Regulatory Filings Packet

March 08 – April 05

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

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.19-11-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON TRACK 3B.2 PROPOSALS

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TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS

- Among other options, key elements of PG&E's "Slice of Day" structural proposal could be integrated with the SCE-CalCCA "net load duration curve" proposal to address temporal resource constraints.

- To address wholesale market price exposure concerns, the Commission could combine a bid cap requirement for RA resources or other price mitigation tools with the SCE-CalCCA framework.

- Staff's Standardized Fixed Price Forward Contract (SFPFC) proposal represents a material and unnecessary departure from the existing RA program, which would exacerbate existing procurement uncertainty, require a major rewrite of the California Independent System Operator (CAISO tariff), place wholesale suppliers in the role of ensuring sufficient supply, and introduce serious jurisdictional questions that present a barrier to timely implementation.

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON TRACK 3B.2 PROPOSALS

The California Community Choice Association[1] (CalCCA) submit these Comments in response to the *Assigned Commissioner's Amended Track 3B and Track 4 Scoping Memo and Ruling,* issued on December 11, 2020 (Scoping Ruling).

I. INTRODUCTION

CalCCA appreciates the opportunity to comment on the second revised structural resource adequacy (RA) reform proposals submitted by stakeholders, recognizing the considerable stakeholder efforts undertaken to refine these proposals. CalCCA's comments address the structural reliability-focused proposals advanced by Pacific Gas and Electric Company (PG&E) and the Energy Division Staff (Staff). These comments further respond to

[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, 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, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

proposals by PG&E and Staff aimed to mitigate load-serving entities' (LSEs') exposure to high prices in the wholesale energy market.

CalCCA's review of the revised proposals leads to three high-level conclusions:

1. Among other options, key elements of PG&E's "Slice of Day" structural proposal could be integrated with the SCE-CalCCA "net load duration curve" (NLDC) proposal to address temporal resource constraints.

2. To address wholesale market price exposure concerns, the Commission could combine a bid cap requirement for RA resources or other price mitigation tool with the SCE-CalCCA framework.

3. Staff's Standardized Fixed Price Forward Contract (SFPFC) proposal represents a material and unnecessary departure from the existing RA program, which would exacerbate existing procurement uncertainty, require a major rewrite of the California Independent System Operator (CAISO) tariff, place wholesale suppliers in the role of ensuring sufficient supply, and introduce serious jurisdictional questions that present a barrier to timely implementation.

Based on these conclusions, CalCCA recommends that the California Public Utilities Commission's (Commission's) Track 3B.2 decision direct stakeholders to move forward to refine and implement the SCE-CalCCA proposal, integrating beneficial aspects of the PG&E proposal where suitable. The Commission should also dismiss the Staff's "tear down and rebuild" approach to reliability policy, which would pose serious and unnecessary risk at a time when the industry most needs certainty and resolve to move forward.

II. ELEMENTS OF PG&E'S SLICE OF DAY PROPOSAL COULD BE INTEGRATED WITH THE SCE-CALCCA PROPOSAL TO ADDRESS TEMPORAL ISSUES ASSOCIATED WITH USE-LIMITED RESOURCES

Several parties have raised concerns with the lack of explicit representation of temporal cycles within the SCE-CalCCA proposal, identifying the potential for some hypothetical portfolios that meet the proposed Net Qualifying Capacity (NQC) and Net Qualifying Energy (NQE) tests but could overlook temporal constraints related to storage or other use-limited resources. As SCE and CalCCA pointed out in their Second Revised Proposal,[2] there are several potential approaches to addressing these issues. An approach could be developed using a two-step process, integrating the SCE-CalCCA and PG&E frameworks.

Assessing the reliability of an LSE's portfolio could begin with the SCE-CalCCA NLDC approach as a foundation, including the netting of solar and wind energy against demand. The sufficiency of NQE and NQC could be tested against the net load duration curve for compliance, as SCE and CalCCA propose. PG&E observes that netting could be beneficially used in conjunction with its Slice of Day approach; "[s]olar and wind resources could benefit by not losing some production around the margin of the slices…."[3] Netting wind and solar would also reduce the complexity of determining slices.[4] And the obvious benefit of avoiding the need for ELCC calculation is retained by using netting.

To test for temporal problems within an LSE's portfolio for use-limited resources that are not netted, the PG&E Slice of Day approach could be layered as a second sufficiency test. A "slice" test could be implemented in a variety of different ways. For example, in a monthly compliance framework the test could examine temporal sufficiency during [the most challenging] "slice" for each defined period. One test slice could come from one day, while the other test slices could come from other days within the month. Alternatively, the test could examine a single representative day in the month and test for sufficiency during each slice of that

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[2] *See Southern California Edison Company (U 338-E) and California Community Choice Association's Revised Track 3B.2 Proposal*, Dec. 18, 2020, at 5-7. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M356/K239/356239899.PDF

[3] *Revised Track 3B.2 Proposals of Pacific Gas and Electric Company (U 39 E)* (PG&E Second Revised Proposal) at A1-7. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M355/K770/355770980.PDF

[4] *Ibid.*

day. No doubt there are other permutations that could be considered. As a simplification, the test could be applied without tying the assessment to slice-specific must-offer obligations.

CalCCA remains concerned about PG&E's treatment of the Must Offer Obligation (MOO) under its proposal. PG&E originally proposed that a resource's MOO would apply to both the day-ahead and real-time markets and would only apply to the slice-of-day for which the resource was shown.[5] Requiring performance and assessing penalties only for a resource's slice-of-day could be overly restrictive for storage and have other implications for resources. Recognizing these concerns, PG&E modified the proposal in its Second Revised Proposal to limit this restriction to only the day-ahead market and to allow storage to change the slice in which it is offered.[6] While this is a substantial improvement, if the slice-of-day construct is applied as a modeling overlay to the SCE-CalCCA proposal, a MOO may not be required. CalCCA looks forward to further discussions with PG&E on this issue.

In short, PG&E's proposal presents interesting ideas to address the temporal issues raised in stakeholder comments on the SCE-CalCCA proposal. The Commission should move forward into a separate Track of this proceeding to begin refining the SCE-CalCCA proposal to address these issues with confidence that a variety of workable solutions – including integrating a slice of day approach – are available.

III. STAFF'S PROPOSAL REMAINS PLAGUED BY A LACK OF CLARITY, UNCERTAINTY, HEIGHTENED RELIABILITY RISK, AND VERY LIMITED STAKEHOLDER SUPPORT

CalCCA appreciates Staff's clear efforts to step back from the existing RA program to explore an entirely new approach to reliability. A new approach, however, is not always a better

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5 *Second Revised Track 3B.2 Proposals of Pacific Gas and Electric Company (U 39 E)*, Feb. 26, 2021, at A1-27. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M369/K237/369237336.PDF

6 *Id.* at A1-28.

approach, as California demonstrated with its Power Exchange experiment in the late 1990s. In the same way, the SFPFC presents too many challenges and risks to gain the shared confidence of stakeholders and policymakers.

The SFPFC proposal designed by Dr. Wolak, despite Staff's best efforts to elaborate on the approach, continues to escape the understanding of many stakeholders. It also remains mired in questions related to its effectiveness in improving reliability, its delegation of the reliability function to wholesale suppliers, the probability for the entirely new approach to disrupt the market, and its conformance with federal law. Regardless of its academic and theoretical merit, the construct, with all of its complexities, cannot be implemented on a time scale that can support reliability needs through the 2020s.[7] Further, the consideration of such an approach risks causing considerable delay for developers and LSEs in the process of making necessary reliability investments.

While all modifications of the RA program will require a transition, none compare with the level of disruption involved in the SFPFC proposal's foundational, dimensional shift from capacity and resource availability requirements to an energy hedging requirement. This change would necessitate the renegotiation of all existing long-term contracts, and worse, the required new provisions are both undefined and untested. This is well beyond minor modifications to provisions surrounding bidding, availability, or other issues that may be required under other proposals.

It is time to close the book on the SFPFC and move on to less seismic, yet equally effective, change. Instead of continuing to sink time into explaining and exploring the SFPFC,

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7 *See* Presentation, Day 3 of Track 3.B.2 Workshops, Feb. 10, 2021, at 66. https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/Day%203%20Track%203.B.2%20ED%20Frank%20Wolak%20CAISO%20Slides%2020210210.pdf

the Commission should dedicate resources to refining the SCE-CalCCA proposed net load duration curve framework to meet the state's reliability goals.

IV. IMPLEMENTING THE SFPFC THROUGH A CENTRALIZED MARKET PRESENTS MYRIAD CHALLENGES AND RISKS TO RELIABILITY AND MARKET OPERATION

CalCCA raised numerous objects to the implementation of the SFPFC as a centralized market in its initial comments on the SFPFC proposal.[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;
- Imposes structural reliability risks by shifting the supply planning responsibility from regulators and LSEs to energy suppliers;
- Violates Public Utilities Code §380(b)(5) and §380(h)(5) by failing to "maximize" 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.

