for project eligibility review."[8]

Instead, CalCCA recommends that a CCAs' participation will become effective upon a CCA's filing a Tier 1 Advice Letter adopting the Commission-approved standard program documents for that CCA. CalCCA also recommends that within 30 days of the CCA's Tier 1

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6 As noted in Appendix A attached hereto, CalCCA has provided an edit to Conclusion of Law 5 to note that the advice letter to be submitted to seek approval for the CCA BioMAT standard program documents will be submitted by the joint CCAs, and will be one Tier 2 Advice Letter.

7 *See* Proposed Decision at 13.

8 *Id.* at 14.

Advice Letter filing, the Commission require the following: (1) the CCA signs the Accion and independent third-party administrator contracts; (2) Accion establishes the individual CCA's webpage on the Accion BioMAT platform; and (3) the CCA manually administers its BioMAT tariff in concert with Accion and the third-party administrator until the automated systems adopted under those contracts are established.

III. THE COMMISSION SHOULD CLARIFY THE CCA TIER 3 ADVICE LETTER AND RULE 2 APPLICATION PROCESSES

The Commission should clarify the CCA Tier 3 Advice Letter and Rule 2 Application processes, which are complicated not only by CCAs being able to join the BioMAT program at any time, but also by the Commission's timeline for approving the CCA Tier 3 Advice Letters. As noted in the Proposed Decision, a participating CCA will file a Tier 3 Advice Letter on or before February 1, 2024, and annually thereafter, seeking approval of eligible BioMAT forecasted revenue requirements recorded in CCA balancing accounts, subject to true-up.[9] In addition, a CCA will file a Rule 2 Application on September 1, 2024, and annually thereafter, to establish the CCA's compliance with the Commission's prudent manager standard.[10]

A. The Timing of the CCA Tier 3 Advice Letter and Rule 2 Application Requirements Should be Clarified in the Event of a CCA Joining the BioMAT Program After February 1

The Commission should clarify the filing requirements for a CCA that files its Tier 1 Advice Letter to participate in BioMAT after February 1 of any year (assuming Energy Division has approved the standard program documents in the Tier 2 Advice Letter). If Energy Division does not approve the standard program documents submitted in the Tier 2 Advice Letter prior to February 1, 2024, no CCA can be required to file its Tier 3 Advice Letter on February 1, 2024.

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9 *Id.*, Ordering Paragraph (O¶) 9, at 61.

10 *Id.*, O¶ 12, at 62.

In addition, if a CCA files its Tier 1 Advice Letter to join the BioMAT program between February 1 and September 1 of any year (including 2024), the CCA should be allowed to file supplemental testimony 14 days prior to October 1 of that year to have its estimated costs incorporated into the IOU's October update. In addition, a CCA's Rule 2 Application to establish compliance with the prudent manager standard should be required to be filed on September 1 in the year following the CCA's Tier 1 Advice Letter filing joining the BioMAT program.

B. The PD's Requirement that CCAs "Request" Inclusion of their Cost Estimates in the IOU's October Update in the Event the Commission Fails to Act on the CCA's Tier 3 Advice Letter Should be Rejected

The PD specifies that if the Commission does not approve pending Tier 3 Advice Letters by 14 days prior to the IOU's October Update in the IOU's Energy Resource Recovery Account (ERRA) Forecast proceeding, the CCA must "serve supplemental testimony in ERRA forecast proceedings that requests that the relevant IOU incorporate an estimate of forecasted CCA BioMAT costs into its forecasted revenue requirements, subject to true up to the amount approved in the AL process."[11] The PD describes this process as a "safeguard for Commission review and approval of eligible CCA BioMAT costs in IOU ERRA proceedings."[12] In addition, the PD states that "[t]his will also assist participating CCAs to ensure that forecasted eligible BioMAT costs are ultimately included and accounted for within the ERRA proceedings."[13] The Commission should reject this additional requirement placed on CCAs participating in the BioMAT program to "request" that the IOU's include the estimates. Instead, if the Commission fails to address the CCA Tier 3 Advice Letters by the time of the October update, the CCAs' forecasted costs should be automatically incorporated into the IOU's forecasted revenue

11 *Id.*, O¶ 10, at 61 (emphasis added).
12 *Id.*, O¶ 10, at 61-62.
13 *Id.*, O¶ 10, at 62.

requirements. While the CCA can submit the Tier 3 Advice Letter and workpapers into the ERRA Forecast proceeding if the Commission hasn't acted, the IOU should not have discretion to include or not include the forecasted costs.

