JANUARY FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.23-10-011

PUBLIC VERSION
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ASSIGNED COMMISSIONER'S SCOPING MEMO AND RULING

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- Request the Federal Energy Regulatory Commission investigate the resource adequacy (RA) capacity market to ensure just and reasonable wholesale market rates;
- Modify the timing of penalty assessments to extend the year-ahead and month-ahead RA cure periods;
- Adopt a temporary waiver process for system and flexible RA to ensure a smooth transition through the initial slice-of-day (SOD) compliance years;
- Increase transparency into investor-owned utility effective planning reserve margin procurement;
- Revise the maximum non-resource specific RA import bid price to ensure out-of-state resources have the right incentives to provide RA capacity to California;
- Create a hydro resource counting methodology that requires mid-year updates to account for above-normal hydro conditions; and
- Evaluate test year showing data to quantify the benefits of hourly transactability and commit to adopting hourly load obligation trading for SOD.

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California Community Choice Association[1] (CalCCA) submits these proposals pursuant to the Assigned Commissioner's Scoping Memo and Ruling[2] (Ruling), dated December 18, 2023. The Ruling seeks party proposals on Track 1 (excluding FCR and LCR issues).

I. INTRODUCTION

The California Public Utilities Commission's (Commission) resource adequacy (RA) program is critical to ensuring sufficient supply is under contract to maintain reliability in the California Independent System Operator (CAISO) balancing authority area (BAA). It has become a significant challenge for load-serving entities (LSE) to procure enough capacity to meet compliance obligations due to capacity market scarcity and increased competition for RA. According to CalCCA's stack analysis referenced in Section II, the amount of RA supply forecasted to be available to meet demand appeared inadequate to meet 2024 compliance obligations in aggregate. The result is LSEs paying sky-high prices for capacity or struggling to find sufficient capacity even if they are willing to pay those sky-high prices.

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1 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 *Assigned Commissioner's Scoping Memo and Ruling*, R.23-10-011 (Dec. 18, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M521/K589/521589385.PDF.

While compliance by all LSEs is all but impossible, the Commission has created a "comply at any cost" compliance regime. LSEs are not only subject to tiered financial penalties of up to $26.64 per kilowatt (kW)-month. They are also subject to non-financial penalties, including the restrictions on expansion for Community Choice Aggregators (CCA) and Electric Service Providers (ESP), that effectively allow marketers to demand any price for RA capacity. In times of market scarcity, this puts upward price pressure on the entire RA market with no incremental benefit to overall system reliability.

Within this proceeding, the Commission should aim to (1) relieve supply constraints as much as possible by increasing LSEs' ability to access in-development and existing RA capacity, and (2) modify RA compliance and penalty mechanisms with the recognition that supply constraints cannot fully be resolved in the near-term. With these objectives in mind, the Commission should:

- Request the Federal Energy Regulatory Commission (FERC) investigate the RA capacity market to ensure just and reasonable wholesale market rates;
- Modify the timing of penalty assessments to extend the year-ahead (YA) and month-ahead (MA) RA cure periods;
- Adopt a temporary waiver process for system and flexible RA to ensure a smooth transition through the initial slice-of-day (SOD) compliance years;
- Increase transparency into investor-owned utility (IOU) effective planning reserve margin (PRM) procurement;
- Revise the maximum non-resource specific RA import bid price to ensure out-of-state resources have the right incentives to provide RA capacity to California;
- Create a hydro resource counting methodology that requires mid-year updates to account for above-normal hydro conditions; and
- Evaluate test year showing data to quantify the benefits of hourly transactability and commit to adopting hourly load obligation trading for SOD.

The proposals included herein are supported by the attached sworn declarations of the following:

- Andrew Mills (California Community Choice Association) (Appendix A);
- Matthew Langer (Clean Power Alliance) (Appendix B);
- Kelly Morris (San José Clean Energy) (Appendix C); and
- Deb Emerson (Sonoma Clean Power) (Appendix D).

II. BACKGROUND

A. The RA Supply and Demand Balance Makes It Difficult, if not Impossible for Every LSE to Meet Its RA Requirements

As demonstrated in the stack analysis presented in Appendix A, the system RA supply available within the CAISO BAA appears, on a forecast basis, inadequate to meet the RA program compliance requirements in September 2024, with a deficiency of 894 megawatts (MW). In 2023, the available supply was so tight that the RA supply exceeded demand by only 135 MW in August, and 582 MW in September. Even if there are disagreements with the inputs and assumptions of the stack analysis in Appendix A, any reasonable changes are likely to conclude that at a minimum, the RA market is razor thin.[3] The February 2023 Joint Agency Reliability Planning Assessment by the California Energy Commission (CEC) and the Commission, which is based on an hourly analysis of anticipated supply and projected demand, roughly substantiates this conclusion.[4] When the stack analysis is viewed in the context of regulatory dynamics and Western market constraints, the razor-thin margin feels much more like a supply deficiency.

Appendices B, C, and D document experiences in an RA market where transactability is increasingly challenging, at the detriment of the LSEs and the customers they serve. The number of responses to requests for offer (RFO) are down, responses often do not contain offers of products needed by the CCAs, and offers do not come in in time to be shown consistent with existing compliance timelines.

Additionally, on January 12, 2024, the CAISO provided more information on the sources of RA and showings for LSEs in the CAISO BAA for the most recent five-year period. The data when combined with the CAISO Net Qualifying Capacity (NQC) lists over the same five-year period depict an RA requirement that has grown more import dependent (See Table 1).

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3 The stack analysis focuses on the sufficiency of supply to enable load-serving entities to comply with RA program requirements and does not analyze the likely sufficiency of energy to meet Summer needs.

4 The Joint Agency Reliability Planning Assessment, SB 846 Quarterly Report ad AB 205 Report, issued on February 9, 2023, assessed hourly supply sufficiency across each year between 2023-2032. Here we focus on the Joint Agency results during critical hours in the month of September 2023-2026 using their assumption that new resources are based on ordered procurement with a delay rate of 40 percent. This assessment differs from the CalCCA assessment in Appendix A because it focuses on hourly supply sufficiency, rather than RA sufficiency for compliance purposes. Despite these differences, which tend to present a more positive view of supply, the assessment shows a very tight supply margin, for Hour 19 in September – arguably the most challenging hour to meet.

Table 1 – Amount of RA Requirement Not Covered by CAISO Connected NQC[5]

Month Ahead September 2019-2023			
Year	NQC	RA Requirement	Amount of RA not Covered by CAISO Connected Resources
2019	50,898	50,242	(657)
2020	47,334	49,135	1,801
2021	44,843	48,351	3,508
2022	46,923	48,944	2,020
2023	49,977	52,476	2,499

At the same time, the amount of capacity from imports has also reduced (see Section III.E.1). This combination of factors has driven the Commission's RA market from one of significant excess capacity with competitive market outcomes to one in which capacity is tight and market prices are high. The significant decline in excess capacity is shown in Table 2.