CalCCA has also raised questions about how the proposal would integrate with the existing Renewable Portfolio Standard (RPS) and Integrated Resource Planning (IRP) programs.

A. The Addendum Does Not Resolve These Issues

Despite workshops and video conferences to further illuminate the SFPFC, neither clarity nor certainty that this model could overcome these shortcomings have emerged. The most recent revision,[9] while attempting to address some of these issues, also falls short.

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[8] *California Community Choice Association's Comments on Track 3B.2 Proposals*, Jan. 15, 2021, Section II. at 3-31. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M360/K563/360563778.PDF

[9] Addendum to Staff Draft Straw Proposal for Consideration in Track 3B.2 of Proceeding R.19-11-009, Feb. 26, 2021 (Addendum).

First, the Addendum tries to explain away the question of fit with the existing RPS program.[10] The Addendum provides a numerical example demonstrating that LSEs may still sign additional bundled RPS hedges under the SFPFC construct, which does not address the problem. It continues to leave unclear how in aggregate this approach does not lead to systematic overhedging as LSEs pay for their full allocation of SFPFC energy equal to 100% of realized system load, in addition to increasing amounts of bundled RPS energy. It is also unclear why renewable resource owners with bundled RPS PPAs would opt to participate in the SFPFC market, given the considerable risk for a renewable resource to commit to supplying a firm energy product, if their net revenues only offset PPA payments.

Second, the Addendum speaks to interactions of the SFPFC with the IRP process.[11] The Addendum's answer to the concern regarding IRP interaction is that the Commission could simply "order" an LSE to construct a resource to meet the state's goal and force the resource to monetize its firm energy value in the SFPFC market. This proposal overlooks the fundamental concerns of relegating LSEs to purely backstop, ordered procurement, and primarily relying on suppliers to develop new resources consistent with meeting IRP goals.

Furthermore, since LSE profiles differ in their required characteristics, this framework would eliminate the characteristics of their own portfolios. For example, it would become extremely complicated for the central auction entity to ensure that the energy delivered to some LSEs meet 100% renewable requirements according to a winter peaking shape, while other LSEs may have different requirements of minimal renewable content according to the load profile of their customers. Where LSEs have policies against certain technology types, such as biomass or nuclear, the accounting the Central Auction Entity would have to engage in to ensure that its

10 *Id.* at 9.
11 *Id.* at 10-11.

process can deliver energy according to these requirements would be fantastically complex. The Central Auction Entity would need to deliver bespoke portfolios to each individual LSE AFTER aggregating the resources procured by each LSE. This is unworkable.

Since independent suppliers would exist outside of the IRP framework, there would be no mechanism to ensure that the resources built would meet the cost, reliability, resource diversity, or emissions goals. Suppliers are not required to plan to any GHG target, leaving no barrier to building and offering large amounts of fossil resources to the auction. In addition, it is not clear how the Commission could enforce requirements, for example, for baseload renewables or long duration storage. At best, IRP orders would result in duplicative procurement, and at worst this unregulated system would cause the state to miss emissions targets or other needs. Finally, with procurement utterly divorced from the IRP's cost optimization modeling, there is almost no chance that the portfolio created by supplier procurement would resemble the lowest cost approach to decarbonization.

Third, the Addendum devotes three short paragraphs, with no legal analysis, to the concerns raised by CalCCA and others over jurisdictional problems with the proposal.[12] The Addendum attempts to compare the mechanism – which involves a wholesale sale of an energy product – to the greenhouse gas emissions market run by the California Air Resources Board. FERC does not regulate GHG allowances, and the jurisdictional boundary between state and federal regulation of GHG remains complex. The discussion also suggests that no sale of energy is taking place, suggesting this is only a financial product; yet the Addendum fails to address the potential jurisdictional issues arising with the Commodities Futures Trading Commission over derivatives. The Addendum fails to advance the jurisdictional discussion.

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[12] Addendum at 16.

Fourth, given the challenges to the centralized SFPFC structure, the Addendum contemplates converting the SFPFC into a bilateral trading structure.[13] It appears to be a "residual" framework that requires LSEs to procure sufficient quantities of SFPFC products to meet their requirements. In addition, there would be a centralized backstop auction "where the CPUC purchases the aggregate shortfall of each quarterly SFPFC product and allocates the purchases of each SFPFC product to each LSE with a compliance shortfall for that product…."[14] CalCCA has previously supported adoption of a residual capacity-based RA structure with a centralized backstop.[15] These rules, however, lack any detail or clarity. Moreover, requiring individual LSEs to fully hedge their demand with purchases of SFPFC energy through bilateral negotiations will cause immense market friction, increase complexity and raise the costs of achieving reliability. The fundamental question remains, however: why is the SFPFC product – a new and entirely untested product – the right reliability solution?

Indeed, the bilateral structure loses several key policy goals of the SFPFC structure. The proposal retains the bilateral structure of the current RA program, maintaining and arguably expanding current market friction based on the greater complexity of the program relative to current rules. Further, ensuring and enforcing uniformity of LSE compliance instruments under a paradigm which relies entirely on individual suppliers to manage the risk associated with offering a firm energy product guarantees an administrative and enforcement nightmare. At a minimum, the proposal would require significant administrative oversight to collect and review LSE compliance submissions.

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13 *Id.* at 11-12.

14 *Id.* at 11.

15 *See generally Joint Motion of California Community Choice Association et al. for Adoption of a Settlement Agreement for a "Residual" Central Procurement Entity Structure for Resource Adequacy,* Aug. 30, 2019. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M313/K990/313990742.PDF.

Fifth, the SFPFC – whether centralized or bilateral – still does not address the risk of entities failing to procure enough energy or taking calculated risks that market energy will be available. While the proposal criticizes LSEs for not having incentives to fully procure because the costs of outages are shared across all LSEs, the same incentive structure would exist for suppliers in this framework. Suppliers would still face a temptation to under procure or contract with resources that may not perform, because the cost of the outages would be borne by customers. Unlike LSEs, these suppliers would not be answerable to those customers. All the SFPFC accomplishes is moving the same risks to a different set of parties.

It seems the same results could be achieved with less disruption by continuing with a more rigorous RA capacity counting regime, a solid IRP process, and a price mitigation measure such as a bid cap. Moreover, the Addendum devotes roughly a page of ink to the proposal, compared with months of development and pages of explanation of the residual methodology proposed by CalCCA and other parties – a proposal the Commission concluded was insufficient in detail.[16]

The bottom line is that after nearly two years of ruminating,[17] the SFPFC proposal remains complex and ill-defined. Unlike the other proposals presented to the Commission, the questions that remain are not simple implementation questions, but foundational legal and policy questions. And the continuing shifting and pivots to try to make this proposal workable are unproductive and only add confusion. It is time to close the book on this proposal.

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[16] D.20-06-002 at 18, Ordering Paragraph 1 at 90.

[17] Dr. Wolak first presented the concept in a Commission workshop on November 1, 2019. file:///C:/Users/EvelynKahl/Downloads/CPUC_Resource_Adequacy_Sacramento-Wolak.pdf

B. The SFPFC Proposal is the Wrong Proposal in Light of the Recent ERCOT Problems

The SFPFC proposal would shift the RA framework from one which is based on clear, legal and financial obligations to participate in the CAISO market to one which relies solely on financial incentives to elicit supplier performance. Without establishing (or at least without articulating) any resource counting structure beyond "quarterly firm energy," the proposal puts a remarkable degree of faith in the ability of suppliers to forecast, plan for, and ultimately fulfill their (financial-only) obligation to provide sufficient energy during all hours of need under the foreseeable range of conditions. Not only does this approach bring back memories of the failed Power Exchange energy-only structure, it triggers more recent memories of disastrous consequences for such a structure.

CalCCA is deeply concerned that this framework – with strong parallels to the energy-based financial incentive structure in the Electric Reliability Council of Texas (ERCOT) – is insufficient to plan for the broad range of contingencies which the RA fleet must be capable of meeting to reliably serve load. Moving forward, the RA fleet will be required to meet not only peak constraints, but also a wide variety of conditions which impact both supply and demand. As an example, in addition to extreme cooling demand, the August 2020 events included significant cloud cover and reduced wind.[18] Assessing and planning for the wide range of risks associated with meeting system needs with low-carbon resources during a period of growing weather uncertainty is a task which will require the best collective efforts of regulators, LSEs, and generators. It would be as imprudent to pass this complex and unpredictable task to the invisible

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[18] Root Cause Analysis at 21; http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

hand of the market as it would be to defer the same decision-making regarding the weatherization of fossil units in northern Texas.[19]

C. The SFPFC Proposal Would Further Bifurcate Commission-Jurisdictional Reliability Product Trading from California and Regional Trading Partners

The complex jurisdictional overlay which divides LSE reliability policies along balancing authority, state, and other jurisdictional lines is an unfortunate reality which can create friction and confusion in reliability planning and product trading. For example, Commission-jurisdictional LSEs must follow Commission-established RA requirements, non-Commission-jurisdictional LSEs in CAISO must follow CAISO-established RA requirements, non-CAISO municipal utilities are not subject to any resource adequacy policy, and WECC utilities outside California are only recently beginning to explore a voluntary resource adequacy program. The complex Venn diagram of obligations has led to some complexities in defining CPUC and CAISO RA rules in a manner which supports the use of "standard trading products" across the western market. CalCCA agrees that this is a beneficial policy goal.

