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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

OPENING COMMENTS ON THE PROPOSED DECISION OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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On behalf of
California Community Choice Association

December 5, 2022

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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

OPENING COMMENTS ON THE PROPOSED DECISION OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

I. INTRODUCTION

The California Community Choice Association[1] (CalCCA) submits these comments on the *Proposed Decision Adopting the Electric Revenue Requirements and Rates Associated with the 2023 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation and the 2023 Electric Sales Forecast for Pacific Gas and Electric Company* (PG&E) (PD) pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission and the procedural schedule established in the Assigned Commissioner's August 4, 2022 Scoping Memo and Ruling.[2]

[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, CleanPower SF, 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.
[2] Application (A.) 22-05-029, Assigned Commissioner's Scoping Memo and Ruling (Aug. 4, 2022).

As CalCCA explained in its testimony and briefs submitted in this proceeding,[3] Power Charge Indifference Adjustment (PCIA) rates include two components: the first based on the cumulative forecasted "Indifference Amount"[4] for the relevant customer vintage in the test year; and the second based on the year-end balance in the Portfolio Allocation Balancing Account (PABA) for the current year. While PG&E allows the second component of PCIA rates (the "true-up"[5]) to fall below zero (where the year-end PABA balance reflects an actual negative Indifference Amount), PG&E refuses to implement a PCIA rate credit where it forecasts a negative cumulative forecasted Indifference Amount for a given vintage in the test year.[6] The PD, while correctly rejecting PG&E's proposal to apply a rate floor in the PCIA,[7] misses this nuance. In doing so, it creates confusion over exactly what it requires PG&E to do.

CalCCA therefore requests that the Commission clarify that PG&E (1) must not apply a rate floor to the <u>cumulative forecast Indifference Amount</u>, and (2) must implement PCIA rate credits resulting in payments to customers if their total PCIA rate, inclusive of the true-up, is negative. CalCCA also requests that the Commission include findings, conclusions, and ordering paragraphs directing the development of a crediting framework for banked renewable energy credits (REC) in the PCIA rulemaking (R.17-06-026) consistent with the parties' agreement on this issue.

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[3] Exh. CalCCA-01 at 7:15-18:5; CalCCA Opening Br. at 9.
[4] The "Indifference Amount" is the difference between the cost of the utility's supply portfolio and the market value of that portfolio. The utility's Indifference Amount is updated annually in each utility's ERRA Forecast proceeding and is the basis for PCIA rates. Exh. CalCCA-01 at 5:3-6.
[5] The PABA—which the Commission created in D.18-01-019—is 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 (related to its PCIA-eligible resource portfolio) during the current year.
[6] Exh. CalCCA-01 at 29:13-22; CalCCA Opening Br. at 12-13.
[7] PD at 25, OP6.

II. COMMENTS

A. The PD Correctly Rejects PG&E's Proposed PCIA Rate Floor, but the Order Should Clarify that PG&E is Directed to Implement PCIA Rate Credits for all Vintages With Cumulative Forecasted Negative Indifference Amounts.

Where the cumulative forecasted Indifference Amount for a given customer vintage is negative in the test year, PG&E proposes to implement a "floor" for that vintage and artificially set the rate for that component of PCIA rates to zero.[8] Under PG&E's imbalanced approach, a customer would only receive a PCIA payment (credit, rather than a charge) if a negative Indifference Amount *actually* accrues to PABA by the end of the year, but would not receive a payment where the *forecast* Indifference Amount is negative.

CalCCA explained that PG&E's approach is flawed for several reasons—among them, that it violates Decision (D.)18-10-019 (which eliminated all PCIA rate limits and specifically made clear that customers should receive rate credits when the Indifference Amount is negative[9]); violates Public Utilities Code § 453(c)'s prohibition against unreasonable differences in charges; and is unjust and unreasonable in violation of Public Utilities Code § 451.[10] Importantly, CalCCA explained that PG&E's proposal is not even-handed, and violates the Commission's indifference framework by implementing forecasted PCIA *charges* in a timely manner, but failing to implement forecasted PCIA *credits* in a timely manner.[11] CalCCA further observed that the true-up mechanism created by D.18-01-019 protects PG&E in the event that a forecasted negative Indifference Amount does not actually materialize.[12]

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[8] Exh. CalCCA-01 at 29:17-22; CalCCA Opening Br. at 12-13.
[9] D.18-10-019 at 88; FOF 20 at 155; COL 21 at 158.
[10] *See* CalCCA Opening Br. at 3-20; CalCCA Reply Br. at 2-8.
[11] CalCCA Opening Br. at 18.
[12] *Id*. at 18-19.

The PD thoughtfully analyzes this issue. It weighs both PG&E's as well as bundled and unbundled customers' interests and correctly identifies the fundamental question underlying the issue: "Should PG&E now have to pay customers based on a forecast, just as previously the customers had to pay based on a forecast?"[13] Having considered that question, the PD correctly finds that the current ERRA ratesetting mechanisms "fully protect PG&E and ensure its recovery of reasonable costs" and observes that "PG&E should be financially indifferent to having or not having a floor."[14]

The PD errs, however, where it describes PG&E's proposal as a "rate floor for the [PCIA] rate."[15] That characterization misses an important nuance: PG&E proposes to implement a rate floor for the component of PCIA rates that reflects the cumulative forecasted Indifference Amount, but does not implement a rate floor for the "true-up" component or for PCIA rates as a whole. In other words, PG&E agreed, at least in theory, to apply PCIA rate credits to customer bills if the true-up component of PCIA rates falls below zero, but refused to do so where the cumulative forecast Indifference Amount for a given customer vintage falls below zero. *This* practice—implementing a floor on the forecast—violates prior Commission decisions, statute, and sound policy. The Commission correctly recognized this nuance in Southern California Edison's (SCE) 2023 ERRA Forecast case, where it states: "SCE's generation portfolio is "below market" for 2023, which requires a PCIA credit on departed load customers' bills . . ."[16]

CalCCA requests that the Commission reflect this subtle distinction in its Order to avoid any confusion over exactly what the Commission requires PG&E to do going forward.

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[13] *Id*. at 18.
[14] *Id*. at 18-19.
[15] *Id*. at 16; 25, OP6.
[16] A.22-05-014 et al., *Application of Southern California Edison Company (U338E) For Approval of its 2023 ERRA Forecast Proceeding Revenue Requirement*, D.22-12-012 at 54.

CalCCA's specific requested modifications to the findings of fact, conclusions of law, and ordering paragraphs in the PD are listed in Appendix A to these comments.

B. The Order Should Direct the Development of a Crediting Framework for Banked Renewable Energy Credits in the Power Charge Indifference Adjustment Rulemaking, Which No Party Opposes.

In this proceeding, PG&E proposed to apply excess 2021 and 2022 Renewable Portfolio Standard credits (Renewable Energy Credits or RECs) to meet its obligations for the 2023 forecast year.[17] CalCCA did not dispute PG&E's proposal, but all parties agreed that PG&E's proposal should only be approved as a temporary solution for 2023.[18] CalCCA however recommended that the Commission require a more permanent framework to credit banked RECs in the PCIA rulemaking, R.17-06-026 in order to ensure that all RPS energy is appropriately valued in the PCIA.[19] PG&E agreed with CalCCA's recommendation in its reply brief[20] and no other party addressed this issue.

The PD notes the parties' agreement that the Commission should order the development of a crediting framework for banked RECs in the PCIA rulemaking.[21] But the PD stops short of actually ordering the development of such a framework. In the interest of clarity, CalCCA requests that the final Order include findings, conclusions and ordering paragraphs directing the development of such a framework, as listed in Appendix A to these comments.

C. Technical Corrections

CalCCA offers two technical corrections to the PD, both related to the order of magnitude of certain line items in PG&E's authorized revenue requirement:

[17] Exh. PGE-01 at 11-13 – 11-21.
[18] CalCCA Opening Br. at 20.
[19] Exh. CalCCA-01 at 24:10-25:4; CalCCA Opening Br. at 20.
[20] PG&E Reply Br. at 14-15.
[21] PD at 20.

- Ordering Paragraph 1.k) states that PG&E is authorized to recover Utility-Owned Generation (UOG) costs of ($2,349,491). The correct value for UOG costs is ($2,349,491,000).[22]

- Ordering Paragraph 1.l) states that PG&E is authorized to recover an ERRA – PFS balance of $82,790. The correct value for the ERRA – PFS balance is $82,790,000.[23]

III. CONCLUSION

CalCCA appreciates the Administrative Law Judge's efforts in resolving the complex issues in this proceeding and respectfully requests that the Commission adopt the revisions discussed in these comments and detailed in Appendix A.

Respectfully submitted,

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December 5, 2022

[22] *See id*. at 6 (summarizing PG&E's 2023 ERRA Revenue Requirement request).
[23] *See id*. (summarizing PG&E's 2023 ERRA Revenue Requirement request).

APPENDIX A

Pursuant to Rule 14.3(b) of the Commission's Rules of Practice and Procedure, CalCCA provides this Appendix setting forth proposed changes to the *Proposed Decision Adopting the Electric Revenue Requirements and Rates Associated with the 2023 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation and the 2023 Electric Sales Forecast for Pacific Gas and Electric Company*, including proposed changes to the findings of fact, conclusions of law and ordering paragraphs. CalCCA's proposed revisions appear in underline and strike-through.

Findings of Fact

- Modify Finding of Fact 8 as follows: "For 2023, PG&E forecasts that the ~~PCIA rate~~ cumulative forecasted indifference amount for some vintages of customers will be negative."
- Modify Finding of Fact 10 as follows: "Current market conditions may reverse in the future, and the negative ~~PCIA rate~~ cumulative forecasted indifference amount for some PG&E customers may become positive."
- Add following Findings of Fact:
    - o If PG&E experiences a Renewable Energy Certificate 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 requirement in those years.
    - o The Commission has previously stated that under the current PABA framework, it cannot be determined whether retired RECs in PABA were unsold or retained for compliance.
    - o A crediting framework within PABA and mechanisms to value banked RECs at the end of the compliance period will help ensure that all RPS energy is appropriate valued in the PCIA.

Conclusions of Law

- Add the following Conclusion of Law: "Pacific Gas and Electric Company should implement PCIA rate credits for those vintages of customers with negative cumulative forecast indifference amounts."
- Add the following Conclusions of Law: "The Commission should direct the development of a framework to credit banked RECs in the PCIA rulemaking, R.17-06-026**.**"

Ordering Paragraphs

- Modify Ordering Paragraph 1.k) as follows: "The Utility-Owned Generation – Related Costs of ~~($2,349,491)~~ ($2,349,491,000)."
- Modify Ordering Paragraph 1.l) as follows: "The ERRA – PFS of ~~$82,790~~ $82,790,000."
- Modify Ordering Paragraph 6 as follows: "Pacific Gas and Electric Company's proposal to implement a rate floor for the cumulative forecasted indifference amount component of the Power Charge Indifference Adjustment rate is denied. Pacific Gas and Electric

Company is directed to implement PCIA rate credits for those vintages of customers with negative cumulative forecasted indifference amounts."

- Add the following Ordering Paragraph: "The Commission shall develop a framework to credit banked RECs in the PCIA proceeding, R.17-06-026."

**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

REPLY COMMENTS ON THE PROPOSED DECISION OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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On behalf of
California Community Choice Association

December 8, 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. (U39E).	Application 22-05-029

REPLY COMMENTS ON THE PROPOSED DECISION OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

The California Community Choice Association[1] (CalCCA) submits these reply comments on the Proposed Decision[2] in the above-captioned proceeding pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission and the procedural schedule established in Commissioner Reynolds's August 4, 2022 Scoping Memo and Ruling.[3]

Pacific Gas and Electric Company's (PG&E) opening comments on the PD offer nothing new in support of its unreasonable proposal to set a "floor" on the cumulative forecasted Indifference Amount component of Power Charge Indifference Adjustment (PCIA) rates. Instead, PG&E recycles several arguments from its opening and reply briefs in opposition to the well-reasoned PD, which rejects PG&E's rate proposal. As CalCCA has now explained three times in this proceeding (in its opening brief,[4] reply brief,[5] and comments on the Fall Update[6]), PG&E's

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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, CleanPower SF, 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.

[2] Application (A.) 22-05-029, Proposed Decision Adopting the Electric Revenue Requirements and Rates Associated with the 2023 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation and the 2023 Electric Sales Forecast for Pacific Gas and Electric Company (Nov. 28, 2022) (PD).

[3] A.22-05-029, Assigned Commissioner's Scoping Memo and Ruling (Aug. 4, 2022).

[4] CalCCA Opening Br. at 8-20.

[5] CalCCA Reply Br. at 4-8.

[6] CalCCA Opening Comments on Fall Update at 3-4.

proposed floor on cumulative forecasted Indifference Amounts is obsolete, unlawful and unjust, and would shift forecast risk from the utility to its customers—both bundled and unbundled. As the PD correctly recognizes, the current ERRA ratesetting mechanisms fully protect PG&E and ensure its recovery of reasonable costs and an artificial rate floor is therefore neither necessary nor warranted.[7] PG&E cannot and does not point to any record evidence requiring the Commission to modify that conclusion. PG&E's hand-wringing about "suffer[ing] inadequate revenues to pay for the costs of its generation portfolio" is a risk associated with forecasts in any year; it is nothing new (and it is mitigated by the true-up). The Commission should reject PG&E's invitation to second-guess the forecast and adjust PCIA rates to guarantee PG&E extra liquidity when that forecast should result in PCIA payments. It should reject PG&E's continued defense of its unreasonable rate floor proposal and adopt the PD with the modifications described in CalCCA's opening comments.

I. THE TRUE-UP LEAVES PG&E FINANCIALLY INDIFFERENT TO RATE CREDITS; IF SUFFICIENT RECORD EVIDENCE TO THE CONTRARY EXISTED, PG&E SHOULD BEAR THAT RISK—NOT CUSTOMERS.

Following the reforms to the PCIA in D.18-10-019, PCIA rates are set based on an annual forecast followed by a true-up to actual costs the following year. The PD correctly observes that under that ratesetting mechanism, "[c]ustomers will see the effect of the sales forecast now as they have done in prior years, and in subsequent proceedings customers will see the appropriate adjustments for actual costs just as they have done in prior years."[8] The PD concludes that PG&E is therefore "financially protected by the existing ERRA rate recovery mechanisms" because where the forecast deviates from actual costs or revenues, the annual true-up makes PG&E and its customers whole. As PG&E's own witness stated on the record: the true-up will "ensure that any forecast-related errors in the annual PCIA are reconciled …."[9]

PG&E nevertheless continues to insist the PCIA framework should only provide PG&E the opportunity to recover forecast costs, and should not provide its customers the opportunity to receive the benefit of forecast revenues. But PG&E does not provide any new arguments in support of its fundamentally imbalanced and utility-friendly proposal. Instead, it misleadingly points to the levels of load departure in its service territory in support of the proposition that negative PCIA

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7 PD at 3; 19; FOF 11 at 22, FOF 12 at 22; COL 8 at 22; OP 6 at 25.
8 *Id*. at 19.
9 Exh. PGE-3 at 8, n. 14.

rates would "place[] significant strain on PG&E in the event that forecasted conditions do not materialize."[10] The level of load departure in PG&E's service territory, however, is not relevant to the Commission's determination of this issue. Both bundled and unbundled customers pay PCIA rates; *both bundled and unbundled customers* had forecasted negative Indifference Amounts at one time in this proceeding that would have entitled them to receive rate credits for 2023 had those market conditions persisted. Conditions may result in the future where only bundled customers have forecasted negative Indifference Amounts. The Commission should not be distracted by PG&E's hand-waving: the utility's proposed floor on cumulative forecast Indifference Amounts harms both bundled and unbundled customers, and the existence of neither group creates more risk for PG&E.

PG&E also asserts "there is no evidence in the record to support PG&E's 'indifference' to a scenario where its balancing account revenues are insufficient to cover the costs of the procurement portfolio."[11] As the applicant, however, PG&E has the burden of affirmatively establishing the reasonableness of all aspects of its application,[12] and that burden of proof generally is measured based upon a preponderance of the evidence.[13] PG&E had ample opportunity to introduce evidence demonstrating the risk of adverse financial impacts to the utility absent a rate floor and to subject that evidence to examination by the parties. It chose not do so.[14]

Now, in its comments on the PD (to which parties have three days to respond and no reasonable opportunity for discovery or further record development), PG&E raises new, conclusory arguments rhetorically contrasting "the financial reality of PG&E's actual financing

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[10] PG&E Comments on the PD at 5.

[11] *Id*. at 3.

[12] Rulemaking (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 (Dec. 28, 2012) (D.12-12-030).

[13] *See, e.g.,* A.17-06-005, *Decision Adopting Pacific Gas and Electric Company's 2018 Energy Resource Recovery Account Forecast and Generation Non-Bypassable Charges and Greenhouse Gas Forecast Revenue and Reconciliation,* pp. 9-10 (Jan. 16, 2018) (D.18-01-009); R.11-02-019, Order Modifying Decision (D.) 12-12-030 and Denying Rehearing, as Modified, p. 29 (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.").

[14] A.20-05-029, *California Community Choice Association's Opening Brief*, pp. 13-19 (Oct. 14, 2022); A.20-05-029, *California Community Choice Association's Reply Brief*, pp. 5-8 (Oct. 14, 2022) (both discussing the lack of record evidence to support the factual contentions in both PG&E's testimony and briefs; PG&E's Witness focused solely on the language in D.18-10-019).

costs" to the rate provided for through PG&E's balancing account.[15] PG&E asserts based on that comparison that the utility would *not* be financially indifferent to having or not having a rate floor.[16] But PG&E does not and cannot point to any record evidence demonstrating that payments to customers based on a forecast, and a true-up of those payments the subsequent year, would in fact pose any risk of financial harm to the utility.