Table 2 – Decline in Available RA and Excess Capacity Causing Tight Market Conditions

Month Ahead September 2019-2023					
	NQC	Total Imports	Total Available RA	RA Requirement	Excess Capacity
2019	50,898	8,587	59,485	50,242	9,244
2020	47,334	8,500	55,834	49,135	6,699
2021	44,843	6,409	51,253	48,351	2,902
2022	46,923	6,236	53,159	48,944	4,215
2023	49,977	6,363	56,340	52,476	3,864

B. The Shortage of RA has Capacity Prices at All-Time Highs

As basic economics would predict, the conditions described in Section II.A. are ripe to produce exorbitant prices, making reliably serving California's electricity customers more expensive. CalCCA's declaration in Appendix A documents how prices have increased substantially in recent years using publicly available data from the FERC Electronic Quarterly Reports (EQR). Declarations from Clean Power Alliance (CPA), San José Clean Energy (SJCE), and Sonoma Clean Power (SCP) in Appendices B, C, and D respectively, substantiate this publicly available data with prices seen and paid for in the market in recent months.

[5] If the amount of resources not covered by CAISO connected resources is negative (in parenthesis), then the RA requirements could have been met entirely by resources internal to the CAISO BAA. If the amount of resources not covered by CAISO connected resources is positive, then CAISO LSEs must secure imports up to the amount shown in the table, assuming all CAISO connected resources are also secured for CAISO RA requirements, in order to meet aggregate RA requirements.

LSEs faced with a responsibility to meet their RA obligation at any cost are being met with generators only willing to sell at prices eight to nine times higher than the CAISO soft-offer cap. The lack of sufficient capacity available to meet RA needs is clearly driving up costs for California electricity customers. These high costs erode affordability, disproportionately affect disadvantaged customers, and could undermine the State's efforts to promote electrification.

C. Shifting to SOD Will Not Solve the RA Market Scarcity Problem

CalCCA conducted the stack analysis referenced in Section II.A consistent with the existing RA program, including requirement setting and counting methodologies. In 2025, the Commission will transition its RA program from its traditional framework to the SOD framework. The SOD framework will alter LSEs' requirements and resources' counting rules in a manner which will lead to portfolio inefficiencies, especially in the absence of hourly transactability, further exacerbating compliance challenges. It will also allow LSEs the flexibility of specifying the hours of storage resource discharging to meet their hourly RA needs. To assess how these modifications will impact the supply and demand balance, CalCCA conducted an additional stack analysis using data from the Draft Master Resource Database from the Commission (July 2023) and the California Energy Demand 2022 Hourly Forecast - CAISO - Planning Scenario. The key assumptions of the SOD stack include:

- Demand: Demand is represented by the 24-hourly values on the day with the highest peak load of each month. The 16 percent planning reserve margin is applied to all 24 hours in SOD and the highest load hour in the traditional stack.
- Wind and Solar: The contribution of wind and solar varies by hour/region and is calculated from exceedance values with historical data. This data was provided in the Draft Master Resource Database.
- Energy Storage: The contribution of storage to any hour is constrained based on characteristics of the resource, including the power rating, the maximum sustained discharge energy, the maximum number of daily cycles, and the availability of excess capacity to charge the storage. Within these capabilities storage is dispatched to minimize any deficits in net supply, or if none exist, to flatten out the net supply.
- Imports: Imports are assumed to be available between hour ending 7 and hour ending 22 following the common "6X16" contract schedule.

The results demonstrate the RA supply stack is still deficient under SOD. As Figure 1 shows, the September 2023 results predict a deficiency in HE 19 of 880 MW.

Figure 1 - September 2023 RA Stack Using Slice-of-Day Assumptions[6]

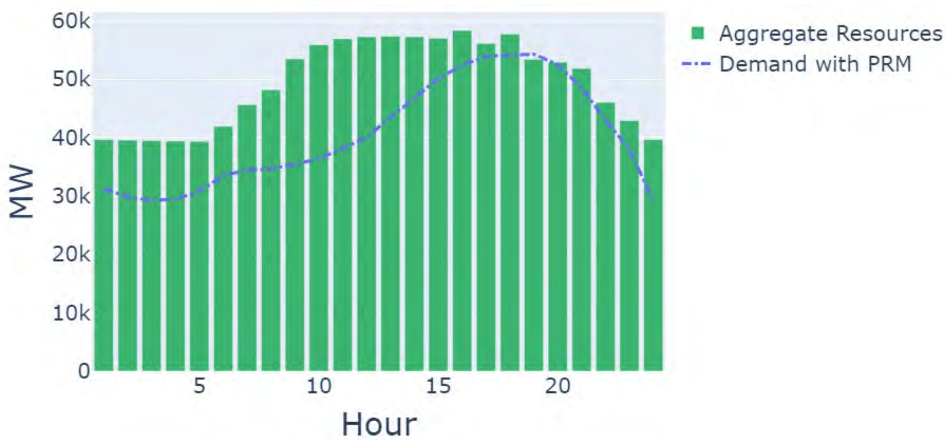

Figure 2 demonstrates how net supply changes from the traditional RA program to the new SOD program. Net supply in September, the most challenging month from an RA compliance perspective, is made worse by switching to SOD.

Figure 2 - Traditional vs Slice-of-Day Tightest Hour RA Net Supply Comparison for Summer 2023

These data suggest that LSEs will continue to face challenges complying with their RA obligations after the transition to SOD.

[6] Unlike the stack analysis referenced in Section II.A. above, this analysis does not include effects on supply from thermal derates, emergency reliability procurement, and substitution due to lack of monthly 24-hour profiles. This would further decrease the RA supply.

III. PROPOSALS

A. The Commission Should Request FERC, the CAISO, and DMM to Investigate the RA Capacity Market to Ensure Just and Reasonable Rates

The proposals in Section III.B through III.G below address the demand side of the supply and demand imbalance, meaning they aim to provide much-needed relief to LSEs who, despite their best efforts, cannot procure enough supply to meet their obligations in aggregate. The root causes of the challenging RA market, however, are on the supply side.

First, it is questionable as to whether there is sufficient supply to satisfy demand at competitive market outcomes. CalCCA's declaration in Appendix A demonstrates that net RA supply is extremely tight and prices are sky-high. This supply and demand imbalance can only be resolved by bringing new RA resources online that will offer their supply to California LSEs. The Commission, LSEs, and resource developers are in the process of doing this through the Integrated Resource Planning (IRP) proceeding, R.20-05-003. It will take time, however, for this procurement to come online and cover the RA need with sufficient excess to assure competitive market outcomes for capacity. The Commission recognized this in D.23-06-029 when evaluating the loss of load expectation (LOLE) study used to adopt the PRM for 2024: [7]

> In recent years, development projects have faced significant delays due to a host of issues, including supply chain delays, labor shortages, interconnection queue limitations, and rising costs. The Commission is very concerned that a large portion of the over 5,800 MW of RA resources under development and modeled into the LOLE study will experience delays and be unavailable for the 2024 RA year.

Second, RA market scarcity can create the opportunity for unjust and unreasonable rates. Such unjust and unreasonable rates can inflate prices paid by LSEs and ultimately ratepayers. There is currently no review of the just and reasonableness of RA capacity, and this Commission does not have the jurisdiction to directly mitigate wholesale market prices if the Commission believes the rates are not just and reasonable.

