November 17, 2022

TO: MCE Board of Directors

FROM: Daniel Settlemyer, Internal Operations Coordinator

RE: Regulatory Filings (Not an agenda item)

Dear Board Members:
Listed below are the key regulatory filings submitted in the Month of October:

- Joint report of PG&E, the Agricultural Energy Consumers Association, CalCCA, the Direct Access Customer Coalition, the Public Advocates Office, and the Small Business Utility Advocates in the Electric Revenue Requirements and Rates (ERRA) proceeding.
- PG&E's data responses to CalCCA regarding the ERRA 2023 Forecast Application
- CalCCA's reply comments on the CPUC's ruling seeking comments on potential near-term actions to encourage additional procurement in the IRP proceeding.
- CalCCA's comments to the CAISO regarding the Capacity Procurement Mechanism (CPM) Phase One Final Draft.
- CalCCA's opening brief on the 2023 ERRA proceeding
- CalCCA's comments on the Proposed Decision approving voluntary allocations and modifying market offer process for the sale of excess renewable resources to lower PCIA adjustment costs.

Recommendation: Information only. No action needed.

OCTOBER FILINGS

FILED
10/05/22
04:59 PM
A2205029

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 2023 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation.

U 39 E

Application 22-05-029
(Filed May 31, 2022)

REPORT OF APPLICANT PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), THE AGRICULTURAL ENERGY CONSUMERS ASSOCIATION, THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION, DIRECT ACCESS CUSTOMER COALITION, PUBLIC ADVOCATES OFFICE AT THE CALIFORNIA PUBLIC UTILITIES COMMISSION, AND THE SMALL BUSINESS UTILITY ADVOCATES

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Dated: October 5, 2022

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 2023 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation. U 39 E	Application 22-05-029 (Filed May 31, 2022)

REPORT OF APPLICANT PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), THE AGRICULTURAL ENERGY CONSUMERS ASSOCIATION, THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION, DIRECT ACCESS CUSTOMER COALITION, PUBLIC ADVOCATES OFFICE AT THE CALIFORNIA PUBLIC UTILITIES COMMISSION, AND THE SMALL BUSINESS UTILITY ADVOCATES

Pursuant to the *Assigned Commissioner's Scoping Memo and Ruling,* dated August 4, 2022 (Ruling) establishing a Status Conference, the September 29, 2022 procedural clarification from Administrative Law Judge (ALJ) Long directing the parties to hold an informal status conference and to report the results during the week of October 3, and Rule 13.9 of the California Public Utilities Commission's Rules of Practice and Procedure (Rule) Pacific Gas and Electric Company (PG&E) submits this Report on behalf of itself and the Agricultural Energy Consumers Association (AECA), the California Community Choice Association (CalCCA), Direct Access Customer Coalition (DACC), Public Advocates Office at the Public Utilities Commission (Cal Advocates), and the Small Business Utility Advocates (SBUA), each of which are parties to PG&E's Application for Adoption of Electric Revenue Requirements and Rates Associated with its 2023 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (the 2023 ERRA Forecast).[1/]

1/ Pursuant to Rule 1.8 of the Commission's Rules of Practice and Procedure, counsel for AECA, Cal Advocates, CalCCA, DACC, and SBUA have authorized PG&E to file this Report on their

I. THERE IS NO NEED FOR EVIDENTIARY HEARING

On September 30, 2022, the parties to this proceeding participated in a meeting to, among other things, determine whether "[t]he parties stipulate to the receipt of prepared testimony into evidence without an evidentiary hearing or, alternatively, to hold the scheduled evidentiary hearing." The parties discussed the potential for alternatives to evidentiary hearing to develop the evidentiary record required for briefing, including the use of expedited data requests and/or additional meetings of the parties. Based on such meetings, and subsequent discussions between PG&E and individual parties, evidentiary hearings are not necessary. Specifically:

- AECA, Cal Advocates, and DACC do not require evidentiary hearing;
- CalCCA and PG&E stipulate to enter PG&E's response to CalCCA_006-Q001-Q004 into the evidentiary record of this proceeding in lieu of an evidentiary hearing;
- SBUA and PG&E remain engaged in the use of expedited discovery and meeting(s) between SBUA and PG&E witnesses in lieu of evidentiary hearings, with the expectation that responses to SBUA Discovery Set 1 is to be entered into the evidentiary record of this proceeding in lieu of an evidentiary hearing.

II. RULE 13.9 MATTERS

Parties also conferred on matters pertinent to Rule 13.9. Rule 13.9 (a) states that " "no later than 10 calendar days after the submission of rebuttal testimony the parties must meet and confer, in person or via remote participation to consider the following: (1) Identifying and, if possible, informally resolving any anticipated motions; (2) Identifying the facts and issues in the case that are uncontested and may be the subject of stipulation; (3) Identifying the facts and issues in the case that are in dispute; (4) Determining whether the contested issues in the case can be narrowed; and (5) Determining whether settlement is possible. With regard to the Rule 13.9 requirements, the parties agreed to cooperate on (1) joint motions to move PG&E, CalCCA and SBUA testimony, PG&E rebuttal testimony, and additional PG&E Data Responses into the

behalf.

record, and (2) motion(s) to seal the evidentiary record in proceeding.[2/] The parties will target submissions of such motions as soon as feasible and in advance of October 14, 2022, the date upon which Opening Briefs are due. PG&E also anticipates a need to submit a motion to move its October Update, due October 17, into the evidentiary record and a corresponding motion to seal such October Update. PG&E anticipates such October Update-related motions will occur during the week of October 17, following service of the October Update.

The parties also discussed the challenges associated with developing statements concerning Rule 13.9 (a)(2) through Rule 13.9 (a)(5) in light of the 2023 ERRA Forecast procedural schedule. Because PG&E's October Update has yet to be submitted, the parties determined that resolution of such matters is infeasible at this time. Parties recognize that the Ruling adopts a procedural schedule that provides for Comment and Reply Comment opportunities following PG&E's service of the October Update. Such commenting opportunities are likely useful for parties to identify and narrow facts relevant to the Commission's resolution of PG&E's 2023 ERRA Forecast Application.

III. CONCLUSION

The parties appreciate the opportunity to submit this Report following the informal meet-and-confer process.

2/ CalCCA and PG&E continue to coordinate on whether a Joint Motion to Seal the Evidentiary Record may be feasible in light of PG&E's compliance obligation arising from Decision 22-01-023. Conclusion of Law 9 of Decision 22-01-023 directs PG&E to report on the outcomes of a meet-and-confer process concerning confidentiality matters in its first motion in its 2023 ERRA forecast proceeding for confidential treatment of data.

Respectfully Submitted,

By: *<u>/s/Maria V. Wilson</u>*
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Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: October 5, 2022

Docket No.: A.22-05-029

Exhibit No.: CalCCA-02

Date: October 6, 2022

Sponsor/Witness: Kolnowski, Vega, Gilbert, Stanley (PG&E)

EXHIBIT CALCCA-02

PG&E'S DATA RESPONSES TO CALCCA

6.01 – 6.04

October 6, 2022

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2023 Forecast
Application 22-05-029
Data Response

PG&E Data Request No.:	CalCCA_006-Q001		
PG&E File Name:	ERRA-2023-Forecast_DR_CalCCA_006-Q001		
Request Date:	September 29, 2022	Requester DR No.:	006
Date Sent:	October 3, 2022	Requesting Party:	California Community Choice Association
PG&E Witness:	Ben Kolnowski / Angelia Vega	Requester:	Nikhil Vijaykar

QUESTION 001

Referring to PG&E Rebuttal Testimony at 8:9-10: Admit or deny that PCIA charges based on forecasted net market costs may not materialize in the test year. If deny, please explain why.

ANSWER 001

PG&E agrees that PCIA charges based on forecast net market costs (Portfolio Cost less the Market Value of Portfolio based on the calculation from the CPUC authorized Market Price Benchmark) may not materialize in the test year. As outlined in PG&E Rebuttal Testimony at 7:1-13, the Portfolio Allocation Balancing Account (PABA) will accumulate amounts based on *actual* recorded costs and realized market revenues during the test year. For a scenario where the cumulative forecast indifference Amount is negative for certain vintages, PG&E would propose to set the forecast component of the PCIA rate attributed to the cumulative Indifference Amount to zero which PG&E interprets to be consistent with Finding of Fact 20 and Conclusion of Law 21 from Decision 18-10-019. In the 2023 test-year, actual amounts for each vintage would be tracked in PABA and any overcollection would be returned to customers the following year based on actual recorded costs and realized market revenues.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2023 Forecast
Application 22-05-029
Data Response

PG&E Data Request No.:	CalCCA_006-Q002		
PG&E File Name:	ERRA-2023-Forecast_DR_CalCCA_006-Q002		
Request Date:	September 29, 2022	Requester DR No.:	006
Date Sent:	October 3, 2022	Requesting Party:	California Community Choice Association
PG&E Witness:	Mia Gilbert	Requester:	Nikhil Vijaykar

QUESTION 002

Referring to PG&E Rebuttal Testimony at 11:14-16: Please explain how a double count of the SFGO GRC revenue requirement would occur when the 2023 GRC final decision is implemented.

ANSWER 002

The credit provided to customers in the 2023 ERRA Forecast is to account for the 2020 GRC plus attrition revenue requirement utilized to set rates on January 1, 2023, being inclusive of the San Francisco General Office (SFGO) GRC revenue requirement.

However, the proposed 2023 GRC revenue requirements exclude any revenue requirements associated with the SFGO. Therefore, in Rebuttal Testimony, PG&E proposes that the Commission authorize PG&E to remove any SFGO revenue requirement (RRQ) credit adopted in a final decision in the instant application, A.22-05-029, upon the implementation of the 2023 GRC in rates. At such time that PG&E's 2023 GRC is implemented, any SFGO RRQ credit in the gain on sale ordered in a final decision in this proceeding to ERRA and PABA is no longer required because the 2023 GRC revenue requirement does not include RRQ for SFGO.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2023 Forecast
Application 22-05-029
Data Response

PG&E Data Request No.:	CalCCA_006-Q003		
PG&E File Name:	ERRA-2023-Forecast_DR_CalCCA_006-Q003		
Request Date:	September 29, 2022	Requester DR No.:	006
Date Sent:	October 3, 2022	Requesting Party:	California Community Choice Association
PG&E Witness:	Mia Gilbert	Requester:	Nikhil Vijaykar

QUESTION 003

Referring to PG&E Rebuttal Testimony at 11:17-21: Please explain why PG&E's proposed adjustment to add back the SFGO GRC revenue requirement credit is needed, given that rates from PG&E's 2023 GRC will not be implemented on January 1, 2023.

ANSWER 003

Please see PG&E's response to Question 2 of this data request.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2023 Forecast
Application 22-05-029
Data Response

PG&E Data Request No.:	CalCCA_006-Q004		
PG&E File Name:	ERRA-2023-Forecast_DR_CalCCA_006-Q004		
Request Date:	September 29, 2022	Requester DR No.:	006
Date Sent:	October 3, 2022	Requesting Party:	California Community Choice Association
PG&E Witness:	Mia Gilbert / Ryan Stanley	Requester:	Nikhil Vijaykar

QUESTION 004

Referring to PG&E Rebuttal Testimony at 11:17-21: Please confirm that PG&E records its authorized GRC revenue requirement to the PABA on a monthly basis. If confirmed, please explain:

a. What will be the basis for GRC revenue requirement recorded to PABA prior to implementation of the 2023 GRC?

b. Whether an adjustment to PABA will be required to remove SFGO GRC revenue requirement recorded to PABA during 2023 prior to a final decision in PG&E's 2023 GRC.