The Commission should reject PG&E's baseless eleventh-hour criticism of the ERRA ratesetting mechanisms and adopt the PD's conclusion.[17] The PD correctly finds that the current ERRA ratesetting mechanisms—which, following D.18-10-019, include an annual true-up—"fully protect PG&E and ensure its recovery of reasonable costs, including financing costs[.]"[18] On that basis, the PD correctly concludes that PG&E "should be financially indifferent to having or not having a rate floor."[19]

Even if the Commission relied on extra-record evidence to determine the utility was not financially indifferent, the utility should not be allowed to overcharge customers in the name of forecast risk. PG&E points to "extremely volatile electricity market conditions" to suggest that its forecasted market revenues may not materialize,[20] but the Commission may not second-guess the forecast just because it results in PCIA payments to customers. Nor may the Commission adjust PCIA rates simply to bolster PG&E's liquidity. Doing so would set bad precedent and undermine the fundamental ERRA ratesetting mechanism, which establishes just and reasonable rates that *rely* on an annual forecast. Further, by requiring its bundled and unbundled customers to make

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[15] PG&E Comments on the PD at 3-4.

[16] *Id*.

[17] The Scoping Ruling categorized this proceeding as ratesetting. Scoping Ruling at 6. The Commission has previously determined that Section 1757 of the Public Utilities Code applies to ratesetting, 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.[17] Cal. Pub. Util. Code § 1757; *see, e.g.*, D.20-05-027, p. 6; *see also, 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.").

[18] PD at 19.

[19] *Id*.

[20] CalCCA notes that while PG&E forecasts significant market revenues from its PCIA portfolio in 2023, it is far from clear that those revenues *will not* materialize as PG&E suggests (ie, that actual market prices will be lower rather than higher than forecast). Indeed, actual market prices were higher than PG&E's forecast **this year**.

payments based on a forecast, but refusing to pay those customers based on the same forecast, PG&E simply seeks to shift any forecast risk that might exist away from the utility and onto its customers. Contrary to PG&E's comments, therefore, those customers *are* harmed by PG&E's proposal to force those customers to wait for payments until PG&E records actual revenues, but make payments before PG&E records actual costs. The Commission should reject PG&E's utility-centric, anti-customer approach and adopt the PD's directive that PG&E flow through the PCIA adjustment whether positive or negative to all bundled and departed customers.

II. THE COMMISSION RECENTLY APPROVED PCIA PAYMENTS FOR CUSTOMER VINTAGES WITH A NEGATIVE CUMULATIVE FORECAST INDIFFERENCE AMOUNT AND SHOULD DO SO AGAIN HERE.

PG&E incorrectly asserts that Commission precedent supports its proposal to implement a rate floor to the cumulative forecast Indifference Amount.[21] Further, Commission precedent on PCIA rates has not been limited to addressing the utility's cost recovery, to the exclusion of payments to customers, as PG&E claims.[22] D.18-10-019 specifically states that "the PCIA rate should be able to go negative and should credit departing customers when IOU portfolio value exceeds costs."[23] More recently, the Commission's decision in Southern California Edison's 2023 ERRA Forecast proceeding notes that "SCE's generation portfolio is "below market" for 2023, which requires a PCIA credit on departed load customers' bills . . ."[24] The PD's rejection of PG&E's PCIA rate floor, therefore, is entirely consistent with Commission precedent. The Commission should therefore adopt the PD with CalCCA's limited recommended modifications.

III. CONCLUSION

For the reasons described in CalCCA's comments on the PD and in these reply comments, CalCCA continues to respectfully request the Commission adopt the PD with the modifications described in the Appendix to CalCCA's opening comments.

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21 PG&E Comments on the PD at 6.

22 *Id*.

23 D.18-10-019 at 88; FOF 20 at 155; COL 21 at 158.

24 A.22-05-14 *et al.*, Application of Southern California Edison (U338E) For Approval of its 2023 ERRA Forecast Proceeding Revenue Requirement, D.22-12-012 at 54.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	Rulemaking 18-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING RELATING TO THE PHASE 2 WORKSHOP IN OCTOBER 2022

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December 9, 2022

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SUMMARY OF RECOMMENDATIONS

CalCCA recommends that the Commission:

- Order the conclusion of automatic enrollment in long-term payment plans, and instead determine in this proceeding the most effective customer engagement to tailor payment plans to individual customer needs;
- Modify the Arrearage Management Plan (AMP) to better serve struggling customers by: (1) allowing payments of 50 percent or more of the monthly amount due to qualify as an "on time payment" for two months out of the 12-month period; (2) providing the option of a "sliding scale" in which payment amounts ramp up over the 12-month period to encourage customers to gradually increase their monthly obligations; (3) reducing the "waiting period" for re-enrollment in AMP from 12 to six months; and (4) allowing customers removed from AMP for system/automation issues that are not the fault of the customer to be immediately re-enrolled;
- Make permanent the proportional allocation between investor-owned utilities (IOUs) and community choice aggregators (CCAs) of any payments made on past-due bills, currently set to expire in September 2024; and
- Require the IOUs to place alerts on CCA customer accounts regarding customer participation in the Community Based Organization (CBO) Arrears Case Management Pilot (CBO Pilot), including any communications between the CBOs, IOUs and the CCA customer, to provide CCAs with insight into CCA customer participation in the CBO Pilot.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	Rulemaking 18-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING RELATING TO THE PHASE 2 WORKSHOP IN OCTOBER 2022

The California Community Choice Association[1] (CalCCA) submits these Comments in response to the *Administrative Law Judge's Ruling Relating to the Phase 2 Workshop in October 2022* (Ruling)*,* issued November 10, 2022, requesting party comments on questions in sections 4 and 5 of the Ruling.

I. INTRODUCTION

CalCCA appreciates the Ruling's thoughtful questions for both investor-owned utilities (IOUs) and other parties following the October 17, 2022 workshop in this proceeding on "Managing Customer Arrearages and Disconnections Amid Rising Rates" (Workshop). Presentations and discussion at the Workshop, as well as party Comments on the Phase 2

[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.

Scoping Memo and Ruling,[2] demonstrate the complexities of preventing disconnections amidst the economic fallout from the Covid pandemic and likely underutilized web of programs available for assistance. As the California Public Utilities Commission (Commission) gears up to add two additional customer assistance programs – the Percentage of Income Payment Program pilot (PIPP pilot) and the Community-Based Organization (CBO) Arrears Case Management pilot (CBO Pilot) – a focus on ensuring customer clarity on all available programs is critical for effective arrearage reduction and disconnection prevention. This is especially the case given distribution of the California Arrearage Payment Program (CAPP) funds is concluding, and arrearages from before, during, and after the pandemic remain, placing customers at risk.

The following provides CalCCA's responses to the "Questions for Party Comments" in the Ruling, with overall recommendations for the Commission to:

- Order the conclusion of automatic enrollment in long-term payment plans (LTPPs), and instead determine in this proceeding the most effective customer engagement to tailor payment plans to individual customer needs;
- Modify the Arrearage Management Plan (AMP) to better serve struggling customers by: (1) allowing payments of 50 percent or more of the monthly amount due to qualify as an "on time payment" for two months out of the 12-month period; (2) providing the option of a "sliding scale" in which payment amounts ramp up over the 12-month period to encourage customers to gradually increase their monthly obligations; (3) reducing the "waiting period" for re-enrollment in AMP from 12 to six months; and (4) allowing customers removed from AMP for system/automation issues that are not the fault of the customer to be immediately re-enrolled;
- Make permanent the proportional allocation between IOUs and community choice aggregators (CCAs) of any payments made on past-due bills, currently set to expire in September 2024; and
- Require the IOUs to place alerts on CCA customer accounts regarding customer participation in the CBO Pilot, including any communications between CBOs, IOUs and the CCA customer, to provide CCAs with insight into CCA customer participation in the CBO Pilot.

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[2] R.18-07-005, *Assigned Commissioner's Phase 2 Scoping Memo and Ruling* (Scoping Ruling) (July 15, 2022).

II. CALCCA RESPONSES TO RULING QUESTIONS ON PAYMENT PLANS

1. Some workshop participants raised concerns about automatic enrollment in long-term payment plans causing confusion for participants. Is automatic enrollment inherently problematic, or is it a matter of how much ME&O is paired with automatic enrollment?

The Commission should order the conclusion of any automatic enrollment in LTPPs, while at the same time increasing customer communications and engagement to ensure customers in need are enrolled in payment plans tailored to their needs. The current automatic enrollment in LTPPs is problematic as it: (1) causes customer confusion due to unexplained higher bills; (2) increases the risk that a customer is unfairly unenrolled from a payment plan for non-payment despite their not having knowledge of enrollment in the payment plan in the first place, or non-payment for systems issues such as failed automatic payments; and (3) increases financial risks for load-serving entities (LSEs) given customers financially able to pay an arrearage may only pay what is required under the payment plan and therefore cash flow to LSEs is unnecessarily delayed. Instead of auto-enrollment, the Commission should order increased Marketing, Education, and Outreach (ME&O) paired with robust customer service to establish payment programs tailored to the needs of individual customers.

CCAs have found auto-enrollment to be ineffective with their customers, causing confusion and setting customers up to be ineligible for payment plans when they are unknowingly dropped from a plan for nonpayment. CCAs have found that customers are confused about automatic higher bills after being automatically enrolled in a LTPP. Customers have also contacted CCAs who unknowingly were removed from a payment plan because their automatic payment from their bank was not acknowledged by an IOU billing system. Finally, other customers who are financially able to pay their entire bill plus any past due amounts may unknowingly be auto-enrolled in a LTPP with an amortized payment schedule for the debt. The

LSE in that case does not receive past due payments at the time it would normally receive them had the customer not been auto-enrolled, impacting cash flow for the LSE.

Instead of auto-enrollment, the Commission has an opportunity to order effective ME&O and customer engagement to ensure all customers have access to payment plans tailored to their situation. Through the data requested in the Ruling, as well as the information gathered through the Meet and Confer ordered by the Ruling, a better understanding of the most effective customer communication to tailor different payment plans for particular customers and prevent disconnection can be obtained. The Commission should further identify the best forms of communication to engage and educate customers of their eligibility for existing programs that meet their needs.

2. A workshop participant asserted that AMP is best for customers who can afford to pay their bills, and the underlying problem is that many AMP-eligible customers can't afford to pay their bills. Could the design of AMP be modified to better serve customers who can't afford to pay their bills? Or should utilities not recommend AMP for certain types of customers?

The AMP design can be immediately modified to better serve customers who struggle to remain current on their bills. Successful completion of the AMP program requires staying current on bills during the 12-month program (with the allowance of up to two sequential, or three non-sequential, missed payments, as long as the customer makes up the payment on the next bill due date). While some customers may be better suited for a different payment plan based on their inability to comply with the AMP rules, CalCCA previously proposed two AMP modifications to assist some customers who are narrowly missing payments and therefore not successfully completing the AMP program.[3]

[3] *See* R.18-07-005, *California Community Choice Association's Comments on Assigned Commissioner's Phase 2 Scoping Memo and Ruling* (Aug. 5, 2022), at 4-7.

First, payments of 50 percent or more of a monthly amount due should qualify as an "on-time payment," but for no more than two months of the 12-month AMP period.[4] A customer may not always be able to pay the full monthly amount, which under the current rules results in a "non-payment." As stated above, current rules allow the customer to remain in the AMP program for only two consecutive or three non-consecutive months of "non-payment." As a "non-payment," the customer is not eligible for debt forgiveness in that month. Allowing the 50 percent or more payment to qualify as an "on-time payment" allows the customer to receive its 1/12th debt forgiveness for that month, and allows the customer to utilize this opportunity twice during the AMP period. Any additional arrearage created would not be added to the debt being forgiven, and would not be eligible for future AMP forgiveness, to incentive customers to remain current.

Adding the ability to receive AMP debt forgiveness for partial (50 percent or more) payment adds a layer of protection and time for struggling customers that will further enhance their ability to complete the AMP program and receive full debt forgiveness. As an example, a customer enrolled in AMP with $1,200 in debt would be eligible to pay 50 percent of their current bill twice during the 12-month period, and in those months still get the 1/12 debt forgiveness (*i.e.*, $100) in each of those months because the 50 percent or more payment would be considered on-time. After using the two chances to only partially pay, if a customer misses, is late, or only partially pays a monthly amount due, the existing AMP rules will subject the customer to a "non-payment" which is only allowed twice consecutively or three times non-consecutively before a customer falls out of the program. The change proposed therefore

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4 *Id.* at 6-7.

provides additional opportunities for customers to remain enrolled in AMP, and hopefully finish the program to ensure full debt forgiveness.

Second, the Commission should allow a "sliding scale" in which payments ramp up over the 12-month AMP period to encourage customers to gradually increase their monthly obligations.[5]

Both of these proposed modifications can provide some additional assistance to those customers currently falling out of AMP for narrowly missing their payments, without removing the payment incentives built into the AMP program.

3. In light of COVID and CAPP payment impacts on arrearages and disconnections, should the Commission wait before making changes to the AMP and/or COVID Long-Term Payment Plans? Or should the Commission modify these programs soon to ensure that these programs serve customers at risk of disconnection?

The Commission should modify AMP now to ensure customers can realize full arrearage forgiveness under the program. In addition to CalCCA's proposed modifications discussed in response to question 2., above, the Commission should also make the following modifications to the AMP program to ensure its success for struggling customers: (1) reduce the "waiting period" for re-enrollment in AMP from 12 to six months; and (2) allow customers removed from AMP as a result of IOU system/automation issues that are not the fault of the customer to be immediately reenrolled in AMP. In addition, the Commission should conclude any auto-enrollment in LTPPs, as set forth in response to question 1., above. Finally, the Commission should make permanent the proportional allocation between IOUs and CCAs of any customer payments made on past-due bills, currently set to expire in September 2024.

First, the Commission should reduce the "waiting period" for re-enrollment in AMP from 12 to six months for both customers that drop out of, and for customers that successfully

5 *Id.* at 7.

complete, the AMP program.[6] Such a reduction in the "waiting period" will increase AMP enrollment and allow customers a second change sooner to benefit from the program. Reducing the "waiting period" to six months also will not materially impact the built-in incentives for customers to keep current on their bills.

Second, all of the IOUs should be required to consistently reinstate customers who fall out of AMP due to IOU automation or system issues that are not the fault of the customer. For example, if a customer's automatic payments to the IOU are not received due to technological issues, the customer should not be thrown out of AMP. Rather, the issue should be remedied, and the customer should be allowed to continue in the AMP program.

Third, with respect to LTPPs, the Commission should order the termination of auto-enrollment in any LTPPs, as set forth in response to question 1., above.

Finally, as set forth in CalCCA's August 5, 2022 comments on the Scoping Ruling, the Commission should make permanent the proportional allocation between IOUs and CCAs of any payments made on past-due bills, currently set to expire in September 2024.[7]

III. CALCCA'S RESPONSES TO RULING QUESTIONS ON CBO PILOT PROPOSAL

1. Do the proposed zip codes for the proposed pilot include Community Choice Aggregation (CCA) customers?

Yes. CCA customers are included to the extent they reside in a proposed zip code.

2. What role should CCAs have in implementing the proposed pilot, if any?

Given that CBOs will report directly to the IOUs, appropriate alerts should be placed on accounts of customers being served by the pilot. In the event a customer calls its CCA, CCA

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6 *See id.*

7 *Id.* at 9 (noting that the Commission directed in D.21-11-014 (Nov. 18, 2021) that the IOUs allocate all past-due payments proportionally between the IOUs and CCAs through September 2024).

account representatives will then have visibility into a customer's involvement in the pilot, including communications between a customer and the CBO.

3. **The CBO Pilot Proposal recommends comparing pilot participants with a control group that receives standard utility support to reveal the impact of the pilot. Should the pilot evaluation also evaluate the impact of CBO interventions compared with a specific amount of utility engagement? For example, should the control group receive calls from their utility following missed payments to reduce involuntary removal from AMP and long-term payment plans?**

Yes. A comparison of engagement by CBOs with pilot participants and IOUs with the control group will provide useful information as to effective communication to reduce involuntary removal from AMP and LTPPs.

4. **The CBO Pilot Proposal recommends that the evaluation consider whether the benefits of the pilot program sufficiently outweigh the costs to warrant program expansion. Should the pilot evaluation determine whether specific pilot interventions are effective enough for the benefits to outweigh the costs? How should the pilot design, pilot reporting, or evaluation design provide insight into whether modifying the program eligibility requirements, services, or administration could result in a better ratio of benefits to costs per customer?**

A comparison of enrollment and removal from various payment plans between pilot participants and a control group will provide valuable information concerning benefits and costs of program expansion. In addition, the evaluation should investigate specific components of the pilot to determine if such components contribute to success in assisting customers and should be expanded (for example, program eligibility methodology or specific services).

5. **Tier 1 service in the CBO Pilot Proposal includes energy education. The Energy Savings Assistance program offers energy education to participants, and utilities also provide educational information about energy usage. How is the Tier 1 service different from these energy education offerings and how do all the different types of energy education interplay?**

No response at this time.

6. **What data could the CBO pilot collect to help to identify the characteristics of customers who can benefit from an AMP vs. those who cannot afford to pay their bills and need a Percentage of Income Payment Plan?**

Data on pilot customers should be collected that include arrearages (in which the AMP or other programs such as Low Income Home Energy Assistance Program may be most beneficial) versus inability to pay bills on a going forward basis (in which a PIPP may be more beneficial).

7. **The CBO Pilot Proposal targets customers in zip codes that meet the Commission's definition of "affordability area of concern" and who have arrears that are at least 90 days old and may be at risk of disconnection. The proposal does not require participants to meet income eligibility requirements to participate. Should the pilot include income eligibility requirements? Why or why not?**

No. Californians continue to suffer from impacts of the pandemic. Income eligibility requirements will prevent customers in need from being provided assistance. As pointed out by The Utility Reform Network during the Workshop, the middle class has been significantly impacted as well as low-income customers. In addition, the evaluation and data resulting from the pilot should reflect customers in need, and not only customers from a certain income bracket.