The SFPFC proposal would turn such a policy goal on its head. Under the SFPFC proposal, Commission-jurisdictional LSEs would enter a new and wholly separate RA paradigm from any which is implemented or under consideration anywhere in the west. Commission-jurisdictional LSEs (and suppliers) would be obligated to be prepared to meet their entire load with energy hedging instruments which are a significant departure from current hedging products and are generally not offered in the market at volumes on the order of what is expected in this construct. As CAISO described during the February 10, 2021 workshop, the SFPFC proposal

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19 Generators within ERCOT are encouraged to follow voluntary best practices for weatherization; however, ultimately, weatherization is an economic decision for individual resources. http://www.ercot.com/content/wcm/key_documents_lists/186082/ERCOT_Weatherization_Workshop_2019_2020_Final.pdf; https://www.powermag.com/ercot-lists-generators-forced-offline-during-texas-extreme-cold-event/

would require a "radical overhaul" of its tariff, and conflict with other LRA's that retain capacity-based reliability constructs.[20]

In contrast, the Commission now has three thoughtfully articulated proposals from market participants which build upon the current framework and reflect the best efforts by market participants to balance necessary added complexity and improved accuracy with administrative simplicity, market liquidity, and other practical concerns. While the proposals from PG&E, SDG&E, and SCE-CalCCA differ significantly in their mechanics, the fundamental frameworks and intended enhancements are directionally consistent, compatible with state and federal law, comprehensible to market participants, and, most significantly, can be implemented without introducing years of planning and procurement limbo which would occur should the RA program be obliterated and rebuilt as a centralized forward energy hedge requirement.

CalCCA strongly encourages the Commission to move forward in its June decision with a robust, functional evolution of the RA program which draws from the best elements of the proposals submitted by market participants, and to withdraw the looming specter of an energy hedge focused restructuring which could abrogate thousands of megawatts of RA contracts designed around the current structure.

V. ADOPTING A HEDGING OR PRICE MITIGATION TOOL ALONG WITH THE SCE-CALCCA PROPOSAL WOULD ENSURE THE COMMISSION'S OBJECTIVES ARE FULLY ADDRESSED

Staff have made clear from their initial proposal their intent to address not only reliability, but the price effects of market power.[21] While the SCE-CalCCA proposal improves

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[20] *See* Presentation, Day 3 of Track 3.B.2 Workshops, Feb. 10, 2021, at 66. https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/Day%203%20Track%203.B.2%20ED%20Frank%20Wolak%20CAISO%20Slides%2020210210.pdf

[21] *See Administrative Law Judge's Ruling on Energy Division's Track 3.B. Proposal*, Aug. 8, 2020, Appendix A (Initial Staff Proposal) at 18.

reliability, it has no effect on the potential exercise of market power. Consequently, to achieve both Staff objectives requires adoption of a hedging or price mitigation tool to complement the SCE-CalCCA proposal. CalCCA supports further examination of such tools.

Three parties have advanced potential solutions to address market power. PG&E was the only party submitting a revised proposal dedicated to market power mitigation, including two variations on a proposal that financially simulates a tolling agreement. While not primarily focused on market power mitigation, the SFPFC proposal is also intended to provide market power mitigation benefits (primarily through ensuring LSEs are uniformly long). Additionally, while not revised, Energy Division's bid cap proposal is intended to reduce market power exercise by resources in the RA fleet.

Despite previously stated concerns,[22] CalCCA supports further consideration of tools aimed to mitigate price risk to LSEs, including the Staff's bid cap proposal. Staff reasonably observes that the expected frequency of energy scarcity events is likely to grow as a result of tightening capacity across the west[23] with price implications. Under these conditions, LSEs should endeavor to manage their physical and financial positions to mitigate price exposure. CalCCA agrees that price mitigation is an important element of risk management in the face of the potential scarcity events; one only need examine the price consequences in the recent ERCOT event -- where wholesale prices rose to $9,000/MWh -- to solidify that point of view. The structure and cap level of any price mitigation tool and the extent of supply covered within

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[22] *California Community Choice Association's Comments on Track 3B.2 Proposals*, Jan. 15, 2021 (CalCCA Comments), at 31-33. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M360/K563/360563778.PDF In addition, CalCCA observes that the RA program is the appropriate avenue to incorporate market power mitigation requirements given the limited ability of the RA program to influence clearing prices during WECC-wide scarcity events which are likely to drive extreme energy prices.

[23] Initial Staff Proposal at 23-24. 32. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M344/K182/344182682.PDF.

an LSE's portfolio (*e.g.*, 80 percent) merit further discussion once the Commission adopts a direction for the reliability solution.

If the Commission intends to move forward with the incorporation of market power mitigation requirements into the RA program, CalCCA urges the Commission to do so in a manner that complements the SCE-CalCCA reliability proposal and is least disruptive of existing contracts and on-going contracting. Specifically, CalCCA recommends that the Commission impose the price mitigation measure *on only new contracts*, executed after the date of this decision. Imposing a bid cap on existing contracts risks either causing massive renegotiation of numerous contracts under a change-in-law provision or abrogating the contract altogether. Limiting any price mitigation tool to *existing* contracts, instead, would allow LSEs and suppliers time to develop an understanding of how to incorporate and execute these terms without the need to renegotiate existing contracts. In addition to considering existing contracts, the Commission should not adopt a market power mitigation proposal that would require significant after-the-fact review of contestable facts, such as the "true" marginal cost of generators. On a regular basis, the Commission should revisit the bid cap and examine whether the amount imposed results in effective market mitigation, but not at the expense of discouraging new resource development. Finally, the Commission should avoid requiring LSEs and suppliers to agree to specific hedging provisions. While hedging provisions within an RA contract in the form of a bid cap may be mutually beneficial for LSEs and suppliers, there are many circumstances for which the proposed hedging requirements contained within the SFPFC proposal and PG&E's pseudo-tolling proposal would leave LSEs overhedged.

VI. CONCLUSION

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

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021.	R.20-11-003

COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE PROPOSED DECISION

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TABLE OF CONTENTS

TABLE OF AUTHORITIES

Other Authorities

Rules

**BEFORE THE PUBLIC UTILITIES COMMISSION
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Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021.	R.20-11-003

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

The California Community Choice Association[1] (CalCCA) submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022* (Proposed Decision) issued on March 5, 2021.

I. INTRODUCTION

CalCCA appreciates the Commission's swift action to address potential reliability events. The Proposed Decision appropriately focuses immediate efforts on the expansion of demand-side solutions, including demand response activities, a new emergency load reduction program (ELRP), and establishment of critical peak pricing (CPP) programs. The Proposed Decision's

[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, 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, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

application of the increased Planning Reserve Margin (PRM) directly to the IOUs – rather than to individual LSEs through 2021 RA requirements – will ensure procurement while avoiding unnecessary disruptions to an already tight RA market. CalCCA has a few concerns, however, with the Proposed Decision.

First, the Proposed Decision, while setting a lower "target" for procurement, essentially approves unlimited procurement for 2021 and 2022 without any rigorous analysis of needs. CalCCA encourages the Commission to limit the directives to 2021 and make the directives subject to a total cap at 150 percent of the targets. Any future procurement orders must be rooted in reliable analyses and appropriately bounded to ensure customers pay only for what is necessary for reliability.

Second, while CalCCA appreciates the Commission's interest in the implementation of critical peak pricing (CPP) programs by all load-serving entities (LSEs), it is unlikely that Community Choice Aggregators (CCAs) will be able to add new programs or expand existing programs for summer 2021. Moreover, as CalCCA explained in testimony, other barriers remain to implementation that have not been addressed. The Commission should realistically focus its efforts on solving these issues for program implementation beyond 2022. In the meantime, however, the Commission should better define the rules around CCA participation in other programs the Commission aims to adopt in this proceeding, namely the ELRP, to clarify how all eligible unbundled customers may participate in this program, what role CCAs would play in the administration of the program, and how costs will be allocated.