ANSWER 004

PG&E confirms that it records its authorized GRC revenue requirement to the ERRA and PABA on a monthly basis, and responds to each subpart as follows:

a. Prior to the implementation of the 2023 GRC, PG&E expects to record in ERRA and PABA the D.20-12-005 authorized electric generation revenue requirement (2020 GRC, plus 2021 and 2022 attrition). This includes the authorized revenue requirement (RRQ) associated with the San Francisco General Office (SFGO).

b. PG&E clarifies its proposed ERRA and PABA adjustments in 2023 to address the sale of its SFGO headquarters:

   - Prior to the implementation of the 2023 GRC, PG&E expects to include the 2023 portion of SFGO RRQ reduction in the gain on sale of SFGO credit of approximately $17 million[1] in both PABA and ERRA.
   - Upon the implementation of the 2023 GRC, PG&E would debit the authorized generation portion of the <u>2023 GRC revenue requirement</u> in both ERRA and PABA. Because the SFGO RRQ would not be included in the

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[1] The $17 million SFGO O&M is the 2023 amortized electric generation amount authorized in D.21-08-027.

authorized 2023 GRC revenue requirement, PG&E would accordingly exclude the SFGO RRQ from the gain on sale of SFGO credit.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	R.20-05-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON SECTION 2 OF THE ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON POTENTIAL NEAR-TERM ACTIONS TO ENCOURAGE ADDITIONAL PROCUREMENT

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October 6, 2022

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SUMMARY OF RECOMMENDATIONS

- The California Public Utilities Commission (Commission) should adopt party proposals to clarify and modify compliance and resource requirements in the 2019 and Mid-term Reliability (MTR) Orders that align with the Commission's reliability and green-house gas (GHG) reduction goals, while encouraging successful procurement of resources, including:

    - California Community Choice Association's (CalCCA's) proposals in Opening Comments to (1) allow trading of compliance obligations, and (2) allow projects without a California Independent System Operator (CAISO) deliverability study to temporarily count for compliance;

    - Alliance for Retail Energy Markets' (AReM's) proposal to move the compliance deadlines currently set for August 1, 2023 and June 1, 2024 and 2025 to September 1 of each year to accommodate short delays in bringing projects online;

    - Sonoma Clean Power's (SCP's) and Redwood Coast Energy Authority's (RCEA's) proposal to allow intra-load-serving entity (LSE) trades of one year of eligible capacity to allow parties to remain compliant while waiting for projects to come online;

    - The proposal of various community choice aggregator (CCA) parties to allow pseudo-tied or dynamically scheduled imports without maximum import capability (MIC) that have achieved their commercial operation date (COD) by the required deadline to be considered compliant;

    - Proposals by SCP/RCEA and Silicon Valley Clean Energy (SVCE) that the pool of eligible zero-emitting resources for MTR Order compliance should be clarified and/or expanded;

    - Southern California Edison Company's (SCE's) proposal that an energy storage resource's derated nameplate capacity should count toward the MTR long-duration storage requirements; and

    - Crediting LSEs for compliance purposes toward the 2019 and MTR Orders for repowered resources, as proposed by SVCE.

- The Commission should adopt a modified version of SCE's penalty waiver proposal through a 12-month MTR compliance extension framework based on an LSE's good faith showing.

- To the extent modifications are made to the baseline incremental procurement obligations:

    - PG&E's recommendation that the Commission issue any LSE obligations by the end of the first quarter of 2023 should be adopted;

SUMMARY OF RECOMMENDATIONS, continued

- Any new obligations should not be required to come online until 2026 or later, as proposed by PG&E, Clean Power Alliance (CPA), Peninsula Clean Energy (PCE), and SCP/RCEA;

- The Commission should adopt SCE's proposal regarding net qualifying capacity (NQC) counting methodologies for the incremental procurement obligations.

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

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	R.20-05-003

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REPLY COMMENTS ON SECTION 2 OF THE ADMINISTRATIVE LAW JUDGE'S
RULING SEEKING COMMENTS ON POTENTIAL NEAR-TERM ACTIONS TO
ENCOURAGE ADDITIONAL PROCUREMENT**

The California Community Choice Association[1] (CalCCA) submits these Reply Comments (Reply Comments) in response to the *Administrative Law Judge's Ruling Seeking Comments on Staff Paper on Procurement Program and Potential Near-Term Actions to Encourage Additional Procurement* (Ruling), issued on September 8, 2022. CalCCA's Reply Comments respond to the September 26, 2022 party Opening Comments on near-term actions the California Public Utilities Commission (Commission) can take to encourage additional procurement.[2]

I. INTRODUCTION

The Ruling, as well as party Opening Comments, accurately portray the challenges faced by load-serving entities (LSEs) to timely bring resources online to comply with Decision (D.)

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[1] California Community Choice Association represents the interests of 23 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, Lancaster Choice 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] All references herein to party Opening Comments are to the September 26, 2022 Comments filed in this Rulemaking (R.) 20-05-003.

19-11-016[3] and D.21-06-035.[4] Party Opening Comments also reflect the difficult market conditions LSEs face given supplier awareness of the strict compliance obligations and potential penalties for non-compliance. Southern California Edison Company (SCE) notes market power exercised by suppliers during contract negotiations resulting from the potential penalties faced by LSEs for delays.[5] The Alliance for Retail Energy Markets (AReM) notes potential increased costs to customers for penalties for delays over which LSEs have no control.[6]

Given the difficult market conditions, the Opening Comments provide various proposals to remove barriers to resource procurement and to encourage viability of projects in development. CalCCA takes no position on the Ruling's proposal concerning modifications to the 2019 Order and MTR Order baselines. Instead, and as set forth more fully below, CalCCA recommends that:

- The Commission should adopt party proposals to clarify and modify compliance and resource requirements in the 2019 and MTR Orders that align with the Commission's reliability and green-house gas (GHG) reduction goals, while encouraging successful procurement of resources, including:
    - CalCCA's proposals in Opening Comments to (1) allow trading of compliance obligations, and (2) allow projects without a California Independent System Operator (CAISO) deliverability study to temporarily count for compliance;
    - AReM's proposal to move the compliance deadlines currently set for August 1, 2023 and June 1, 2024 and 2025 to September 1 of each year to accommodate short delays in bringing projects online;
    - Sonoma Clean Power's (SCP's) and Redwood Coast Energy Authority's (RCEA's) proposal to allow intra-LSE trades of one year of eligible capacity to allow parties to remain compliant while waiting for projects to come online;

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3 D.19-11-016, *Decision Requiring Electric System Reliability Procurement for 2021-2023,* R.16-02-007 (Nov. 7, 2019) (2019 Order).

4 D.21-06-035, *Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026),* R.20-05-003 (June 24, 2021) (MTR Order).

5 SCE Comments at 10-11.

6 AReM Comments at 7-8.

    - The proposal of various community choice aggregator (CCA) parties to allow pseudo-tied or dynamically scheduled imports without maximum import capability (MIC) that have achieved their commercial operation date (COD) by the required deadline to be considered compliant;
    - Proposals by SCP/RCEA and Silicon Valley Clean Energy (SVCE) that the pool of eligible zero-emitting resources for MTR Order compliance should be clarified and/or expanded;
    - SCE's proposal that an energy storage resource's derated nameplate capacity should count toward the MTR Order long-duration storage requirements; and
    - Crediting LSEs for compliance purposes toward the 2019 and MTR Orders for repowered resources, as proposed by SVCE.
- The Commission should adopt a modified version of SCE's penalty waiver proposal through a 12-month MTR Order compliance extension framework based on an LSE's good faith showing.
- To the extent modifications are made to the baseline incremental procurement obligations:
    - Pacific Gas and Electric Company's (PG&E's) recommendation that the Commission issue any LSE obligations by the end of the first quarter of 2023 should be adopted;
    - Any new obligations should not be required to be online until 2026 or later, as proposed by PG&E, Clean Power Alliance (CPA), Peninsula Clean Energy (PCE), and SCP/RCEA; and
    - The Commission should adopt SCE's proposal regarding net qualifying capacity (NQC) counting methodologies for the incremental procurement obligations.

II. MODIFICATIONS TO EXISTING PROCUREMENT REQUIREMENTS AND ADOPTION OF A FRAMEWORK FOR EXTENSIONS OF TIME FOR COMPLIANCE WILL ENCOURAGE LSES TO CONTINUE WITH SUCCESSFUL PROCUREMENT IN A DIFFICULT MARKET

The Commission should adopt various party proposals to encourage successful procurement by LSEs despite the multiple barriers detailed in the Ruling. First, by modifying (or in some cases clarifying) existing compliance and resource requirements set forth in the 2019 and MTR Orders, the Commission can encourage additional procurement while still advancing its reliability and GHG goals. Second, the Commission should adopt a framework to allow extensions of time for compliance with the MTR Order in the event circumstances outside of an LSEs' control cause project delays, to allow LSEs to avoid backstop procurement and potential penalties. Importantly, the proposals set forth herein can potentially calm the market by reducing supplier market power and reduce potential costs to customers by preventing significant penalties imposed on LSEs.

A. Modifications to the 2019 Order and MTR Order Requirements Will Provide Compliance Flexibility While Advancing Commission Reliability and GHG Goals

Modifications to the 2019 Order and MTR Order compliance and resource requirements presented in Opening Comments should be adopted by the Commission to encourage successful resource procurement in the difficult market environment. Parties recommend several modifications that will clarify and/or relax the 2019 Order and MTR Order requirements, while still advancing the Commission's reliability standards and commitment to GHG emissions reduction targets. CalCCA recommends first that the Commission adopt its recommendations set forth in its Opening Comments to (1) allow trading of compliance obligations, and (2) allow projects without a deliverability study to temporarily count for compliance.[7] CalCCA also recommends that the Commission adopt each of the party recommendations set forth below.

First, CalCCA recommends Commission adoption of AReM's recommendation to move the MTR compliance deadlines currently set for August 1, 2023 and June 1, 2024 and 2025 to September 1 of each year.[8] This short "grace period" will allow counterparties to work out very short delays without compromising other financial incentives that developers have to get resources on as soon as possible.

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7 CalCCA Opening Comments at 9-12.

8 AReM Opening Comments at 9.

Second, the Commission should allow for intra-LSE trades of one year of eligible capacity, as proposed by SCP/RCEA.[9] As SCP/RCEA note, this provision will reward LSEs that exceed compliance obligations. In addition to CalCCA's recommendation to allow trades of compliance obligations, intra-LSE trading will allow parties to remain compliant while waiting for projects to come online.

Third, the Commission should adopt the proposal of various CCA parties to allow pseudo-tied or dynamically scheduled imports without MIC that have achieved COD by the required deadlines to be considered compliant.[10] Such compliance should hinge on an LSE demonstrating its good faith efforts to secure MIC through the CAISO MIC expansion process, through the annual elections and long-term reservations.

Fourth, the Commission should adopt the recommendations of SCP/RCEA and SVCE that the pool of eligible zero-emitting resources for MTR compliance be clarified and/or expanded. Specifically, the Commission should adopt:

- SCP/RCEA's recommendation to:
    - remove the requirement that generation and storage resources be co-located or contractually bound, but rather allow an LSE that contracts for two or more separate resources that provide the capabilities required by the zero-emitting category to be applied together, using the latest contract start date, as a composite in satisfying the requirement.[11]
- SVCE's recommendation to allow LSEs to:
    - separately procure energy and batteries so long as the energy is deliverable to the system, and

9 SCP/RCEA Opening Comments at 8.

10 *Id.* at 7; PCE Opening Comments at 3; CCSF Opening Comments at 4-5; SVCE Opening Comments at 5-6.

11 SCP/RCEA Opening Comments at 6-7.

- count hybrid resources for which it may not contract the energy directly but where the energy is otherwise not used for MTR compliance and has economic incentives to charge the battery and dispatch during peak hours.[12]

Fifth, the Commission should adopt SCE's recommendation that an energy storage resource's derated nameplate capacity that can be discharged for eight hours count toward the MTR long-duration storage requirements.[13] SCE requests, for example, that in the case of a four-hour resource with 100 megawatts (MW) nameplate, that an LSE can count the resource's derated 50 MW capacity with the resource discharge for eight hours.

Finally, the Commission should adopt SVCE's recommendation that the Commission clarify that LSEs can be credited for compliance purposes toward D.19-11-016 and D.21-06-035 for repowered resources.[14] CalCCA agrees that such resources, for which LSEs are investing significant capital to overhaul and improve, should be counted for compliance with the 2019 and MTR Orders.

By adopting these proposals, the Commission can provide additional flexibility for LSEs to comply with the 2019 and MTR Orders, while still advancing its GHG or reliability goals. Such flexibility may allow LSEs to include resources not previously compliant with these Orders.

B. A Modified Version of SCE's Penalty Waiver Proposal Should Be Adopted Through a 12-Month MTR Compliance Extension Framework Based on an LSE's Good Faith Showing

In the event procurement under the MTR Order is delayed for reasons beyond an LSE's control, the Commission should adopt a framework building on SCE's proposal to waive penalties that will give an LSE a twelve-month compliance extension. Such an extension will be

12 SVCE Opening comments at 6.
13 SCE Opening Comments at 11-12.
14 SVCE Opening Comments at 5.

accompanied by a delay of backstop procurement and waiver of penalties, based on an LSE's "good faith effort" showing.