The FERC has wholesale market jurisdiction, which means it is the FERC that must take action to ensure that rates are just and reasonable in California and the West's RA capacity markets. Given the RA market tightness and high prices the California RA market is experiencing, the Commission

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[7] D.23-06-029; *Decision Adopting Local Capacity Obligations for 2024 - 2026, Flexible Capacity Obligations For 2024, and Program Refinements*, R.21-10-002 (June 29, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M513/K132/513132432.PDF

should request FERC investigate the RA market for capacity and determine if the rates are just and reasonable. In addition, the Commission should work with the CAISO and the Department of Market Monitoring (DMM) to investigate how the western RA market is functioning, including whether RA capacity market prices are just and reasonable in their expert view.

B. The Commission Should Modify the Timing of Penalty Assessments to Extend the Year-Ahead and Month-Ahead RA Cure Periods

LSEs must show RA Plans to the Commission to demonstrate compliance with their year-ahead RA (YARA) requirements and month-ahead RA (MARA) requirements. LSEs must make their YARA RA Plan showings on October 31st prior to the start of the compliance year.[8] LSEs must make their MARA RA Plan showings 45 days prior to the compliance month. If, on October 31st or 45 days prior to the compliance month, an LSE's showing is deficient, the LSE has five business days after notification by Energy Division to cure its deficiency before the Commission assess penalties.[9] Because of this timing, new resources that reach commercial operation dates (COD) or existing resources that contract with LSEs between the showing deadline and the compliance month are not accounted for in Energy Divisions assessment of penalties.[10]

Supply constraints in the RA market described in Section II, necessitate modifications to ensure regulatory and procedural barriers do not inhibit LSEs from accessing RA capacity. To partially relieve the supply constraints, the Commission should extend the cure period such that LSEs could cure their YARA or MARA deficiencies up to the start of the RA operational month. For example, if an LSE has a deficiency for September, within its year-ahead RA filing on October 31 or its September month-ahead RA filing on July 15, but resolves its deficiencies before September 1, the Commission will find the LSE compliant with its RA obligations. As a compliant entity, the LSE would not be subject to penalties or other consequences for non-compliance.

The Commission should also derate penalty dollar amounts if an LSE can resolve its deficiency between the start of the compliance month and the end of a compliance month. Therefore, if an LSE resolved a deficiency between the start and end of the compliance month, the dollar amount of the

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8 Pursuant to Rule 1.15 of the Commission's Rules of Practices and Procedure, if the due date falls on a Saturday, Sunday, or holiday, it is extended to the following business day.

9 2024 RA Guide at 54: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/guides-and-resources/final-2024-ra-guide-clean.pdf.

10 Appendix B explains how the significant number of in-development resources creates uncertainty and COD risk that the LSE takes on when contracting for RA.

penalty would be prorated by the percentage of days the LSE was deficient. For example, if an LSE cured its September deficiency by September 15, the LSE's penalty would be prorated by 50 percent.

The Commission should adopt this proposal to unlock new and existing capacity that becomes available between the showings and the RA month at a time when it is much needed and at a time when many mid-term reliability (MTR) projects are coming online. Enabling LSEs to procure such capacity and count it towards its RA obligations will provide some much-needed relief to LSEs struggling to close open positions with scarce amounts of RA supply.

Declarations from CPA and SCP in Appendices B and C, respectively, demonstrate that LSEs take efforts to continue to cure their YARA and MARA deficiencies after the Commission's five-day cure period. In the instances described in their declarations, both CCAs were able to fill their deficiencies prior to the first of the RA operational month and in the case of CPA it had no MARA deficiency by the applicable Month Ahead filing date. Despite these efforts that can result in LSEs fully covering their RA obligation at the start of the RA operational month, current rules still result in penalties. Recognizing efforts LSEs are already taking to resolve RA deficiencies before the start of the RA operation month, the Commission should adopt this proposal to reduce penalties on LSEs who, in fact, did bring enough RA capacity to cover their share of the RA need.

C. The Commission Should Adopt a Temporary Waiver Process for System and Flexible RA to Ensure a Smooth Transition through the Initial SOD Compliance Years

As the analysis in Section II reveals, supply constraints in the RA market have intensified in recent years, and CalCCA's Stack Analysis predicts will continue through at least 2025. At the same time, the Commission is in the process of implementing its SOD RA framework, a novel framework that significantly revises the RA program and that has yet to be fully tested despite a compliance requirement that begins in less than one year. Recognizing these complex market dynamics coupled with regulatory uncertainty, the Commission should adopt a temporary waiver process for system and flexible RA. The system and flexible RA waiver process would be in place from 2025 through 2027 to align with SOD implementation and allow for a smooth transition through the first three compliance years under the new framework.

LSEs would be required to demonstrate procurement efforts taken to justify the Commission granting a waiver. Depending on the justification provided to the Commission by an LSE, the LSE would be eligible for either a partial waiver or a full waiver. A partial waiver would provide LSEs with a waiver of penalty points and any other non-financial consequences for RA non-compliance. To receive a partial waiver, an LSE must show tight market conditions (similar to how an LSE supports requests for the existing Local RA Waiver) including:

a. A demonstration that the LSE reasonably and in good faith solicited bids, including participation in all IOU solicitations and reasonable effort in the bi-lateral market, for its system and/or flexible RA capacity needs, and

b. A demonstration that despite having actively pursued all commercially reasonable efforts to acquire the resources needed to meet the LSE's system and/or flexible procurement obligations, it either:

   (i) Received no bids aligned with reasonable prices (with reasonable prices defined as the CAISO's CPM soft offer cap + an adder), or

   (ii) Received bids which included what the LSEs believe are unreasonable terms and/or conditions, in which case the waiver request demonstrates why such terms and/or conditions are unreasonable.

A full waiver would provide an LSE a waiver of financial penalties, penalty points, and any other non-financial consequences for RA non-compliance. To receive a full waiver, an LSE must show:

a. **Highly constrained market conditions** (similar to how an LSE supports requests for the existing Local RA Waiver): In addition to the criteria above, LSE must demonstrate it received insufficient bids and/or bi-lateral offers to satisfy its system and/or flexible obligations.

b. **PPA Delay:** The LSE is able to demonstrate that delays in COD for new capacity projects contributed to the LSE's need for a waiver.

c. **SOD Waiver:** The LSE made reasonable efforts to meet the SOD compliance obligations but were unable due to SOD implementation issues.

The waiver approval process should be clear, so that LSEs have a clear expectation of when a waiver is reasonable. The Commission should direct Energy Division and stakeholders to conduct a workshop to further develop the criteria for granting a waiver, including determining the adder applied to the CPM soft offer cap to set a reasonable price that would be used to apply partial waivers as described above. The Commission could also use a publicly available stack analysis as an item for consideration, but not a requirement, for a waiver. Under the current market conditions of run-away prices, Commission action to place reasonable expectations of LSE spending could have a significant impact in limiting the prices for capacity.

The Commission should adopt a temporary waiver process to mitigate against the excessively high capacity prices and avoid penalizing LSEs for deficiencies that they could not resolve with the amount RA resources on the system. Penalizing LSEs for requirements they had no way of meeting, particularly during a time of such significant transition, only increases customer costs without any marginal reliability benefit. For these reasons, the Commission should adopt a temporary system and flexible waiver process from 2025 through 2027.