8. **The pilot proposal recommends an independent evaluation by a third-party but does not specify how the third-party evaluator should be hired or supervised. Who should conduct the request for proposals, select the evaluator, and supervise the evaluator? What role should the CBO Working group have in these processes?**

The CBO Working Group, including CCA representatives but excluding the CBOs providing services in the pilot, should have the ability to provide input on the hiring and supervision of the third-party evaluator.

9. **The pilot proposal includes a recommended preliminary scope for the evaluation. What other questions should the Commission require the evaluation to address?**

No response at this time.

10. **The pilot proposal includes separate line-items for administrative costs and education and outreach costs. What is included in the administrative costs**

line-item, and how do these types of costs differ from education and outreach costs?

No response at this time.

11. The pilot proposal notes that the utilities' administrative costs include Single Point of Contact costs to support CBOs with specific customer account resolution issues. How are these costs additional to costs that would otherwise be incurred by the utilities? What portion of the utilities' administrative costs for the pilot will serve this purpose?

No response at this time.

12. The pilot proposal recommends that, on a monthly basis, CBOs will receive additional payments for each customer enrolled at the end of the preceding month in the case management pilot (enrolled is defined as a customer with a signed agreement to participate in case management). The pilot proposal also recommends tracking the number of customers who unenroll or withdraw from the pilot. How should the Commission define unenrollment or withdrawal from the pilot? Can participants be involuntarily removed from the pilot, and if so, for what reasons?

No response at this time.

13. How should the pilot address participating customers who move after enrollment in the pilot?

No response at this time.

IV. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl,
General Counsel to the
CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

December 9, 2022

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 COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON STAFF PAPER ON PROCUREMENT PROGRAM

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December 12, 2022

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SUMMARY OF RECOMMENDATIONS

- The California Public Utilities Commission (Commission) should explore California Community Choice Association's (CalCCA') Option as it is superior to the options presented in the Staff Options Paper in its ability to advance the reliable operations of the electric grid throughout the clean energy transition while maintaining affordable electric service for customers;

- The Commission must revise the September 8, 2022 Ruling's stated objectives to increase focus on customer affordability;

- The motivating factors for a procurement program outlined in section 7 of Attachment A should be redefined to include reliability, GHG-reduction, and affordability;

- The Commission should reject the Standard Fixed Price Forward Contract outlined in the Staff Options Paper, as financial risk and market power can and should be addressed in more effective ways;

- The Commission should combine compliance showings with other filings to the extent practical for the ease of filers and reviewers, but not at the expense of getting program design right;

- The Commission should mitigate the risk of compounding Integrated Resource Plan, Resource Adequacy (RA), and Renewable Portfolio Standard penalties by implementing a universal penalty waiver process if load-serving entities can demonstrate good faith efforts to procure;

- Instead of establishing mid-to-long-term procurement requirements for local resources independently, the Commission should coordinate with the California Independent System Operator Corporation through the Transmission Planning Process to study the cost alternatives of transmission to eliminate local constraints and resources to meet local RA requirements with resources within the local area; and

- If interim procurement is necessary prior to the implementation of the procurement program, then it must be attribute based and not resource specific.

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON STAFF PAPER ON PROCUREMENT PROGRAM

The California Community Choice Association[1] (CalCCA) submits these Comments in response to *Administrative Law Judge's Ruling Seeking Comments On Electricity Resource Portfolios For 2023-2024 Transmission Planning Process* (Ruling), filed October 7, 2022, on Staff Options Paper on procurement program included in the *Administrative Law Judge's Ruling Seeking Comments on Staff Paper on Procurement Program and Potential Near-Term Actions to Encourage Additional Procurement*, dated September 8, 2022 (September Ruling).

I. INTRODUCTION

Over the past several years, the California Public Utilities Commission (Commission) has ordered an unprecedented amount of procurement on extremely expedited timelines in response to climate-induced reliability challenges. These orders, coupled with barriers to getting new

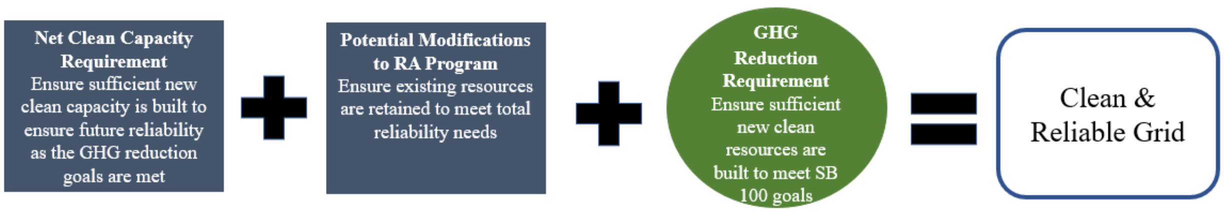
[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Energy 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.

supply online quickly -- supply chain interruptions, permitting, interconnection, and inflation -- have created a seller's market and a rushed and unpredictable procurement environment driving significant cost increases and affecting load-serving entities' (LSEs') ability to comply with procurement mandates. A new procurement framework is necessary to ensure the Integrated Resource Planning (IRP) process balances reliability, greenhouse gas (GHG) reduction, and customer affordability through orderly and predictable procurement of new resources.

The Staff Options Paper creates a framework for the development of options around four design elements (need determination, need allocation, compliance and enforcement) and offers four integrated options for exploration. CalCCA comments on these options, including the following key observations:

- The Staff Options include procurement obligations many years forward of a need, which risks procuring a mix of resources that do not meet the actual need as it develops and/or are excessively costly. Instead, the Commission should project needs out ten years or more to allow LSEs to better plan for future years but only focus compliance obligations on three-year forward periods;
- Option 4, the Standardized Fixed Price Forward Energy Contracting (SFPFC) model, departs significantly from current capacity-based mechanisms to firm energy requirements in a way that fails to address reliability needs, threatens to materially disrupt the market and existing contracts, violates existing law, and encroaches on the roles other entities. Further, its efficacy in producing competitive prices in the current market environment for both energy and capacity is questionable;
- The mass based GHG methodology incorporated in Staff Options 2 and 3 is less consistent with the current Renewable Portfolio Standard (RPS) regime than the Clean Energy Standard (CES) approach. In addition, the mass-based model is dependent on the Clean System Power calculator and will lead to inaccurate results if the calculator's assumptions are incorrect; and
- The Staff Options risk duplicative penalties for the failure to procure resources to meet reliability needs: once in the IRP process and once in the Resource Adequacy (RA) compliance process. Double penalties are unnecessary and only increase costs to customers for a not-for-profit LSE; escalating penalties also risks sending market signals that further inflate the price to build new resources.

CalCCA presents another option for exploration: a "Net Clean Capacity Procurement Framework" for reliability which focuses solely on *clean* resource procurement and a GHG-reduction framework similar to Staff's CES option (CalCCA Option). CalCCA's Option, together with potential enhancements to the RA program to ensure retention of sufficient gas resources,[2] ensures a reliable and clean grid for California's future.



The CalCCA Option would accomplish reliability and GHG objectives with a requirement to procure clean resources coupled with a CES GHG-reduction framework. The resources procured through the CalCCA Option could then be shown in the RA program, which would continue to require a showing to demonstrate the ability to meet total RA needs for each LSE. The combination of the IRP through the procurement obligations and RA through showing obligations would ensure that the CalCCA proposal meets both GHG and reliability goals. Critically, unlike the Staff Options, the CalCCA Option provides this security without creating duplicative or overlapping compliance requirements and risking duplicative penalties for LSEs.

In response to the questions in the September Ruling, CalCCA makes the following recommendations in addition to its comments on the CalCCA Option combined with consideration of RA program revisions:

[2] In the RA proceeding, the Commission should consider inviting proposals from stakeholders to augment the RA program to address retention of the existing fleet of gas resources through the transition to clean resources. For example, the Commission could explore a multi-year forward system RA requirement, local gas resources could be contracted over a longer time horizon through the CPEs, or directed procurement could be ordered to address retention of plants critical for reliability.

- The Commission must revise the September Ruling's stated objectives to increase focus on customer affordability;
- The motivating factors for a procurement program outlined in section 7 of Attachment A should be redefined to include reliability, GHG-reduction, and affordability;
- The Commission should reject the SFPFC option outlined in the Staff Options Paper, as financial risk and market power can and should be addressed in more effective ways;
- The Commission should combine compliance showings with other filings to the extent practical for the ease of filers and reviewers, but not at the expense of getting program design right;
- The Commission should mitigate the risk of compounding IRP, RA, and RPS penalties by implementing a universal penalty waiver process if LSEs can demonstrate good faith efforts to procure;
- Instead of establishing mid-to-long-term procurement requirements for local resources independently, the Commission should coordinate with the California Independent System Operator Corporation (CAISO) through the Transmission Planning Process (TPP) to study the cost alternatives of transmission to eliminate local constraints and resources to meet local RA requirements with resources within the local area; and
- If interim procurement is necessary prior to the implementation of the procurement program, then it must be attribute based and not resource specific.

These recommendations, described in detail in the sections below, aim to advance the reliable operations of the electric grid throughout the clean energy transition while maintaining affordable electric service for customers.

II. THE COMMISSION SHOULD EXPLORE CALCCA'S OPTION

In this section, CalCCA presents an alternative option to the four proposed in the Staff Options Paper: a "Net Clean Capacity Procurement Framework" and CES GHG-reduction framework combined with potential revisions to the RA program to meet both GHG and reliability goals. This combined framework addresses each of the fundamental program elements for reliability and GHG reduction outlined in the Staff Options Paper (*i.e.*, need determination, need allocation, compliance, and enforcement). Under CalCCA's Option, the need determination and allocation elements focus on the clean resources needed to meet reliability and GHG reduction targets. This focus helps the state on intentionally transitioning to clean generating capacity through the IRP planning process. The compliance and enforcement mechanisms focus on ensuring LSEs take good faith efforts to procure while limiting the ability for suppliers to exercise market power and minimizing the need for backstop procurement. Finally, potential revisions to the RA program could help ensure that the combination of new clean resources are met with retention of necessary existing resources to meet reliability needs.

A. Reliability

1. Need Determination

a. Clean Resource Need Determination

To determine the system reliability need that will be met through the new procurement program, Energy Division staff will first perform a loss-of-load expectation (LOLE) study to determine the amount of effective total capacity and clean capacity needed to achieve the planning standard (*e.g.*, one-in-ten years) and GHG benchmark for the target year. The LOLE study will consider needs at least ten years out and will be conducted at least every three years, in alignment with the cadence of LSE requirement allocation.

Upon completion of the LOLE study, Energy Division will allocate the ten-year out clean capacity need to all LSEs. Energy Division will allocate the requirements using a "Net Clean Capacity" need allocation methodology with the following steps:

1. Conduct an LOLE study to determine ***Total Effective Capacity Need*** (*i.e.*, effective capacity needed to meet one-in-ten LOLE);
2. Determine the percentage of Total Effective Capacity Need that must be met by clean capacity (*i.e.*, the "***Net Clean Capacity Need***"). In setting this target, the

Commission shall consider existing resources available to meet the Total Effective Capacity Need, clearly identify assumptions about expected resource retirements, and set the trajectory of new clean build necessary to meet the Senate Bill (SB) 100 target;

a. Net Clean Capacity Need = Total Effective Capacity Need – Ineligible Capacity + Replacement of Planned Retirements + Discretionary Adjustments

b. Where:

    i. "***Ineligible Capacity***" means existing capacity that is not eligible to meet the Net Clean Capacity Need:

        1. Resources eligible to meet the Net Clean Capacity Need include renewables,[3] storage, combustion or fuel cell technologies using biogas, green hydrogen, hybrid battery storage technology (with the portion of capacity eligible determined per a Commission-approved methodology), and demand side resources (including demand response, behind-the-meter renewables and behind-the-meter storage according to RA eligibility rules). All hydro resources would also be eligible, including Investor Owned Utility (IOU) legacy hydro on the condition that the IOU resources be allocated or made available through market sales to customers responsible for the costs of the resources through the Power Charge Indifference Adjustment (PCIA).

[3] Renewables are defined as RPS-eligible resources.

ii. "***Replacement of Planned Retirements***" means the megawatts (MW) of capacity necessary to replace resource retirements assumed by the Commission.

iii. "***Discretionary Adjustments***" mean adjustments to the need the Commission determines are necessary for the following reasons: adjusting the trajectory towards SB 100, advancing GHG-reduction, addressing market power, or other related reasons.

b. Total System Need Determination

The clean resources requirement described in section II.A.1.a above would be coupled with the RA program to ensure the Total System Need is met. The RA program currently requires LSEs to show RA contracts one year forward for system RA and is currently under revision to ensure the shown RA portfolio meets reliability needs in all 24 hours. At this time, the 24-hour RA framework has yet to be tested or implemented, so it remains to be seen if the RA program is sufficient to retain existing resources that are ineligible under CalCCA's Option. If the Commission determines in the future that enhancements to the RA program are necessary for the retention of existing ineligible resources, the Commission could consider enhancements to the RA program within the RA proceeding. For example, the Commission could consider extending the RA program multiple years forward. Through this process, LSEs would be required to show that not only are they procuring new clean resources to meet the grid's needs but that they have also procured other resources to ensure that the grid has sufficient capacity to meet the RA identified grid reliability needs.

A combination of net clean requirements in IRP and reliability requirements in RA would cover both long and short-term needs in a manner similar to an IRP that has a full requirement (*i.e.*, ensures total system reliability and advances GHG reduction), but does so in a manner that is similar to LSEs' current reliability and renewable procurement compliance obligations. This programmatic design makes the transition to the new enforcement regime simpler and ensures that LSEs have procured all resources necessary to meet grid reliability while transitioning to a GHG free grid. Thus, the Commission should consider how the RA methodologies currently under development could be shaped to address any needs not addressed in this proposal in IRP.

In this design, as with the Staff Options, if an LSE finds itself non-compliant with the clean requirements, it will still be obligated to procure resources necessary to meet reliability. Similarly, an LSE that wishes to go above the minimum clean requirements may do so and those resources will count toward their RA obligations.

2. Need Allocation

Requirements under the CalCCA Option, like other options, would be in proportion to each LSE's load share for clean capacity requirements to be met with either new and existing resources. LSE compliance obligations for the next ten years would be updated using the most recent LOLE study. For the inception of the procurement program, needs would be expressed in terms of Effective Load Carrying Capability (ELCC), rather than in terms of 24-hour slices. The Commission would utilize ELCC through the first compliance period. After the first compliance period, the Commission would conduct an assessment to determine whether there is a need to transition to expressing needs in terms of 24-hour slices in alignment with the RA program.

The Net Clean Capacity Procurement Framework only sets requirements based on the Net Clean Capacity Need (not the Total Effective Capacity Need) such that the requirements ensure sufficient new or existing clean capacity increasingly covers the total reliability need. The RA program would then ensure, as it does today, that existing resources are retained to meet the total reliability need that is not met by clean capacity. As discussed above, the Commission could explore enhancements in the RA proceeding to ensure retention of existing resources.

3. Compliance

a. Compliance Process

Following the allocation of the Net Clean Capacity Need to LSEs, the Commission would assess compliance on a forward-looking basis, ensuring that LSEs have contracted for 90 percent of their obligation two years before the end of the compliance period (one year after requirement allocation), and 100 percent of their obligation one year before the end of the compliance period (two years after requirement allocation). At the end of the compliance period, the Commission would assess compliance on a backward-looking basis to ensure the LSE's resources are all online by the conclusion of the compliance period. For the backward-looking showing, LSEs must demonstrate online status by December 31st of the last year of the compliance period.

LSEs would meet their obligations using new and existing clean resources because the Commission would allocate all of the clean resource need, rather than the incremental clean resource need identified from one LOLE study to the next. This avoids the need for baselining, which can be arbitrary, and penalizes LSEs who took early action[4] to procure by requiring them to procure more than their total share of the need. LSEs can carry over excess procurement in one compliance period to count towards future compliance periods.

LSEs would also be able to count their share of eligible resources from the Voluntary Allocation and Market Offer (VAMO) processes and resources allocated to them via the Cost Allocation Mechanism (CAM) or Modified Cost Allocation Mechanism (MCAM). In addition, the existing large hydro resources of the IOUs would be allocated or made available through

[4] Not only does this penalize early action but can discourage meaningful hedging of new development risk. If prices are low, LSEs should over-procure to hedge against the risk of price increases. However, with the potential for a baseline change, LSEs may not procure at the low prices since while those prices are attractive, it may ultimately lead to excess procurement under a baseline change that would be more costly to customers.

market sales to LSEs with customers responsible for the costs of the resources through the PCIA. These resources have been long paid for, and will continue to be paid for, by departed load. Given that these resources are capable of generating clean energy, they should count toward meeting the clean requirement and should have a VAMO process so that LSEs can receive and allocation and/or participate in a market offer process to meet their customers' needs from resources that their customers have and will continue to pay for.

While LSEs would be allocated their shares of the need ten years out, LSEs would not make forward showings for years beyond the current three-year compliance period. LSEs could still procure further in advance than three years and the option assumes the Commission would continue to authorize the IOUs to procure their needs in a timely manner that may go beyond the three-year compliance obligation. Needs identified in years four through ten would serve as advisory targets to help LSEs begin to plan their procurement further out (*e.g.*, for long lead time resources or hedging of future new clean resource price risk) without putting unnecessary and overly restrictive prescriptions on when LSEs need to make procurement decisions. Requiring binding showings more than three years out forces LSEs to make unnecessarily risky deals with too much uncertainty. Binding showings beyond three years could also result in LSEs entering into high-price contracts or into contracts with technologies that may become obsolete as new technologies advance over time. Additionally, in the current market where parties are facing supply chain interruptions, COVID-19 impacts, permitting and interconnection delays, etc., LSEs are finding that having flexibility to adjust their portfolios before locking them in for compliance will aid in getting more resources under contract and online. Flexibility in future commitments also significantly helps LSEs retain bargaining power to negotiate reasonable prices.