SCE proposes that the Commission:

> explicitly find that it will not assess penalties on an LSE whose procurement was delayed for reasons beyond its control, so long as the LSE took commercially reasonable steps to contract with resources and included commercially reasonable terms in its contracts such as (but not limited to) reasonable credit and collateral terms, sufficient failure to deliver penalties, and other contractual requirements that properly incent performance.[15]

CalCCA agrees with SCE's general request that penalties should be waived for delays outside the control of an LSE. However, SCE fails to provide further details as to how the Commission should address the corresponding backstop procurement, and the potential duplicative procurement that can occur once an LSE's (delayed) planned project comes online. As a result, CalCCA recommends that the Commission adopt the following framework for extensions of time for compliance and backstop procurement, and a corresponding waiver of penalties, for delays in meeting milestone compliance dates under the MTR Order.[16]

First, an LSE will submit a request to the Commission's Executive Director for extension of time to comply prior to an MTR compliance deadline. The request will demonstrate an LSE's "good faith efforts" to comply and to bring its required capacity online given the "totality of the circumstances" as required by Resolution M-4846. "Good faith efforts" may include the factors

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[15] SCE Opening Comments at 10.

[16] While the Commission provides such a framework for extensions of time to comply with the 2019 Order compliance obligations in D.20-12-044, the 2019 Order does not incorporate penalties for noncompliance. *See* D.20-12-044, *Decision Establishing Process for Backstop Procurement Required by Decision D.19-11-016,* R.20-05-003 at 12-21 (Dec. 17, 2020) (outlining milestones for LSEs to demonstrate compliance and avoid the Commission ordering backstop procurement and providing Commission staff with latitude to evaluate whether delays are "reasonable and warranted" allowing an extension for compliance). Therefore, an LSE will temporarily avoid the costs associated with backstop procurement if granted an extension from timely compliance with a 2019 Order obligation but will not face penalties.

listed by SCE, including "commercially reasonable steps to contract with resources" and "commercially reasonable terms" in its contracts to incent performance.[17] Importantly, the LSE must demonstrate that the delay results from factors beyond its control, and what those factors include. The "totality of the circumstances" may include (but are not limited to) the factors listed in the Ruling (including changed circumstances in the electric sector, regulatory and statutory impacts, market constraints and supply chain impacts), as well as factors listed in D.20-12-044 to be considered by the Commission for compliance delays with respect to the 2019 Order.[18] Factors included in D.20-12-044 include:

- Resource-specific considerations:
    - Whether there is complete contract failure or delay
    - Length of delay estimated
    - Whether a project has failed to meet multiple milestones
    - Whether the delay is related to interconnection or transmission
    - Project stage of development
    - Quality of LSE or developer remediation plan (including diagnosis for the delay/failure and achievable mitigation steps, backed up by evidence)
- LSE-specific considerations:
    - Pattern of success in meeting previous milestones
    - Quality of mitigation or remediation plan
    - Thoroughness of documentation[19]

As recommended in Resolution M-4846, conduct of the LSE in alerting Energy Division as to delays and attempting to minimize the delays should be considered along with the "totality of the circumstances." If the LSE can show such good faith efforts the extension should be liberally granted.

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17 *See* SCE Opening Comments at 10.
18 D.20-12-044 at 19-20.
19 *Id.* at 19-20.

If granted, an extension of time should automatically provide a twelve-month extension to comply. During the twelve-month period, an LSE should be required to provide a report every other month with the LSE's efforts to comply and any changes to the scheduled online date of resources. In the event the LSE needs to submit an additional request for extension at the end of the twelve months, the LSE's efforts during the prior twelve-month period can be a factor in the Commission's evaluation of whether to grant a further extension.

While SCE proposes that the Commission "find" that it will not impose penalties based on delays caused by factors outside of an LSE's control, CalCCA's proposal to allow an extension of time for compliance also addresses the avoidance of backstop procurement as well as the corresponding waiver of penalties. In addition, CalCCA's proposal envisions a project receiving an extension, but the LSE still working to get the impacted project online. As a result, the extension of time is wholly in line with the Ruling's request for tools to encourage projects to remain viable and for procurement to be successful. Finally, given the potential for capacity from Diablo Canyon to temporarily remain online, extensions of time to allow a project to be brought online should be less of a concern from a short-term reliability perspective, and rather can be a longer-term viable solution to the current project delays. As a result, CalCCA encourages the Commission to adopt its framework for extensions of time based on an LSEs' "good faith efforts" to bring projects online despite project delays.

III. MODIFICATIONS TO BASELINE INCREMENTAL PROCUREMENT OBLIGATIONS MUST INCORPORATE ADEQUATE TIME FOR LSE PROCUREMENT AND CLEAR COUNTING RULES

CalCCA takes no position on the Ruling's proposals to modify the 2019 and MTR Order baselines. However, in the event the Commission adopts its baseline proposal, it should incorporate adequate time for LSEs to procure the additional capacity and provide clear NQC counting rules.

First, in the event any further procurement obligations are placed on LSEs, the Commission should adopt PG&E's recommendation that the Commission issue the LSE obligations expeditiously, or by the end of the first quarter of 2023.[20] Given the difficulties of procuring additional resources in the current market, LSEs need to be notified quickly of any new obligations for timely compliance.

In addition, as proposed by PG&E and various CCA parties, the Commission should delay the online date of such resources to June 1, 2026 or longer, rather than 2025.[21] LSEs facing severe market constraints need adequate time to procure and bring online new resources, and a deadline in 2025 fails to provide the requisite amount of time. In addition, the CAISO's recommendation that the Commission require the resources to come online "by 2024 at the latest"[22] fails to recognize current market constraints and project delays and should be rejected.

Finally, several parties noted that the Commission must recognize the potential that a resource's current NQC value may differ between when the baseline was created and 2025 (or 2026, as recommended above).[23] SCE notes that the counting methodologies for D.19-11-016 and D.21-06-035 procurement are different. The Commission should therefore adopt SCE's proposals to:

- Use the D.19-11-016 counting methodology (counting based on RA qualifying capacity methodologies in place at the time of the decision, and for hybrid and co-located resources, the methodology adopted in D.20-06-031) for "baseline" resources counted toward D.19-11-016 procurement;
- Use the net RA NQC counting rules in effect at contract execution for "baseline" resources online before 2023 that are counted toward D.21-06-035 requirements; and

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20 *See* PG&E Opening Comments at 4.

21 *See id.* at 4; CPA Opening Comments at 2; PCE Opening Comments at 2; SCP/RCEA Opening Comments at 5.

22 *See* CAISO Opening Comments at 4.

23 *See* AReM Opening Comments at 6; SCE Opening Comments at 7-8.

- Use the marginal ELCC values or RA NQC rules, as applicable, as provided in D.21-06-035 for "baseline" resources that come online in 2023 or later that are counted toward D.21-06-035 requirements.[24]

SCE's proposal fairly categorizes resources according to which decision they are being counted toward, and the NQC guidance available when a project comes online.

IV. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl,
General Counsel and Director of Policy
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

October 6, 2022

24 SCE Opening Comments at 7-8.

California Community Choice Association

SUBMITTED 10/07/2022, 02:09 PM

Contact
Shawn-Dai Linderman (shawndai@cal-cca.org)

1. Please provide a summary of your organization's comments on the CPM Enhancements Track 1 draft final proposal

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the Capacity Procurement Mechanism (CPM) Enhancements Phase One Draft Final Proposal. CalCCA supports the Draft Final Proposal with a caveat regarding the tariff clarification to forbid resources from taking on new Resource Adequacy (RA) obligations after they have accepted a CPM designation.

The CAISO proposes two modifications that would provide additional flexibility in accessing CPM capacity. First, the CAISO proposes to have the authority to reduce the volume (in megawatts (MW)) of significant event CPM designations when the designated capacity is otherwise committed to the CAISO (e.g., through a RA contract, Reliability Must-Run (RMR) designation, or monthly CPM designation). Second, the California Independent System Operator Corporation (CAISO) proposes to have the authority to reduce the term of significant event CPM designations when the designated capacity is already committed or unavailable to the CAISO (e.g., capacity contracted to an entity outside the CAISO balancing authority area, RA resources not on a supply plan, or planned outage substitution). CalCCA supports these enhancements as they will provide the CAISO additional access to CPM capacity which may result in increased reliability and lower CPM costs.

However, in the draft final proposal the CAISO also indicates that it plans to clarify the tariff to forbid resources from taking on new RA obligations after they have accepted a CPM designation if those new RA obligations conflict with the CPM obligations. CalCCA understands that this aspect of the proposal would apply to Significant Event CPMs and CPMs associated with resolving RA deficiencies (and not exceptional dispatch CPMs).

CalCCA supports this clarification *<u>for CPMs associated with resolving RA deficiencies only</u>*. For CPMs resolving RA deficiencies, the RA credit associated with the CPM capacity is allocated to load-serving entities (LSEs). Therefore, it makes sense to forbid the CPM capacity from taking on new RA obligations because that capacity is already counting towards RA obligations and the RA value of that capacity is already allocated out to LSEs through CPM credits. CalCCA agrees with the CAISO that the CPM rules should ensure the same MW of capacity is not sold twice and is not counted for RA twice.

CalCCA does not support this clarification for Significant Event CPMs. For Significant Event CPMs, the RA credit associated with the CPM capacity is not allocated to LSEs because these CPM types are meant to obtain capacity in excess of RA requirements. If these CPMs extend beyond the initial 30-day term, there may be a situation where an LSE is looking to buy capacity for its monthly showing, but the capacity is already tied up in a long-term CPM. For example, assume a 10 MW resource accepts a 90-day CPM on September 10. The CPM, therefore, lasts until December 10. If an LSE is looking to procure an additional 10 MW for its November monthly RA showing due Sept 15 or its December monthly RA showing due October 15, after the resource accepts the multi-month CPM, it would not be able to access that capacity for its November or December RA obligation. The CPM process should be a backstop to the RA program, meaning that it should not preclude LSEs from procuring RA from resources if they can use the capacity for their RA showings. This is especially critical in today's RA market, where RA capacity is extremely scarce and LSEs must procure most, if not all, available RA capacity to meet their obligations in peak months. Therefore, CalCCA recommends that the CAISO clarify the tariff to forbid resources from taking on new RA obligations after they have accepted a CPM designation if those new RA obligations conflict with the CPM obligations *for CPMs associated with resolving RA deficiencies only*. For Significant Event CPMs, the CAISO should allow the CPM resource to enter into an RA contract to serve CAISO Balancing Authority (BA) load and when it does, release the resource of its CPM status. The CAISO could issue another Significant Event CPM to cover the capacity from the resource that transitioned from a CPM resource to an RA resource should the need for the Significant Event CPM continue and excess capacity to CPM exists. Allowing LSEs to contract with capacity that is CPM capacity but whose RA value is not already allocated to LSEs would better enable LSEs to meet their RA obligations at lower costs and reduce the risk of the CAISO needing to perform additional CPM to cover RA deficiencies.

CalCCA understands that the CAISO's clarification that would forbid resources from taking on new RA obligations after they have accepted a CPM designation if those new RA obligations conflict with the CPM obligations would not apply to Exceptional Dispatch CPMs and that resources that receive an Exceptional Dispatch CPM could subsequently enter into an RA contract and have their CPM volume adjusted. CalCCA recommends this rule apply to Significant Event CPMs as well. If the CAISO believes this rule should not apply to Significant Event CPMs, more clarification is needed as to why it would apply for Exceptional Dispatch CPMs and not Significant Event CPMs.

2. Please provide specific comments (if applicable) on proposal 4.1

CalCCA has no additional comments at this time.

3. Please provide specific comments (if applicable) on proposal 4.2

CalCCA has no additional comments at this time.

4. Please provide specific comments (if applicable) on proposal 4.3

CalCCA has no additional comments at this time.

5. Please provide specific comments (if applicable) on proposal 4.4

CalCCA has no additional comments at this time.

6. Please provide specific comments (if applicable) on proposal 4.5

CalCCA has no additional comments at this time.

Middle River Power, LLC

SUBMITTED 10/07/2022, 11:50 AM

Contact
Brian Theaker (btheaker@mrpgenco.com)

1. Please provide a summary of your organization's comments on the CPM Enhancements Track 1 draft final proposal

Middle River Power (MRP) appreciates the opportunity to comment on the draft final proposal.

MRP generally supports the direction of the proposal and provides the comments below for additional consideration and clarification.