II. THE COMMISSION SHOULD LIMIT ITS CONCLUSIONS TO SUMMER 2021 AND CAP PROCUREMENT AT 150 PERCENT OF THE TARGET, RETURNING FOR 2022 TO PROCUREMENT ORDERS BASED ON FULL AND ACCURATE NEEDS ASSESSMENT

The Proposed Decision finds a need for incremental resources "to address grid needs during the system peak and net peak demand periods for summer 2021 and 2022 …."[2] The Commission then sets a low-side target for procurement of 1000 MW total, divided among the IOUs, but places no hard cap at the top.[3] While CalCCA supports this target for Summer 2021 in light of "emergency" conditions, extending the order to 2022 without rigorous analysis or a hard cap takes a step too far. The Commission's directives should be limited to Summer 2021 with a clear path to a more detailed, rigorous analysis of needs for Summer 2022. The directive should also be subject to a hard cap on total procurement.

CalCCA recommended an upper bound on any emergency procurement of 1073 MW, to be in place until further analysis establishes a more concrete analysis of need.[4] CalCCA therefore supports the Commission's proposed decision to increase the IOUs' PRM by 2.5 percent as a stopgap measure. This equates to a minimum procurement target of 450 MW for PG&E, 450 MW for SCE, and 100 MW for SDG&E, based on 2.5 percent of the CPUC jurisdictional share of CAISO peak load per the California Energy Commission's 2021 Integrated Energy Policy Report forecast.[5]

CalCCA does not, however, support the absence of a hard cap. The Proposed Decision provides no cap on total procurement, limiting only generation and front-of-meter resources to 150 percent of each IOU's target.[6] In fact, "IOUs are to consider their respective upper end

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2 Proposed Decision, Finding of Fact 5, at 48.
3 *Id.*, Ordering Paragraph 11, at 66.
4 Exhibit CCCA-1 at 3.
5 Proposed Decision at 39.
6 *Id.* at 40.

targets as 'soft caps' for all resources authorized for procurement in this proceeding" except with respect to incremental supply side generation and in-front-of-meter storage resources.[7] But all new procurement – whether in front of or behind the meter – will come at a cost to customers. A total cap is therefore appropriate for 2021 and should be set at 150 percent of the lower bound target.

In addition, CalCCA continues to stress the need for further analyses before ordering procurement beyond 2021. CalCCA observed *nearly two years ago* that a more robust assessment than the stack analysis prepared by Staff was needed to have greater confidence in any procurement order.[8] The Proposed Decision, once again, relies roughly on a stack analysis, in this case one presented by CAISO.[9] CalCCA urged the Commission to authorize or direct a more suitable loss of load expectation analysis, as the only such analysis presented (by Southern California Edison) merits further review.[10] In fact, the existing loss of load expectation analysis does not support the conclusion reached by the stack analysis.[11] Similarly, the Commission's recent ruling the R.20-05-003, examining replacement of the Diablo Canyon Power Plan, once again relies on a stack analysis.[12] Due to recurrent "emergencies," deeper analysis continues to give way to back-of-the-envelope calculations. Ultimately, the Commission and CAISO will need to determine the correct PRM based on a judgment about the optimal and acceptable

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7 *Ibid*.

8 *Opening Comments of California Community Choice Association on Assigned Commissioner and Administrative Law Judge Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues*, July 22, 2019, at 9-17. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M310/K224/310224703.PDF

9 *Comments of the California Independent System Operator Corporation on Order Instituting Rulemaking Emergency Reliability*, November 30, 2020.

10 Exhibit CCCA-1 at 4.

11 *Id*. at 6.

12 *Administrative Law Judge's Ruling Seeking Feedback on Mid-Term Reliability Analysis and Proposed Procurement Requirements*, Feb. 22, 2021, at 9-10.

probability of an outage. A PRM that is too low will lead to outages which damage customers and economic activities, while a PRM that is too high results in wasted customer costs. Given the vast sums of money at stake, developing a PRM warrants a more rigorous analysis than the back-of-the-envelope analyses that have been conducted to date.

California customers are being asked to fund virtually unbounded procurement to address a need that has not been properly quantified. While there is little choice for summer 2021, surely there is adequate time before Summer 2022 to reconcile any inconsistencies in current analyses, and assess the progress made through the efforts taken this year. Any procurement ordered in the Commission's final order should be limited to 2021 and limited to 150 percent of the lower bound target procurement.

III. CCA CPPS ARE UNLIKELY TO BE IN PLACE BY SUMMER 2021

As noted, CCAs support the Commission's efforts to reduce the likelihood of reliability events to the extent practicable. It is unlikely, however, that CCAs will be positioned to implement or expand CPP programs for Summer 2021.

The Proposed Decision notes the Commission sees "an opportunity for CCAs and electric service providers (ESPs) to contribute to the reliability of the electric grid during peak demand days by proactively launching and expanding CPP programs."[13] Therefore, the Commission directs the IOUs to host a workshop on non-IOU CPP programs by April 7, 2021, to facilitate a peer knowledge exchange on the topic for summer 2021 and to identify barriers and solutions to non-IOU LSE program expansion.[14] In addition, the Commission "strongly encourages" CCAs and ESPs to take steps to launch or expand existing non-IOU CPP programs by summer 2021

[13] Proposed Decision at 15.
[14] *Ibid*.

(and by extension, summer 2022), and encourages non-IOU LSEs to conduct CPP program load impact and cost effectiveness studies after this summer to inform the development of policies to expand programs in summer 2022.[15]

Despite the support for CCA CPP programs, the Proposed Decision does not address the challenges CalCCA noted to further CPP development. For example, CCAs have encountered difficulty in receiving appropriate and accurate interval data from the IOUs necessary for the calculations to implement a CPP program.[16] To help alleviate this issue, CalCCA supported UCAN's proposal to require the IOUs to enter into Service Level Agreements with CCAs to enable the requisite data to be provided. Pioneer Community Energy also expressed concerns that the technical requirements for a CCA to implement CPP are complex, and in its case would require significant technical modifications, and a lengthy board approval process.[17] Finally, CCAs that so far implemented CPP-like programs are generally still reviewing the results of recently-implemented, small-scale programs.[18] The overall benefits of such programs, including load reduction, have yet to be fully analyzed and have not so far been implemented to scale.

CalCCA appreciates the urgency of the potential reliability needs this summer and intends to do what is in its power to continue to aid in efforts to strengthen the grid's reliability. CalCCA members welcome the opportunity to share knowledge with the IOUs and look forward to creating CPP programs or other load-shifting programs suited to their local service areas. However, the implementation issues raised will continue to impede CPP development. Thus, CalCCA urges the Commission to recognize that even with diligent effort, CCAs' adoption of full-scale CPP-like programs is unlikely to be immediate.

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15 *Ibid*.
16 Exhibit CCCA-1 at 26.
17 *Id*. at 25.
18 *See Id*. at 26-29.

IV. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

EVELYN KAHL
General Counsel
California Community Choice Association

March 15, 2021

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	R.11-05-005

RESPONSE OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION TO JOINT PETITION FOR MODIFICATION OF DECISION 13-05-034 BY PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) AND SOUTHERN CALIFORNIA EDISON COMPANY (U 338 E)

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March 15, 2021

Table of Contents

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	R.11-05-005

RESPONSE OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION TO JOINT PETITION FOR MODIFICATION OF DECISION 13-05-034 BY PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) AND SOUTHERN CALIFORNIA EDISON COMPANY (U 338 E)

Pursuant to Rule 16.4(f) of the Rules of Practice and Procedure of the California Public Utilities Commission's (Commission), the California Community Choice Association (CalCCA)[1] hereby submits this response to the Petition for Modification of Decision (D.) 13-05-034 by Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) (collectively, the Utilities).

I. INTRODUCTION

The Utilities seek modification of D.13-05-034 to authorize the cost recovery of all existing and future Renewable Market Adjusting Tariff (ReMAT) contracts through the Public Purpose Program charge (PPPC).[2] They base their request on grounds that all customers benefit

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[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, 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, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

[2] *See generally Joint Petition for Modification of Decision 13-05-034 by Pacific Gas and Electric Company (U 39 E) and Southern California Edison Company (U 338 E)*, Feb. 11, 2021 (noticed on Feb. 18, 2021) (Petition).

"equally" from these contracts. While the Utilities propose that costs be allocated to all customers, they propose to retain the resource adequacy (RA) and renewable portfolio standard (RPS) benefits for bundled customers.[3]

As an initial matter, the Petition lacks clarity. In one place the Petition requests that the "*all costs*" of these contracts be recovered through the PPPC,[4] yet elsewhere Petition requests PPPC recovery of "existing ReMAT contract *above-market costs* (and above-market costs of future ReMAT contracts)."[5] In addition, CalCCA continues to have concern about the ongoing trend of "de-vintaging" costs and which is slowly eroding the Power Charge Indifference Adjustment (PCIA) methodology by shifting IOU costs onto customers who have departed IOU service. Most troubling, however, the Utilities' proposal retains the prime benefits of these contracts – RA and RPS attributes[6] – for bundled customers while asking departing load customers to share the burden of above-market costs.