D. The Commission Should Increase Transparency into IOU Effective PRM Procurement

Transparency into the quantity of capacity that is available for LSEs to meet their RA obligations is critical, particularly when it appears there is insufficient supply available for LSEs to meet their obligations. One major piece of information that is missing is the details around IOU procurement used to meet the "effective PRM."

The effective PRM was adopted for use in the RA program through 2025 in D.23-06-029.[11] The Commission adopted the effective PRM, in part, because:

> Adopting a higher PRM before there is certainty on installed RA resources will likely result in RA shortages that will unnecessarily inflate RA costs. A lack of sufficient RA resources with a higher PRM may result not only in LSE deficiencies, but in increased prices for all RA capacity as demand exceeds supply, and such an outcome will be detrimental to ratepayers.[12]

Despite this well-intentioned objective, the effective PRM can result in increased demand for RA capacity and therefore increased prices at a detriment to ratepayers, because the Commission allows the IOUs to procure RA-eligible resources to meet their effective PRMs. This practice adds additional demand for the already scarce RA supply, impacting LSEs' ability to meet minimum compliance obligations. This is especially true if the IOUs do not make attempts to sell excess RA until close to or after LSEs' compliance deadlines, as described by SCP in Appendix D.

The Commission posts *Excess Resources Report* (Report) spreadsheets that document IOU procurement used to meet the effective PRM. The 2023 Reports show a significant amount of procurement listed in each IOU spreadsheet as being "IOU Supply Plan Summer Reliability MW Amount."[13] Resources placed on a supply plan presumably are RA eligible, and the Reports thus indicate IOU effective PRM procurement did in fact compete with other LSEs' procurement of RA to meet their own compliance obligations.

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[11] D.23-06-029, *Decision Adopting Local Capacity Obligations for 2024 -2026, Flexible Capacity Obligations for 2024, and Program Refinements*, R.21-10-002 (July 5, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M513/K132/513132432.PDF.

[12] *Id*. at 23.

[13] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

To gain transparency into what is procured by the IOUs for the effective PRM, the Commission should issue reports upon each effective PRM showing that includes by resource ID (or the intertie for a non-resource specific import) the product purchased, the duration of the contract, the quantity purchased, when the contract began negotiation, and the date the contract was entered into. This report should include an analysis of whether the IOUs reasonably made these resources available to the market so that other LSEs could meet their RA obligations, as well as an assessment of whether the efforts by the IOUs to procure excess exacerbated RA market tightness and raised prices. This will provide stakeholders with a better understanding of what portion of the RA supply stack was used for the effective PRM and whether those resources could have otherwise served to meet LSE compliance obligations.

E. The Commission Should Revise the Maximum Non-Resource Specific RA Import Bid Price to Ensure Out-of-State Resources Have the Right Incentives to Provide RA Capacity to California

The Commission's RA program allows LSEs to contract with resources imported from outside of the state to meet their RA obligations. D.20-06-028 modified eligibility rules for non-resource-specific RA imports to count towards RA such that the energy from non-resource-specific imports must be bid into the CAISO market at levels between negative $150/ megawatt-hour (MWh) and $0/MWh or self-scheduled during the availability assessment hours.

As described in CalCCA's declaration in Appendix A, structural shifts in the RA market, including increased load growth, retirements of generation, and reductions in the portion of solar plant capacity that contributes to RA, have made it challenging for LSEs to meet their obligations and will continue to cause challenges through at least 2025. At the same time, RA has become a priority issue in other parts of the West as other regions experience load growth, retire aging coal plants, and turn to resources like solar for future needs. This shift in many Western states has resulted in a net-peak load concerns much like those in California, making it ever more difficult to import firm energy over all of the availability assessment hours at a price take bid.

1. New Information Points to the Need to Revise the RA Import Bid Cap

In R.21-10-002, CalCCA proposed revisions to the rules adopted in D.20-06-028 to allow non-resource-specific RA imports to bid up to a maximum bid price based upon estimated costs of the typical marginal resource. This proposal intended to attract additional RA capacity to California in light of the supply constraints described in Section II and the increased importance placed on RA across the West. It would have also established bid prices that would not have the "phantom supply" issue that caused the Commission to adopt the current stringent bidding rules.[14]

D.23-06-029 did not adopt CalCCA's proposal, citing insufficient record to replace the current maximum import RA bid price or to determine whether modifying the maximum RA import bid price would increase the volume of imports rather than just reducing the RA price of imports.[15] D.23-06-029 concluded that should information arise as to why the current RA import bidding requirements warrant modification and Energy Division should present that information to the Commission and stakeholders for consideration.[16] Since this conclusion was made, additional information has emerged, making CalCCA's proposal relevant in this proceeding.

First, the CAISO has posted data on the types of resources used to meet RA requirements both YA and MA for the most recent five-year period. The YA RA showings for the month of September data presented in Table 3 below demonstrate that since the Commission adopted the existing RA import bidding rules in 2020, year-ahead RA imports have steadily declined, from 4,218 MW in 2020 to 1,499 MW in 2023. While the imports in the MA RA showing for September are higher than the YA RA showing for September, they likewise show the declining trend of imports as can be seen in Table 4.

Table 3 - Downward Trend of Imports in Year-Ahead RA showings

Year-Ahead (September)						
Year	Non-Resource Specific Imports	Resource Specific Imports	Total RA Shown	MWs of Non-Resource Specific Imports	MWs of Resource Specific Imports	Total RA Imports
2019	9.20%	3.63%	43,996	4,046	1,599	5,645
2020	9.97%	3.65%	42,313	4,218	1,545	5,763
2021	5.18%	5.00%	41,997	2,177	2,101	4,278
2022	3.01%	5.06%	43,041	1,294	2,179	3,473
2023	3.27%	5.33%	45,802	1,499	2,442	3,941

[14] The "phantom supply" issue was a concern that import RA suppliers could sell non-resource specific RA imports with no intention of delivering, because non-resource specific imports could bid in near or at the bid cap with low probability of being dispatched.

[15] D.23-06-050 at 55.

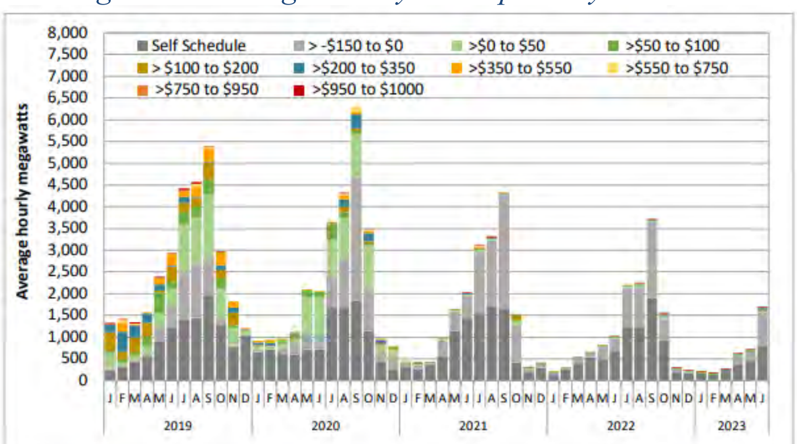
[16] *Id.*

Table 4 - Downward Trend of Imports in Month-Ahead RA showings

Month-Ahead September						
Year	Non-Resource Specific Imports	Resource Specific Imports	Total RA Shown	MWs of Non-Resource Specific Imports	MWs of Resource Specific Imports	Total RA Imports
2019	13.91%	3.23%	50,111	6,970	1,617	8,587
2020	13.17%	4.19%	48,973	6,450	2,050	8,500
2021	8.75%	4.62%	47,936	4,196	2,213	6,409
2022	7.99%	4.68%	49,201	3,932	2,304	6,236
2023	7.22%	4.77%	53,087	3,833	2,530	6,363