One aspect of the draft final proposal that MRP does not support is the new insertion limiting the ability for resources to sell capacity to other LSEs after a CAISO CPM designation. MRP believes the CAISO's restriction on selling CPM capacity is too broad and should be limited to only instances of exceptional dispatch CPM and intra-month significant event CPM designations. As written, if the CAISO were to issue CPM designations for Local, System or Flexible capacity deficiencies in the year-ahead timeframe, the CPM capacity could not be contracted to an LSE even if the LSE needed the capacity to meet its own RA obligations. Allowing for the CPM capacity to be contracted to LSEs within the CAISO is beneficial to the CAISO because it (1) ensures that the capacity is under RA contract, (2) leaves the CAISO no worse off operationally, and (3) ensures that the total costs of the CPM designation would be reduced because the new LSE would take on that cost. Whether or not the contractual cost is higher or lower than CPM is irrelevant because the LSE wanted to buy the capacity for its needs rather than rely on the CAISO CPM to meet that obligation.

2. Please provide specific comments (if applicable) on proposal 4.1

MRP understands the CAISO proposes to vary the volume of mid-term significant event CPM designations because a resource may have varying volumes of RA commitments that straddles two months. *First,* MRP requests the CAISO define the term "mid-term". MRP interprets this term to primarily apply to a CPM designation that occurs after the first day of the operating month with a potential 30-day designation duration lasting until the next operating month. If this interpretation is accurate, then MRP agrees that the CAISO should have the ability to reduce the volume of the CPM designation. *Second,* MRP suggests that it is possible for a resource to be held back from being shown as RA capacity during an operating month because the LSE that owns or controls the capacity may wish to use it as substitute capacity for a planned outage. For example, consider a situation in which LSE 1 procured a 100 MW resource (RES A) for April and needed the capacity for substitution capacity for the 2nd week in the month for another resource (RES B) that is scheduled to be on planned outage then. In this case, RES A would not be able to submit offers into the CSP because it is unable to offer the capacity for the entire month. If the CAISO needed to solicit significant event CPM offers prior to the operating month, as it did so in 2018, MRP believes that RES A should have the capability to offer its capacity, if authorized by LSE 1, into the CAISO's CSP process. MRP highlights this example primarily to question whether the CAISO should limit its proposal to vary the volume of significant event CPMs throughout a 30-day term to only "mid-term" significant event CPMs or if it should have the capability to do such for any significant event CPM.

3. Please provide specific comments (if applicable) on proposal 4.2

MRP generally supports this proposal but requests the CAISO clarify whether MRP's example above of a resource being used for planned outage substitution for one week during an operating month would be allowed to effectively have two discontinuous CPM designation terms. Under this section of the CAISO's proposal, the CAISO states that this would not be allowed, but if there is a significant event and the CAISO needs the capacity, it makes little sense for the CAISO to not be able to procure the capacity. MRP requests the CAISO provide in the final proposal details as to what might be permitted in MRP's example regarding capacity held back to provide substitute capacity above. MRP also requests the CAISO consider if the CAISO's CSP tool in CIRA can be utilized to facilitate such availability information from the scheduling coordinator of the resource to the CAISO rather than CIDI tickets.

4. Please provide specific comments (if applicable) on proposal 4.3

Inasmuch as the CAISO is proposing to post CPM designation information in OASIS rather than through market notices, MRP continues to request the CAISO post CPM designation data in OASIS that provides more information on the nature and length of the designation than the information previously provided in the market notices. To be clear, MRP is not asking for information that would be considered sensitive, but rather for more complete non-sensitive information.

5. Please provide specific comments (if applicable) on proposal 4.4

No comment..

6. Please provide specific comments (if applicable) on proposal 4.5

No comment..

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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 2023 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation. (U39E).	Application 22-05-029

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING BRIEF

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On behalf of
California Community Choice Association

October 14, 2022

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SUMMARY OF RECOMMENDATIONS

- Order Pacific Gas and Electric Company (PG&E) to remove the obsolete and unlawful rate floor in its tariff and adopt Power Charge Indifference Adjustment (PCIA) rate credits for vintages where the forecasted, cumulative indifference amount is negative.

- Enact the procedural recommendation in D.20-02-047 to create a more permanent crediting framework for banked renewable energy credits in the Power Charge Indifference Adjustment rulemaking, R.17-06-026.

- Adopt CalCCA's uncontested recommendations to adjust PG&E's revenue requirement to address (1) the sale of PG&E's San Francisco headquarters, (2) the correct on-peak and off-peak load weights, and (3) Witness Shuey's accounting methodology to reflect PG&E's Modified Cost Allocation Mechanism procurement.

- Adopt CalCCA's uncontested recommendation to transfer the final year of Energy Resource Recovery Account-PCIA Financing Subaccount amortization to the vintage 2020 consistent with Commission direction in D.22-02-002.

- Apply the legal standard enumerated in this Brief to PG&E's October 17, 2022 updated testimony, *i.e.*, the October Update.

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 2023 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation. (U39E).	Application 22-05-029

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 (Commission) and the July 25, 2022 Scoping Memo and Ruling setting the schedule for this proceeding,[1] California Community Choice Association[2] (CalCCA) hereby submits this Opening Brief regarding the *Application of Pacific Gas and Electric Company (PG&E) for Adoption of Electric Revenue Requirements and Rates Associated with its 2023 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation. (U39E)* (Application).[3]

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[1] Application (A.) 22-05-029, *Assigned Commissioner's Scoping Memo and Ruling* (August 4, 2022) (Scoping Ruling).

[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, Energy For Palmdale's Independent Choice, Lancaster Choice 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.

[3] A.22-05-029, *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2023 Energy Resource Recovery Account and Generation Non-*

Five years removed from Decision (D.) 18-10-019, most implementation details of the Commission's revised framework for the Power Charge Indifference Adjustment (PCIA) have been settled. Evidence of this can be seen in the few contested issues remaining in this proceeding. However, the high energy prices in California, and the implementation of recently adopted mechanisms such as the modified Cost Allocation Mechanism (ModCAM) and the Voluntary Allocation and Market Offer (VAMO) process create novel issues the Commission will need to address. These factors, as well as errors within PG&E's prepared testimony and workpapers, implicate the following issues in the Scoping Ruling:[4]

> 1. Whether PG&E's requested 2023 ERRA Forecast revenue requirement is reasonable, including but not limited to consideration of the following:
>
>   a. forecast costs for fuel and purchased power expenses;
>
>   b. disposition of PG&E's forecast December 31, 2022 year-end balancing account balances;
>
>   c. disposition of recorded Voluntary Allocation Market Offer Memorandum Account (VAMOMA) balances; and
>
>   d. approval of PG&E's methodology to include 2021 and 2022 renewable energy credits (RECs) toward the 2023 Power Charge Indifference Adjustment (PCIA) revenue requirement calculation and to allocate the value of 2021 and 2022 RECs to benefit bundled and departing load customers responsible for applicable Portfolio Allocation Balancing Account (PABA) vintage costs.
>
> 5. Adopt rate design proposals associated with PG&E's total electric procurement revenue requirements to be effective in rates on January 1, 2023, including Green Tariff Shared Renewables (GTSR) rates.
>
> 6. Whether PG&E has adequately supported its new proposed REC

Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (May 31, 2022) (Application).

[4] Scoping Ruling at 2-3.

Tracking and Accounting Methodology, and whether the Commission should rule that the consideration of that methodology beyond the 2023 Renewables Portfolio Standard (RPS) Compliance year is beyond the scope of this proceeding. At the PHC PG&E confirmed that its proposal was strictly limited to 2023 and was [*sic*] PG&E was not seeking, nor relying on any approval, for subsequent years.

7. That PG&E should continue to return the ERRA-PCIA Financing Subaccount (ERRA-PFS) credit to bundled and unbundled customers by amortizing the final year of that credit through the PABA consistent with Decision 22-02-002.

On Issue 1, the Commission should adopt CalCCA's uncontested recommendations to adjust PG&E's revenue requirement to reflect (1) the sale of PG&E's San Francisco headquarters, (2) the correct on-peak and off-peak load weights, and (3) CalCCA's proposed accounting methodology for PG&E's ModCAM procurement.

On Issue 5, California's high energy prices have led to the likelihood of forecasted negative indifference amounts for the first time. In response, PG&E unlawfully proposes to set rates differently between vintages, using the forecasted indifference amounts for some customer vintages (those that are positive) but not other customer vintages (those that are negative). This rate proposal intentionally overcharges customers in vintages with negative indifference amounts. It conflicts with the Commission's past elimination of all limits on PCIA rate changes, including the elimination of the rate floor (D.18-10-019) and the rate cap (D.21-05-030). The only policy reason PG&E has identified for its proposal is that negative forecasted indifference amounts, and the resulting PCIA rate credits, may not come to pass because they are forecasts. That reasoning ignores the same forecasted nature of PCIA rate charges, Commission policy behind the use of forecasted revenue requirements to set rates, the Commission's implementation of a true-up to resolve the delta between forecasted and recorded net revenues, and the potential for volatility that inaccurate ratesetting creates. The proposal's vintage-specific, adverse impacts affect bundled and unbundled customers alike. The only assured beneficiary of a delaying PCIA rate credits is PG&E, not customers.

Regarding Issue 6, the VAMO and other market factors will require PG&E (as well as Southern California Edison (SCE)) to utilize banked RECs to meet its RPS obligations in 2023. Such RECs should be credited to the Indifference Amount at the level of today's RPS Adder. This temporary solution, proposed by PG&E, is unopposed but unlikely to withstand REC allocations and sales in the near future. A permanent crediting framework for banked RECs is needed. An ordering paragraph stating the Commission will develop such a framework in the PCIA rulemaking, R.17-06-026, is permitted in this case, similar to D.20-02-047.

Regarding Issue 7, the Commission should adopt CalCCA's uncontested recommendation to transfer the final year of ERRA-PFS amortization to the vintage 2020 consistent with Commission direction in D.22-02-002.

PG&E's October 17, 2022 updated testimony (October Update) will modify some of the revenue requirements and rates resulting from these issues, as well as the other issues in scope in this proceeding. CalCCA looks forward to addressing those issues in its November 1, 2022, comments on the October Update.

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 the applicant, PG&E has the burden of affirmatively establishing the reasonableness of all aspects of its application,[5] and that burden of proof generally is measured based upon a preponderance of the evidence.[6]

The Scoping Ruling categorized this proceeding as ratesetting.[7] The Commission has previously determined that Section 1757 of the Public Utilities Code applies to ratesetting,[8] meaning 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.[9] As a result, the Commission cannot grant the relief requested in PG&E's Application without substantial evidence to support the rates requested.[10] California courts will overturn Commission decisions that lack substantial evidence.[11] Mere rubber-stamping of uncorroborated, disputed evidence does not meet this standard.[12] The

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5 R.11-02-019, *Decision Mandating Pipeline Safety Implementation Plan, Disallowing Costs, Allocating Risk of Inefficient Construction Management to Shareholders, and Requiring Ongoing Improvement in Safety Engineering,* p. 42 (December 28, 2012) (D.12-12-030).

6 *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 (January 16, 2018) (D.18-01-009); R.11-02-019, *Order Modifying Decision (D.) 12-12-030 and Denying Rehearing, as Modified,* p. 29 (July 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.").

7 Scoping Ruling at 6.

8 Cal. Pub. Util. Code § 1757; *see, e.g.,* R.14-07-002, et. al, *Order Denying Rehearing of Decision (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.").

9 *See, e.g.*, D.20-05-027, p. 6.

10 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 (February 5, 2014).

11 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 (February 5, 2014).

12 *See id*.

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.[13]

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.[14]

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."[15]

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

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[13] Cal. Pub. Util. Code § 451.

[14] 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 (July 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* (September 2, 2010) D.10-09-010). 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, pp. 2-3 n. 3.

[15] Cal. Pub. Util. Code § 453(c).

increases as a result of an allocation of costs that were not incurred on behalf of the departing load."[16] 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 IOUs' portfolios that accrue to bundled customers.[17]

In the Commission's unique ERRA Forecast applications, where policymaking is largely forbidden,[18] 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 requirements, rate proposals, and issue-specific requests must be reasonable.[19] Its proposed PCIA rates must be reasonable and comply with all applicable rules, regulations, resolutions and decisions for all customer classes.[20]

As described in detail below, PG&E's proposed, arbitrary rate floor for the PCIA contradicts a number of the statutory provisions described above and Commission precedent. The modifications to the revenue requirement, and the approach to the ERRA-PFS, agreed upon by parties must be made to ensure rates are just and reasonable.

PG&E's October Update will modify its currently requested 2023 ERRA forecast revenue requirement of $4.486 billion.[21] The same standards enumerated in this Opening Brief will apply

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16 Cal. Pub. Util. Code § 365.2.