The Commission should reject the Petition. The PCIA was designed precisely to for this purpose: equitable recovery of the above-market costs of utility-procured resources, including RPS resources. ReMAT contracts are simply above-market RPS resources and thus are well-suited to PCIA recovery. In addition, not all customers benefit equally, as the Utilities suggest. The prime benefits of these resources – energy and Renewable Portfolio Standard (RPS) credit -- accrue to bundled customers. To ask all customers to pay the costs of the resources without sharing equally in the benefit effectuates a cost shift from bundled to departing load customers. On these and other grounds, Commission should reject or materially modify the Petition.

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3 Petition at 11. The Utilities propose that bundled customers will pay the Power Charge Indifference Adjustment (PCIA) market price benchmark (MPB) for the attributes.
4 Petition at 11.
5 Petition at 6.
6 Petition at 11.

If the Commission nonetheless grants the Utilities' request for PPPC recovery of ReMAT costs, it should make three important changes. First, the Commission should clarify that the PPPC would recover *all* ReMAT costs, not simply the above-market costs. Second, the Commission should ensure that all customers paying the costs of these resources benefit equally. Any ReMAT resource products or attributes – chiefly the RPS credit -- must be allocated on a long-term basis to all customers paying the PPPC. Third, the Commission should make ReMAT funding available to Community Choice Aggregators (CCAs) on behalf of their customers under the same terms and conditions that apply to the Utilities.

II. BUNDLED CUSTOMERS ARE THE PRIME BENEFICIARIES OF REMAT CONTRACTS

The Utilities' proposal rests squarely on premise that the ReMAT contracts benefit *all* customers *equally* because the contracts "serve California's broader public policy goals and irrespective of the Utilities' customers' needs."[7] CalCCA submits that ReMAT contracts do not provide unique policy benefits, and contract benefits are not shared equally.

The Utilities argument that ReMAT "benefits" all customers rests on the claim that ReMAT procurement "serves California's broader public policy goals." CalCCA does not disagree that the contracts serve public policy goals, but these benefits are not unique and these benefits are not the only benefits of these resources. The Utilities' argument ignores CCA RPS procurement – procurement that often goes beyond the minimum compliance requirements – which also serves California's goals. CCAs likewise have their own unique requirements, such as accelerated RPS and GHG-free energy procurement requirements.[8] CCA procurement and

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[7] Petition at 6.

[8] For example, Peninsula Clean Energy's board has adopted requirements of 100% carbon free energy by 2021 and 100% renewable by 2025. (see https://www.peninsulacleanenergy.com/wp-content/uploads/2020/06/PCE-Strategic-Guide-Online-W.pdf?utm_source=strategy_page&utm_medium=website_innnerclick&utm_campaign=PDF_Tracker)

tariffs, like ReMAT contracts, "serve California's broader public policy goals," but the CCAs' customers alone bear cost responsibility. Moreover, if "public benefit" were the only requirement to justify allocating costs to all customers, all RPS procurement in the Utilities' portfolios would qualify. The rationale is not sound and would effectively unravel the existing PCIA methodology.

The Utilities' argument that the benefits are "equal" similarly misses the mark. Bundled customers and departing load customers ***do not*** share equally in the benefits of ReMAT contracts. Because these contracts are part of the PCIA portfolio, Utilities have the "right of first refusal" to receive the energy, RA, and RPS credit associated with these contracts, as they do for all PCIA resources. The resources can be retained to serve bundled load or sold in the market, at the utility's discretion. Furthermore, the IOU argument that these resources are procured indifferent to bundled customer need ignores the fact that IOUs are fully capable of planning their RPS and RA procurement in light of these contracts in their portfolios. Departing load customers who are equally obligated to pay the above-market costs of these resources do not share in this benefit. They have access to these valuable attributes only if the Utilities decide they do not need these attributes for bundled customers. Even then, the access may be only short-term, while the Utilities' have a long-term call on the resources. The Utilities do not propose in the Petition to give up these benefits but seek to retain the RA and RPS attributes associated with the contracts.[9] Beyond a doubt, bundled customers alone receive the ***direct*** benefits of these contracts.

Not only do the Utilities fail to call out these bundled benefits, but they are not accounted for in the costs identified in the Petition. The Petition states:

[9] Petition at 11.

> To date, SCE's and PG&E's customers have paid $31 million and $27 million, respectively, under these contracts. For SCE and PG&E, the expected costs of these contracts over their remaining terms is $149 million and $96 million, respectively.[10]

PG&E further forecasts that over a 20-year period, "the total cost exposure would be approximately $665 million" for additional contracts.[11] Nowhere in the Petition do the Utilities quantify the imputed benefits of these contracts to bundled customers. So while they are seeking recovery of "above-market" costs, they appear to be using "total costs" for persuasive effect.

The unique benefits of the ReMAT program are questionable, and bundled and departing load customers do not benefit equally from ReMAT contracts. CalCCA urges the Commission on these grounds to reject the Petition. The vintaged PCIA methodology is designed to address contracts like ReMAT contracts, and the costs should remain in the PCIA.

III. ABOVE-MARKET RPS COSTS BELONG IN THE PCIA

Today, all above-market RPS costs are recovered through the PCIA, and ReMAT costs are no different. The fact that the procurement was mandated does not change the analysis; the costs are still simply above-market RPS costs. There are no reasonable grounds for distinction.

If the Utilities' real complaint is that the ReMAT causes overprocurement, there are other tools to address this problem. The Utilities can adjust their procurement to compensate for the ReMAT products in their portfolios. Critically, a proposal in R.17-06-026 by Working Group 3[12] would directly address this problem by allowing the allocation of RPS energy to LSEs whose

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10 Petition at 6.

11 *Id.* at 8

12 *See* R.17-06-026, *Final Report of Working Group 3 Co-Chair: Southern California Edison Company (U-338 E), California Community Choice Association, and Commercial Energy*, Feb. 21, 2020 (WG 3 Proposal), §V.D. at 32-40 https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M335/K710/335710541.PDF

customers pay the above-market costs of RPS contracts. If this were the problem, however, the Utilities would not be proposing to retain the resource attributes.

CalCCA submits, however, that the Utilities' complaint can boiled down to the fact that they no longer like the operation of the PCIA in the face of a declining load. They consequently are seeking, in a piecemeal fashion, to unravel the PCIA – first with the Bioenergy Market Adjusting Tariff (BioMAT)[13] and now with ReMAT. The Petition at its heart would change the rules for what belongs in and out of the PCIA.

CalCCA urges the Commission to stop allowing the Utilities to unravel the PCIA without examining the principles their choices embody. The Utilities have presented no clear argument to remove these costs from the PCIA, and the Commission should reject the Petition.

IV. IF THE COMMISSION PERMITS PPPC RECOVERY OF THE REMAT COSTS, IT MUST MODIFY THE UTILITIES' PROPOSED METHODOLOGY

As the Utilities note, the Commission has allowed "unique benefit" cost recovery previously in the case of the tree mortality nonbypassable charge (TM NBC) for biomass energy procurement and the BioMAT program. If the Commission once again accepts the Utilities' arguments for offloading more costs onto CCA customers, the CCA customers paying for the program must receive equal benefits. The Commission should allow CCA customers to receive their share of direct benefits of the resources they fund, and their CCAs must be able to participate in the ReMAT program.

First, if the Commission determines that the ReMAT contracts are uniquely in the public interest, *all* ReMAT costs should be recovered through the PPPC not simply the above-market costs. The Commission took a similar approach in adopting tree mortality nonbypassable charge (TM NBC) for biomass energy procurement in D.18-12-003. The TM NBC was designed to

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13 *See generally* D. 18-12-003.

cover the "net" costs of the procurement, after sales of energy and associated Renewable Energy Credits.[14] Similarly, the BioMAT program received PPPC recovery of "net costs" from all customers, after the sale of attributes of value.[15]

CalCCA propose an alternative approach, consistent with the PCIA Working Group 3 proposal. The costs recovered in the PPPC would be net of energy revenues, but the RA and RPS value would be allocated on a *long-term* basis to all LSEs whose customers pay the PPPC. This approach also is similar to the treatment of RA value under the Cost Allocation Mechanism, where customers pay the net costs of reliability resources and receive an allocation of RA attributes. If ReMAT contracts are deemed to have been procured on behalf of CCA customers, then CCAs should receive the direct benefits of the resources for which their customers are paying.