IV. THE COMMISSION SHOULD CLARIFY THE CONTRACTING PROCESSES AND FRAMEWORK FOR ACCION AND THE THIRD-PARTY ADMINISTRATOR

The Commission should clarify the contracting process and framework for Accion and the third-party administrator. Currently, the PD requires CCAs and IOUs "to solicit contract terms" to develop the Accion platform to incorporate CCAs into the BioMAT program.[14] While no timeframe is provided for contracting between Accion and the CCAs/IOUs, the PD does require that "the central BioMAT Accion webpage must be completed within 90 days of the effective date of this decision."[15] In addition, "individual CCA BioMAT Accion webpages must be completed within 90 days of a CCA's election to participate in the BioMAT program."[16] Finally, the PD requires CCAs to consult with the IOUs to "solicit contract terms to hire an independent third party that shall administer the BioMAT pricing and the contract offer process" (including the "management of merged project queues, and power purchase agreement executions and awards").[17]

CalCCA recommends the IOUs be required to originally enter into the contracts with Accion for the webpages, and the third-party administrator, with terms jointly negotiated by the IOUs and joint CCAs, and with terms allowing CCAs to become parties to both contracts within 30 days of a CCAs' Tier 1 Advice Letter filing adopting the Commission approved program documents. In other words, both contracts should provide for participating CCAs to have

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14 *Id.*, O¶ 2, at 58.
15 *Ibid.*
16 *Ibid.*
17 *Id.*, O¶ 4, at 59.

contract parity (along with the IOUs) with both Accion for the webpage and the third-party administrator. Given CCAs are subject to the prudent contract administrator standard for their BioMAT PPAs, any participating CCA should have a direct contractual relationship with especially the third-party administrator, who will be administering the contracts on behalf of the CCA. Therefore, for both the Accion webpage and third-party administrator contracts, the joint CCAs should be involved in the negotiation of those contracts, which can be originally entered into by the IOUs but should contain terms to allow new participating CCAs to become parties to the contracts within 30 days of their Tier 1 Advice Letter filings adopting the Commission-approved program documents.

CalCCA also recommends that timelines and a framework be added to the PD for the contracting requirements to ensure timely establishment of the systems and third-party administrator arrangements for CCA participation in BioMAT. Table 1 below provides CalCCA's proposed overall timeline, which includes requirements for: (1) Accion contract terms to be solicited by the CCAs and IOUs within 30 days of the final Decision; (2) Accion contract to be entered into by IOUs within 60 days of the final Decision, with the ability for CCAs to become parties within 30 days of a CCA's Tier 1 Advice Letter filing joining BioMAT; (3) the central Accion webpage (with dropdowns for each participating IOU/CCA) to be created within 60 of the final Decision; (4) a standard framework created by Accion within 60 days of the final Decision for individual CCA webpages on the Accion BioMAT platform; (5) Accion individual CCA webpages to be developed within 30 days of a CCA Tier 1 Advice Letter filing electing to participate in BioMAT; (6) solicitation by CCAs and IOUs of contractual terms for the independent third party administrator within 30 days of the final Decision; and (7) contract for independent third party administrator negotiated by CCAs and IOUs signed by IOUs within 60 days of final Decision, with contract terms allowing CCAs to become parties to the contract within 30 days of the Tier 1 filing.

V. THE COMMISSION SHOULD REQUIRE IOU BIOMAT TARIFF CHANGES TO INCORPORATE CCAS INTO THE BIOMAT PROGRAM

Given the multitude of changes to the BioMAT processes in the PD both for CCAs and IOUs, the Commission should require the IOUs to propose any necessary changes to their program documents on the same timeline as the requirements for CCAs to submit their program documents. Specifically, the Commission should require the IOUs to submit any necessary changes to their program documents, including their BioMAT tariffs, within 30 days of the final Decision.