As expected, the decrease in import RA showings resulted in fewer import RA offers into the CAISO market. The CAISO DMM's *Q2 2023 Report on Market Issues and Performance* shows RA import bid quantities have consistently declined since 2019.[17] Figure 3 shows that since D.20-06-023 was adopted, the vast majority of RA imports no longer bid a price above $0 per MW hour, as D.26-06-023 intended. However, RA import bidding has also steadily decreased, an outcome that exacerbates an already tight RA market.

Figure 3 - Average Hourly RA Imports by Bid Price



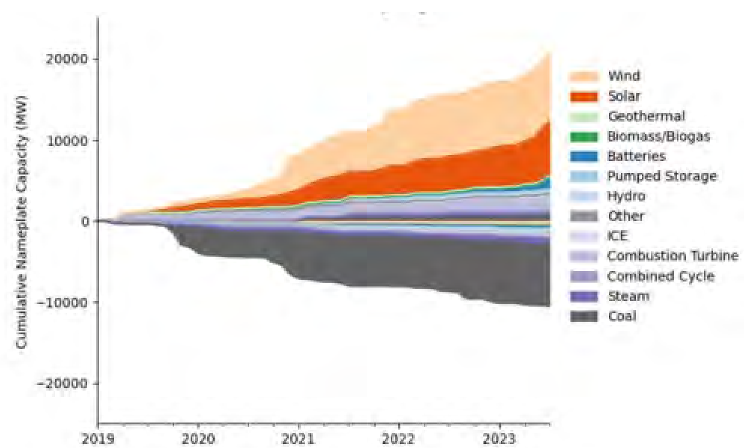
<u>*Second*</u>, LSEs' experiences in the market demonstrate suppliers' unwillingness to transact RA with Commission-jurisdictional LSEs under the current rules. While the Commission's intent with D.20-06-028 was to prevent speculative supply, there is no evidence to conclude that the decline in shown RA imports is only attributable to speculative supply. This decline could also be attributed to (1) suppliers being unwilling to take the risk of selling energy into the CAISO market at a loss or (2)

[17] *Q2 2023 Report on Market Issues and Performance:* https://www.caiso.com/Documents/2023-Second-Quarter-Report-on-Market-Issues-and-Performance-Nov-16-2023.pdf.

suppliers being able to sell to buyers outside of California who are not subject to D.20-06-023. As described in SJCE's declaration in Appendix C, sellers of import RA have expressed unwillingness to flow power into California because it is economically infeasible to sell the supply as import RA under the current rules.

Third, in the broader West, capacity characteristics are changing, possibly resulting in additional competition for RA capacity. As shown in Figure 4, non-CAISO Western Electricity Coordinating Council (WECC) has experienced significant coal retirements between 2019 and 2023. Coal has largely been replaced with intermittent resources like wind and solar.

Figure 4 - Non-CAISO WECC Capacity



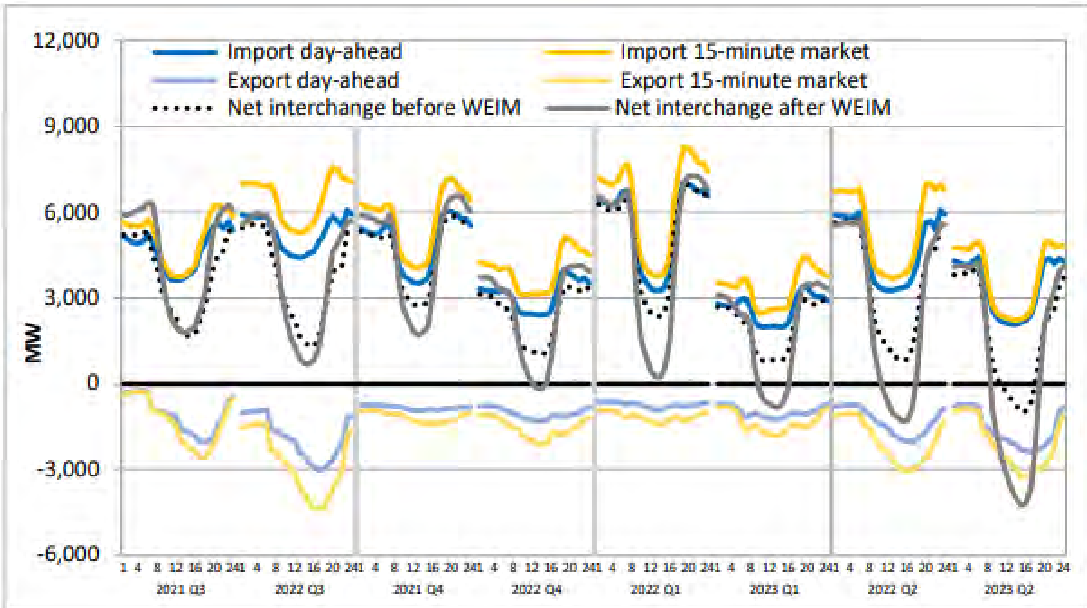
Data Source: EIA Form 860M from January 2019-July 2023

As this shift has occurred, other BAAs have recognized the need to ensure sufficient capacity is available to serve their load through forward commitments and have begun implementing their own RA programs. The Western Resource Adequacy Program (WRAP) had its first non-binding RA showing in October 2022 for 2023, and BAAs may be contracting with capacity that could have been available to meet California RA obligations to meet their WRAP RA obligations.[18]

DMM's *Q2 2023 Report on Market Issues and Performance* shows that the CAISO BAA is importing less and exporting more in recent years. Figure 5 below shows that average net interchange when exporting increased in the middle of the day between 2021 and 2023. Additionally, during the evening hours when solar declines, imports have decreased.

[18] The desire by other BAAs to have sufficient capacity could reduce the available resources to California by either limiting the resources available to California to import and by entities outside of California procuring capacity from California resources for export.