Second, if CCA customers are required to pay for the ReMAT program, then CCAs must be allowed to fully participate in the program. The Commission has determined that broad allocation of costs to all customers through distribution rates is only appropriate where all customers are offered a fair and equitable share of benefits from the program. Where a program benefits only bundled customers or is available only to bundled customers, the costs of such program should be recovered in the IOUs' generation rates.[16] Similar programs, such as the BioEnergy Renewable Auction Mechanism (BioRAM) program under the tree mortality

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14 D.18-12-003 at 22.

15 D.20-08-043 at 15-16

16 *See, e.g.,* D.12-12-004 at 52-53 ("requiring the customers of CCAs and ESPs, who cannot enroll in SDG&E's dynamic pricing tariffs, to pay the costs of implementing those tariffs, is not consistent with cost causation principles, and would not be reasonable. . . For these reasons, we require that the costs of SDG&E's dynamic pricing decision be recovered from all bundled customers through generation rather than distribution rates."). See also D.13-03-032 at 70-71 (agreeing that distribution projects should be recovered through distribution rates, but requiring costs of a pilot that solely benefits bundled customers to be recovered through generation rates).

nonbypassable charge,[17] or the DAC-GT and CS-GT programs[18] provide for CCAs to participate under these programs for which CCA customers pay. In both cases, "both groups of customers pay for the program" so "the potential benefits of the program should not be limited based on the retail energy choice of customers."[19] This model of at minimum expanding eligibility of CCAs to participate in programs their customers pay for is already proving successful in the DAC-GT and CS-GT program in which several CCAs have moved forward with their own programs.

Given this precedent, establishing a similar structure here would represent a continuation of this equal access approach. Although there remain implementation details to be developed, the existence of several other similar programs should make this a relatively straightforward process to develop program requirements and procedures.

V. CONCLUSION

The California Community Choice Association appreciates the opportunity to submit this response and urges the Commission to reject or, in the alternative, substantially modify the Utilities proposed cost recovery methodology.

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
General Counsel to the
California Community Choice Association

March 15, 2021

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17 *See* Resolution E-4977 at 13 ("If an IOU is unable to execute a new or amended contract with an eligible seller pursuant to this section, we find that a CCA may enter into a contract with that seller, and the procurement expenses incurred therein may be collectible through the Tree Mortality non-bypassable charge, if such contracts conform to all of the terms and conditions of BioRAM 2, including the rules and conditions established through this Resolution.").

18 D.18-06-027. (approving CCA participation that the funds for the program " are *intended* to benefit both bundled and unbundled customers. Consistent with this, it is reasonable for CCA customers to be eligible for a comparable CCA DAC-Green Tariff.")(emphasis added.)

19 D.18-06-027 at 90.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the Self-Generation Incentive Program and Related Issues.	)))))	Rulemaking 20-05-012 (Filed May 28, 2020)

REPLY COMMENTS OF MARIN CLEAN ENERGY AND SONOMA CLEAN POWER AUTHORITY IN RESPONSE TO THE MARCH 2, 2021 ASSIGNED COMMISSIONER'S RULING

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March 29, 2021

For: Marin Clean Energy
Sonoma Clean Power Authority

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the Self-Generation Incentive Program and Related Issues.	Rulemaking 20-05-012 (Filed May 28, 2020)

REPLY COMMENTS OF MARIN CLEAN ENERGY AND SONOMA CLEAN POWER AUTHORITY IN RESPONSE TO THE MARCH 2, 2021 ASSIGNED COMMISSIONER'S RULING

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and Assigned Commissioner Rechtschaffen's March 2, 2021 *Ruling Requesting Comment* ("Assigned Commissioner's Ruling"), Marin Clean Energy ("MCE") and Sonoma Clean Power Authority ("SCP"), (together, the "Joint CCAs") hereby submit the following reply comments.

I. REPLY COMMENTS ON SGIP EQUITY RESILIENCY BUDGET

A. Equity Resiliency Budget Eligibility Should Be Expanded To Include Customers Impacted By Actual Wildfires

The Joint CCAs strongly agree with the Center for Sustainable Energy ("CSE") and the California Solar & Storage Association ("CalSSA") that the Equity Resiliency Budget ("ERB") eligibility requirements should be expanded to include both customers impacted by public safety power shutoff ("PSPS") events and customers who have been de-energized as a result of an actual wildfire.[1] As noted by CSE, expanding ERB eligibility to include customers who have lost power due to wildfires "fits squarely within the Commission's intent to provide resiliency benefits to customers most likely to be impacted by wildfires and related PSPS events."[2] While

[1] CSE Opening Comments at 1-2; CalSSA Opening Comments at 1-2.
[2] CSE Opening Comments at 2.

it is not possible to fully predict which customers will be impacted by future PSPS or wildfire-related outages, the Joint CCAs agree that the existing eligibility criteria (location within a Tier 2 or Tier-3 High Fire Threat District ("HFTD") or having experienced PSPS outages) are reasonable indicators of increased outage risk in the future.

Real-world experience demonstrates that power loss due to an actual wildfire is as strong an indicator of future de-energization risk as location within a Tier-2 or Tier-3 HFTD. In both SCP and MCE service areas, there are locations that are both frequently affected by wildfires and PSPS outages. For instance, Angwin, California, located in MCE's service area, experiences repeat PSPS outages every year, and was also de-energized due to the Glass fire (at a time when no PSPS event was called). The Joint CCAs note that these experiences contradict Southern California Edison Company's ("SCE's") assertion that having experienced past wildfire outages is not a good indicator of risk for future wildfire outages.[3] De-energization due to actual fires is as good of an indicator as past PSPS events, and as a practical matter there is little difference between the two.

As a clarification, the Joint CCAs do not believe that it is necessary or prudent to change the definition of a "discrete PSPS event" in order to expand ERB program eligibility. As noted by The Utility Reform Network ("TURN"),[4] PSPS events are specifically defined as voluntary outage events necessary to protect the public safety and are subject to a complex and well-developed set of Commission requirements.[5] Wildfire-related outages, in many cases, may be involuntary, or may otherwise not meet the Commission's established definition of a "PSPS event." In order to avoid regulatory confusion and inconsistent definitions of the same term, the

[3] SCE Opening Comments at 2-3.
[4] TURN Opening Comments at 4.
[5] Resolution ERSB-8.

Commission should expand ERB eligibility without modifying the definition of "discrete PSPS event." As such, the ERB eligibility criteria should be modified to provide as follows:

> Residential customers are eligible for the Equity Resiliency Budget if they meet at least one of the following criteria:
>
> 1. The customer is located in a Tier 3 or Tier 2 HFTD, or
>
> 2. Prior to the date of application for SGIP incentives, the customer has been subject to:
>
>   - Two or more discrete PSPS events;
>   - Two or more power losses due to an actual wildfire; or
>   - One discrete PSPS event and one power loss due to an actual wildfire.

The Joint CCAs note that in Opening Comments, both Pacific Gas and Electric Company ("PG&E") and SCE state that they are capable of tracking wildfire-related outages, meaning that expanding ERB eligilbity criteria to include customers who have experienced such outages is procedurally feasible.[6] It is also worth pointing out that all of the utilities, even those opposed to updating the definition of a "PSPS event" under the SGIP, seem to be amenable to updating the eligibility criteria for the ERB as outlined above.

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[6] *See,* SCE Opening Comments at 4; PG&E Opening Comments at 5-6.

II. CONCLUSION

The Joint CCAs thank the Commission for its consideration of these reply comments.

Dated: March 29, 2021

Respectfully submitted,

/s/ David Peffer

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For: Marin Clean Energy
Sonoma Clean Power Authority

April 5, 2021

Via E-Mail

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Subject: Comments of CleanPower San Francisco, East Bay Community Energy, Marin Clean Energy, Peninsula Clean Energy Authority and San Jose Clean Energy on Draft Resolution E-5124

Dear Energy Division:

In accordance with General Order (GO) 96-B, General Rule 7.4, and the instructions set forth in the Comment Letter issued on March 11, 2021, Marin Clean Energy ("MCE"), East Bay Community Energy ("EBCE"), CleanPower San Francisco ("CleanPowerSF"), Peninsula Clean Energy Authority ("PCE"), and San Jose Clean Energy ("SJCE"), jointly the "Joint Community Choice Aggregators" or "Joint CCAs", submit these comments on Draft Resolution ("DR") E-5124. The DR approves, with modifications, the Joint CCAs' Advice Letters ("AL") to create tariffs to implement the Disadvantaged Communities Green Tariff ("DAC-GT") and Community Solar Green Tariff ("CSGT") programs.