With respect to long lead-time resources, advisory targets will serve as a signal to the market that there is a need for them. As long as LSEs and the market are informed of a need for long lead-time resources well in advance, there is no need to require a demonstration of contracts further out than the three-year compliance window proposed here. It is the development process that is long lead time, not the contracting process. Projects that sign contracts too early (*i.e.*, more than two years before its commercial online date (COD)) may have less certainty over equipment costs, interconnection costs and timing, permitting timelines, financing costs, and other major development milestones, and ultimately may be more uncertain to come online than projects that are further along in the development process. Therefore, signals need to be provided to begin development early, rather than requiring the signing of contracts early.

As discussed in section II.A.1.b, the RA program would continue to ensure LSEs have met requirements for total reliability, and the Commission could consider enhancements to the RA program within the RA proceeding to ensure overall reliability continues to be met and existing ineligible resources are retained through the RA program.

b. Initial Implementation Timeline

Allowing sufficient lead time to comply with any newly adopted IRP Procurement Program is critical to the success of the program. CalCCA proposes the initial compliance period begin at least two years after the date of a Commission Decision adopting a new Procurement Program. As a result, the initial forward showing would occur three years after the date of a Commission Decision adopting a new Procurement Program. It is critical to have at this lead time so LSEs are not crammed into a short window for procurement which would continue to feed the existing seller's market and drive high prices. The initial needs determination and allocation should take place in 2024, with the first compliance period beginning in 2026, as described below.

For example, assume two consecutive compliance periods: 2026 through 2028 and 2029 through 2031:

	Jan. 15 2024	Dec. 31 2026	Dec. 31 2027	Dec. 31 2028	Feb. 1 2029
2026 - 2028	Commission allocates Year 2026 through 2036 needs to LSEs (Binding need is 2026-2028)	LSEs make forward showings demonstrating contracts for 90 percent of Year 2026 through Year 2028 need	LSEs make forward showings demonstrating contracts for 100 percent of Year 2026 through Year 2028 need	All resources procured to meet compliance obligation must be online	LSEs make backward showings demonstrating online status by Dec 31, 2028
2029 - 2031			Commission allocates Year 2029 through 2039 needs to LSEs (Binding need is 2029 – 2031)		

	Dec. 31 2029	Dec. 31 2030	Dec. 31 2031	Feb. 1, 2032
2029 - 2031	LSEs make forward showings demonstrating contracts for 90 percent of Year 2029 through Year 2031	LSEs make forward showings demonstrating contracts for 100 percent of Year 2029-2031	All resources procured to meet compliance obligation must be online	LSEs make backward showings demonstrating online status by Dec 31, 2031

c. Compliance Trading

In addition to these mechanisms to ensure compliance, the Commission should allow LSEs to trade excess incremental resources as well as their procurement obligations to allow LSEs to meet their obligations at the lowest cost to their customers, ensuring that the Commission's affordability goals are also met. Trading *excess incremental resources* above an LSEs' procurement requirement is expressly allowed under both Decision (D.) 19-11-016 and the Mid-term Reliability (MTR) order, D.21-06-035. [5] The Commission continue to allow

[5] Staff states in "Frequently Asked Questions" regarding D.19-11-016 that the decision "is silent on whether LSEs must directly contract for the resources they procure to meet their incremental resource procurement obligations. Consequently, staff believes that LSEs can use contracts for resources procured from other LSEs to meet their procurement obligations, provided the underlying resource meets the D.19-

trading excess incremental resources in the new procurement program and should further clarify that LSEs can transact their *procurement obligations* so that if an LSE develops an eligible resource, it can dedicate any portion or any period of the resource commitment to meet the compliance requirement of another LSE. CalCCA made this same request in its comments on near term actions to encourage additional procurement, and reiterates this request here.[6]

For example, assume LSE A has procured capacity in excess of its compliance obligation for 2026-2028 and LSE B needs to procure additional capacity to meet its own 2026-2028 compliance obligation. LSE B should be able to pay for LSE A to take on its open compliance obligations. By encouraging LSEs to work together in this, the Commission can ensure the collective obligations are met, and that LSEs avoid excess costs or penalties to the extent possible.

4. Enforcement

Enforcement of the Net Clean Capacity Need would be separate from but complementary with the RA enforcement scheme. Penalties will apply for LSEs who fail to comply with their procurement obligations for each three-year compliance period. The Commission should make penalties scalable based on the size of an LSE's deficiency such that the exact amount of the penalty an LSE could be facing is unknown by other market participants as procurement activity occurs. For example, an LSE with a small deficiency relative to its obligation would be required

11-016 definition of incremental resource (and, of course, provided that the LSE from which the resource was purchased backs the sold portion of the resource out of their own compliance showing." See "IRP Procurement Track Frequently Asked Questions," at 1-2, Question 3, located at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-termprocurement-planning/more-information-on-authorizing-procurement/irp-procurement-track. The Commission also states in the MTR Order that "LSEs will continue to have the ability to transact for excess procurement from another LSE, as long as that procurement has not yet been shown for IRP compliance by the first LSE." MTR Order at 77.

6 *California Community Choice Association's Comments on Section 2 of the Administrative Law Judge's Ruling Seeking Comments on Potential Near-Term Actions to Encourage Additional Procurement*, Rulemaking (R.) 20-05-003 (Sept. 26, 2022): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M497/K247/497247449.PDF.

to pay a smaller dollar per MW penalty than an LSE with a larger deficiency relative to its obligation. Masking the exact penalty amount LSEs face will reduce the ability for suppliers to exercise market power by reducing the probability that suppliers can bake the penalty value into the prices of their offers.

After LSEs make their annual compliance filings, the Commission may assess penalties on LSEs who fail to have enough resources under contract to meet their forward showing requirements or who fail to meet the backward-looking check assuring their total requirements over the compliance period were met with resources online by December 31 of the last year of the compliance period.

LSEs can apply for a deferral of the assessment of penalties when delays occur due to factors beyond the control of the LSEs. LSEs would need to apply for a deferral prior to the end of the relevant compliance period or as part of their backward showing. Deferrals would be granted upon demonstrations of good faith efforts to procure. Granting a deferral would result in an LSE being able to delay meeting their requirement for one year in the amount approved by the Commission. Any further delay would require another deferral request. If a deferral is not granted and the LSE cures within the next year (rather than waiting for the end of the next three-year compliance period), the Commission should consider a discounted penalty for that LSE. Demonstrations of good faith efforts should include but not be limited to at least two of the following:

- Evidence of a solicitation;
- Evidence of bids in a solicitation;
- An executed contract;
- Evidence of site control;
- An interconnection agreement; and

- A notice to proceed.

Other factors that the Commission should use to evaluate applications for deferrals:

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; and
- Quality of LSE or developer remediation plan (including diagnosis for the delay/failure and achievable mitigation steps, supported by evidence).

LSE-specific considerations:

- Pattern of success in meeting previous milestones;
- Quality of mitigation or remediation plan; and
- Thoroughness of documentation.

Penalties would not result in an LSE being relieved of its obligation because the capacity associated with the penalty still needs to be built to meet the reliability need. Instead, the MW associated with the penalty would continue to be a part of the LSE's obligation into its next compliance period. This approach should obviate the need for backstop procurement in most cases because LSEs would be incentivized to get any capacity shortfalls from one compliance period filled before the next compliance period. Moreover, LSE's incentives are buttressed by the GHG-reduction framework, which penalizes LSEs for failure to meet the clean energy goals of SB 100, accounted for in the GHG-reduction framework, provide a path to 2045. If the Commission does develop a backstop mechanism, however, LSEs should get credit towards their future compliance obligations for any backstop done on their behalf. In general, LSEs should be responsible for and incentivized to do their own procurement, so any backstop mechanism developed for a new procurement framework should be limited.

B. GHG Reduction

1. Need Determination

The GHG-reduction element of the procurement program would begin on January 1, 2031 (after the conclusion of the 60 percent by 2030 RPS compliance period) as a modified extension of the existing RPS program and extend through 2045. Similar to Staff's Options 1 and 4, the Commission would utilize a CES approach to establish annual clean energy sales targets for each compliance period. This approach would translate the electric sector GHG target into an annual energy-based requirement, consistent with the existing RPS program. The Commission would determine the electric sector GHG targets necessary to extend from the existing 2030 RPS standard to the 2045 SB 100 standard. Resources eligible to count towards the Clean Energy Standard would include those that qualify for SB 100. This mechanism is very similar to the Clean Energy Standard discussed in the Staff Options Paper.

2. Need Allocation

The need allocation under the new procurement program would follow the same allocation method as currently used in RPS by setting a CES percentage of load target, with each LSE's need being defined as its annual energy sales multiplied by the CES percentage. In this case, the LSE need metric would be an annual megawatt-hour (MWh) target for CES-eligible generation.

3. Compliance

Through 2030, the existing RPS framework would remain the single compliance mechanism for GHG reduction. Assessment of compliance would begin with energy sales beginning on January 1, 2031. Forward showings would not be required for an annual CES target framework. Once the first three-year compliance period under the new framework concludes, LSEs would need to show procurement of 100 percent of the Renewable Energy Credits (RECs) or Zero Emissions Credits required to meet their required percentage of electric retail sales over that period. Credits must be retired at the end of the three-year compliance period.

4. Enforcement

Enforcement under the "Net Clean" framework would begin as a backwards look at the first three-year compliance period to ensure LSEs have met their required percentage of electric retail sales over that period. Like the RPS program, there would be no forward showings or backstop procurement. Instead, enforcement would be conducted via penalties assessed on a $/MWh basis following the compliance period.

III. THE NET CLEAN CAPACITY PROCUREMENT FRAMEWORK IS SUPERIOR TO THE OPTIONS PRESENTED IN THE STAFF OPTIONS PAPER

The Staff Options Paper outlines four options for addressing reliability within the procurement framework:

1. Capacity contracting with marginal ELCCs
2. Capacity contracting with average ELCCs
3. Capacity contracting with slice-of-day
4. Standardized Fixed Price Forward Energy Contracting

Like options 1-3, CalCCA's proposed Net Clean Capacity Procurement Framework retains the existing capacity-based structure. CalCCA's Option presented in section II above most closely resembles Staff Option 1 in that it is an ELCC based assessment of resources along with a clean energy standard rather than a mass-based program. A key difference between the CalCCA Option and all of the Staff options is the time horizon of the compliance obligations (a three-year versus ten-year obligation). In addition, LSEs would show contracts with clean resources to meet the clean portion of the reliability need in the IRP program (while showing RA contracts for clean and ineligible resources to meet to the total reliability need through the RA program). As discussed in section II, requiring showings of resource with online dates as far away as ten years can carry considerable risk. Developers will have to price in uncertainty related to costs, changes in technology, and economic drivers (*e.g.*, inflation, recession or expansion, etc.) over such a lengthy horizon. As such, contracts will either transfer such risk to the buyer or come at the risk of the contract ultimately failing. For this reason, the Commission should allow LSEs to determine when it is appropriate to execute contracts with projects that have online dates further out than three years. The Commission should then focus the showings process on a more reasonable three-year compliance period and use years four through ten to inform LSEs of future needs so that they may develop strategies around procurement including diverse contract lengths and appropriate cost risk layering of procurement knowing future needs.

Option 4, the SFPFC, would introduce a seismic shift from capacity-based requirements to firm energy requirements. The Commission already dismissed the SFPFC proposal in the RA proceeding in D.21-07-014, citing a lack of significant details and a "broad range" of party opposition.[7] Among those parties was CalCCA, whose comments in the RA proceeding go into extensive detail describing the flaws of the SFPFC.[8] In summary, the SFPFC:

- Lacks clarity;
- By failing to eliminate the risk of supply shortfalls, fails to address the problem it purports to solve;
- Threatens to materially disrupt the market and interfere with existing contracts by introducing an entirely new reliability product and market;

[7] D.21-07-14 at 36.
[8] *California Community Choice Association's Comments on Track 3B.2 Proposals*, R.19-11-009 (Jan. 15, 2021): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M360/K563/360563778.PDF.

- Imposes structural reliability risks by shifting the supply planning responsibility from regulators and LSEs to energy suppliers;
- Violates Public Utilities Code section 380(b)(5) and section 380(h)(5) by failing to "maximize" community choice aggregators' (CCAs') ability to "determine the generation resources used to serve their customers;
- Encroaches on Federal Energy Regulatory Commission (FERC) jurisdiction; and
- Unlawfully usurps the CCA's role in managing risk.

The fundamental concerns raised by CalCCA and the other parties opposed to the SFPFC in the RA proceeding still stand.

Additionally, as described in response to question 6 below, while the Staff Options Paper frames the SFPFC as a way to address market power concerns, there are more effective ways to do this without completely disrupting the RA and IRP programs. This includes first understanding that LSEs are already hedging, although the products may not be identical to the product specified in the SFPFC. Doing so will help to inform whether customers are significantly exposed to energy market power. Second, the Commission must get on a measured and reasonable track to building new resources effective at meeting the energy needs, which the SFPFC proposal does nothing to facilitate or plan for. The best defense to market power is to ensure sufficient competition. Finally, the CPUC should work together with the CAISO to further evaluate and develop system market power mitigation for energy that will be backed by a FERC jurisdictional tariff.

The SFPFC is just an alternative cost hedge mechanism to achieve GHG and reliability goals. The cost effectiveness of this mechanism should not be assumed to be better than that of the current practices of LSEs. In fact, if SFPFC was clearly the most cost-effective mechanism to develop new resources and meet RA needs today, then arguably, LSEs would largely be already following such a model. LSEs are not following such a model and instead are choosing a mix of contractual arrangements designed to meet their capacity and energy needs. Such options should be left open to LSEs such that the Commission's Affordability goals can be met. The Commission should, therefore, abandon further consideration of the SFPFC and focus its efforts on workable, capacity-based proposals, like the CalCCA Net Clean Capacity Procurement Framework.

IV. RESPONSES TO QUESTIONS IN THE RULING

1. Objectives

a. Do the stated objectives of the new procurement program in Attachment A appropriately capture the Commission's direction given in D.22-02-004? If not, provide additions and/or alternatives.

The stated objectives in the Staff Options Paper generally capture the Commission's direction in D.22-02-004. However, the Commission must modify the stated objectives to include customer affordability. Any new procurement program must strike a reasonable balance between three primary objectives: customer affordability, reliability, and GHG emissions reductions. Failure to assess proposed new procurement programs through this lens could result in achieving one objective at the expense of another. A recent Commission report on affordability confirms this fact, noting that "[i]f handled incorrectly, California's policy goals could result in rate and bill increases that would make other policy goals more difficult to achieve and could result in overall energy bills becoming unaffordable for some Californians."[9] Despite this, customer affordability is noticeably absent in the objectives and throughout the Staff Options Paper.

[9] *Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates and Equity Issues Pursuant to P.U. Code Section 913.1* (May 2021): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2021/senate-bill-695-report-2021-and-en-banc-whitepaper_final_04302021.pdf.

The Commission is mandated by the legislature to ensure the IRP results in cost-effective procurement that minimizes impacts on ratepayer bills. Public Utilities Code section 454.51 requires the Commission to "identify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy *in a cost-effective manner*."[10] The IRP process is intended to ensure that LSEs, among other priorities, "[m]inimize impacts on ratepayers' bills" through their planned resources.[11] In furtherance of the IRP goals of reliability, GHG reductions and cost-effectiveness, the Commission is charged with "reducing the need for electricity generation resources and new transmission resources in achieving the state's energy goals *at the least cost to ratepayers*."[12]

The state is already facing affordability impacts stemming from the lack of sufficient resources. For example, as the RA capacity market has gotten tighter, RA prices have risen significantly. As recently as 2019, the RA report showed weighted average system RA prices of $3.46/kilowatt (kW)-month.[13] In September 2022, the Commission issued its calculation of market price benchmarks for PCIA with both a true-up for 2022 at $8.11/kW-Month, and a 2023 forecast at $7.39/kW-month. Each of which represents a more than a 100 percent increase in the cost of RA in just three years. The extraordinary procurement orders in the IRP have fed a seller's market at the same time supply chain, COVID-19, and inflation have all driven the costs of new build up significantly. Since most of these expensive new projects are not yet delivering energy, they are also not yet factored into rates. Additionally, the CAISO is projecting the need for a record number of new transmission projects to meet SB 100 with an estimated cost of over

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10 Cal. Pub. Util. Code § 454.51(a) (emphasis added).
11 *Id.* § 454.52(a)(1)(D).
12 *Id.* § 454.52(a)(3) (emphasis added).
13 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2019rareport-1.pdf, at 22.

$30.5 billion. The Commission must mitigate these significant drivers of rising prices need to the maximum extent possible through thoughtful policies that extend, or at least do not limit, LSEs negotiating power.

While the Staff Options Paper includes objectives that indirectly hint at customer affordability (*e.g.*, objective 2 and objective 13), failure to explicitly include it as an objective risks failing to view <u>*all*</u> elements of a new procurement framework through the lens of their impact on customer bills. This includes, as described in response to question 4 and 5 below, the penalty structure in place to enforce compliance, as compounding penalties in the RA, IRP, and RPS programs pose a significant risk to customer affordability. The Commission must also recognize that the more optionality present in meeting a compliance objective, the more negotiating power LSEs will have to enter into less expensive contracts. Mandates that are very specific and leave few options for LSEs to meet are more likely to lead to high prices and continue to exacerbate customer affordability concerns.

b. How should the program's objectives be prioritized?