Figure 5 - Average Hourly Net CAISO Interchange by Quarter



Finally, CalCCA has recreated its analysis performed for 2022 to analyze the percentage of availability assessment hours that a non-specified RA import from a Combustion Turbine (CT) would expect to take a loss in the energy market by becoming a price taker. This analysis used U.S. Energy Information Administration (EIA) data on gas prices in the west and typical Operation and Maintenance (O&M) costs for a CT, California Air Resources Board (ARB) prices for GHG Cap and Trade allowances, and CEC data to determine that the most relevant heat rate for a CT in California is a 12 MMBtu/MWh heat rate resource.[19] The analysis then looked at CAISO Open Access Same-time Information System (OASIS) for the marginal cost of energy during the availability assessment hours for the summer months. Since a non-specified energy import must bid no higher than $0 during these hours, they receive the market clearing price which is not guaranteed to cover the cost of operating the resource. By using a 12 MMBtu/MWh heat rate resource, a range of gas price in the west, O&M costs expected of the resource and the costs of GHG allowance, CalCCA can compute the cost per MWh to operate the resource and compare that cost to the CAISO market clearing price. Based upon this information for 2023, there were a very large number of hours that an entity bidding a non-specified

[19] https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_STX_m.htm, https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf, https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/program-data/cap-and-trade-program-data-dashboard, https://www.energy.ca.gov/sites/default/files/2021-06/CEC-200-2019-001.pdf.

import for RA into California would expect that the energy market revenues would be insufficient to cover the cost of operating the resources (see Table).

Table 5 - Percent of Hours Non-Resource Specific Imports From a 12 MMBtu/MWh Heat Rate CT Would be Expected to Lose Money in the CAISO Energy Market

Percent of AAH Where CAISO MCE is Less Than the Estimated Cost @ 12 MMBTU/MWh				
	June	July	August	September
Low Gas Price	96%	38%	40%	89%
High Gas Price	100%	65%	72%	99%

Further, CalCCA evaluated the anticipated losses the sample resource would be expected to experience on average during the Availability Assessment Hours for each month (See Table 6). Given the significance of the number of occurrences and the expected value of the energy market revenue shortfall, it would be illogical for many resource owners to commit to providing a non-specified import as an RA resource if that resource has an operational cost that is greater than the maximum bid price of $0/MWh.

Table 6 - Expected Energy Market Losses from a Non-Resource Specific Import Provided by a 12 MMBtu/MWh Heat Rate CT

Loss Where Example Peaker Generation Cost is Greater Than CAISO MCE ($/MWh)				
	June	July	August	September
Low Gas Price	$ 5.81	$ 1.70	$ 0.94	$ 4.19
High Gas Price	$ 12.48	$ 4.77	$ 4.27	$ 9.25

In totality, this information points to the inability to assume imports will be made available to California in the same magnitude the state has relied upon historically due to an evolving resource mix West wide and increased competition for capacity. The Commission should aim to remove barriers to contracting with California LSEs for import RA to ensure California LSEs can compete on a level playing field with other LSEs for scarce supply.

2. The Commission Should Adopt a New Import RA Bid Cap Based Upon Estimated Costs of the Typical Marginal Resource

In light of this new information pointing to downward trends in the availability of RA imports to California and increased demand for capacity across the West, the Commission should adopt a maximum non-resource specific RA import bid price to ensure out-of-state resources have the right incentives to provide RA capacity to California. The Commission should set this maximum non-resource specific RA import bid price based upon the estimated marginal resource's costs. Costs for a CT, the typical marginal resource, can be reasonably estimated based upon heat rate, natural gas prices and penalties, variable O&M, and GHG costs. The Commission should use the heat rate, gas price, variable O&M, and GHG data to set tiers for maximum energy bid prices of RA imports based on gas price forwards.

Typically, the resource on margin during the availability assessment hours is a CT. Costs for a CT can be reasonably estimated based upon heat rate, natural gas prices and penalties, variable O&M, and GHG costs.[20] The Commission should establish tiers that reflect the maximum bid price of a non-resource specific import based on these cost categories. Such tiering would reflect the acceptable electric energy bids dependent on the primary cost driver that is volatile, which is the price of natural gas. The following describes how the Commission could calculate each element of costs (including heat rate, gas prices, variable O&M, and GHG) to form the tiers.

Heat Rate

The CEC has studied the heat rates of CTs. It has shown those heat rates to range from just over 8,000 Btu/ kilowatt-hour (kWh) to just under 13,000 Btu/kWh. Within this study, the CEC shows that all but a handful of CTs have a heat rate no higher than 12,000 Btu/kWh.[21] Based upon this information, it would be reasonable to assume for purposes of this calculation a heat rate of 12,000 Btu/kWh.

Natural Gas Prices

There are several sources the Commission could use to obtain gas prices. One common source is the Intercontinental Exchange (ICE).[22] The common trading hubs for the west include; Malin, Sumas, Kern River Opal, Cheyanne, El Paso Permian, and Waha.[23] The Commission should use these points and ICE gas prices to determine the cost of natural gas that would be used to establish the maximum bid price for non-resource specific RA imports during the Availability Assessment Hours. The Commission could use the maximum of the gas prices of these points or a weighted average of these points to determine the gas cost to the RA import energy bid formula. To avoid setting the prices for import bids excessively frequently, the Commission should use a monthly forward quote for these

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[20] In fact, the Commission had historically done a similar estimation to calculate the avoided cost for combined heat and power.

[21] https://www.energy.ca.gov/sites/default/files/2021-06/CEC-200-2019-001.pdf, at 21-22.

[22] ICE publishes a list of all natural gas trading hubs for which they have indices. https://www.ice.com/publicdocs/NA_Phys_Gas_hubs.pdf.

[23] https://atlas.eia.gov/datasets/eia::natural-gas-trading-hubs/explore.

points and establish the parameters monthly to determine which tier of the maximum import RA energy price the current market conditions allow.

Variable O&M

The EIA has studied the variable O&M costs of a variety of different resources and lists the variable O&M of a CT at $4.70/MWh in 2019.[24] The Commission could adjust this amount annually for inflation or update it if the EIA provides a new study. Using inflation information from the Bureau of Labor Statistics, the variable O&M would equate to $5.73 currently.

GHG

The California ARB provides information about the auction prices, allowance floor prices, and secondary market prices that can be used to estimate GHG costs.[25] The EPA lists natural gas as having a GHG content of 53.06 kilogram (kg) / Million British Thermal Units (MMBtu).[26] Assuming a heat rate of 12,000 British thermal units (Btu) / kWh, producing 1 MWh requires 12,000,000 Btu or 12 MMBtu. Multiplying 12 MMBtu by 53.06 kg gives 636.72 kg/MWh. Since there are 1000 kg per metric tonne (which is how the California ARB cap and trade allowances are denominated), 1 MWh from a CT with a 12,000 Btu/kWh heat rate emits .63672 metric tonnes. At the present allowance price based upon information from CARB, that equates to $24.77/MWh.[27]

Tiers

The Commission should use the heat rate, gas price, variable O&M, and GHG data described above to set the tiers for maximum energy bid prices of RA imports. In order to create the tiers, the Commission should first annually evaluate the variable O&M and GHG costs. At present, these costs are $5.73/MWh and $24.77/MWh, respectively. Therefore, before considering the cost of natural gas to produce a MWh, variable O&M and GHG represent a cost of $30.50 /MWh. Next, the Commission should establish tiers based upon natural gas price levels up to $10/MMBtu, $20/MMBtu, and $30/MMBtu.[28] The Commission would determine which tier resources can bid to each month based upon gas price forwards. With a 12,000 Btu/kWh heat rate, these correspond to generation costs of

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24 https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.

25 https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/program-data/cap-and-trade-program-data-dashboard.

26 https://www.epa.gov/sites/default/files/2021-04/documents/emission-factors_apr2021.pdf.