I. INTRODUCTION

The Joint CCAs support the DR and thank the Commission for the hard work, thoroughness, and careful consideration of the parties' positions reflected in the DR. The following comments request clarifications and make recommendations on certain requirements and conclusions proposed in the DR. Specifically, the Joint CCAs recommend the following clarifications and modifications:

i. PG&E should be directed to transfer MCE's and EBCE's budget request for program year ("PY") 2021 to the CCAs within 60 Days of approval of this Resolution;
ii. PG&E should be directed to forecast and track "CCA Integration Costs" to be included on the CCA's Annual Budget Advice Letters;
iii. The CCAs should submit updated budgets that forecast CCA Integration Costs for PYs 2021 and 2022;

iv. The final Resolution should establish a methodology for distributing CCA Integration Costs among participating CCAs;
v. The Commission should demonstrate flexibility in approving CCAs' budgets in the future if CCA Integration Costs lead to CCA budgets exceeding the admin budget cap;
vi. The CCAs should submit updated budgets that accurately forecast the 20% discount costs for PYs 2021 and 2022;
vii. The Commission should direct the CCAs and PG&E to collaborate to identify long-term solutions to eliminate manual billing and data transfer processes;
viii. The Joint CCAs request clarification if solicitation capacity can be rounded up for both the DAC-GT and CSGT Programs;
ix. CleanPowerSF should not be directed to submit updated marketing budgets for the DAC-GT program due to the auto-enrollment provisions. EBCE should be directed to only submit an updated marketing budget for PY 2021;
x. The Joint CCAs request that the Commission correct three inadvertent errors in the Resolution.

II. COMMENTS

A. PG&E Should Be Directed to Transfer MCE's and EBCE's Budget Request for Program Year 2021 to the CCAs within 60 Days of Approval of this Resolution

The DR correctly asserts that the California Public Utilities Commission ("CPUC" or "Commission") has already directed Pacific Gas & Electric ("PG&E") in D.20-12-038 to set aside funding for MCE's and EBCE's budget request for PY 2021 in the utility's 2021 ERRA proceeding.[1] The DR also establishes that PG&E must remit program funds to the CCAs in four quarterly installments (by January 1, April 1, July 1 and October 1 for the upcoming quarter) or within 30 days of issuance of the ERRA Forecast approval.[2]

However, the DR stops short of establishing a timeline for PG&E to remit the funds for the approved PY 2021 budgets to MCE and EBCE. The CCAs recommend that the Commission direct PG&E to transfer the requested budget for Q1, Q2 and Q3 of 2021, as approved in D.20-12-038, to the respective CCA by July 1, 2021. The fund transfers for Q4 would occur on October 1, 2021 per the usual fund transfer schedule.

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[1] D.20-12-038, *Decision Adopting Pacific Gas and Electric Compa*ny's 2021 Energy Resource Recovery Account Forecast, Generation Non-Bypassable Charges Forecast, Greenhouse Gas Forecast Revenue Return and Reconciliation, and Related Calculations and Rate Proposals, at 26.
2 DR at 9f.

B. The Joint CCAs Request Several Clarifications and Modifications Regarding the Requirements for Tracking "CCA Integration Costs"

The DR establishes that PG&E can recover costs from the programs that incur to the utility in order to facilitate CCA participation under the programs (e.g., administrative or IT costs).[3] The Joint CCAs find this conclusion to be reasonable. However, the DR lacks detail and makes a few erroneous assumptions regarding how this process would best be implemented. Specifically, the Joint CCAs request that the following modifications be made to the requirements for tracking and reporting CCA integration costs.

1. PG&E Should Be Directed to Forecast and Track CCA Integration Costs to Be Included on the CCA's Annual Budget Advice Letters

The DR states that the Joint CCAs will be responsible for forecasting and tracking their corresponding share of CCA integration costs, as well as for reporting these costs in their annual budget ALs.[4] The Joint CCAs cannot forecast and track costs incurred by PG&E as the CCAs have no insight into either expected labor hours nor labor rates incurred by PG&E. Similarly, the Joint CCAs are not in the position to report on actual costs incurred by the utility for supporting CCA integration activities as CCAs don't have access to PG&E's internal reporting systems that track labor costs.

Instead, the final Resolution must direct *PG&E* to forecast and track CCA integration costs and inform the CCAs about such costs in anticipation of the filing of the annual budget AL. More specifically, the Joint CCAs recommend the following process:

1. PG&E to forecast CCA integration costs for each CCA by December 1 of each year for the budget submission due on February 1 the following year (e.g., by December 1, 2021 for the PY 2023 budget that is due on February 1, 2022). If a CCA plans a "special project" (e.g., an IT project due to CCA expansion) that may affect the CCA integration costs, the respective CCA will inform PG&E of such a project by November 1 each year (i.e., 30 days before the forecast is due);
2. PG&E to report actual CCA integration costs for each CCA for the previous PY by January 15 of each year to the CCA;
3. Each CCA to include both the forecasted CCA integration costs for the upcoming PY and the actual CCA integration costs for the previous PY in their annual budget AL filing due on February 1 each year;
4. PG&E must provide line-item details about the cost forecast to the CCAs upon request. The CCAs and PG&E shall try to resolve any questions or concerns regarding CCA Integration Costs before the budget AL submission is due. If a resolution cannot be found, the CCA may dispute any costs during the annual budget AL process or request that the issue be discussed during a Billing Working Group meeting.[5]

3 Id at 11.
4 Id.
5 Id.

2. The CCAs Should Submit Updated Budgets that Forecast CCA Integration Costs for PYs 2021 and 2022

Each CCA has already submitted program budgets for PYs 2021 and 2022. PCE, CleanPowerSF and SJCE submitted PY 2021 and 2022 budgets attached to their Implementation AL submissions.[6] MCE and EBCE had included PY 2020 and 2021 budgets in their Implementation AL submissions and submitted a budget AL for PY 2022 to the Commission on February 1, 2021.[7] The Commission approved MCE's budget AL for PY 2022 on March 5, 2021.

CCA integration costs were not included in any of the CCAs' budget forecasts for PY 2021 and 2022. To incorporate this data, the Joint CCAs propose that the Commission direct each CCA in the final Resolution to submit an updated budget forecast via Tier 1 AL for PY 2021 and 2022 within 60 days of the approval of the final Resolution. PG&E must be required to inform each CCA of its forecasted CCA integration costs within 30 days of the approval of the final Resolution so that CCAs can incorporate these costs appropriately into the updated budgets.

Once approved by the Commission, these updated CCA budgets for PY 2021 and 2022 can be incorporated by PG&E into the 2022 ERRA Update filing due in November 2021. As noted above, EBCE and MCE's 2021 budgets were already approved by the Commission and included in PG&E's final 2021 ERRA filing. Per D.20-12-038, PG&E should propose a true-up of the difference between (a) the 2021 set aside amount for the pending requests of MCE and EBCE for their DAC-GT and CS-GT programs and (b) the amount approved by CPUC resolutions of such requests in its 2022 ERRA forecast application.[8] The Joint CCAs recommend that the additional CCA integration costs for MCE and EBCE for PY 2021 be incorporated into the budget forecasts for PY 2022.

3. The Final Resolution Should Establish a Methodology for Distributing CCA Integration Costs Among Participating CCAs

The DR establishes that CCA integration costs that apply to all participating CCAs (e.g., IT costs) must be distributed among participating CCA subaccounts.[9] However, the Resolution does not propose a methodology for how exactly costs shall be allocated to each CCA. The Joint CCAs recommend that PG&E shall distribute CCA integration costs in equal parts among participating CCAs and request that the Commission include this directive in the final Resolution.

4. The Commission Should Demonstrate Flexibility in Approving CCAs Budgets in the Future if CCA Integration Costs Lead to CCA Budgets Exceeding the Admin Budget Cap

[6] CPSF AL 12-E, PCE AL 11-3, SJCE AL 15-E.
[7] MCE AL 42-E and 47-E, EBCE AL 14-E and 19-E.
[8] D.20-12-038 at COL 4.
[9] DR at 11.

The DR determines that the Joint CCAs will be responsible for forecasting and reporting their corresponding share of CCA integration costs in their annual budget ALs. The DR adds that these integration costs will count toward each CCAs' administration cost cap which is set at 10% of the total annual budget.[10]

The Joint CCAs acknowledge that in principle, this is a sensible solution to track CCA integration costs. However, we would like to caution that tracking and reporting the CCA integration costs *incurred by PG&E* can have negative impacts on the CCA's budgets. The CCAs have no oversight over PG&E's spending under the CCA Integration Costs line item and can therefore not control for costs incurred in this category. Hence, spending under this line item may lead to CCA budgets not being able to meet the cost cap on administrative costs as established by Resolution E-4999.[11]

A simple example demonstrates how CCA integration costs could become an issue for the CCA admin costs cap. For their own program roll-out, PG&E forecasted IT costs amount to approximately $4.4 million for both programs for the first two PYs.[12] Even if only half of those costs would incur to implement IT upgrades for the Joint CCAs, the costs allocated to each participating CCA would still amount to approximately $400,000 per CCA. Comparing this, for example, to CleanPowerSF's total admin budget of $533,928 for the first two PYs demonstrates how the PG&E CCA integration costs can grossly outweigh the CCA admin costs.