When designing a procurement framework, the Commission must take on the difficult yet important task of balancing multiple, sometimes competing objectives. The Commission must focus on balancing three primary objectives: reliability, GHG-reduction, and affordability. It seems clear that an unreliable grid threatens both GHG reduction and affordability. In recent heat-wave events, businesses with emergency back-up generation had been authorized to run that generation to reduce their own load on the grid. This back-up generation is often in the form of diesel combustion engines with the GHG emissions that accrue to such technology. In addition, electricity in California is used for personal needs (*e.g.*, household consumption of lighting, heating, ventilation, and air conditioning, appliance needs, etc.), business needs to produce products and provide services, and uses essential to public health and safety (*e.g.*, medical devices, telecommunications, traffic light infrastructure, etc.). The loss of any of these services have a multitude of impacts on customers among them affordability. Ultimately, reliability has impacts on both of the other measures as well as its own consequences and should therefore be the target with GHG reduction and affordability constraints to obtain reliability cleanly and affordably.

c. Do you agree with how the four factors motivating the need for a procurement program (reliability, environment, financial risk, and market power) are described in the Appendix and Section 7 of Attachment A? If not, provide alternative viewpoints with supporting rationale.

For the reasons described in response to questions 1 and 6, the Commission should modify the motivating factors necessitating a procurement program to include reliability, environment (*i.e.*, GHG reduction), and customer affordability.

d. Do you agree that a new procurement program is needed? If not, explain why.

A new procurement framework will help ensure the IRP balances reliability, GHG-reduction, and customer affordability through *orderly* and *predictable* procurement as opposed to ad hoc procurement orders that require LSEs and suppliers to continually play catch up. Between D.19-11-016 and the MTR procurement order, the Commission has issued 14,800 MW of procurement orders with online requirements between 2021 and 2026.[14] This unprecedented amount of near and mid-term "emergency" procurement on extremely expedited timelines resulted from the rapidly changing electricity market in California, climate-change driven uncertainty, and the retirement or planned retirement of several power plants. This, coupled with numerous barriers to getting new supply online quickly, including supply chain interruptions,

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[14] D.19-11-016, *Decision Requiring Electric System Reliability Procurement for 2021-2023*, R.16-02-007 (Nov. 13, 2019), and D.21-06-035, *Decision Requiring Procurement to Address Mid-Term Reliability*, R.20-05-003 (June 30, 2021).

permitting, interconnection, and inflation, has created a rushed and unpredictable procurement environment and seller's market that is affecting the ability of all LSEs to procure sufficient resources to comply with procurement mandates affordably. Any new procurement framework should determine needs based upon routine and robust modeling to prevent the need for any further "emergency" obligations and to stabilize the procurement landscape.

e. Should the program be designed to drive resource attribute-focused procurement by all LSEs, or should it also be able to deliver some form of centralized, resource-specific procurement (e.g., large-scale and/or long lead-time resources)? Explain your reasoning.

Any new procurement program adopted in this proceeding must be designed to drive attribute-focused procurement such that CCAs retain maximum flexibility to procure generation to serve their respective communities. CCAs are already advancing the achievement of the state's climate goals with leadership at the local level. State statute recognizes this in California Public Utilities Code section 366.2(a)(5), which provides:

> A community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator's customers, except where other generation procurement arrangements are expressly authorized by statute.

The Commission should design a procurement program in recognition of this statutory requirement and avoid building in programmatic centralized or resource-specific procurement.

Establishing a robust planning process and programmatic procurement structure will inform the market of the need for long lead time resources well in advance (if modeling demonstrates that *any* long lead time resources are, in fact, necessary), obviating any perceived benefits of centralized resource-specific procurement. For example, CalCCA proposes the Commission regularly study procurement needs at least ten years out so that LSEs know what they will be required to procure well into the future to inform planning. The Commission should also work with the CAISO to plan for transmission infrastructure needs further out than ten years in the IRP planning track to provide certainty to market participants about where transmission infrastructure will exist when planning their procurement. Allowing LSEs to make their own procurement decisions, as opposed to prescribing procurement of specific technologies through a central buyer, will allow the market to decide the most cost-effective projects to pursue that possess the right attributes to meet reliability and GHG-reduction targets.

2. The "fundamental program elements" and "additional design features" introduced in Section 4 of Attachment A build on concepts detailed in the November 2020 Staff Proposal for a Procurement Framework in IRP. Comment on their general suitability for discussing potential procurement program designs.

The "fundamental program elements" described in section 4 of the Staff Options Paper (need determination, need allocation, compliance, and enforcement) are generally suitable for discussing potential procurement program design. CalCCA's proposal is structured to address the same fundamental program elements. CalCCA makes the following recommendations on the additional design features outlined in the Staff Options Paper:

- **Defining procurement subcategories as part of need determination**:

  The Staff paper asks if additional subcategories are necessary and discusses elements such as firm clean, long-duration storage, and new versus existing resources. Such designations are not necessary. The option put forth by CalCCA in section II sufficiently addresses the development of new resources while addressing the need to retain existing resources for reliability and GHG goals. Specific subcategories such as firm clean and long duration storage will be enabled by the planning processes to examine the needs of LSEs and the system as a whole. As the ELCC of non-firm clean resources decreases, the cost effectiveness of either firm clean or clean with sufficient energy storage will improve and LSEs will make appropriate economic decisions to develop the set of resources that meets reliability, environmental, and affordability goals in concert. Long duration storage similarly will be reviewed for economic value as a tradeoff in the cost efficiency of more batteries with the same inverters as a short duration battery. Again, ELCC and the RA structure will help to ensure that LSEs have sufficient information to make such economic decisions while addressing reliability and environmental goals.

- **Managing changes over time between the program's need determination and the real-time energy market**:

This issue is more of a concern with a build requirement as far ahead of operation as the Staff Options which go out through ten-years. Contracting that far in advance of the expected COD will lock in both high prices and obsolete technologies and hamper California's ability to avail itself of cutting-edge technological advances. The CalCCA option in section II instead relies on nearer term obligations of three-years which is a sufficient lead time as well as providing more flexibility to contract on a short- or long-term basis with better information on the value of resources in meeting actual real-time energy market operations' needs. Years four through ten would be informational to allow the LSE to begin planning for that future period while adjusting actual procurement in the first three-year window to better align with operational needs.

- **Requiring that procurement is conducted via centralized auctions or standard offer processes**:

  The primary difficulty with a standardized central procurement functionality is that it will be based around a specific target which will tend to make all LSEs procurement identical rather than allowing LSEs to procure based upon their own needs and customers desires. The bilateral mechanism accompanied by measures to ensure reliability and meet SB 100 goals enables LSEs to flexibly meet that need. An LSE wishing to meet more of the current SB 100 goal would be enabled to do so simply in a bilateral market. It is not clear what process and how complex those processes would be to allow LSEs to procure differing portfolios through a standard and centralized effort.

- **Ensuring need allocation and compliance flexibility to address future load migration between LSEs or market exit**:

  In order to accomplish this objective, compliance obligations must either be in the very near term or be graduated such that further out time horizons have very low obligations. The CalCCA Option is ideal from this perspective given the three-year compliance horizon with a ten-year planning element.

- **Risk mitigation strategies to account for inaccuracies or errors in need determination, allocation, compliance, and enforcement**:

  As discussed in section II, the CalCCA option addresses the need for backstop mitigation by placing the compliance obligation in both environmental aspects and in the RA program to ensure reliability. Doing so could be anticipated to meet both needs in the necessary time periods and obviate the need for backstop procurement. Errors such as those in load and resources forecasts are also addressed in the CalCCA option by routine IRP examination with new compliance target setting as well as providing updated information about needs in future periods.

3. **Comment on any content in the November 2020 Staff Proposal for a Procurement Framework in IRP that you think is particularly relevant to developing a programmatic approach to procurement now, especially if it was not included in Attachment A.**

CalCCA has no comments on the November 2020 Staff Proposal that are not addressed in these comments.

4. **Comment on each of the fundamental program elements and features described in Section 5 of Attachment A on Designing for Reliability. Is the range of options for each design element or feature appropriate? Explain your rationale.**

a. Need Determination

Need determination is a critical component of a new procurement framework. Robust need analysis through regular LOLE studies vetted by stakeholders is key to ensure procurement targets accurately reflect the reliability need and avoid "emergency" procurement orders that create a rushed procurement landscape or over-procurement that results in unnecessary customer cost increases. CalCCA's Net Clean Procurement Framework would rely on regular LOLE studies performed by Energy Division to determine the Total Effective Capacity Need and the percentage of that need required to be clean to ensure a reasonable trajectory towards SB 100 targets.

i. Expression of Reliability Need

CalCCA's Net Clean Procurement Framework would rely on the ELCC approach for the initial implementation of the new procurement framework, as opposed to a 24-hour slice approach. After the first compliance period of the new procurement framework, the Commission should conduct an assessment to determine whether there is a need to transition to a 24-hour slice framework to provide more regulatory certainty to program participants. This would include certainty around reliability requirements, resource counting, and the ability to meet IRP and RA obligations with the same portfolio. At this time, the 24-hour RA framework has yet to be tested or implemented and there is insufficient evidence in the record indicating a need to transition to a 24-hour slice framework in IRP in addition to RA. The IRP and RA programs serve fundamentally different purposes. The IRP ensures new resources are built to allow the state to transition to a zero-carbon resource fleet and meet the state's reliability targets. The RA program ensures that on a yearly and monthly basis, enough capacity is under contract and offered to the CAISO such that the CAISO can reliably operate the grid all hours of the day. An assessment of the need to transition to a 24-slice IRP should consider if, despite these differences, aligning the IRP with the 24-hour slice RA framework is a necessary objective to provide more regulatory certainty to LSEs and suppliers.

ii. Scope of Reliability Need

CalCCA's Net Clean Capacity Procurement framework focuses on the portion of the reliability need that must be served by clean capacity in order for the state to take meaningful steps towards reaching SB 100 targets. Under this approach, LSEs would be required to procure enough capacity to cover their portion of the Net Clean Capacity Need (*i.e.*, percent of the total need required to come from clean capacity). LSEs could use new or existing clean resources to meet this need.

Requiring LSEs to procure the total effective need as opposed to just the clean portion of the need would duplicate the existing RA program and expose LSEs to multiple compliance obligations for the same reliability need. Therefore, LSEs may face potential duplicative penalties for not meeting the same reliability need. The RA program would still require LSEs to meet the total reliability need plus a reserve margin. This would ensure total reliability needs continue to be met with existing resources to ensure a reliable and orderly transition away from fossil fuel resources. In addition, the Commission could also consider modifications to the RA program to retain existing resources that are ineligible to meet the Net Clean Capacity Need.

b. Need Allocation

The Commission must ensure that its methodology for allocating reliability needs to LSEs fairly accounts for clean procurement LSEs have already done, so as not to punish early procurers of clean resources. Past procurement orders allocated *incremental* reliability needs on a *pro-rata load share* basis. This created the need for baselining, which can be arbitrary and potentially punish early actors by ignoring past procurement efforts. This approach also strongly disincentivizes repowering of older facilities that would otherwise retire, leaving the system as a whole short. By allowing LSEs to use existing and new clean capacity to meet their allocation of the entire Net Clean Capacity Need allocation, the Commission would ensure each LSE is equally contributing to the clean energy transition.

c. Compliance

Regular compliance filings will ensure each LSE is making progress towards the clean energy transition. The compliance element of any procurement framework must not require showings too far in advance. Requiring LSEs to show contracts with projects many years prior to the project's COD is unnecessary because LSEs that do not bring on sufficient resources in a compliance period will face penalties. Additionally, requiring showings long into the future reduces flexibility for LSEs to pivot in response to market conditions and risks undermining affordability.

CalCCA's Net Clean Capacity Procurement Framework includes a compliance framework that requires LSEs to make forward showings in three-year compliance periods to ensure LSEs can make cost-effective procurement decisions and avoid signing risky contracts unnecessarily. Needs identified in years four through ten would serve as advisory targets to help LSEs plan their procurement further in advance (*e.g.*, for long-term contracts or long lead time resources) without putting unnecessary and overly restrictive prescriptions on when LSEs need to make procurement decisions. This approach would still send signals to the market about needs beyond the binding compliance period, including through LSE solicitations, to allow LSEs and suppliers to plan further in advance, but would not require LSEs to lock into contracts further in advance than is necessary.

d. Enforcement

Financial penalties with compound effects should be avoided. For example, a requirement to develop resources to meet reliability needs in an IRP setting can also cause a non-compliance in the RA program. Unless the compound penalties are designed with a specific goal in mind and the levels are set appropriately, they are unlikely to serve an enforcement purpose. Compound penalties could also inadvertently signal to resource providers that LSEs should be willing to pay higher prices, and the ultimate effect will be higher costs for customers.

The Staff Options Paper also contemplates "non-financial enforcement" in the form of a suspension or removal of an LSE's license to serve load in instances of repeated non-compliance.[15] The Commission must not attempt to adopt non-financial enforcement mechanisms. Adopting such an extreme enforcement mechanism would have severe impacts on market power and continue to feed a seller's market. Additionally, there is no express statutory authority that provides the Commission the ability to remove an LSE's license to serve load for failure to meet its obligations established in this proceeding.

[15] Staff Options Paper at 23.

5. Comment on each of the fundamental program elements and features described in Section 6 of Attachment A on Designing for GHG-Reduction. Is the range of options for each design element appropriate? Explain your rationale.

a. Need Determination

As noted in section II, CalCCA supports an energy-based model to determine the emissions targets. In addition, the Staff Paper correctly identifies the need to translate the SB 100 goals into annual needs such that the IRP can determine need.

b. Need Allocation

An annual energy-based need allocation is simpler to implement than a mass-based system where the mass-based system will have errors associated with the model used to calculate the hourly emissions of resources. For this reason, the Commission should use an energy-based approach that is in line with the current RPS methodology.

c. Compliance

The current RPS compliance program has been successful and can be expected to continue to be successful if the IRP provides sufficient requirements and signals. This should include clear near-term compliance needs with a process for failure of such compliance obligations as well as long-term system need. This is why CalCCA has provided an option in which there is a development compliance requirement in the first three-years, an after-the-fact assessment of actual emission reductions, and a forward planning process to identify needs in the years four through ten of the cycle.

d. Enforcement

Enforcement should provide reasonable pathways for LSEs to comply while not providing an effective price point for the market that can be used if and when market power exists. As described in section II, CalCCA proposes a compliance regime in which the exact amount of compliance for an LSE is not public but is enforced by the Commission. Doing so mitigates the risk that the penalty price becomes the default market price for resources necessary for compliance. In addition, there are elements where non-compliance has significant immediate impact (*e.g.*, reliability) and others in which non-compliance delays meeting future objectives (*e.g.*, SB 100). The non-compliance with these events can be treated differently as non-compliance with future objectives in the immediate period may have future opportunities to correct such non-compliance. A process for deferral of such requirements could be examined to ensure that those goals are met by the ultimate deadlines established but also met with customer affordability in mind.

In addition, waiver processes may be necessary under some extreme circumstances. In the current environment, there are significant capacity constraints which makes meeting RA needs extraordinarily difficult. The key to this scenario is to have a meaningful and purposeful IRP that makes regular progress toward meeting reliability needs and avoiding a process that waits until it is too late and then orders significant procurement to be online in short order. During what should become the unusual circumstance of constrained capacity, the Commission must consider a waiver process as described in section II.

6. Comment on the other program design considerations raised in Section 7 of Attachment A. Should they affect the design of the program and, if so, how?

a. Financial risk and risk of LSE market exit

The new procurement program design should not include elements to mitigate financial risk and risk of LSE market exit. As the Staff Options Paper correctly notes, the Commission has an existing POLR process to return customers to the IOU in the event of a CCA or Electric Service Provider ceasing load service.[16] The Commission and stakeholders are further refining

[16] Staff Options Paper at 29.

this process within the POLR proceeding, R.21-03-011. The Staff Options Paper suggests that most issues related to LSE bankruptcy would be within the scope of the POLR proceeding but that the scope of the new procurement program design will need to "consider how the POLR meets reliability and GHG reduction targets for the load of returning customers that it might assume…"[17] The Commission should not consider how the POLR meets reliability and GHG-reduction targets within the proceeding. Parties have already begun to consider these questions within the POLR proceeding and these considerations should continue to be made within that proceeding.

As described in CalCCA's comments in the POLR proceeding, the POLR's most urgent role is to provide energy to returning customers in the short term.[18] Importantly, CalCCA and many other parties recommend the POLR be a short-term service with customers moving to traditional LSE service after perhaps 60 days. Meeting RA, RPS, and IRP compliance requirements in the longer term, however, should be approached more cautiously, considering market conditions and compliance timelines to avoid imposing unnecessary costs on customers or duplicating procurement efforts. For example, depending on the timing of customer return, the POLR may not be able to procure RA for those customers given RA showings are due 45 days prior to the month. And if the POLR service terminates after 60 days, it would be inappropriate for the POLR to take on any contracting beyond that period. While RPS procurement is critical in the long run, it does not have the same urgency as energy and RA to ensure reliability. Thus, the POLR should procure any needed resources in a manner that avoids market power exercise or unnecessary costs and if a return falls close to an upcoming compliance date, the POLR

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17 *Id.*

18 *California Community Choice Association's Comments on Administrative Law Judge's Ruling Distributing Workshop Agenda and Providing Questions for Additional Post Workshop Comments*, R.21-03-011 (Mar. 28, 2022), at 11-12.

should receive a temporary deferral of the obligation. This requirement may be shifted to the LSE taking the customer over from the POLR to avoid backsliding on RPS. Compliance with IRP mandates, like RPS, are a longer-term concern and should similarly be handled by the LSE taking the customer after POLR service. The IRP mandates are designed to get new resources built, and if the returning LSE has accomplished some or all of its obligations, the POLR should not duplicate these costs. When developing the process for ensuring compliance obligations are met when customers are being served by the POLR, the Commission should be mindful of market conditions in considering the timing of any "catch up" procurement to avoid unnecessary costs. In addition to these considerations, the steps the POLR will take to meet RA, RPS, and IRP compliance obligations will likely require revisiting within Phase 2 of the POLR proceeding, which will consider a non-IOU assuming POLR responsibility. The question of how reliability and GHG-reduction targets are met in the event of customer return to the POLR is best considered within the POLR proceeding and should not be developed within this procurement framework discussion.