VI. THE PROPOSED DECISION'S PROPOSED TIMELINE AND REQUIREMENTS FOR CCA INCORPORATION INTO THE BIOMAT PROGRAM SHOULD BE ADOPTED, WITH MODIFICATIONS

The following modifications and additions to the timeline proposed in the PD will ensure timely and effective incorporation of CCAs into the BioMAT program. CalCCA's proposed modified timeline is depicted in Table 1, below.

Table 1: Timeline for Incorporation of CCAs into BioMAT Program

Event	Description	PD Proposed Date	CalCCA Proposed Date
Joint CCA Tier 2 Advice Letter	With pro forma program documents and standard templates	Within 30 days of FD	Within 30 days of FD
IOU Tier 2 Advice Letters	With changes to program documents	None	Within 30 days of FD
CCAs and IOUs solicit Accion contract terms		Within 90 days of FD	Within 30 days of FD
CCAs and IOUs issue solicitation for independent third-party administrator		No date proposed	Within 30 days of FD
IOUs sign new Accion contract, with terms allowing CCAs to become parties upon Tier 1 Advice Letter filing joining BioMAT			Within 60 days of FD

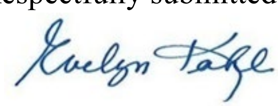
Event	Description	PD Proposed Date	CalCCA Proposed Date
Accion develop central webpage for BioMAT program	With dropdowns for participating IOUs/CCAs	Within 90 days of FD	Within 60 days of FD
Accion develops standard framework for individual CCA webpages on Accion BioMAT platform		None	Within 60 days of FD
IOUs sign new independent third-party contract, with terms allowing CCAs to become parties upon Tier 1 Advice Letter filing joining BioMAT		None	Within 60 days of FD
CCA Tier 1 Advice Letter to join BioMAT program	Adopting Energy Division approved program documents and standard templates		Any time after Energy Division approval of Tier 2 pro forma program documents and standard templates
CCA executes contract with Accion		None	Within 30 days of Tier 1 Advice Letter filing
Accion individual website for CCA based on standard framework		None	Within 30 days of Tier 1 Advice Letter filing
CCA executes contract with independent third-party administrator		None	Within 30 days of Tier 1 Advice Letter filing
CCA begins transacting under BioMAT		None	Upon Tier 1 Advice Letter filing (manual transacting until webpage/automated systems established)
CCA Tier 3 Advice Letter	Seeking approval of net BioMAT program costs/cost forecast; report on contracts executed during prior year	Feb. 1 (and annually thereafter)	No change, except if CCA submits Tier 1 Advice Letter between Feb. 1 and Oct. 1 of any year, the BioMAT program costs/cost forecasts can be submitted in supplemental testimony 14 days prior to the IOUs' October update, for that year only
CCA Rule 2 Applications	CCA individual Applications to establish compliance	Sept. 1 (and annually thereafter)	Sept. 1 (and annually thereafter) in the year following the CCA's

Event	Description	PD Proposed Date	CalCCA Proposed Date
	with prudent manager standard		Tier 1 Advice Letter filing joining the BioMAT program
IOU ERRA October Updates	To include Commission-approved CCA BioMAT costs or CCA forecasted costs	Oct. 1 (each year)	Oct. 1 (each year)
CCA submit invoices to respective IOUs for payment of BioMAT costs		Jan. 1, 2025 (and quarterly thereafter)	First Jan. 1 after CCA submits forecasted costs to IOU in prior year either on Feb. 1, or through supplemental testimony prior to October update

VII. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and requests adoption of the recommendations proposed herein.

Respectfully submitted,



Evelyn Kahl,
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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

October 30, 2023

ATTACHMENT A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON PROPOSED DECISION IMPLEMENTING ASSEMBLY BILL 843 - SETTING RULES TO ENABLE COMMUNITY CHOICE AGGREGATORS TO PARTICIPATE IN THE BIOENERGY MARKET ADJUSTING TARIFF PROGRAM

PROPOSED CHANGES TO
FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDERING PARAGRAPHS

FINDINGS OF FACT

~~7. GO 96-B Energy Industry Rule 5 does not explicitly prevent CCAs from filing advice letters. GO 96-B, Energy Industry Rule 9 provides a regulatory process for load-serving entities, including CCAs, to submit compliance filings.~~

CONCLUSIONS OF LAW

2. To the extent necessary and feasible, the Commission should adopt CCA BioMAT requirements that are ~~applicable~~ similar to IOUs to streamline the BioMAT program.