17 Cal. Pub. Util. Code § 366.2(f)(2), (g).

18 D.18-01-009, p. 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).

19 *See* Scoping Ruling at 2.

20 While not specifically memorialized in this year's scoping ruling, this standard has long been acknowledged as the standard for ERRA Forecast proceedings. *See, e.g.,* A.21-06-001, *Assigned Commissioner's Scoping Memo and Ruling*, p. 6 (August 11, 2021); A.13-05-015, *Scoping Memo and Ruling of Assigned Commissioner*, p. 4 (September 12, 2013).

21 Application at 4.

equally to the calculation of PG&E's 2023 rates included in that October Update, including, but not limited to, the reasonableness of PG&E's proposed treatment of (a) Resource Adequacy (RA) resources and 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 2023 indifference amount, (d) the calculation of the 2022 year-end PABA balance, and (e) the allocation of indifference charges among vintages and customer classes.[22]

II. CONTESTED ISSUES

A. <u>Scoping Issue 5</u>: PG&E Must Remove Its Zero-Dollar Rate Floor and Allow PCIA Rate Credits When Negative Indifference Amounts Exist.

Scoping Issue 5 requires the Commission to determine whether to "[a]dopt rate design proposals associated with PG&E's total electric procurement revenue requirements to be effective in rates on January 1, 2023, including Green Tariff Shared Renewables (GTSR) rates."[23] The 2023 forecast represents an historic shift, as PG&E's long-underwater generation portfolio moves "into the money." At issue is how quickly that expected change should flow through to customers. The Commission has been clear that customers should receive the good from the portfolio in the same way they have received the bad these past many years. PG&E says customers should wait on forecasted portfolio net revenues, leading to the present ratesetting dispute. That position contravenes Commission precedent, unjustifiably discriminates between customers in its service territory, will result in inconsistent PCIA ratemaking between IOUs, is unreasonable and unsupportable, and must be rejected.

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22 *Id*.

23 A.22-05-029, *Assigned Commissioner's Scoping Memo and Ruling*, p. 2 (August 4, 2022) Scoping Ruling).

1. Negative Indifference Amounts Mean the Forecasted Value of PG&E's Generation Portfolio Outweighs Its Costs.

CalCCA Witness Shuey's direct testimony contains an extensive and uncontested explanation of how PCIA rates are set.[24] Those rates depend on two key components: (1) the forecasted Indifference Amount and (2) the 2022 year-end balance in the PABA.[25] Key to understanding the disputed rate design issue is PG&E's 2023 forecasted Indifference Amount, *i.e.*, the difference between the forecasted cost of PG&E's generation portfolio in 2023 and the forecasted market value of PG&E's generation portfolio in 2023:[26]

PG&E's Total Portfolio Cost includes capital investment recovery and fixed maintenance costs for utility owned generation (UOG), purchased power such as that from power purchase agreements (PPA), fuel costs for UOG and PPAs with tolling agreements, and California Independent System Operator grid charges and revenues, net of any sales.[27]

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24 Exh. CalCCA-01 at 4:12-9:7.

25 Exh. CalCCA-01 at 4:12-9:7. Prior to Decision 18-10-019, the PCIA rate was set only on a forecast basis with no after-the-fact true-up for unbundled customers. Decision 18-10-019 approved a true-up for the PCIA using actual recorded net costs for PCIA-eligible resources and billed revenues from both bundled and departing load customers. This true-up now occurs via the PABA, a rolling true-up between the forecasted costs and revenues used to determine the Indifference Amount and the actual costs and revenues PG&E realizes during the year related to its PCIA eligible resource portfolio. Because rates are determined during 2022, including the true-up for 2022, this true-up is developed using (1) actual values that are available to date and (2) a forecast of actual values for the remainder of the year. PG&E's May Application includes an estimate of the 2022 year-end PABA balance comprising a combination of actual entries from January through March 2022 and a projection of activity from April through December 2022. *Id.*

26 Exh. CalCCA-01 at 4:12-9:7.

27 D.11-12-018, pp. 8-9.

However, it is the second component, the Portfolio Market Value, that drives the dispute here. Portfolio Market Value is derived from total eligible resource output multiplied by the Market Price Benchmarks (MPBs), an administratively determined set of proxy values that represents the market value of the IOU's resource portfolio.[28] Portfolio Market Value consists of three principal components: Energy Value, RPS Value,[29] and RA Value.[30]

The Energy Value is determined by multiplying the relevant portfolio volume, *i.e.*, how much energy will be generated by PG&E's generation resources, by the Energy Index.[31] The Energy Index reflects the estimated market value of each unit of energy in PG&E's portfolio, in dollars value per megawatt hour ($/MWh).[32] The high price of non-RPS energy in California for 2022 and 2023 has increased the forecasted Energy Value component substantially compared to PG&E's original forecast. The result is that the forecasted value of PG&E's generation portfolio is likely to outweigh its costs, resulting in negative indifference amounts in some vintages.

2. Energy Division's Published Energy Index Likely Will Result in Negative Indifference Amounts for Some Vintages.

As CalCCA Witness Shuey lays out in his direct testimony, rising wholesale market prices increase the possibility that the value of PCIA-eligible resources will be greater than their cost, resulting in a negative Indifference Amount for PG&E for certain vintages.[33] PG&E's October

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

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

30 RA Value is the estimated financial value, measured in dollars, that is attributed to the resource adequacy component of a utility portfolio for a given year. *Id*.

31 *Id*.

32 *Id*. at 7.

33 Exh. CalCCA-01 at 27:5-30:16.

Update will be filed on October 17, 2022, and will include an Energy Index based on forward market prices the Commission's Energy Division calculated and served on parties on September 30, 2022.[34] The Energy Index price is $84.22/MWh, which is more than 30% greater than the index originally forecasted in PG&E's Prepared Testimony.[35] Replacing PG&E's filed energy prices from March with the Energy Division Energy Index would cause the market value of several of PG&E's individual resource vintages to exceed their costs, creating negative indifference amounts for those vintages.[36]

PG&E Witness Klingler's testimony does not contest these facts but deflects the issue, stating that negative indifferences amounts have "not been confirmed by PG&E at this time" because the October Update has not been filed.[37] While PCIA rates will change twice more after the October Update, and before their implementation on January 1, 2023,[38] the likelihood of negative PCIA rates warrants that the mid-December decision in this proceeding address the issue of whether PG&E's PCIA rates may go negative and become rate credits in 2023.

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34 *Id.*; CPUC Energy Division, *Calculation of the Market Price Benchmarks for the Power Charge Indifference Adjustment Forecast and True Up*, p. 1 (September 30, 2022) (PCIA Benchmarks).

35 *Compare* Exh. CalCCA-01-C at 28:3-8 *to* PCIA Benchmarks at 1.

36 *See* Exh. CalCCA-01 at 28:17-29:2 (reaching a similar conclusion with regard to NYMEX futures for the NP-15 market in 2023 that are *lower* than the published Energy Division Energy Index).

37 Exh. PGE-3 at 6:23-28.

38 The first change will take place as part of the Tier 2 Advice Letter PG&E will submit as its Annual Electric True-Up (AET) on November 15, 2022. That advice letter will include projected year-end balances in the ERRA and PABA, updating them "with recorded balances through October 31 and projected balances for November and December." The second change will take place as part of the Tier 1 Advice Letter PG&E will submit as its AET on December 31, 2022. That advice letter will include projected year-end balances in the ERRA and PABA, updating them with "either October 31 or November 30" data, "based on the available recorded data included in the revenue requirements used to calculate January 1 rates, and projected balances through December 31." Resolution E-5217 at Ordering Paragraphs 1-3.

3. PG&E's Tariff Addressing Negative PCIA Rates is Obsolete.

PG&E admits that language addressing forecasted negative indifference amounts in its tariffs is obsolete. PG&E's current Electric Schedule CCA-CRS tariff (which delineates the PCIA rates charged to CCA customers) includes the following language in Special Condition 4:[39]

> Should the total indifference amount be less than zero, the negative indifference amount will be used to offset future positive indifference amounts after September 1, 2006. The resulting CRS will not be negative, will not result in any net payment to customers who leave utility service, and will not be applied against other nonbypassable charges. Modifications to these charges will not affect other nonbypassable charges.[40]

When asked in discovery whether PG&E would allow PCIA rates to fall below zero for unbundled customers, the utility responded that Special Condition 4 as written has been rendered obsolete by PCIA reforms adopted in D.18-10-019 and D.19-10-001.[41] PG&E also indicated it plans to update Special Condition 4, although it did not say when.[42]

4. Commission Precedent Has Eliminated All PCIA Rate Limits, Including Rate Floors.

Despite admitting its tariff is obsolete, PG&E offers an unlawful and unreasonable position that fails to meet the requirements of the Commission's indifference framework. Witness Klingler proposes that if the utility forecasts a negative indifference amount for a given vintage in 2023, PG&E would implement a floor for that vintage and set the rate for that component at zero rather than allowing it to go negative.[43] That means in the likely scenario that certain vintages have negative indifference amounts in 2023, PG&E would not apply a rate credit reflecting that

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[39] Exh. CalCCA-01 at 29:3-16.

[40] *Id*. (citing to PG&E Electric Schedule CCA-CRS, Special Condition 4).

[41] *Id*. (citing PG&E's response to CalCCA data requests 2.15 and 2.16).

[42] *Id*. (citing PG&E's response to CalCCA data request 2.12).

[43] Exh. PG&E-03 at 7:4-13.

indifferent amount to those customers' bills; instead, it would subject those customers to a rate floor that is not authorized by any statute or Commission decision. The floor would only be removed if a negative indifference amount actually accrued to the PABA by the end of 2023, *i.e.*, in next year's true-up of forecasted PCIA rates.[44] In that case, the recorded credit would be allowed to offset the PCIA rate in the subsequent year for return to customers.[45] That is, customers would not see the rate credits due to them until 2024.

Decision 18-10-019 interpreted the mandates in Sections 365.2 and 366.2 of the California Public Utilities Code to set forth a new framework on indifference in California.[46] The decision eliminated any rate floor associated with PCIA rates,[47] but it adopted a PCIA rate cap. The Commission later dismantled the rate cap in D.21-05-030,[48] meaning the Commission's indifference framework currently has no limits on PCIA rate changes.

As part of D.18-10-019, the Commission made clear that PCIA rate credits should be permitted when the Indifference Amount is negative, or, in other words, the market value of PG&E's PCIA-eligible resources is greater than its cost. It specifically stated that "the PCIA rate should be able to go negative and should credit departing customers when IOU portfolio value exceeds costs."[49] PG&E's position would prevent such negative rates and credits if they are due to forecasted portfolio revenues exceeding forecasted costs, creating an artificial limit on PCIA rates in violation of this decision and the Commission's indifference framework.

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44 *Id*.

45 Exh. CalCCA-01 at 29:21-22 (citing to PG&E's response to CalCCA data request 2.14).

46 Cal. Pub. Util. Code § 365.2; Cal. Pub. Util. Code § 366.2(f)(2), (g).

47 D.18-10-019, p. 88; FOF 20 at 155; COL 21 at 158.

48 D.21-05-030 at Ordering Paragraph 1.

49 D.18-10-019, p. 88; FOF 20 at 155; COL 21 at 158.

PG&E's non-attorney Witness Klingler ignores the above-quoted language in D.18-10-019 and does not address it. Instead, he focuses on a finding of fact and conclusion of law that actually *support* the concept of negative PCIA rates to somehow suggest D.18-10-019 *prohibits* forecasted rates from going negative.[50] Conclusion of Law 21 in D.18-10-019 states: "The PCIA framework should allow for a net credit to departing load customers if utility portfolios provide positive net market value as demonstrated through actual recorded market transactions and realized revenues," and Finding of Fact 20 includes similar language.[51] Relying on this language, he suggests the Commission meant to limit the application of PCIA credits to the true-up process, *i.e.*, only allowing credits based on recorded revenues instead of forecasted revenues, stating such an approach is "the Commission's direction."[52]

PG&E's witness is wrong. Neither of those provision states "the PCIA framework should allow for a net credit to departing load customers" ***only*** "if utility portfolios provide positive net market value as demonstrated through actual recorded market transactions and realized revenues."[53] They simply acknowledge one instance that may lead to negative rates, in support of the idea that negative rates *should* exist.

The context provided in the rest of the decision makes clear that the only limit the Commission placed on the PCIA in D.18-10-019 was tied to the (now defunct) PCIA rate cap. The issue of negative PCIA rates is discussed only in the context of PCIA rate caps in a section entitled

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50 Exh. PG&E-3 at 7:20-8:20.