27 https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/program-data/cap-and-tradeprogram-data-dashboard shows current allowance prices at approximately $27.50 per metric tonne.

28 The Commission could choose to create additional tiers if there is a concern of natural gas prices rising significantly above $30/MMbtu.

$120/MWh, $240/MWh, and $360/MWh. To get the final maximum bid price for energy, the Commission would then add the cost of variable O&M and GHG, bringing the final numbers to:

Gas Prices up to	*Max Bid Price*
$10/MMBtu	$150.50/MWh
$20/MMBtu	$270.50/MWh
$30/MMBtu	$390.50/MWh

Establishing maximum bid prices in this manner would allow owners of generating resources outside of the state to rationally bid their resources economically to the CAISO energy market while ensuring that the maximum bid price is not so high that the bid price is unlikely to be struck. This will enable sellers of RA imports to California to be better assured that they will be able to operate economically and will enable California LSEs to compete with capacity buyers in WECC for those resources.

The Commission should adopt a maximum import RA bid price based upon the costs of the typical marginal resource in the market. This proposal ensures the maximum bid price would not be so low that it requires generators to operate at a loss. Additionally, the maximum bid price would not be so high that it invites the "phantom supply" issues described in Section III.E.1. This is because cost-based bids during high demand market conditions are likely to clear leaving the RA supplier with significant cost risk by not providing the energy from the non-resource specific RA import.

F. The Commission Should Create a Hydro Resource Counting Methodology that Requires Mid-Year Updates to Account for Above-Normal Hydro Conditions

D.20-06-031 allows a hydro resource to count its capacity in one of two ways. First, a hydro resource can choose to count based on its maximum generating capability. If a resource elects to use this counting methodology, it will be subject to Resource Adequacy Availability Incentive Mechanism (RAAIM) charges if it is available for less than its NQC and does not provide substitution. Second, a hydro resource can choose to count based on an exceedance methodology with more weight placed on dry hydro years. The exceedance methodology effectively derates the amount of capacity available from hydroelectric facilities to account for historical water availability for use at the facility. This second option is more conservative, and so hydro resources that elect this option receive a RAAIM exemption, meaning they will not be subject to charges for availability less than their NQC.

Adding the second option improved the counting rules for hydro resources by accounting for the potential impacts drought may have on hydro availability. The RA program lacks a process, however, to check whether availability assumed in the YA timeframe is consistent with actual availability in the MA timeframe. Lacking such a process could result in stranded RA supply when a hydro resource uses the second option for QC counting in the YA, but then has an above-average hydro year. These circumstances occurred in 2023, between the YARA showings and the MARA showings in the summer months. The Commission should therefore require a process for determining which hydro counting methodology best represents the availability of the resource once hydro conditions for the RA month are known.

Hydro conditions from 2022 to 2023 demonstrate how the changes in precipitation levels year to year impact the availability of capacity in a manner that, under current practices, may have the potential to strand available RA supply. YA RA showings for 2023 occurred in October 2022. At the time of the YA showings, the California Department of Water Resources (CDWR) reported snow-pack levels at zero percent of normal. Without knowing the amount of rain and snow that would occur between the YA RA showings and the summer RA months, and because the exceedance methodology relies on historical hydro availability during dry years, the amount of hydroelectric generation for YA RA was likely very low. Between the YA showings in October 2022 and the summer of 2023, however, California experienced record-setting precipitation. As of June 14, 2023, CDWR reported that the water content of snowpack for the State was at 333 percent of normal. In addition to the snowpack, rain helped to fill reservoirs prior to the snow melt placing many of California's reservoirs above their historical average as early as March.

With conditions better known in June, significant amounts of hydroelectric generation in and out of state could likely have been made available between the YA RA showings and the MA RA showings for the summer months. It is unclear if this increased capacity was made available in the MA, however, because the Commission has no requirement for the IOUs, who hold the largest amount of RA from hydro, to use an NQC methodology for MA supply that most accurately reflects hydro conditions. The CAISO has made historical RA showings data available that suggests the full value of hydro resources may not have been made available in the summer of 2023, potentially due to this lack of requirement. YARA hydro showings for the month of September totaled 5,337.62 MW and only increased to 6,018.44 MW in the MARA showings despite record hydro conditions occurring after the YARA showings were made in October 2022 but prior to the MARA showings made in July 2023.[29]

The Commission should therefore require hydro counting rules to include mid-year updates that reflect the true availability of the resource as more information about hydro conditions become

[29] https://www.caiso.com/Documents/HistoricalResourceAdequacyAggregateData.xlsx.

known. Such a process would be consistent with existing CAISO processes for increasing NQCs mid-year and would ensure that a potentially large increase in NQC from hydro resources is made available to the market so that LSEs are more likely to meet RA requirements. While this action may have occurred in 2023, there is no requirement for it to do so and no transparency into the amount of hydro being made available to the market to help participants better gauge likely market supply and demand conditions.

G. The Commission Should Evaluate Test Year Showings Data to Quantify the Benefits of Hourly Transactability and Adopt Hourly Load Obligation Trading for SOD

D.22-06-050 adopted the 24-hour SOD framework to restructure the RA program to ensure that it provides grid reliability at all times of the day.[30] Despite setting 24 requirements and 24 net qualifying capacity values, D.22-06-050 requires LSEs to continue to transact resources monthly. This means that if an LSE contracts for a resource, it must do so for the resource's net qualifying capacity in all 24 hours for that month. D.22-06-050 found that if "transactability and inefficiency" issues arise due to the inability to transact on the same hourly granularity as the requirements, then the Commission may consider proposals to include the ability for LSEs to trade their RA obligations with each other on an hourly basis.[31]

The current RA supply and demand balance described in Section II necessitates reconsideration of the need to transact hourly as soon as possible. The inability for LSEs to shape their portfolios to their hourly requirements could create artificial scarcity in the RA market by requiring LSEs to show resources in all hours they are available even in hours the LSEs do not need them to meet their compliance obligations. This unnecessarily limits LSEs' ability to capture the diversity inherent in their load shapes and resource portfolios. Given the RA market is already extremely tight, and prices are sky-high, restrictions on the ability to transact under SOD will only further impede compliance and cost-effective procurement.