5. Joint CCAs should submit a Tier 2 advice letter~~s~~ with the Commission's Energy Division to seek approval of templates for standard BioMAT tariffs, PPAs, NBC rate schedules, PPRs, and balancing accounts.

6. An independent third party should administer BioMAT pricing and contracting because CCA or IOU project applicant legal names and project locations ~~would~~ could be revealed and compromise confidentiality.

8. CCA net BioMAT costs, including PPA costs and RA and RPS attribute costs, should be collected from customers through NBCs in IOU PPP surcharges.

9. CCA BioMAT RA and RPS attribute~~s~~ prices should be based on Commission-determined market price benchmarks used in the IOUs' NBC methodology.

10. GO 96-B Energy Industry Rule 5 does not explicitly prevent CCAs from filing advice

letters. GO-96-B, Energy Industry Rule 9 provides a regulatory process for load-serving entities, including CCAs, to submit compliance filings. CCAs should be authorized to submit advice letters to seek Commission approval of BioMAT program documents and recovery of BioMAT costs. CCAs should not be authorized to recover BioMAT administrative costs, other than those required of Accion and any independent third party vendor, through IOUs' PPPAMs.

ORDERING PARAGRAPHS

1. Community Choice Aggregators (CCAs) that elect to participate in the Bioenergy Market Adjusting Tariff (BioMAT) program will submit a joint CCA Tier 2 Advice Letter to the California Public Utilities Commission's (Commission's) Energy Division seeking Commission approval of standard BioMAT program documents including but not limited to a program tariff~~s~~, standard power purchase agreement, program participation request form~~s~~, non-bypassable charge rate schedule~~s~~, and balancing accounts within 30 days of the effective date of this decision. After approval by Energy Division of the standard BioMAT program documents submitted by the joint CCAs through the Tier 2 Advice Letter, an individual CCA seeking to participate in the BioMAT program shall file a Tier 1 Advice Letter with the Commission adopting the approved standard BioMAT program documents. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company (collectively, the IOUs) shall each submit a joint Tier 2 Advice Letter within 30 days of the effective date of this decision to propose changes to their BioMAT program documents to effectuate the changes set forth in this decision.

2. Community Choice Aggregators (CCAs) that elect to participate in the Bioenergy Market Adjusting Tariff (BioMAT) program will collectively consult with Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company (collectively, the IOUs), and Accion to solicit contract terms within 30 days of the effective date of this Decision that will require the IOUs to sign the contract with Accion, with terms allowing CCA

to join the contract within 30 days of a CCA's filing of a Tier 1 Advice Letter joining the BioMAT program. The IOUs shall sign the Accion contract with Accion within 60 days of the effective date of the decision. ~~and to~~ Individual CCAs that have filed their Tier 1 Advice Letter to participate in the BioMAT program must sign the Accion contract with 30 days of their Tier 1 Advice Letter filing. The Accion contract shall require Accion to develop ~~individual CCA BioMAT websites and portals on the Accion BioMAT platform as well as~~ a central BioMAT Accion webpage within 60 days of the effective date of this decision. The Accion contract shall require Accion to develop a standard framework for individual CCA BioMAT webpages on the Accion BioMAT platform, within 60 days of the effective date of this decision. Within 30 days of an individual CCA's Tier 1 Advice Letter filing, Accion must develop the CCA's Accion website. IOU and CCA ~~BioMAT Accion~~ webpages shall provide ~~CCA~~ BioMAT participants with access to a central BioMAT Accion webpage. ~~The central BioMAT Accion webpage must be completed within 90 days of the effective date of this decision.~~ Individual CCA BioMAT Accion webpages must be completed within 90 days of a CCA's election to participate in the BioMAT program. Vendor costs associated with the provision of these services are eligible for recovery against IOU-managed PPPAMs.