The Staff Options Paper also contemplates whether the Commission can and should regulate the financial risks taken on by LSEs within the context of their load service and suggests that the SFPFC or an alternative approach may be necessary to sufficiently mitigate LSEs' financial risk.[19] The Commission should not adopt the SFPFC option for the reasons described in section III above and should not regulate CCA financial risks within the context of their load service. CCAs all have their own risk management policies approved by their governing boards and all have incentives to hedge their own financial risks. Additionally, each LSE has its own risk tolerance that it takes into account through its hedging practices. LSEs already utilize

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[19] *Id.*

physical and financial hedges to reduce exposure to energy price volatility and are in the best position to choose their hedging strategies that work best for their portfolio. The Commission's view of the appropriate amount of risk an LSE should take should not supersede the CCA's view of the appropriate amount of risk to take.

b. Risk of Market Power

The ability for market participants to exercise market power in the capacity and energy markets must be monitored and mitigated against. However, the Staff Options Paper's means of addressing market power is fundamentally flawed. The Staff Options Paper puts forth the SFPFC proposal as a potential option to address issues of market power. For the reasons described in section III, the Commission must not adopt the SFPFC option since it is: 1) unproven at reducing costs in the immediate environment; 2) dictates the precise amount and mechanism for hedging which is likely to be inefficient; and 3) is a significant departure from the current IRP and RA mechanisms that would require significant development for implementation. The potential exercise of market power, including both capacity and energy market power, can and should be addressed as described below.

i. Capacity Market Power

The currently constrained capacity supply provides the opportunity for suppliers to exercise market power in the RA space. The Commission does not have jurisdictional authority to mitigate market power in the wholesale capacity market. Since the Commission cannot directly mitigate market power, its best mechanism is to avoid situations likely to lead to market power. This includes a well thought out and implemented IRP program that plans for and builds capacity in a non-emergency manner so that conditions are not present to allow suppliers to exercise market power. This requires developing a process that considers and addresses the causes of capacity constraints including, project delays, supply chain issues, and interconnection queue and interconnection process delays.

Unless, and until, sufficient capacity exists to satisfy market needs and provide for some amount of excess to provide competition in the market, capacity market constraints will continue to lead to high prices and the continued use of emergency procurement orders with high costs and questionable effectiveness to meet reliability needs will continue.

ii. Energy Market Power

As long as market constraints exist, market power can be exercised. Splitting the discussion between capacity and energy is only useful in the notion that differing market power mitigation techniques of FERC regulated wholesale markets exist. Fundamentally, if an entity has market power in the capacity market, then it should be assumed that they will also possess market power in the energy market any time the market demand nears or exceeds capacity requirements. Thus, imagining that the requirement for an SFPFC will be effective in mitigating energy market power ignores that those same resources under a capacity constraint will be able to exercise market power in the cost of the capacity as well. Unless one can eliminate all options for entities to exercise market power, it cannot be expected that measures in one venue will not be met with an equal and opposite reaction in another.

Further, an SFPFC would need a mandatory fixed price that cannot be exceeded. Setting this price will necessarily establish a Commission directed hedge. While the Commission can clearly direct the IOUs in such a manner, as it is the Commission that authorizes the rates the IOUs charge to customers in the case of a CCA, it is the CCA Board that takes such action. An SFPFC cannot and should not be used to circumvent the autonomy and rate making authority of the CCA.

In energy market space, the FERC and CAISO rules should (and do) cover energy market power. The CAISO currently has a local market power mitigation process in place that identifies uncompetitive local areas and mitigates local suppliers' bids to the greater of a pre-established default energy bid or the broader system competitive price. The CAISO is also contemplating market power mitigation rules that would apply on a system level, in addition to at a local level.[20] The CAISO also has independent market monitor that can do referrals to the FERC for the exercise of market power.

Finally, the Commission has already resolved concerns about import RA and the reliability of capacity out of state that can bid the price cap and likely not be dispatched. In the event that it is dispatched, it faced no RA consequences and only faced the Real-Time energy imbalance costs. This issue does not present itself with regard to resources internal to the CAISO as the only way for those resources to provide energy is to be in the CAISO market. In addition, those resources have must-offer obligations with bids that can be mitigated under local area constraints or if the resource fails to offer to the energy market. The concern with out-of-state resources was that they would sell capacity to California while selling their energy outside of California. In-state resources cannot accomplish this without bidding an export into the CAISO market, and under the CAISO process an RA resource would not have a priority to export that resource meaning it can be used to satisfy the energy needs that the RA program was designed to address.

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20 *See CAISO Price Formation Enhancements Issue Paper*, at 19-23 for a discussion of expanding market power mitigation to the system level: http://www.caiso.com/InitiativeDocuments/Issue-Paper-Price-Formation-Enhancements.pdf.

Given these conflicts, the Commission must carefully navigate the issues surrounding market power with the only meaningful manner of addressing the issue being to appropriately plan and build resources to avoid market power in the first place.

c. Past and Centralized Procurement

The Commission should allow LSEs to count their share of past and centralized procurement towards both their reliability obligations and GHG-reduction obligations. In the Staff Options Paper, the Commission correctly seeks to "…follow the cost causation principle where costs are borne by, and benefits are credited to, the customers on behalf of whom they were procured."[21] Under CalCCA's Net Clean Capacity Procurement Framework, LSEs would need to demonstrate procurement of clean capacity to meet reliability targets and clean energy to meet GHG-reduction targets. Under the PCIA, the Commission allocates clean resource attributes through the VAMO. Under RA and IRP, the Commission allocates procurement done on behalf of all LSEs through the CAM or MCAM. LSEs should be able to count their share of eligible resources from the VAMO processes and eligible resources allocated to them via the CAM or MCAM for their Net Clean Capacity Need requirement for reliability or their CES requirement for GHG-reduction.

One open issue that requires resolution is how to treat resources that become CAM resources after IRP procurement showings occur. This includes resources procured by the local RA Central Procurement Entity (CPE). CalCCA's Net Clean Capacity Procurement Framework would require forward showings of 90 percent two years forward and 100 percent one year forward. For the RA year 2023, the CPE should have completed its procurement two years forward. However, CPE procurement did not conclude until a few months prior to the RA

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21 Staff Options Paper at 30.

compliance year. The Commission must consider how LSEs would be able to count procurement done on their behalf by the CPE when CPE procurement concludes after IRP procurement showings occur. In addition, the Commission has committed to reviewing the Central Procurement of local RA and within that process should consider how the mechanism, whether the continued use of a central entity or an LSE based program, enables LSEs to meaningfully predict their IRP obligations under shorter-term centralized procurement.

7. Assess the straw options in Section 8 of Attachment A. Include in your comments an assessment of the options against the program's objectives listed in Section 3 of Attachment A.

CalCCA in section II has offered an additional option. The ability of that option to address the objectives in section 3 of the Staff paper is listed in response to question 8. With regard to the four options presented in the Staff Options, CalCCA offers the following:

1. **Realization of policy goals** – CalCCA is concerned that the four options in the Staff Options will create significant risks of undermining affordability. The main question is how prescriptive these requirements need to be to meet those goals and how open they can be to allow LSE flexibility and potentially cost savings in doing so. As such, the Staff Options are generally more prescriptive with either longer horizons of procurement requirements with associated risks of missing other opportunities or prescribing the wrong resources and in Option 4 where the compliance instrument is very narrowly specified effectively removing all optionality in procurement. Additionally, the requirement to have 100 percent of all resources five years in advance is a significant departure from existing procurement practices and industry standards. For example, it would essentially eliminate the existence of short-term contracts that are used routinely today to economically optimize portfolio positions.

2. **Economic efficiency** – As with objective one, the fewer options present to LSEs on behalf of their consumers, the less likely the outcome is the most economically efficient. With multiple aspects of economic efficiency (reliability, energy, environment) it is hard to imagine that a clear single most efficient outcome can be identified let alone targeted by specific compliance requirements. This is why the CalCCA Option attempts to allow for entities to use discretion in how to combine those elements to meet the states goals, grid needs, and customer desires. Specifically, the Staff Option 4 is the most restrictive by mandating a specific product (*i.e.*, SFPFC) with Options 1 – 3 still prescribing procurement in very forward time frames which risks procuring a sub-optimal resource mix or procuring at too high of a price.

3. **Predictable compliance design** – The CalCCA Option is designed to move away from the present practice of ordering procurement under rushed proceedings and establish a predictable compliance design. CalCCA is concerned, given the issues raised with the Staff Options, that they would require reworking to address affordability and thus would not present a predictable compliance design.

4. **Planning and Procurement** – The CalCCA proposal is the most developed in terms of identifying a clear boundary between planning and procurement obligation. While the Staff Options err on the side of early procurement when such a result could have detrimental consequences (See response to #2 above).

5. **Complement the RA program** – Notably, the SFPFC is a significant departure from the current RA structure that was discussed significantly in the RA proceeding. Section III of these comments discusses these concerns. Using

SFPFC (option 4 of the Staff paper) would therefore require a significant rebuild of the RA mechanism to make the IRP and the RA program complementary. In addition, the CalCCA-offered option in section II of these comments uses both the IRP and the RA process to ensure that the reliability and state policy goals are met through a complimentary mechanism and process. Staff Options 1-3 are generally aligned with the RA program.

6. **Complement the RPS program** – The Staff Option for a mass-based system does not clearly fit within the current RPS program. The energy-based models (*i.e.*, Staff Option Clean Energy Standard and the CalCCA Option) fit with the current RPS program. In fact, CalCCA's option would use the RPS program and extend that process through 2045 to meet the implementation of SB 100.

7. **Evolve procurement** – The CalCCA Option makes a clear statement of intention to focus the IRP primarily on ensuring the state is transitioning to a fleet of clean resources in a reliable manner. Each option allows the requirements to adjust by regularly updating the IRP forecast to account for changes in grid conditions. The Staff Options however lock in some procurement on a long-term horizon which will either come with significant implementation risk or lose opportunities to evolve pivot procurement strategies as new information about needs are known. The CalCCA option addresses this by limiting the obligations to three-years forward while using years four through ten to inform LSEs of expected needs.

8. **Ensure competition** – In the immediate term, all of the options will struggle with a constrained capacity market. The objective of each option should be to mitigate

against short term shortages by planning and procuring in an orderly and meaningful fashion.

9. **Ensure existing resources persist and new resources are built** – Arguably each of the options accomplish this objective. However, longer-term full requirements types of obligations may tend to place demands on existing emitting resources that end up being longer than necessary. This is present in all of the Staff Options. The CalCCA Option allows for an orderly transition of the fleet while maintaining reliability. By doing so, decisions to retain existing fleet can be made more regularly while still providing enough information to the market to understand the needs of existing resources in the near future to allow for necessary investment and maintenance.

10. **Allow parallel resource specific procurement to occur** – As a general matter, CalCCA believes the Commission should direct procurement on an attribute basis and allow the market to determine the best solutions. Resource specific procurement risks feeding a seller's market and removing negotiating power from LSEs.

11. **Co-optimize transmission and procurement planning** – None of the options explicitly address the coordination of the IRP and the CAISO TPP. Each of the proposals will require that the IRP and the CAISO TPP work in concert and in a sufficiently forward manner to develop the necessary transmission infrastructure to gain access to both resources and load.

12. **Recognize retail choice and allocate fairly** – Provided the options do not rely on baselines to determine starting points of allocating procurement needs, each of the options can address this objective.

13. **Mitigate risk of Market Power** – See response to objective 8

14. **Fulfill relevant objectives of the ESJ action plan** – Each of the options is capable of meeting this objective and none appear to be more or less effective in doing so.

8. Do you recommend adopting any of the options as presented in Attachment A? Explain your reasoning and justify your recommendation, by including assessment of your preferred approach against the program's objectives listed in Section 3 of Attachment A. If you do not recommend any of the options in Attachment A, indicate whether you recommend:

a. A hybrid of the elements described
b. A hybrid of some elements described and some not described
c. An entirely different approach than the options described

CalCCA recommends the Commission develop its alternative option described in section II above. Section III above describes how the CalCCA Option is superior to the options outlined in the Staff Options Paper. The CalCCA Option meets the objectives outlined in the Staff Options Paper in the following ways:

1. **Realization of policy goals**
   - Establishes a "Clean Capacity" requirement based on the trajectory of new clean build necessary to meet the SB 100 target reliably, making assumptions about how much of the existing fleet will retire;
2. **Economic efficiency**
   - Allows LSEs make cost-effective procurement decisions by focusing on attributes rather than specific technologies;
   - Allows LSEs the flexibility to adjust their procurement plans by not requiring demonstrations of contracts too far in advance;
   - Excuses LSEs of penalties if they can demonstrate "good faith efforts" to procure;
3. **Predictable compliance design**
   - Establishes a routine needs assessment process that regularly updates LSEs of their obligations over ten years out;

- Allows LSEs to meet their binding obligations over three-year periods;
- Implements a penalty structure that will incent compliance while not penalizing LSEs for circumstances outside their control;

4. **Planning and procurement**
   - Transitions away from the order-by-order approach by continually establishing targets that define the amount of capacity required to come from clean resources;
5. **Compliment the RA program**
   - Allows the RA program to continue to focus on meeting total reliability needs with existing resources by exploring enhancements to RA obligations, while setting clean resource procurement targets through the new programmatic procurement framework;
6. **Compliment the RPS program**
   - After the latest RPS compliance period, continues the CES approach with modifications to extend targets through 2045 and expand resource eligibility to those that qualify for SB 100;
7. **Evolve procurement**
   - Requires a regular process for determining reliability needs based on evolving load and resource assumptions;
8. **Ensure competition**
   - Ensures reasonable competition for supply- and demand-side resources by requiring orderly procurement of clean resources, including demand-side and behind the meter resources, to meet reliability needs as opposed to rushed procurement that limits the pool of resources eligible to comply;
9. **Ensure existing resources persist and new resources are built**
   - Complements the existing RA program, which could be enhanced to better retain existing resources necessary for an orderly transition to a zero-carbon fleet;
   - Focuses on reliably replacing the carbon-emitting fleet with clean resources by setting increasing clean capacity requirements through 2045;
10. **Allow parallel resource specific procurement to occur**
    - For the reasons described in response to question 1.e., a new procurement framework should not require resource-specific procurement action;

11. Co-optimize transmission and procurement planning

- Allows the IRP planning track and CAISO TPP to assess transmission infrastructure needs further out to help inform procurement of resources where transmission is available;
- See CalCCA's response to questions 10 and 11 for additional discussion on transmission;

12. Recognize retail choice and allocate fairly

- Allows LSEs the flexibility to procure on an attribute basis, rather than on a resource-specific basis;
- Avoids mandating centralized procurement on behalf of all LSEs;
- Allows LSEs to count past and existing centralized procurement done on their behalf towards their obligations;

13. Mitigate risk of market power

- Supports the build of new clean resources and complements the RA program that will retain existing resources to ensure the capacity market has sufficient surplus above the requirement to make it competitive;
- Creates a measured procurement framework that avoids rushed, order-by-order procurement that limits the pool of viable projects; and

14. Fulfill relevant objectives of the ESJ Action Plan

- The CalCCA option would develop new renewable resources and through the RA program would provide an orderly path to retirement of emitting resources. To the extent the ESJ action plan wishes to target certain facilities for retirement due to local health and welfare impacts, the CalCCA proposal would not present obstacles to doing so. In this sense, the CalCCA proposal is no different than the four Staff Options.

9. Should the new program's compliance showings should be combined with the current annual compliance reports required by the renewables portfolio standard program, filing of LSEs' individual IRPs, and/or other existing regular planning and procurement filings? Do you have any other suggestions to minimize the time and effort required of LSEs and staff?

The Commission should strive to streamline compliance filings to the extent practical for the ease of filers and reviewers. More important, however, is streamlining compliance obligations such that LSEs are not exposed to penalties multiple times for the same failure. To this aim, CalCCA structured its proposed GHG-reduction framework in a way that would not add a new compliance obligation, demonstration, and enforcement related to GHG-reduction. This would be accomplished by extending the existing RPS framework and augmenting it to extend to SB 100 targets. Therefore, the existing RPS program would continue as is through the latest RPS compliance period (60 percent by 2030). After the conclusion of this compliance period, CalCCA's proposed GHG-reduction framework would begin. This framework would extend the existing RPS program and its compliance showing structure through 2045. This approach not only has the benefit of limiting the number of compliance showings required for LSEs to submit and Commission staff to review but also has the benefit of retaining only one GHG-reduction obligation LSEs must meet, and therefore, limits the possibility of penalizing LSEs multiple times for the same failure. Should the Commission identify additional ways to streamline compliance filings, it should do so, but not at the expense of getting the program design right.

10. Local reliability is raised briefly in Section 5.1.1 of Attachment A. Requirements are currently set for the near-term as part of the resource adequacy program. Are these sufficient, or should there be medium-to-long-term procurement requirements as well? If so, should they be part of the new program or should they be addressed on an order-by-order basis in parallel with the program? Explain your reasoning.

The existing approach to ensuring local reliability is not adequate. Local reliability needs are responsible for retention of some of the most polluting generation in the state, undermining the state's decarbonization and environmental justice goals. However, addressing local reliability needs is a complex problem requiring coordination between CAISO and the Commission to ensure the most cost effective and efficient solution to this serious issue.