The Joint CCAs hope that the large majority of all program development and CCA integration costs will incur during the first two years of implementation and will hence not fall under the 10% program cap. However, the Joint CCAs are concerned that high CCA integration costs could persist into future PYs as the DR only directs PG&E to share a plan for a long-term billing solution by its 2022 Budget Advice Letter filings. Presumably, implementation of this plan will likely last into 2023, which is beyond the second program year for all CCAs. If and when high CCA integration costs persist into the third or following PYs, we expect the Commission to demonstrate flexibility in approving the CCAs' admin budgets if they were to exceed the program cap due to high CCA integration costs.

C. The CCAs Should Submit Updated Budgets That Accurately Forecast the 20% Discount Costs for PYs 2021 and 2022

The DR determines that the full bill discount on both the generation and the delivery portion of the bill will be applied as a line-item credit to the CCA charges (i.e., the generation

[10] DR at 11.
[11] Resolution E-4999, OP 2 at 67.
[12] The example assumes that the large majority of IT costs would be completed in these years. See more at PG&E AL 5609, Updated Program Budget Estimates and 2019-2021 ME&O Plans for the DAC-GT and CSGT Programs from August 2019 at 2f.

portion) on customers' monthly bills.[13] In other words, CCAs will forecast, track and report the full discount on both portions of the bill in their annual budget ALs. CCAs will then recover the full 20% discount costs from the programs.

In their Implementation ALs, most CCAs had proposed that CCAs cover only the 20% discount on the generation portion of the bill while the IOUs cover the 20% discount on the delivery portion of the bill (i.e., the "hybrid approach").[14] Consequently, most CCAs only forecasted a revenue loss due to the 20% discount provided on the generation portion of the bill in their budget submissions for PY 2021 and 2022. To the best of the CCAs' knowledge, PG&E did not forecast the revenue loss for providing the 20% discount to participating CCA customers in any of their budget filings. Hence, the 20% discount on the delivery portion of the bill has not been forecasted in any of the Program Administrator ("PA") budget filings to date. To accurately forecast the 20% discount on the full portion of the electric bill (i.e., the generation and delivery portion), the Joint CCAs recommend that the Commission direct the CCAs[15] in the final Resolution to submit an updated budget forecast via Tier 1 AL for PY 2021 and 2022 within 60 days of the approval of the final Resolution.

Once approved by the Commission, these updated budgets can be incorporated by PG&E into the 2022 ERRA Update filing due in November 2021. As described in section B.2, the Joint CCAs recommend that additional costs for 2021 incurred by EBCE and MCE will be included in the PY 2022 budget forecast.

D. The Commission Should Direct CCAs and PG&E to Collaborate to Identify Long-Term Solutions to Eliminate Manual Billing and Data Transfer Processes

The DR specifies that PG&E is required to include in their 2022 budget AL "information detailing which billing option has been pursued as a long-term solution and the efforts taken by PG&E to eliminate manual data transfers between PG&E and participating CCAs through IT software updates or other automated processes."[16]

The Joint CCAs strongly recommend that the Commission direct PG&E to *collaborate closely with the CCAs* to identify long-term solutions to eliminate manual billing and data transfers procedures. Specifically, the Joint CCAs recommend that the Commission direct PG&E to convene a billing workshop by December 15, 2021 to present their proposals for long-term solutions to eliminate manual data transfers to the Joint CCAs and Energy Division staff. The discussion and solutions identified during that workshop (and in subsequent conversations, if

[13] DR at 11f.

[14] Only CleanPowerSF had calculated the 20% discount on the total electric bill, not only the generation portion of the bill.

[15] As CleanPowerSF already calculated the 20% discount on the total electric bill in CPSF AL 12-E, CleanPowerSF should not be directed to update its budget to include PG&E charges.

[16] DR at 12f.

necessary) should be the basis for the proposals made by PG&E in the budget AL on February 1, 2022.

E. The Joint CCAs Request Clarification if Solicitation Capacity Can Be Rounded Up for Both the DAC-GT and CSGT Programs

The DR stipulates that CCAs may solicit above their allocated MW capacity by rounding up to the next whole number of MWs. The DR further notes that **DAC-GT customers** must only be enrolled up to the approved capacity allocation for each CCA.[17]

The Joint CCAs would like to request that the Commission clarify in the final Resolution that rounding up of solicitation capacity is allowed for CCAs for both the DAC-GT and the CSGT program. All the justifications of why rounding up solicitation capacity should be allowed apply equally to both the DAC-GT and the CSGT program and the Joint CCAs see no reason why rounding up should only be allowed for the DAC-GT program. The Joint CCAs agree that customers will only be enrolled up to the approved capacity allocation for each of the programs and any costs related to the surplus capacity will be recovered by the CCA from its generation rate base.

F. CleanPowerSF Should Not Be Directed to Submit Updated Marketing Budgets for the DAC-GT Program Due to the Auto-Enrollment Provisions. EBCE Should be Directed to Only Submit an Updated Marketing Budget for PY 2021

The Joint CCAs appreciate the Commission approving the different auto-enrollment mechanisms for the DAC-GT program proposed by MCE, EBCE and CleanPowerSF. The DR further directs CleanPowerSF and EBCE to submit updated marketing budgets for the DAC-GT program for PYs 2021 and 2022 to account for reduced marketing budgets due to the auto-enrollment provisions.[18]

EBCE plans to submit an updated marketing budget for PY 2021 in the Tier 1 budget AL to be submitted to the Commission within 60 days of issuance of the final Resolution. However, EBCE clarifies that its PY 2022 budget request, submitted February 1, 2021, already reflected reduced spending due to auto-enrollment, and respectfully requests that the Commission remove the requirement to update the PY 2022 budget.

CleanPowerSF clarifies that the marketing budget submitted with CleanPowerSF Implementation AL 12-E on December 31, 2020 already considered auto-enrollment provisions. CleanPowerSF would also like to add that its proposed auto-enrollment strategy is unlikely to result in subscription of 100% of its DAC-GT capacity. Data received from PG&E in March 2021 indicates that CleanPowerSF customers who are eligible for both the Arrearage Management Plan ("AMP") and DAC-GT represent around 50% of the total DAC-GT program capacity. PG&E has

[17] DR at 14.
[18] Id at 20.

forecasted that around 50% of customers eligible for the AMP will likely enroll in the program,[19] meaning that only 25% of CleanPowerSF's DAC-GT program capacity will likely be auto-enrolled. Hence, CleanPowerSF projects that upwards of 75% of its program capacity will be available for "proactive" customer enrollment and therefore planned a "hybrid" ME&O strategy which is partially focused on educating auto-enrolled customers and partially focused on engaging in proactive customer outreach. As such, CPSF believes that its DAC-GT marketing budget as proposed in CleanPowerSF Implementation AL 12-E is appropriate for its program size and in comparison to other PAs. For these reasons, CleanPowerSF requests that the Commission remove the requirement for refiling of an updated marketing budget for CleanPowerSF from the final Resolution.

G. The Joint CCAs Request That the Commission Correct Three Inadvertent Errors in the Resolution

The DR contains three typos that should be corrected.

First, the DR mistakenly refers to PG&E's 2021 ERRA Forecast filing and uses an incorrect name for San Jose's CCA in OP 2 of the DR. OP 2 states that "Pacific Gas and Electric (PG&E) will include CleanPowerSF's (CPSF), Peninsula Clean Energy's (PCE), and San Jose Clean **Power's (SJCP)** [emphasis added] estimated budget for Program Years (PY) 2021 and PY 2022 in its **2021** [emphasis added] Energy Resources Recovery Account (ERRA) Forecast Filing."[20] Instead, it should state "Pacific Gas and Electric (PG&E) will include CleanPowerSF's (CPSF), Peninsula Clean Energy's (PCE), and San Jose Clean **Energy's** (SJC**E**) estimated budget for Program Years (PY) 2021 and PY 2022 in its **2022** Energy Resources Recovery Account (ERRA) Forecast Filing." This also aligns with the statement in "Finding of Facts #13".[21]

Second, page 15 of the Draft Resolution lists the CCAs that proposed adopting DAC-GT customer enrollment rules similar to the CSGT program by allocating a percentage of the DAC-GT project output to each customer enrollment. PCE is missing from the list of CCAs while MCE is mentioned twice.

III. CONCLUSION

The Joint CCAs thank the Commission for reviewing these comments on Draft Resolution E-5124.

Respectfully Submitted,

[19] Data shared by PG&E on January 19th, 2021.
[20] DR at p.27.
[21] DR at p.25.

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