4. Community Choice Aggregators (CCAs) that elect to participate in the Bioenergy Market Adjusting Tariff (BioMAT) program shall collectively consult with Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to jointly solicit and negotiate contract terms within 30 days of the effective date of this decision to hire an independent third party that shall administer the BioMAT project pricing and the contract offer process. The contract terms with the independent third party will require the IOUs to sign the contract with the independent third party, with terms allowing CCAs to join the contract

within 30 days of a CCA's Tier 1 Advice Letter joining the BioMAT program. The IOUs shall sign the contract with the independent third party within 60 days of the effective date of the decision. Individual CCAs that have filed their Tier 1 Advice Letter to participate in the BioMAT program must sign the independent third party contract with 30 days of their Tier 1 Advice Letter filing. The pricing and contract offer process shall include management of merged project queues, and power purchase agreement executions and awards. Vendor costs associated with the provision of these services are eligible for recovery against IOU-managed PPPAMs

8. Each Community Choice Aggregator's (CCAs) BioMAT program costs will be recovered from customers through Pacific Gas and Electric Company, Southern California Edison Company, or San Diego Gas & Electric Company (collectively, the IOUs) non-bypassable charges (NBCs) included in each respective IOU's Public Purpose Program (PPP) surcharges. IOU PPP surcharges will be recorded in the IOUs' PPP Adjustment Mechanism (PPAM) balancing accounts. Independent third-party costs, including the costs of Accion and the independent third-party administrator, will be shared equally between all IOUs and CCAs participating in BioMAT and shall be collected from customers in NBCs, included in the IOUs' PPP surcharges, and recorded in the IOUs' PPAM balancing accounts.

9. Each Community Choice Aggregator (CCA) that elects to participate in the Bioenergy Market Adjusting Tariff (BioMAT) program shall a submit Tier 3 Advice Letter (AL) that seeks California Public Utilities Commission (Commission) approval of eligible BioMAT forecasted revenue requirements recorded in CCA balancing accounts that reflect BioMAT program net costs, including power purchase agreement costs on or before February 1, 2024 and annually thereafter. The Tier 3 ALs shall also include a report on BioMAT power purchase agreements executed during each quarter of the prior year. After Commission approval of the Tier 3 ALs, Pacific Gas

and Electric Company, Southern California Edison Company, or San Diego Gas & Electric Company shall include Commission-approved CCA BioMAT costs in the October Update to their Energy Resource Recovery Account forecast applications which will be utilized by the Commission to issue final decision(s) in these proceedings. If a CCA files its Tier 1 Advice Letter between February 1 and September 1 of any year, the CCAs' forecasted revenue requirements can be submitted in supplemental testimony 14 days prior to the October 1 IOU filing of its October Update in the ERRA Forecast proceeding (in lieu of the February 1 filing and for that year only).

10. If the California Public Utilities Commission (Commission) does not approve pending Tier 3 Advice Letters (ALs) by 14 days prior to the October Update filing date set in the annual Energy Resource Recovery Account (ERRA) forecast proceedings for Pacific Gas and Electric Company, Southern California Edison Company, or San Diego Gas & Electric Company (collectively, the IOUs), Community Choice Aggregators (CCAs) that participate in the Bioenergy Market Adjusting Tariff (BioMAT) program are directed to serve supplemental testimony in ERRA forecast proceedings ~~that requests that~~ and the relevant IOU will be required to incorporate ~~an~~ the CCA's estimate of forecasted CCA BioMAT costs into its forecasted revenue requirements, subject to true up to the amount approved in the AL process. This contingency will provide a safeguard for Commission review and approval of eligible CCA BioMAT costs in IOU ERRA proceedings. This will also assist participating CCAs to ensure that forecasted eligible BioMAT costs are ultimately included and accounted for within the ERRA proceedings.

12. Each Community Choice Aggregator (CCA) that elects to participate in the Bioenergy Market Adjusting Tariff program shall file an application, to establish CCA compliance with the California Public Utilities Commission's prudent manager standard for each calendar year, by

September 1 in the year following the CCA's Tier 1 Advice Letter filing ~~, 2024~~ and annually ~~by September 1st~~ thereafter.