51 D.18-10-019 at COL 21 and FOF 20 (the latter stating "The PCIA rate can produce a credit to departing load if a utility portfolio provides positive net market value as demonstrated through actual recorded market transactions and realized revenues.").

52 Exh. PGE-03 at 8:7.

53 D.18-10-019 at COL 21 and FOF 20 (the latter stating "The PCIA rate can produce a credit to departing load if a utility portfolio provides positive net market value as demonstrated through actual recorded market transactions and realized revenues.").

"Should the Commission 'Cap' the PCIA rate?"[54] That section was a subsection of section 6.2.3, which *followed* the section discussing a true-up, section 6.2.2, meaning the concept of negative rates was not tied to the true-up but to the rate cap. The Commission concluded: "We revise the cap mechanism to remove the floor. We agree with comments by Brightline and [The Utility Reform Network (TURN)] that the PCIA should be able to go negative and should credit departing customers when IOU portfolio value exceeds costs." This context, when combined with D.21-05-030's elimination of the rate cap, demonstrates how the Commission has sought to eliminate all limits on PCIA rate changes.

5. A Rate Floor Unjustifiably Discriminates Between Groups of PG&E Customers and Will Result in Inconsistent Implementation Between IOUs.

PG&E's rate floor violates Public Utilities Code §453(c)'s prohibition against "any unreasonable difference" in "rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service" for a utility's customers."[55] Under the Commission's PCIA framework, each generation resource and departing customer is assigned a vintage, and a distinct portfolio of generation resources is identified for each vintage year based on when a commitment to procure each resource was made.[56] Customers are assigned to vintage years according to the date departing bundled IOU service.[57] Customers continuing to receive bundled service from the IOU are included in the latest vintage (*e.g.*, vintage 2023 in the current

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[54] D.18-10-019, pp. 82-88 (discussing negative PCIA rates in a section entitled "6.2.3.2. Should the Commission "Cap" the PCIA rate?").

[55] Cal. Pub. Util. Code § 453(c).

[56] Exh. CalCCA-01 at 7:1-17.

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

Application). Each vintage is assigned a separate Indifference Amount,[58] and customers are responsible for the cumulative PCIA rates for their vintage. [59]

PG&E's proposal would set rates differently between customer vintages. For customers in vintages with positive indifference amounts, PG&E will set rates based on the forecasted indifference amounts. For customers in vintages with negative indifference amounts, PG&E will set rates based on something less than the forecasted indifference amount. That approach creates a difference in ratesetting between customers, a difference that would exist for customers with similar load profiles in each of PG&E's rate classes. For example, one residential customer on schedule E-1 would pay the PCIA calculated in one manner, and a similar residential customer on schedule E-1 would pay the PCIA calculated in a different manner. As discussed in the following sections, there is no reasonable basis to support these differences, and therefore they violate §453(c).

Moreover, customers in SCE's service territory would benefit from negative indifference amounts and forecasted PCIA credits in a timely manner while customers in PG&E's service territory would not. SCE's October 10, 2022, updated testimony in its on-going 2023 ERRA forecast application forecasts negative indifference amounts and PCIA rate credits in 2023 for *nine* of its vintages.[60] "The updated Energy Index for 2023 is over $20/MWh higher than the actual energy value received by SCE's PABA portfolio of resources in 2022 (through August 2022). This results in negative PCIA rates for the majority of departing load vintages – *meaning SCE will record debits (instead of credits) in the PABA for most departing load customer revenue in 2023* … ."[61]

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[58] D.11-12-018, p. 9.

[59] Exh. CalCCA-01 at 7:1-17.

[60] A.22-05-014, Exh. SCE-05 at Appendix B (October 10, 2022).

[61] A.22-05-014, Exh. SCE-05 at 119:14-120:4 (October 10, 2022) (emphasis added).

No party in that case currently opposes the implementation of PCIA rate credits based on forecasted negative indifference amounts. Only PG&E opposes PCIA rate credits.

6. The Rate Floor Has No Sound Policy Basis, and is Unjust and Unreasonable.

PG&E's arbitrary rate floor violates Public Utilities Code Section 451 because it is unjust and unreasonable.[62] There simply is no good policy reason to prohibit negative PCIA rates and intentionally overcharge customers. When a negative indifference amount exists, PG&E's portfolio of resources is worth more than the costs to operate it, producing net revenues for ratepayers. PG&E's approach denies conveying the full value of this economic benefit back to customers in a timely manner. It would only pass along the forecasted net revenues necessary to earn the portion of the revenue requirement that would allow for $0/kWh PCIA rates and fail to return the rest of it. PG&E's approach would require customers in vintages with negative indifference amounts to overpay the PCIA in 2023 on the basis that actual, recorded revenues had not yet been realized.

The only policy justification Witness Klingler offers for the special treatment PG&E requests appears to be that a forecasted, negative "net market value may or may not materialize in the test-year."[63] This argument fails for numerous reasons, including the reason discussed above, *i.e.*, D.18-10-019 did not limit the implementation of negative indifference amounts to those that have materialized in a test year.

a. The Commission Sets Rates Based On a Forecast and True-Up Methodology That Undermines PG&E's Sole Justification For its Proposal.

In essence, PG&E argues that while *positive* PCIA rates should be set on a forecast basis, *negative* PCIA rates should be set on an actual basis. No policy supports this distinction. California

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[62] Cal. Pub. Util. Code § 451.

[63] Exh. PGE-03 at 8:9-10.

sets generation rates based on forecasted revenue requirements with a true-up to correct for the delta between that forecast and the actual recorded net revenues. As noted in PG&E's Application, "Section 454.5(d)(3) requires the Commission to: Ensure timely recovery of prospective procurement costs incurred pursuant to an approved procurement plan. The commission shall establish rates based on forecasts of procurement costs adopted by the commission, actual procurement costs incurred, or combination thereof, as determined by the commission. …."[64] The use of forecasted rates has the specific purpose of implementing the most accurate rates possible in a timely manner; the true-up ensures customers end up paying only what they owe.

PG&E is willing to follow this policy for PCIA charges but not credits. In response to CalCCA data request, Witness Klingler admits that the converse of PG&E's justification for its proposal is true: "PCIA *charges* based on forecast net market costs (Portfolio Cost less the Market Value of Portfolio based on the calculation from the CPUC authorized Market Price Benchmark) may not materialize in the test year," either. [65] That is, the drawback PG&E identifies in suggesting the Commission refrain from moving forward with PCIA credits—that they are based on forecasts and, therefore, may not materialize—also exists for positive indifference amounts that result in PCIA charges. PG&E's position is inconsistent: the utility has no issue implementing forecasted PCIA *charges* in a timely manner, but it is unwilling to implement forecasted PCIA *credits* in a timely manner.

Not only is it inconsistent, the true-up mechanism addresses the concern Witness Klingler identifies. The purpose of the PABA adopted in D.18-10-019 is to record the actual above market costs of PCIA-eligible resources and capture the variance between the forecasted Indifference

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[64] Application at 6-7; Cal. Pub. Util. Code § 454.5(d)(3) (emphasis added).

[65] Exh. CalCCA-02 (PG&E's response to CalCCA data request 6.01) (emphasis added).

Amount and actual recorded values.[66] This mechanism obviates the need for artificial floors on the Indifference Amount forecast.[67] As Witness Klinger states, the true-up will "ensure that any forecast-related errors in the annual PCIA are reconciled and cost-shifting is prevented."[68]

b. Arbitrary Limits on PCIA Rates Create Volatility.

The Commission found in D.21-05-030 that arbitrary limits on PCIA rates result in more harm than good. With regard to the PCIA cap, all parties agreed in 2021 "that the PCIA cap must be removed," citing concerns over "the unintended consequences of increasing rate volatility" (CalCCA and TURN) and "a material risk of continual cost-shift to bundled service customers" (the IOUs).[69] The Commission agreed with CalCCA and TURN, finding "the PCIA cap does not serve its intended purpose of reducing volatility and uncertainty."[70] PG&E's proposal would have the same unintended effect of delaying credits owed to customers, risking volatility. If wholesale prices continue to climb, or some other market or regulatory factor results in overcollecting PCIA revenue in 2023, PG&E's proposal will exacerbate the resulting rate changes.

c. The Proposal Harms Bundled and Unbundled Customers Alike.

This issue does not pit bundled customer against unbundled customer. PG&E's approach impacts any customers in vintages with a negative indifference amount. It can be felt by bundled customers as well as unbundled customers. If, in a given year, the only vintage that has a forecasted negative indifference amount is the current vintage, taking PG&E's approach would withhold rate relief *only* from bundled customers.

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66 Exh. CalCCA-01 at 30:1-30:16.

67 *Id*.

68 Exh. PGE-3 at 8, n. 14.

69 D.21-05-030, pp. 6-7.

70 *Id*. at FOF 1.

The rate floor is unjust. Because the PCIA rate cap mechanism has been discontinued, there is no longer any limit on PCIA rate increases, including increases driven by lower market prices for energy.[71] Consequently, and in the interest of fairness, there should not be a limit placed on PCIA rate decreases.[72] Such a limit only benefits PG&E and harms customers. For the numerous legal and policy reasons discussed herein, PG&E should be ordered to update its obsolete tariff. The Commission should direct PG&E to implement PCIA rates credits resulting from forecasted negative indifference amounts.

B. Scoping Issue 6: A Need Exists for the Timely Development of a REC-Tracking Framework in the PCIA Proceeding.

PG&E's proposal to apply excess 2021 and 2022 RPS credits to meet its obligations for the 2023 forecast year is not in dispute and should be approved, but, as all parties agree, only as a temporary solution for 2023.[73] Witness Shuey explains in detail the adjustments that would be made to enact PG&E's solutions,[74] and PG&E's rebuttal testimony does not take issue with those adjustments.[75] The amount of such adjustments will need to be updated in the October Update,[76] and CalCCA reserves the right to address this issue in forthcoming comments, as necessary.

The currently disputed part of this issue stems from CalCCA's recommendation that the Commission require a more permanent crediting framework for banked RECs be developed in the PCIA proceeding, R.17-06-026, to ensure all RPS energy is appropriately valued in the PCIA.[77]

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71 Exh. CalCCA-01 at 30:1-30:16.

72 *Id*.

73 *Id*. at 23:1-27:4.

74 *Id*. at 24:10-25:4.

75 Exh. PGE-3 at 24:7-9.

76 Exh. CalCCA-01 at 24:10-25:4.

77 *Id*. at 25:6-27:4.

The problem is that PG&E's proposal may not be workable going forward; indeed, PG&E acknowledges that it is only a temporary solution.[78] The viability of PG&E's proposal for 2023 hinges on the availability of excess RECs from prior years within the applicable RPS compliance period (2021 and 2022) that were already paid for by bundled customers in those years.[79] If PG&E experiences a Retained RPS shortfall in future years similar to the one it forecasts for 2023, PG&E may not have sufficient excess RECs (within the RPS compliance period) to meet its Retained RPS requirements in those years.[80] In fact, Witness Shuey's testimony demonstrates that if PG&E attempts to repeat its 2023 solution for 2024, it is likely to have insufficient banked RECs for the solution to work.[81]

The issue is pressing for two other reasons. First, the on-going implementation of the Voluntary Allocation and Market Offer process will result in the allocation of RECs to other LSEs, further impacting the degree to which PG&E could be left short of its annual RPS compliance target.[82] Second, the issue is ripe for other California utilities, as well. SCE's October Update includes a similar short-term solution for a similar issue, where currently SCE forecasts the results of the VAMO process will leave that utility short of sufficient RECs to meet its 2023 compliance obligations.[83] SCE has proposed to use recently generated, unsold RECs to meet its obligations.[84] It acknowledges further refinement of this method may be necessary for future years.[85]

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78 *Id*.

79 *Id*.

80 *Id*.

81 *Id*.

82 *Id*.

83 A.22-05-014, Exh. SCE-05 at 123:16-124:3.

84 *Id*.

85 *Id*. (calling its approach "an interim methodology that may be subject to further refinement in future years").

PG&E's rebuttal testimony does not dispute any of Witness Shuey's assertions. Instead, it takes issue with Witness Shuey recommendation that the Commission address the issue in R.17-06-026: "PG&E recognizes the merits of [CalCCA's] testimony, and does not oppose this suggestion, but views a recommendation for a going-forward proceeding to address matters related to REC tracking outside of the scope of this proceeding."[86]

This statement ignores the fact the Commission has already identified the proceeding in which the issue should be considered. The Commission stated in D.20-02-047: "Under the current PABA framework, it cannot be determined whether retired RECs in PABA were 'unsold' or 'retained for compliance.' 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."[87] The Commission need only agree with its prior direction as part of this proceeding to address the issue in a timely manner.