To understand this complexity, it is critical to consider the nature of the problem. The CAISO sets and the Commission adopts local RA requirements to ensure LSEs contract with generation located within locally constrained areas to serve local area load. The amount of generation physically located within the locally constrained area required to maintain local reliability is highly dependent on the transmission available to transmit energy from resources outside the local area to load within the local area. If the transmission capacity within the local area is limited, resources located within the local area are needed to maintain reliable local operations. The local RA requirements can decline if new transmission is built that allows resources outside the local area to be delivered to local area load. Therefore, there are two ways to address local reliability, either by: (1) having sufficient generation physically located within the local area; or (2) having sufficient transmission build to relieve the local area constraints and allow generation outside the local area to be delivered to load within the local area.

The Commission should not independently establish IRP procurement requirements specific for local reliability, whether through a new procurement program or an order-by-order basis. If the Commission did so, it would essentially make the decision to rely on new local resources to maintain local reliability over new transmission, without the appropriate assessment of which is the more cost-effective option and which is the most feasible given land use considerations. With regard to this question, CalCCA assumes the use of the term mid-term and long-term procurement refers to the length of time in advance of the resource becoming commercially operational and does not refer to how long the resource would be under contract once it is operational. Instead of establishing mid-to-long-term procurement requirements for local resources independently, the Commission should coordinate with the CAISO through the TPP to study the cost alternatives of transmission to eliminate local constraints and resources to meet local RA requirements with resources within the local area. It should also coordinate with the California Energy Commission to determine which solutions are feasible given existing land use. This coordination to determine the cost-effectiveness and feasibility of transmission or resource alternatives must occur before considering medium to long term procurement obligations specific to local areas.

11. How would the approaches described in Section 5.1.1 of Attachment A need to be amended or expanded in order to minimize local air pollutants and other GHG emissions in disadvantaged communities associated with location-specific procurement?

The Commission and the CAISO must begin explicitly studying the ability to reliably serve load in local areas and disadvantaged communities while reducing reliance on fossil fuel resources. Many local areas currently rely on fossil fuel resources to maintain reliability and meet local RA requirements. Each year, the CAISO enters into reliability must-run contracts with local resources looking to retire because they must be retained for local reliability. Without robust upfront planning focused specifically on how to reliably phase out local carbon emitting resources, California risks jeopardizing the fast-approaching SB 100 target of zero-carbon resources supplying 100 percent of electric retail sales to end-use customers by 2045.

As described in response to question 10 above, local reliability can be addressed through locating generation within the local area or building new transmission to relieve the local area constraints. The ability to retire fossil fuel resources in local areas will depend on either (1) eliminating transmission constraints that limit the number of resources capable of serving load in the local area, or (2) bringing online enough effective carbon-free resources inside of the local area to replace the existing fossil fuel resources. The Commission and the CAISO must begin studying the feasibility and cost-effectiveness of transmission alternatives and new clean resource alternatives in local areas. Studying reduced reliance on fossil fuel resources in local areas now will result in forward planning that ensures an orderly and reliable transition from reliance on fossil fuels in local areas at least cost.

12. D.22-02-004 ordered two storage projects be procured to mitigate the need for transmission upgrades and noted that the new procurement program may be able to address opportunities of this nature. Do you think that is appropriate? If so, explain why, and how the program design should consider this.

CalCCA supports mitigating the need for transmission upgrades with non-transmission alternatives such as battery storage when such alternatives are cost-effective. Transmission upgrade costs need to be considered carefully, given the state will require significant transmission upgrades to support the development of new resources needed to transition to a clean resource fleet. The CAISO has projected over $30 billion in transmission upgrade costs in the next 20 years,[22] which will result in significant increases to the CAISO's transmission access charge. The identification of cost-effective non-transmission alternatives will be an important element in keeping customer bills affordable.

The appropriateness of addressing non-transmission alternatives through the new procurement program will depend on how the framework is structured for this purpose. *First*, non-utilities must have the opportunity to develop non-transmission alternatives identified as mitigating the need for transmission upgrades. D.22-02-004 ordered Pacific Gas and Electric Company to procure the storage projects identified to replace transmission upgrades.[23] The Commission should not continue the practice of mandating procurement of non-transmission alternatives to the IOUs. A future procurement program should ensure non-utilities have the same opportunities to develop projects that would mitigate the need for transmission upgrades. *Second*, the Commission must address how it would allocate the costs and benefits of non-transmission alternatives to LSEs, including for transmission-avoiding Distributed Energy

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22 California ISO 20-Year Transmission Outlook (May 2022): http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf.

23 D.22-02-004 at 160-162.

Resource projects, as such alternatives will result in avoided transmission upgrade costs. *Finally*, before directing or incenting LSEs to develop non-transmission alternatives through the procurement program, the CAISO TPP must assess non-transmission alternatives to ensure such alternatives are reliable. The CAISO conducts studies within its local capacity requirement study process to determine the amount of battery storage that can locate within transmission-constrained areas and maintain reliable operations without additional transmission upgrades.[24]

13. Comment on the need to develop interim approaches to manage the risk of the preferred program design taking longer to implement.

An interim procurement approach is unnecessary under CalCCA's proposed Net Clean Procurement Framework given the timing of existing procurement orders and the proposed implementation date of CalCCA's proposed framework. The MTR procurement order requires LSEs to bring new capacity online through 2026. The first compliance period under the Net Clean Procurement Framework would pick up directly where the MTR procurement order leaves off, running from January 1, 2026 to December 31, 2028. This would allow for a seamless transition from MTR into the new procurement framework. Issuing new procurement orders between the MTR order and the new procurement framework could create significant disruptions to procurement already underway given current market constraints and potential project delays resulting from supply chain disruptions, interconnection and permitting delays, etc. Therefore, the Commission should focus on implementing the new procurement framework in a timely manner, rather than develop an interim process that would continue the order-by-order approach.

[24] California Independent System Operator, *2023 Local Capacity Technical Study* (April 28, 2022), at 25-26.

14. Assess the interim options discussion in Appendix 10.3 of Attachment A. Include in your comments an assessment of the options against the program's objectives listed in Section 3 of Attachment A.

The first option outlined in the Staff Options Paper is a "resource-specific" approach that would "require LSEs to procure directly what they include in their individual integrated resource plans."[25] The Commission must not adopt this approach for several reasons. *First*, LSE's IRP plans are intended to be planning tools, not procurement mandates, and should remain as such. This is because reliability and GHG-reduction needs identified in one planning cycle may differ in future planning cycles as load and resource assumptions and state policies evolve. *Second*, holding LSEs accountable for development of resources based upon needs forecasted ten or more years into the future leaves LSEs with no flexibility to adjust their plans as new technologies evolve and become economic. *Third*, in many cases, LSEs alone cannot ensure projects are built and online consistent with what is planned in its IRP. Factors outside LSEs' control (*e.g.*, supply chain disruptions, transmission limitations, etc.) can impact LSEs' ability to remain consistent with its IRP. *Fourth*, it is the resource attributes, not the specific technology, that contribute to reliability and GHG-reduction. Mandating procurement on a resource basis rather than an attribute basis unnecessarily restricts LSE from making economically efficient procurement decisions and remaining flexible to changing conditions.

15. Do you recommend adopting either of the interim options in Appendix 10.3 of Attachment A? If not, what do you recommend? Explain your rationale.

The Commission should not adopt either of the interim options outlined in the Staff Options Paper. Instead, the Commission should focus on developing and implementing the new procurement framework that adheres to the Staff Options Paper's objectives three, "…a predictable and orderly program design that enables LSEs to anticipate, understand, and comply

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25 Staff Options Paper at 42.

with their obligations while also making it difficult and burdensome to avoid compliance…" and four, "…transitioning away from the current order-by-order procurement paradigm for new resources".[26] For the reasons described in response to question 1.d. above, the Commission should stay away from interim approaches that could conflict with ongoing MTR procurement activity and exacerbate the existing challenges LSEs and suppliers are facing under the current just-in-time order-by-order approach.

If significant delays keep the Commission from implementing the new procurement framework in a timely manner and the Commission suspects that interim procurement may be needed to maintain system reliability, the Commission must take an analytical and measured approach to determining if interim procurement orders are warranted. This approach would begin with robust LOLE analysis vetted by stakeholders used to identify the capacity necessary to meet reliability standards. This analysis would take into account existing capacity and capacity already ordered through the D.19-11-016 and MTR procurement orders. Following the LOLE analysis identifying a need for additional procurement, the Commission must take into account then-current market conditions (including any transmission constraints) for new build to avoid disrupting procurement already underway to meet the MTR procurement order and avoid undue price pressure on project contracting. If, after the conclusion of a thorough reliability needs assessment and an assessment of market conditions, the Commission decides to issue interim procurement orders, they must be attribute-based rather than resource-specific for the reasons described in response to question 14.

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[26] Staff Options Paper at 8.

V. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the CalCCA Option 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

December 12, 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 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation. (U39E.)	A.20-07-002
Expedited Application of Pacific Gas and Electric Company Under the Power Charge Indifferent Adjustment Trigger. (U39E.)	A.20-09-014
CONSOLIDATED	

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO PETITION OF THE REGENTS OF THE UNIVERSITY OF CALIFORNIA, SCHOOL PROJECT FOR UTILITY RATE REDUCTION, AND E&B NATURAL RESOURCES MANAGEMENT CORPORATION (DA PARTIES) FOR MODIFICATION OF DECISION 21-01-007

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On behalf of
California Community Choice Association

December 12, 2022

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SUMMARY OF RECOMMENDATIONS

- Deny the *Petition of the Regents of the University of California, School Project for Utility Rate Reduction, and E&B Natural Resources Management Corporation (DA Parties) for Modification of Decision 21-01-007* as unreasonable, procedurally improper, and/or unactionable under the Commission's ratemaking regime.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of SAN DIEGO GAS & ELECTRIC COMPANY (U902E) for Approval of its 2021 Electric Procurement Revenue Requirement Forecasts and GHG-Related Forecasts.	A.20-04-014

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO PETITION OF THE REGENTS OF THE UNIVERSITY OF CALIFORNIA, SCHOOL PROJECT FOR UTILITY RATE REDUCTION, AND E&B NATURAL RESOURCES MANAGEMENT CORPORATION (DA PARTIES) FOR MODIFICATION OF DECISION 21-01-007

I. INTRODUCTION

Pursuant to Rule 16.4(f) of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure, the California Community Choice Association (CalCCA)[1] hereby submits this Response to the *Petition of the Regents of the University of California, School Project for Utility Rate Reduction, and E&B Natural Resources Management Corporation (DA Parties) for Modification of Decision 21-01-007* in the above-captioned proceeding(s) (DA PFM). Petitioners filed nearly identical PFMs across the 2021 Energy Resource Recovery Account (ERRA) Forecast decisions in all three investor-owned utility (IOU) service territories: Decision (D.) 20-12-038 (Pacific Gas and Electric Company, or PG&E), D.20-12-035 (Southern California

[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. CalCCA was a party to A.20-04-014, A.20-07-002, A.20-07-004, A.20-07-009, A.20-09-014, and A.20-10-007.

Edison, or SCE), and D.20-04-014 (San Diego Gas & Electric Company, or SDG&E); and decisions in the PG&E Power Charge Indifference Adjustment (PCIA) Undercollection Balancing Account (PUBA) trigger proceeding (the same D.20-12-038 referenced above) and the SDG&E PCIA Undercollection Balancing Account (CAPBA) trigger proceeding, D.20-12-028. CalCCA has filed an identical version of this Response in all six dockets, some of which have been consolidated.

The relief requested in all four PFMs is to exempt a discrete group of DA customers from having to pay surcharges tied to undercollections that took place in 2020 on the theory those customers did not contribute to the undercollection because they were bundled customers at the time.[2] The PFMs warrant rejection for three reasons. First, all customers, including bundled customers that later departed for DA service, paid the PCIA in 2020, undermining the PFM's central argument that the DA Parties' customers did not contribute to the undercollection in the Portfolio Allocation Balancing Account (PABA) in 2020. Second, the Petitioners lack good cause for not participating in the underlying dockets, and relitigating those cases here prejudices CalCCA's members. Third, it does not appear petitioners' requested relief can be provided since there is no mechanism of which CalCCA is aware to refund rates to only one group of customers in a vintage but not others—and Petitioners do not explain how such relief could be provided.

II. THE COMMISSION SHOULD DENY THE PFM

A. The DA Parties Contributed to the PABA Undercollection as Bundled Customers

The mechanics of the Commission's PCIA framework—and the DA Parties' apparent misunderstanding of those mechanics—underlie the requested relief. Prior to D.18-10-019, the

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[2] Petition at 2-3; 12-13 (all citations herein are to the DA Parties' Petition for Modification of D.20-12-028).

PCIA rate was set only on a forecast basis with no after-the-fact true-up for unbundled customers. D.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 a utility realizes during the year related to its PCIA-eligible resource portfolio.

PCIA rates for 2021 were set, therefore, based on two key components: (1) the forecasted Indifference Amount, *i.e.*, the difference between the forecasted cost of a utility's generation portfolio in 2021 and the forecasted market value of PG&E's generation portfolio in 2021; and (2) the 2020 year-end balance in the PABA.[3] The Indifference Amount and the year-end PABA balance are added together to form the revenue requirement underlying PCIA rates. The PCIA revenue requirement is allocated among *both* bundled and unbundled customers based on their vintage,[4] *i.e.*, the year unbundled customers left a utility's service[5] or the current year for bundled customers, and their rate class using the allocation factors from PG&E's most recently approved GRC.[6] That means *both bundled and unbundled customers pay the PABA balance*.

D.18-10-019 limited "the change of the PCIA from one year to the next. Starting with forecast year 2020, the cap level of the PCIA rate should be set at $0.005/kilowatt-hour (kWh) more than the prior year's PCIA, differentiated by vintage."[7] If the year-over-year increase in departing load PCIA rates exceeded the rate cap in a given year, bundled customers rates were

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3 Because 2021 rates were determined during 2020, including the true-up for 2020, the true-up was developed using (1) actual values that are available to date and (2) a forecast of actual values for the remainder of the year.

4 *See, e.g.,* PG&E Preliminary Statement HS at Sections 2, 5; PG&E Preliminary Statement CP at Section 5.

5 D.11-12-028 at 9.

6 D.18-10-019 at 122 and Ordering Paragraph ("OP") 4 (October 11, 2018).

7 *Id.*, Conclusions of Law 19-20, OP 9(a)-(c) (October 11, 2018).

increased instead to "finance" the amount above the cap. A separate balancing account, the PUBA/CAPBA, was also established to record the shortfall in revenue charged to departing load customers due to PCIA rates being limited by the \$0.005/kWh cap in annual rate changes. Unbundled customers are responsible to pay for the shortfall recorded to PUBA, plus interest, to compensate bundled customers for having paid for the amount in excess of the cap.

The Petition argues the DA Parties' customers were still bundled customers in 2020, as a result of it taking so long for them to become departed customers, and, therefore, they should not have to pay either the PABA balance or the PUBA/CAPBA balances that accrued that year.[8] The Petition cites to the decision in SDG&E's ERRA Forecast case as support for its arguments. In that case, a group of CCAs successfully argued CCA customers in SDG&E's service territory that were bundled customers at the time, and then later departed, should not have to pay the CAPBA surcharge (known as the PUBA in SCE and PG&E's service territories).[9] The customers at issue in the SDG&E case did not contribute to the CAPBA balance (they paid their full PCIA rates as bundled customers) and, therefore, the Commission agreed they should be exempt.

That situation is distinguishable from the situation here. While the DA Parties may have a colorable argument with regard to the PUBA and CAPBA surcharges,[10] the argument fails with regard to the PABA revenue requirement underlying the PCIA. *All* customers pay the PABA revenue requirement via the PCIA. Bundled customers pay the PCIA as part of the ERRA generation rate; departing load customers pay the PCIA in addition to the generation rates of their

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8 Petition at 12-13.

9 Petition at 10-12.

10 The PUBA/CAPBA surcharge would only apply to departed customers, unlike the PABA revenue requirement.

CCA or DA provider.[11] Thus, the DA Parties' customers *did* contribute to the 2020 undercollection in the PABA because they paid PCIA rates that year via their bundled generation rates.

On this point, the Petition does not offer much in terms of analysis. It includes conclusive assertions that appear to assume bundled customers do not pay rates based on the PABA revenue requirement and that the PCIA rate mechanism is only paid by unbundled customers.[12] Such assumptions are incorrect. The PCIA rate in 2021 included recovery of the PABA that accrued during 2020. The DA Parties' customers owed a share of that amount and paid it.

B. Petitioners Fails to Meet Their Procedural Burden

Even if the Commission finds the DA Parties have a compelling argument with regard to the CAPBA/PUBA surcharges, the PFM should be rejected on procedural grounds. To file a PFM, the petitioner has to file within one year or "explain why the petition could not have been presented within one year of the effective date of the decision."[13] Petitioners fail to present a good excuse, stating "they do not have the resources to routinely participate in ratemaking proceedings on the IOUs' annual ERRA and related applications. Consequently, Petitioners did not participate in the consolidated proceedings in which D.20-12-038 was issued."[14] In fact, they assert they did not realize the issue was an issue until July 2021.[15]

However, the DA Parties admit they follow the PCIA proceeding, Rulemaking (R.) 17-06-026,[16] and DA interests regularly participate in the ERRA Forecast proceedings through either the Direct Access Customer Coalition (DACC) and/or the Alliance for Retail Energy Markets

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11 *See, e.g.,* PG&E Preliminary Statement HS at Sections 2, 5; PG&E Preliminary Statement CP at Section 5.

12 Petition at 10-13.

13 California Public Utilities Commission Rules of Practice and Procedure, Rule 16.6(d)-(e) (May 2021).

14 Petition at 10.

15 Petition at 13-15.

16 Petition at 10.

(AReM). Either DACC or AReM was a party to all of the proceedings underlying the PFMs. It is difficult to believe any load-serving entity in California—especially one whose aim is to find more affordable energy for its customers—does not have the resources available to track and participate in the proceedings that will set the rates their customers pay in the following year. Putting aside the concern that no party appears to be tracking those customers' interests before the Commission, the Commission should not set the precedent that a sophisticated load-serving entity's unwillingness to make the funds available to track the rates its customers will pay can justify a lack of participation and allow after-the-fact ratemaking changes.

C. The Requested Relief Cannot Be Provided

The PFMs request the applicable IOU "not recover the PCIA undercollections that resulted in the PUBA and PABA balances from direct access customers that were assigned pre-2020 PCIA vintages based on timing of their NOIs but were not allowed to depart bundled service prior to January 1, 2021." However, those undercollections were already recovered, and un-recovering them in these circumstances could amount to retroactive ratemaking.[17]

Further, CalCCA is unaware of a rate mechanism that would allow recorded revenues to be un-recovered from one set of a customers in a vintage but not another set of customers. The revenue requirements have not changed, and if the revenues recorded were applied to those revenue requirements, the result would be the creation of a new undercollection that other customers in those vintages would need to be paid—or that shareholders would need to bear. The DA Parties' Petition does not provide a ratemaking solution for the complex unwinding of balancing accounts that would need to take place in order to provide the relief requested.

[17] *S. Cal. Edison Co. v. Pub. Utils. Com.,* 20 Cal. 3d 813 (1978).

III. CONCLUSION

For the foregoing reasons, the CalCCA respectfully requests the Commission deny the DA PFM.

Respectfully submitted,

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December 12, 2022

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ORDER INSTITUTING RULEMAKING TO IMPLEMENT ASSEMBLY BILL 843 – THE BIOENERGY MARKET ADJUSTING TARIFF PROGRAM

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December 13, 2022

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SUMMARY OF RECOMMENDATIONS

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

- Adopt the Order Instituting Rulemaking's (OIR's) scoped issues, consistent with Assembly Bill (AB) 843 and the recommendations of CalCCA, the joint investor-owned utilities (Joint IOUs) and the Public Advocates Office (Cal Advocates), that community choice aggregators (CCAs) participating in the Bioenergy Market Adjusting Tariff (BioMAT) program be placed on a level playing field with the IOUs and that any CCA submission in this proceeding be subject to review by the Commission and the public;

- Reject Cal Advocates' recommendation to remove from scope the potential extension of the BioMAT program based on its argument that the Commission should not allow re-litigation of its decision to end the BioMAT program on December 31, 2025. The Commission has broad authority to modify its previous decisions pursuant to Public Utilities Code section 1708, and the Commission should consider extending the BioMAT program to December 31, 2030 given the recent addition by AB 843 of CCAs to the program;

- Adopt the Joint IOUs' recommendation for one Workshop, provided the Workshop is held in February and additional Workshops can be scheduled if necessary; and

- Adopt the OIR's proposed scoped item for the Commission to decide the processes for CCAs to submit BioMAT tariffs and/or contracts to the Commission.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ORDER INSTITUTING RULEMAKING TO IMPLEMENT ASSEMBLY BILL 843 – THE BIOENERGY MARKET ADJUSTING TARIFF PROGRAM

The California Community Choice Association[1] (CalCCA) submits these Comments in response to the *Order Instituting Rulemaking to Implement Assembly Bill 843 – the Bioenergy Market Adjusting Tariff Program* (OIR)*,* issued October 26, 2022, pursuant to Rule 6.2 of the California Public Utilities Commission's (Commission's) Rules of Practice and Procedure, and the directives provided by the OIR.

I. INTRODUCTION

Community choice aggregators (CCAs) are focused on establishing a streamlined and collaborative process to ensure expedient implementation of Assembly Bill (AB) 843. Also crucial is the ability of CCAs to participate in the Bioenergy Market Adjusting Tariff (BioMAT) program under the same overall rules and cost recovery processes as the investor-owned utilities (IOUs). CalCCA looks forward to working with all parties to effectively meet these objectives.

[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.

CalCCA specifically responds herein to the Opening Comments of the Joint IOUs and The Public Advocates Office at the California Public Utilities Commission (Cal Advocates), and recommends that the Commission:

- Adopt the OIR's scoped issues, consistent with AB 843 and the recommendations of CalCCA, the Joint IOUs and Cal Advocates, that CCAs participating in the BioMAT program be placed on a level playing field with IOUs and that any CCA submission in this proceeding be subject to review by the Commission and the public;
- Reject Cal Advocates' recommendation to remove from scope the potential extension of the BioMAT program based on its argument that the Commission should not allow re-litigation of its decision to end the BioMAT program on December 31, 2025. The Commission has broad authority to modify its previous decisions pursuant to Public Utilities Code section 1708, and the Commission should consider extending the BioMAT program to December 31, 2030 given the recent addition by AB 843 of CCAs to the program;
- Adopt the Joint IOUs' recommendation for one Workshop, provided the Workshop is held in February and additional Workshops can be scheduled if necessary; and
- Adopt the OIR's proposed scoped item for the Commission to decide the processes for CCAs to submit BioMAT tariffs and/or contracts to the Commission.

II. THE JOINT IOUS AND CAL ADVOCATES CORRECTLY STATE THAT THE COMMISSION MUST ENSURE EXISTING BIOMAT RULES AND COMMISSION OVERSIGHT APPLY EQUALLY TO IOUS AND CCAS

CalCCA agrees with the Joint IOUs and Cal Advocates that CCAs participating in the BioMAT program must be placed on a level playing field with IOUs, and any CCA submission in this proceeding should be subject to review by the Commission and the public.[2] Indeed, AB 843 includes many sections requiring equal treatment of CCAs and IOUs with respect to Commission oversight and CCA BioMAT contracting. For example, AB 843 requires CCAs to base their tariffs and contract on the IOU's approved tariffs and contracts, without modification.[3] AB 843 also provides the Commission with "ongoing review authority over any contracts of

[2] Joint IOU Opening Comments at 2-3; Cal Advocates' Opening Comments at 3-4.
[3] Public Utilities Code § 399.20(f)(5)(B).

[CCAs] submitted pursuant to this section consistent with its review of the contracts of electrical corporations entered into pursuant to this section."[4] In short, the CCAs are not looking to "reinvent the wheel" or to receive any special treatment – rather, the CCAs look forward to a collaborative, streamlined process to allow CCAs to begin contracting with BioMAT projects under the same rules as the IOUs as soon as possible.

III. CAL ADVOCATES' ARGUMENT TO EXCLUDE FROM SCOPE THE POTENTIAL EXTENSION OF THE BIOMAT PROGRAM GIVEN DECISION (D.) 20-08-043'S ESTABLISHMENT OF A 2025 END DATE IGNORES THE COMMISSION'S AUTHORITY TO MODIFY ITS OWN DECISIONS

The Commission should reject Cal Advocates' argument to exclude from scope the potential extension of the BioMAT program which Cal Advocates states unnecessarily constitute "relitigation of recent revisions to the program."[5] Cal Advocates states:

> [t]he Commission already considered and extended the BioMAT program in D.20-08-043. Had the Legislature intended a CCA's participation to require program extension, it would have done so; AB 843 did not extend the program so there is no need to relitigate this issue here."[6]

While Cal Advocates is correct that AB 843 does not specifically address the extension of the program, the Commission has broad discretion pursuant to Public Utilities Code section 1708 to modify its own decisions.[7] To the extent the Commission decides that extending the BioMAT proceeding is appropriate, it has the authority to do so pursuant to section 1708. Cal Advocates argues that the Commission's recent extension of the program to December 31, 2025 renders unnecessary extending it again. However, the Commission should determine whether the program should be extended, especially given the legislative direction to add CCAs as procuring

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4 *Id.* § 399.20(f)(5)(K).

5 Cal Advocates Opening Comments at 1.

6 *Id.* at 2-3.

7 Pub. Util. Code § 1708 provides that "[t]he Commission may at any time . . . rescind, alter, or amend any order or decision made by it."

entities under the program. Accordingly, extending the BioMAT end date should remain in scope for the Commission's consideration.[8]

IV. THE JOINT IOUS' RECOMMENDATION FOR ONE WORKSHOP SHOULD BE ADOPTED, PROVIDED THE WORKSHOP IS HELD IN FEBRUARY AND ADDITIONAL WORKSHOPS CAN BE SCHEDULED IF NECESSARY

The recommendation of the Joint IOUs that a Workshop be held after the Prehearing Conference and issuance of the Scoping Memo and Ruling should be adopted.[9] However, the Commission should order the Workshop to be held in February 2023 (after the Prehearing Conference and the Scoping Memo being issued in January/February) instead of April 2023 (as recommended by the Joint IOUs). This schedule will allow for additional Workshops, if necessary, prior to the Proposed Decision being issued in Q3 2023, as set forth in the OIR.[10] CalCCA suggested in its Opening Comments that three Workshops may be necessary to address the various issues within scope. However, after discussing the Workshop schedule and proposed agenda with PG&E on behalf of the Joint IOUs, CalCCA agrees that beginning with one workshop is prudent, while leaving time for additional Workshops if necessary.

The Joint IOUs recommend a "BioMAT 101" format for the Workshop, to attain mutual understanding of how the BioMAT program functions to inform how CCA-based BioMAT procurement should be structured.[11] CalCCA recommends the following agenda for the first

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8 Similarly, the Commission should reject Cal Advocates argument to exclude from scope considerations regarding the application of BioMAT pricing to CCAs. Cal Advocates states the "[t]his issue should not be included in the scope because AB 843 does not change the BioMAT pricing methodology." Cal Advocates Opening Comments at 2. Cal Advocates states that the Commission has already fulfilled its obligation to establish a BioMAT pricing methodology and therefore CCAs must be subject to that methodology. However, the Commission's obligation set forth in Public Utilities Code section 399.20 regarding BioMAT pricing is ongoing, and the Commission has the authority to modify and update its previous determinations on BioMAT pricing related to both CCAs and IOUs.

9 *See* Joint IOU Opening Comments at 4.

10 OIR at 7.

11 Joint IOU Opening Comments at 4.

Workshop (and as stated above recommends additional Workshops if all of the items below cannot be addressed in the first Workshop):

1. BioMAT 101
    a. Tariffs
    b. Queue/tracking/program participation requests
    c. Contracting
        i. Pricing
    d. Contract administration
    e. Commission oversight
        i. Contract approval
        ii. Ongoing contract administration oversight
        iii. Cost recovery to ensure just and reasonable rates
    f. Programmatic improvement suggestions based on experience running BioMAT
2. Ideas for Incorporating CCAs into above aspects of BioMAT program
    a. CCA Contracts
    b. IOU queues/tracking/program participation requests
    c. Commission oversight of CCA BioMAT contracts
        i. Processes for
            i. Contract approval
            ii. Ongoing contract administration oversight
            iii. CCA Cost recovery to ensure just and reasonable rates

V. THE OIR PROPERLY PLACES WITHIN SCOPE THE PROCESSES FOR CCAS TO SUBMIT BIOMAT TARIFFS AND CONTRACTS TO THE COMMISSION

CalCCA agrees with Cal Advocates that the process for CCA BioMAT filings must be designated by the Commission.[12] Depending on the documents being filed (*i.e.*, standard contracts, tariffs, etc.), the Commission will need to determine the appropriate processes to

[12] Cal Advocates Opening Comments at 3-4.

ensure compliance with AB 843, Commission rules, and the due process rights of the public to review such filings.[13] As such, the OIR properly places within scope Commission determination of such processes.

VI. CONCLUSION

For all the foregoing reasons, CalCCA requests the adoption of the recommendations set forth herein.

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

December 13, 2022

[13] While Cal Advocates includes in its Opening Comments its legal argument as to why CCAs are not permitted by Commission rules to file Tier 1-3 Advice Letters, the Commission has required in several proceedings that CCAs submit such Advice Letters. For example, D. 22-07-008 (July 14, 2022) requires that CCAs wishing to obtain IOU data for Power Charge Indifference Adjustment (PCIA) forecasting purposes file a Tier 2 Advice Letter. In the Disadvantaged Communities Green Tariff/Community Solar Green Tariff context, the Commission requires CCAs to file Advice Letters for different approvals, including but not limited to: (1) a Tier 3 Advice Letter to propose an implementation plan (D.18-06-027, Ordering Paragraph 17, at 104 (June 22, 2028)); (2) a Tier 2 Advice Letter for approval of solicitation documents (Resolution E-5102 (Nov. 5 ,2020)); (3) a Tier 2 Advice Letter for approval of a power purchase agreement (Resolution E-5102); and (4) a Tier 2 Advice Letter to implement program eligibility changes (Resolution E-5212, Ordering Paragraph 4 (Oct. 6, 2022)).

California Community Choice Association

SUBMITTED 12/20/2022, 08:59 AM

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

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

The California Community Choice Association (CalCCA) thanks the California Independent System Operator (CAISO) for adopting its recommendation to allow conversions of exceptional dispatch or significant event Capacity Procurement Mechanism (CPM) capacity to Resource Adequacy (RA) capacity if a resource enters into an RA contract with a California Load Serving Entity (LSE) after being designated as CPM capacity. This will ensure the CAISO backstop does not usurp LSEs' abilities to meet their RA obligations, while also ensuring the capacity retains its must-offer obligation (MOO) and remains available to serve CAISO load.

CalCCA supports the CAISO's Revised Draft Final Proposal.

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

CalCCA has no additional comments.

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

CalCCA has no additional comments.

4. Please provide specific comments (if applicable) on the proposed classification of the stakeholder initiative as described in chapter 6

CalCCA has no additional comments.

California Community Choice Association

SUBMITTED 12/21/2022, 10:16 AM

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

1. **Please provide a summary of your organization's comments on the Day-Ahead Market Enhancements (DAME) Draft Final Proposal and the December 7, 2022 stakeholder call discussion:**

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the Day-Ahead Market Enhancements (DAME) Draft Final Proposal. CalCCA opposes the DAME draft final proposal subject to resolution of the issue of double payments to generators providing Resource Adequacy (RA) capacity. Under the DAME proposal, generators providing RA will be paid to be available to the real-time market once through the RA contact and again through the imbalance reserve (IR) or reliability capacity (RC) payment. Many RA contracts require the generator to transfer availability payments from the California Independent System Operator Corporation (CAISO) market to its load serving entity (LSE) counterparty. In today's market, RA resources bid zero dollars for their Residual Unit Commitment (RUC) availability bids and get paid zero dollars for their RUC awards. As such, many RA counterparties do not have the systems and processes in place to facilitate the transfer of such payments. Once DAME goes into effect and generators will be paid for their IR and RC payments, a settlement process must be in place to allow for the transfer of these payments from RA resources to LSEs.

To resolve this issue, the CAISO should allow inter-scheduling coordinator trades (ISTs), as proposed in the Fourth Revised Straw Proposal, for both IR and RC payments to allow RA counterparties to transfer IR and RC revenues consistent with their RA contracts. An IST Is a settlement service already offered by the CAISO to effectuate bilateral transactions between scheduling coordinators (SCs). The CAISO currently offers ISTs for energy, ancillary services, and unit commitment.[1] To enable ISTs when a resource sells only a portion of its capacity as RA to an LSE, the CAISO should allow the counterparties to set a percentage of its capacity that would be traded through the IST (rather than a specific megawatt (MW) amount). The CAISO will also need to differentiate the portions of the capacity payments that are attributable to the availability payments versus opportunity cost payments. While this may seem like it adds significant complexity, the CAISO will need to do this differentiation regardless, because under the draft final proposal, the CAISO proposes to provide the information necessary for counterparties to work out the transfer of revenues among themselves. This information necessarily includes the portions of the payments that are attributable to availability payments versus opportunity cost payments.

Allowing ISTs for IR and RC would not result in the CAISO getting involved in dictating the allocation of capacity payments between counterparties because ISTs are an optional service. Both counterparties would need to agree to the IST and have matching

ISTs for the CAISO to process the IST. Therefore, the CAISO would simply provide the settlement mechanism to facilitate what parties have already agreed to bilaterally.

In summary, the CAISO should adopt the IST functionality for IR and RC products to facilitate the settlement of revenues in a manner consistent with the RA contracts between generators and LSEs.

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[1] http://www.caiso.com/Documents/SIBRInter-SCTrades_IST_Tutorial.pdf.

2. Please provide your organization's overall position on the DAME draft final proposal:

OPPOSE WITH CAVEATS

For the reasons described above, CalCCA opposes the draft final proposal subject to resolution of the double payment issue.

3. Please provide a summary of your organization's comments on the summary of changes and responses to stakeholder feedback from the fourth revised straw proposal, as described in Section 1:

See response to question 1 above.

4. Please provide your organization's comments on the proposed resource adequacy day-ahead must-offer obligation for imbalance reserves as described in Section 3.2:

CalCCA supports the RA resources having a must offer obligation for imbalance reserves for the portion of their RA capacity that is not self-scheduled.

5. Please provide your organization's comments on the proposal to establish default bids for mitigation of imbalance reserve and reliability capacity, as described in Sections 3.2 and 3.4.

CalCCA has no comments at this time.

6. Please provide your organization's comments on the proposal to establish eligibility criteria to provide IRU based on a resource's day-ahead energy offer price, as described in Section 4.3:

CalCCA has no comments at this time.

7. Please provide your organization's comments on the proposed transitional measures for CAISO load-serving entities as described in Section 5, in context of the removal of inter-SC trading of imbalance reserves and the removal of the reverse settlement of reliability capacity revenue for RA capacity from the proposal:

As described in response to question 1, CalCCA opposes removing the ability for counterparties to use ISTs to transfer capacity payments from one counterparty to another from the proposal. The CAISO should allow ISTs for IR and RC to enable counterparties to effectuate the terms of their contracts with respect to how capacity payments from the CAISO market are allocated between the parties.

8. Please provide your organization's comments on the proposed WEIM Governing Body Role, as described in Section 7:

CalCCA has no comments at this time.

9. Please provide any additional comments on the Day-Ahead Market Enhancements (DAME) Draft Final Proposal and the December 7, 2022 stakeholder call discussion:

CalCCA has no comments at this time.