CalCCA therefore urges the Commission to order the development of a framework to credit banked RECs in the PCIA proceeding, R.17-06-026. Such an order should include issues such as a 'lookback' period over which the IOU can go back to use excess RECs, the quantity of excess RECs that can be used from each vintage, what to do if there are insufficient excess RECs available, the value that will be placed on the RECs, and specific methodologies for tracking excess RECs and whether they have been previously charged to customers.[88]

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86 Exh. PGE-03 at 3:1-8.

87 D.20-02-047, pp. 15-16.

88 Exh. CalCCA-01 at 25:6-27:4.

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

A. Scoping Issue 1: Issues Impacting PG&E's Revenue Requirement.

1. Reflecting the Sale of the San Francisco General Office (SFGO).

Witness Shuey recommended PG&E correct an error in the calculation used to determine the amount of annual amortization of the gain on sale of its SFGO headquarters included in the 2023 Indifference Amount.[89] He also recommended PG&E adjust the GRC revenue requirement included in the Indifference Amount because it is based on PG&E's 2020 GRC and does not reflect the SFGO sale.[90] PG&E has agreed with these recommendations,[91] and it has committed to making these adjustments in the October Update.[92]

Further, in discovery issued in lieu of hearings, PG&E clarified that it will request "the Commission authorize PG&E to remove any SFGO revenue requirement (RRQ) credit adopted" in this case "upon the implementation of the 2023 GRC in rates" to avoid double counting.[93] CalCCA supports this approach.

2. On-Peak and Off-Peak Load Weights

Witness Shuey recommended PG&E correct an error in the On-Peak and Off-Peak Load Weights used to calculate the Load Weighted Average Price used as the Energy Index MPB.[94] PG&E agreed to make this change in the October Update.[95]

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89 *Id*. at 11:9-13:19.

90 *Id*.

91 Exh. PGE-03 at 9:25-11:23.

92 *Id*. at 2:16-19. CalCCA reserves the right to address those adjustments, if necessary, in forthcoming comments.

93 Exh. CalCCA-02 (PG&E's response to CalCCA data requests 6.02-6.04)

94 Exh. CalCCA-01 at 10:4-11:8.

95 Exh. PGE-03 at 9:6-24. CalCCA reserves the right to address this adjustment, if necessary, in forthcoming comments.

3. Accounting Related to the Modified Cost Allocation Mechanism

Witness Shuey recommended PG&E update the PCIA and ERRA forecast to include the impact of procurement required for bundled customers pursuant to D.19-11-016, consistent with Commission direction in D.22-05-015.[96] His direct testimony lays out in considerable detail how doing so requires three steps: 1) determining bundled customers' share of the total procurement, 2) quantifying the cost of the contracts, and 3) identifying the capacity benefits of those contracts, *i.e.*, whether the contract capacity is used to meet PG&E's RA compliance obligations and, if so, applying the System RA Adder to compute the value of Retained RA.[97] Table 8 of his testimony illustrates the various entries required to properly transfer the net procurement costs incurred in 2022 to the 2019 PABA vintage and to reflect the corresponding accounting for Retained RA in the PABA and ERRA balancing accounts.[98]

It is disappointing PG&E's rebuttal testimony gives this issue little attention, stating no more than it "appreciates CalCCA's review of PG&E's Modified Cost Allocation Mechanism (ModCAM) testimony, and recognition that, based on its issuance date, ModCAM cost recovery matters addressed in D.22-05-015 could not be reflected in the Prepared Testimony."[99] The Commission should consider Witness Shuey's framework unopposed, adopt it as part of this proceeding, and implement updated figures based on the correct amounts in the October Update. To the extent necessary, CalCCA will address the issue further in its comments on the October Update.

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96 Exh. CalCCA-01 at 17:1-22:14.

97 *Id*.

98 *Id*.

99 Exh. PGE-03 at 2:19-22.

B. Scoping Issue 7: PCIA Financing Subaccount.

Witness Shuey recommended PG&E transfer the final year of ERRA-PFS amortization to PABA vintage 2020 consistent with Commission direction in D.22-02-002.[100] PG&E agreed to make this change in the October Update.[101]

IV. CONCLUSION

For the foregoing reasons, the CalCCA respectfully requests the Commission:

- Order PG&E to remove the obsolete and unlawful rate floor in its tariff and adopt PCIA rate credits for vintages where the forecasted, cumulative indifference amount is negative.
- Enact the procedural recommendation in D.20-02-047 to create a more permanent crediting framework for banked RECs in the PCIA rulemaking, R.17-06-026.
- Adjust PG&E's revenue requirement to address (1) the sale of PG&E's San Francisco headquarters, (2) the correct on-peak and off-peak load weights, and (3) Witness Shuey's accounting methodology to reflect PG&E's Modified Cost Allocation Mechanism procurement.
- Transfer the final year of ERRA-PFS amortization to the vintage 2020 consistent with Commission direction in D.22-02-002.
- Apply the legal standard enumerated in this Brief to the October Update.

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

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[100] Exh. CalCCA-01 at 14:1-16:21.

[101] Exh. PGE-03 at 11:24-12:2. CalCCA reserves the right to address this adjustment, if necessary, in forthcoming comments.

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

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	R.18-07-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION APPROVING VOLUNTARY ALLOCATIONS AND MODIFYING MARKET OFFER PROCESS FOR THE SALE OF EXCESS RENEWABLE RESOURCES TO LOWER POWER CHARGE INDIFFERENCE ADJUSTMENT COSTS PURSUANT TO DECISION 21-05-030

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SUBJECT MATTER INDEX

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SUMMARY OF RECOMMENDATIONS

- ✓ The permission granted in the PD for the investor-owned utilities (IOUs) to include bid floors in their respective Market Offers should be removed. The PD justifies the inclusion of bid floors on an unsupported and unproven supposition that market manipulation can occur, and on a misleading characterization of the treatment of "unsold" Renewables Portfolio Standard (RPS) resources for the purposes of calculating the PCIA.

- ✓ The Commission should ensure that Market Offer deliveries begin expeditiously, by (1) removing the requirement in the PD that the IOUs offer long-term transactions in this first Market Offer if such a requirement will cause delay in the issuance of the solicitation, (2) incorporating CalCCA's proposed schedule allowing Market Offer deliveries to begin no later than mid-February, 2023, and (3) ensuring that load-serving entities (LSEs) receive full calendar year value for 2023 even if deliveries do not begin on January 1, 2023.

- ✓ The PD should include a clarification that the "solicitation period" during which the IOUs may not hold concurrent RPS solicitations includes the period from the date of the posting through the final approval of contracts resulting from the Market Offers.

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

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	R.18-07-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION APPROVING VOLUNTARY ALLOCATIONS AND MODIFYING MARKET OFFER PROCESS FOR THE SALE OF EXCESS RENEWABLE RESOURCES TO LOWER POWER CHARGE INDIFFERENCE ADJUSTMENT COSTS PURSUANT TO DECISION 21-05-030

The California Community Choice Association (CalCCA)[1] submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Approving Voluntary Allocations and Modifying Market Offer Process for the Sale of Excess Renewable Resources to Lower Power Charge Indifference Adjustment Costs Pursuant to Decision 21-05-030* (Proposed Decision or PD), mailed on September 29, 2022.

I. INTRODUCTION

CalCCA supports the Proposed Decision's significant steps toward ensuring the Market Offer process carries out the intent of the portfolio optimization ordered in Decision (D.) 21-05-

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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 Choice 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.

030 (Phase 2 Decision).[2] Importantly, a decision on the Market Offer ensures that the second step of the Voluntary Allocation Market Offer (VAMO) process established in the Phase 2 Decision moves forward expeditiously, allowing load-serving entities (LSEs) access to the investor-owned utilities' (IOUs') excess renewable resources on behalf of their customers.

The Commission should, however, make two important modifications to the Proposed Decision. First, the PD incorrectly concludes that the IOUs are entitled to establish bid floors for the Market Offers. The PD bases its conclusion on both a fear of presumed LSE conduct that has simply not come to pass, and on a characterization of language from D.19-10-001 that may be misleading.[3] As such, the basis supporting the PD's conclusion regarding the use of bid floors by the IOUs is suspect. The IOUs should be prevented from establishing bid floors for the Market Offers, which, if used, can decrease the volume of Renewables Portfolio Standard (RPS) resources sold through the Market Offers, and in so doing, can increase the Power Charge Indifference Adjustment (PCIA). Both results will frustrate the purpose of VAMO as intended by the Phase 2 Decision.

Second, the Commission should ensure that market offer deliveries begin expeditiously by removing the requirement that the IOUs offer long-term transactions in this first Market Offer if such a requirement will cause delay in the issuance of the solicitation. Instead, CalCCA's proposed schedule allowing Market Offer deliveries to begin no later than mid-February, 2023 should be incorporated into the PD. CalCCA reiterates the significance to participants of receiving the Market Offer deliveries throughout 2023, as well as receiving the full calendar year value of the products those participants have purchased.

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2 D.21-05-030, *Phase 2 Decision on Power Charge Indifference Adjustment Cap and Portfolio Optimization,* R.17-06-026 (May 20, 2021).

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

The Commission should also clarify the PD's requirement that the IOUs not be permitted to run RPS solicitations concurrently with the "solicitation period" of the Market Offer, to avoid future confusion regarding the exact terms of the prohibition.

CalCCA therefore recommends the following modifications and clarifications to the PD, as described more fully below and as provided in Attachment A:

- ✓ The permission granted in the PD for the IOUs to include bid floors in their respective Market Offers should be removed. The PD justifies the inclusion of bid floors on an unsupported and unproven supposition that market manipulation can occur, and on a misleading characterization of the treatment of "unsold" RPS for the purposes of calculating the PCIA.
- ✓ The PD should ensure that Market Offer deliveries begin expeditiously at full calendar year value, by (1) removing the requirement that the IOUs offer long-term transactions in this first Market Offer if such a requirement will cause delay in the issuance of the solicitation, (2) incorporating CalCCA's proposed schedule allowing Market Offer deliveries to begin no later than mid-February, 2023, and (3) ensuring that LSEs receive full calendar year value for 2023 even if deliveries do not begin on January 1, 2023.
- ✓ The PD should include a clarification that the "solicitation period" during which the IOUs may not hold concurrent RPS solicitations includes the period from the date of the posting through the final approval of contracts resulting from the Market Offers.

II. FACTUAL, LEGAL, AND TECHNICAL ERRORS AND CLARIFICATIONS

A. The Justification Offered in the PD Permitting the IOUs' Use of Bid Floors Does Not Support the PD's Conclusion

Bid floors in the IOUs' Market Offers should be rejected because: (1) they would prevent the sale of RPS resources, thereby increasing the PCIA, contrary to the intent of the VAMO process established in the Phase 2 Decision; and (2) the IOUs cannot reasonably set bid floors given there is no reference market for Market Offer transactions.

Countering the arguments in CalCCA's Comments on the Market Offer Process,[4] the PD states:

[4] *See California Community Choice Association's Comments on Market Offer Process*, R.18-07-003 (June 6, 2022) (CalCCA Comments on Market Offer Process), at 4.

> We disagree with CalCCA and find [San Diego Gas & Electric Company's (SDG&E's)] and [Southern California Edison Company's (SCE's)] comments reasonable, that the RPS markets and the rules for an RPS sales framework are well established. Bid floors, should they be used, would avoid market manipulation and artificially low RPS product prices.[5]

However, SDG&E's and SCE's comments cannot reasonably be used as a basis to support the PD's conclusions regarding bid floors. According to the PD:

> SDG&E contends that a bid floor would discourage gaming of the VAMO process by requiring participants who might defer all of their procurement to the Market Offer and bid artificially low prices. SCE argues that according to D.19-10-001, retained and unsold RECs are valued at the relevant market price benchmark for the year when the RECs are used for compliance.[6]

SDG&E's concern has simply not come to pass. According to the PD itself, 27 LSEs accepted Voluntary Allocations.[7] Thus, an overwhelming majority of LSEs did not "defer all of their procurement" to game the system. The Voluntary Allocation phase of VAMO is complete; there is no reason for LSEs to bid "artificially low prices" in the Market Offers and SDG&E's fears have proved to be unfounded. Their fears therefore cannot be used as a reasonable rationale to permit bid floors in the Market Offers.

In addition, SCE's argument mischaracterizes D.19-10-001. What SCE fails to emphasize in their cite to D.19-10-001 is that the Decision requires unsold RPS to be valued at $0 <u>unless and until</u> that RPS is eventually "used for compliance" by the IOU.[8] Until such time, the IOU may continue to hold the RPS at $0. There is no requirement that this RPS be "used for compliance," and there is also no deadline by which the "banked" RPS must be used. Thus, banked Renewable Energy Credits (RECs) can be held at $0 indefinitely.

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5 PD at 23.
6 *Id.* at 22.
7 *Id.*, Attachment A.
8 D.19-10-001 at 35.

The anomaly in the treatment of "banked" RPS versus RPS "used for compliance" likely dates from the origin of the VAMO concept, in which Working Group 3 proposed all RPS remaining after the entire VAMO process be allocated to the LSEs.[9] It made sense for the proposed allocation to be on a pro-rata basis, and "at no cost."[10] The Phase 2 Decision, however, declined to require this allocation of unsold RPS, and maintained the existing method for determining that RPS's value.[11] This resulted in the current situation whereby unsold RPS can be held by the IOUs indefinitely at $0. The inequity in the treatment of "unsold" RPS will therefore be exacerbated by the use of bid floors in the Market Offers.

The likely outcome of the Market Offer process if a bid floor is adopted is that the IOUs will impute a "value" to the RPS that may exceed the actual value of that RPS to the market – *i.e.*, what participants are willing to bid in the Market Offer. Thus, some portion of RPS is likely to remain unsold. Allowing the IOUs to, in effect, deem the resources "unsold" prevents a potential reduction in the PCIA.

As CalCCA has repeatedly argued,[12] the use of bid floors in the Market Offers contradicts the purpose of the Commission's portfolio optimization efforts in the Phase 2 Decision, which is to achieve a "voluntary, market-based redistribution of excess resources" in the IOUs' supply portfolios.[13] By proposing bid floors, the IOUs will have calculated that offers below a certain price should be rejected because the "value" of the RPS to the IOU is greater than the bid floor they specify. As CalCCA has repeatedly expressed, there is no analogous established market for the products in the Market Offer. Thus, the IOUs' establishment of a bid

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9 *Final Report of Working Group 3 Co-Chairs: Southern California Edison Company, California Community Choice Association, and Commercial Energy*, R.17-06-026 (February 21, 2020), at 37.

10 *Id.*

11 Phase 2 Decision at 29.

12 CalCCA Comments on Market Offer Process at 4.

13 *See* Phase 2 Decision at 10 (citing D.18-10-019 at 3).

floor must be based on some calculation of the value of that RPS <u>to the IOU</u>. The IOUs' establishment of a bid floor therefore substitutes the IOUs' estimation of the "value" of that RPS for the true "market" value the Phase 2 Decision presumably intended to achieve. As a result, the PD's allowance of bid floors in the Market Offer should be removed as set forth in Appendix A hereto.

B. The Commission Should Ensure that Market Offer Deliveries, at Full Calendar Year Value, Begin Expeditiously

Of paramount importance to the CCAs is that the Market Offer process begin expeditiously, as proposed in both the IOUs' Market Offer filing, as well as the schedules included in Assigned Commissioner and ALJ Rulings on the VAMO process.[14] As such, CalCCA recommends that if the PD's requirement that the IOUs offer 35 percent of the remaining long-term contracts after the Voluntary Allocation results in significant delay of the Market Offer solicitation, such a requirement should be rejected for this first Market Offer. In addition, CalCCA recommends that the Commission adopt the Market Offer schedule set forth below, which is modeled after the IOUs' proposed schedule in their Market Offer filing, but

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[14] *See* R.18-07-003, *Joint Filing on Track 1 – Draft 2022 Renewables Portfolio Standard Procurement Plan – Market Offer Process* (May 20, 2022), at 12 (incorporating the IOUs' proposed Market Offer timeline for 2022); *see also* R.18-07-003, *Amended Scoping Memo and Ruling of the Assigned Commissioner* (Apr. 6, 2022), at 4 (providing a "home for administration of the VAMO issues related to the RPS program"); *Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2022 Renewables Portfolio Standard Procurement Plans and Denying Joint IOUs Motion to File Advice Letters for Market Offer* Process (Apr. 11, 2022) (requiring IOUs' proposed Market Offer Process filings by May 2, 2022); *Administrative Law Judge's Ruling Modifying the Schedule for Track 1 of the 2022 Renewables Portfolio Standard Procurement Plan*, R.18-07-003 (Apr. 21, 2022) (modifying the schedule for the VAMO filings and process); *Administrative Law Judge's Ruling Modifying the Renewables Portfolio Standard Program's Procedural Schedule to Accommodate Filing of Voluntary Allocation and Market Offer Information Adopted in Decision 21-05-030* (May 20, 2022) (May 20 ALJ Ruling) (modifying the procedural schedule for the VAMO filings and setting the schedule for the Proposed Decision and resolution of the IOUs' Tier 2 Market Offer Pro Forma Contract Advice Letters for the third quarter of 2022, and for the IOUs to commence Voluntary Allocation and Market Offer deliveries in the first quarter of 2023).

revised to reflect the date of issuance of the PD. In addition, even if the Market Offer deliveries begin after January 1, 2023, LSEs should still receive full calendar year value of the RPS resources for 2023, as set forth below.

1. The PD's Requirement of the Addition of Long-Term Transactions to the Market Offer Should Be Rejected if it Causes Delay in the Issuance of the First Market Offer Solicitation

CalCCA encourages the Commission to remove the long-term product requirement in the PD for this first Market Offer if this is necessary to ensure that the Market Offer solicitation occurs expeditiously. The PD requires the IOUs to offer 35 percent of the remaining PCIA-eligible long-term contracts after the Voluntary Allocations, despite both PG&E and SCE only offering short-term transactions in their pro forma contracts.[15] In recent discussions with CalCCA, the IOUs have informed CalCCA that the IOUs are not currently in position to move forward quickly with Market Offer solicitations if those solicitations are required to include a long-term product.

Both the IOUs and LSEs have worked to advance the VAMO process since early 2022, with several decision, rulings and resolutions issued to ensure the VAMO moves forward.[16] In addition, the May 20, 2022 ALJ Ruling acknowledges through its tight schedule the urgency of completing review and approval of the various issues, methodologies, and Advice Letters associated with VAMO to allow deliveries associated with both the Voluntary Allocation and Market Offer transactions to begin on or before January 1, 2023.[17]

CalCCA once again emphasizes the importance of early 2023 deliveries under this first Market Offer and urges the Commission to take steps necessary to expedite the Market Offers so

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15 PD at 16-19.
16 *See infra,* n. 14.
17 May 20 ALJ Ruling at 4-7.

that transactions for delivery in early 2023 can be executed and approved. Accordingly, CalCCA requests that the Commission remove the requirement in the PD that this initial Market Offer include a long-term transaction requirement if such removal will avoid delay in the initial Market Offer solicitation.

2. The PD Should Incorporate CalCCA's Proposed Market Offer Schedule Ensuring Market Offer Deliveries Begin by Mid-February 2023

Set forth below is a proposed schedule for the Market Offer process that will enable deliveries to begin mid-February 2023. Because the PD includes directives for the IOUs regarding additional and/or revised terms for their Market Offer Pro Forma contracts, CalCCA proposes the schedule below to enable the IOUs to establish the Market Offer solicitation and socialize it with LSEs. The schedule also provides the required time for participants to obtain approval of the Market Offer contracts from their respective governing boards, once notified of their accepted offer from the IOUs. The proposed schedule is similar to the timeline the Commission approved for LSEs to make their selections under the Voluntary Allocation process. Unlike the Voluntary Allocation process, however, where LSEs had only to make an allocation percentage from their own IOU, the Market Offer process now allows LSEs to not only choose a percentage but also determine an appropriate price for not one but for all three of the IOUs' Market Offer solicitations.

CalCCA proposes the schedule in the table below, which assumes the Decision is issued on November 3, 2022.

<u>CalCCA Proposed VAMO Schedule</u>:

VAMO Milestone	Date
Final Decision Proposed– MO Process	November 3, 2022
IOUs submit Revised Pro Forma Contracts via Advice Letter	Week of November 7, 2022
Commission issues Draft Resolution approving Advice Letter	Week of November 28, 2022
IOUs issue Market Offer Solicitations	Week of December 12, 2022
IOUs hold Participants' Webinar	Week of December 12, 2023
Market Offer Bids Due	December 28, 2022
IOUs Notify Participants of Bids Selected	January 6, 2022
IOUs Provide Selected Participants with Agreements for Execution	No Later than January 13, 2023
Market Offer Deliveries Commence	February 10, 2023

3. The PD Should Ensure That LSEs Receive Full Value for Their 2023 Market Offer Purchases

Under the Market Offer process, LSEs will bid on (and if successful receive) a percentage of available RPS resources. Even if the Market Offer deliveries do not begin on January 1, 2023 as previously planned, LSEs should still receive the full percentage value based on the full calendar year of available resources. In other words, the Market Offer should not pro-rate the percentages based on a start date <u>after</u> January 1, 2023. If such a pro-ration occurs LSEs will not have received the full value of the RPS they intended to purchase.

There are several ways to ensure that LSEs receive the full calendar year value of the RPS resources. The PD can allow LSEs to choose different percentages for each year (2023 and 2024), to recognize that the 2023 resources will likely not be available for the full year. Or, the PD could keep the same percentage factor but require the IOUs to fulfill this obligation (based on a full year's allocation) over the remaining ten to eleven months of 2023. Neither of these proposed solutions appears problematic to implement, provided the Market Offer is not oversubscribed (e.g., LSEs request to purchase more RPS resources than are available in the remaining eleven months).

C. The PD Should Clarify the Length of the "Solicitation Period" During Which the IOUs May Not Hold Concurrent RPS Solicitations

The PD correctly prohibits the IOUs from holding RPS solicitations concurrently with the Market Offer.[18] CalCCA respectfully requests a minor clarification to define specifically the "solicitation period" for these purposes. CalCCA requests this "solicitation period" include the date the solicitation is posted by the IOU through and including the date the final executed agreement under that solicitation is formally approved by the Commission. If instead, the "solicitation period" is defined as encompassing the entire delivery period (January 2023 through December 2024), this would preclude the possibility of further IOU RPS solicitations during that time if RPS resources still remained available after both the Voluntary Allocation and Market Offer process.

III. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and requests adoption of the recommendations proposed herein. For all the foregoing reasons, the Commission should modify the Proposed Decision as provided in Attachment A.

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[18] *See* PD, Conclusion of Law 10, at 36, and Ordering Paragraph 9, at 39.

Respectfully submitted,

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ATTACHMENT A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION APPROVING VOLUNTARY ALLOCATIONS AND MODIFYING MARKET OFFER PROCESS FOR THE SALE OF EXCESS RENEWABLE RESOURCES TO LOWER POWER CHARGE INDIFFERENCE ADJUSTMENT COSTS PURSUANT TO DECISION 21-05-030

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

FINDINGS OF FACT

27. The rules for an RPS solicitations protocols/ framework are well established. Notwithstanding the practice in previous RPS solicitations, the Market Offer is unique and ~~no~~ IOUs may not set bid floors~~to avoid market manipulation~~.

CONCLUSIONS OF LAW

~~5. If SCE uses bid floors it should follow the bid floor methodology approved in D.21-01-005 for its 2021 RPS Plan.~~

11. It is reasonable to not allow concurrent solicitations of similar RECs under VAMO and non-VAMO processes for the same solicitation period, which shall be defined as the period from the date the solicitation is posted through and including the date the final executed agreement under the solicitation is formally approved.

ORDERING PARAGRAPHS

4~~. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall offer 35 percent of the remaining Power Charge Indifference Adjustment eligible long-term contracts in the Market Offer~~.

9. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each not conduct concurrent non-Market Offer solicitations for similar Renewables Portfolio Standard products during the same solicitation period, which shall be defined as the period from the date the solicitation is posted through and including the date the final executed agreement under the solicitation is formally approved.

12. ~~Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall update their proposed timeline for the Market Offer process~~. The following timeline for the Market Offer process is adopted:

VAMO Milestone	Date
IOUs submit Revised Pro Forma Contracts via Advice Letter	Week of November 7, 2022
Commission issues Draft Resolution approving Advice Letter	Week of November 28, 2022
IOUs hold Participants' Webinar	Week of December 12, 2023
Market Offer Bids Due	December 28, 2022
IOUs Notify Participants of Bids Selected	January 6, 2022
IOUs Provide Selected Participants with Agreements for Execution	No Later than January 13, 2023
Market Offer Deliveries Commence	February 10, 2023