1. The Commission Should First Evaluate the Need

An assessment of the extent to which hourly transactability would alleviate some supply tightness would help inform the Commission of the need to allow LSEs to trade their RA obligations

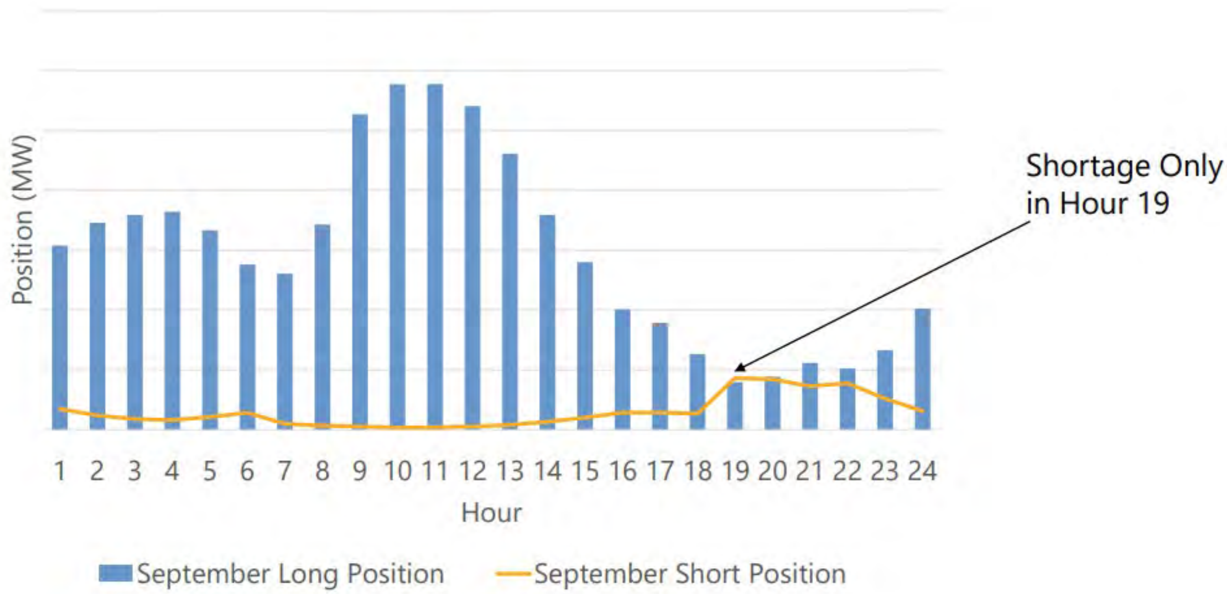
30 D.22-06-050, *Decision Adopting Local Capacity Obligations for 2023-2025, Flexible Capacity Obligations for 2023, and Reform Track Framework*, R.21-10-002 (June 23, 2022), at 55: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540633.PDF.

31 *Id.*, at 97.

on an hourly basis. CalCCA has evaluated its members' test year YARA showings and found that *the ability for its members to transact load obligations on an hourly basis would have increased compliance with the test year SOD YARA requirements*. If fact, on an aggregated basis, long positions could have fully covered short positions for all CCAs, as demonstrated in the figures below.

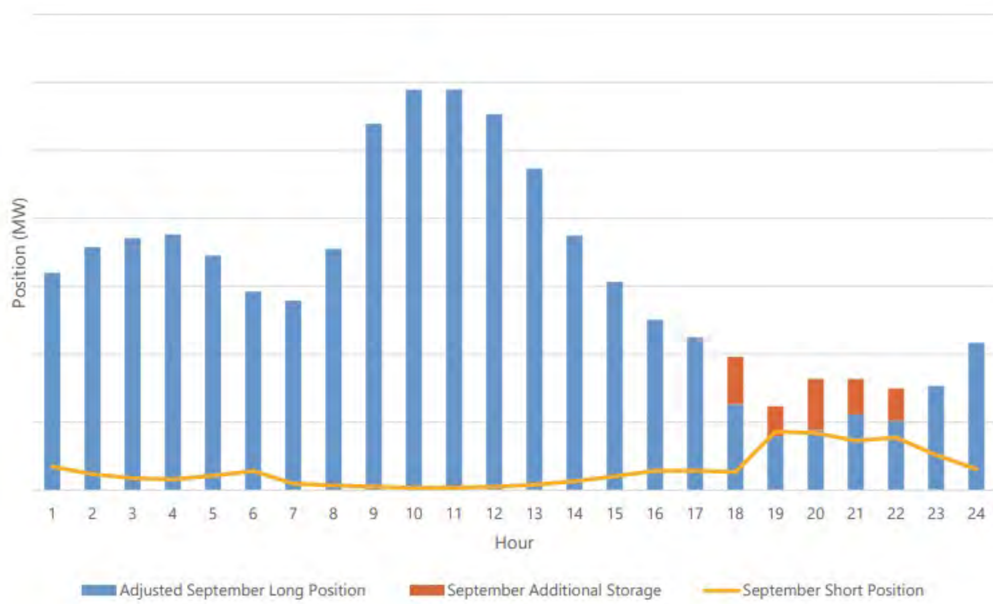
Figure 6 shows aggregated short and long positions by hour for September _as individually filed_. In aggregate, there is a shortfall in HE 19. The orange line depicts the sum of the short RA position for all CCAs that were short in that hour. The blue bars depict the sum of the long position for all CCAs that were long in that hour. If the blue bar fully covers the height of the orange line, the aggregate of CCAs would have complied. This also indicates that the ability to transact hourly, either resources or load obligation, would have made it significantly easier to comply rather than seek resource swaps of the combination of resources that will still make all CCAs compliant.

Figure 6 - Aggregate CCA Short and Long SOD Positions for September, As Filed



When CalCCA adjusted CCA positions such that storage from CCAs that were long in those hours was shown instead in hours with aggregate shortfall, short positions were completely eliminated (See Figure 7). Similar to Figure , the orange line represents the sum of CCA short positions from those CCAs short in that hour while the blue bars represent the sum of CCA long positions from those CCAs long in that hour. Added to this figure is additional storage capacity not used by CCAs that had already met their compliance. This may happen where, for example, a CCA has 10 MWs of battery storage capacity with a four-hour duration but only uses 10 MWs in a single hour and less than that capacity in other hours. This could then leave incremental capacity that could be used for compliance but cannot be traded since all hours for a given amount of capacity must be transacted. Since the NQC of the battery is 10 MWs and the LSE showed 10 MWs in one hour, there is no battery capacity to be sold. However, if an LSE were allowed to transact individual hours of the battery or transact load obligations, the entire amount of capacity from the battery could be used for compliance purposes. This can be seen by the orange bars incremental to the blue bars which clearly cover the short position of all CCAs in all hours in Figure 7.

Figure 7 - Aggregate Short and Long Positions for September if Long CCAs Showed Storage in Excess of Their Own Requirement



These data only show part of the picture, however, given it evaluates only a subset of LSEs, a subset of non-binding requirements, and a subset of the RA supply stack that will be needed to comply with the first binding set of requirements.

To broaden the data set and allow for stakeholder review, the Commission should release aggregated data in its February 1, 2024, SOD report that shows whether hourly transactability would have improved test year compliance at a system level. To do this, the Commission should tally the violations per hour in MWs there were in LSEs' test year YARA showings. The Commission should then aggregate LSEs' test year YARA requirements and showings and tally the violations per hour in MWs there were at an aggregated level. In aggregating the LSEs showings, the Commission should also optimize the aggregated storage fleet rather than apply them to the hours that the individual LSEs did if a different set of hours would produce a compliant outcome. If aggregating LSEs' requirements and showings results in a reduction in the MW of violations, then the Commission can conclude that hourly transactability that allows LSEs to more effectively shape their procurement to match their obligations can unlock much needed procurement efficiencies.

2. The Commission Should Then, At Minimum, Adopt Hourly Load Obligation Trading

After establishing a need for hourly transactability, the Commission should, at minimum, adopt hourly load obligation trading beginning for the first binding SOD compliance year.[32] Hourly load obligation trading was originally proposed by the California Energy Storage Alliance (CESA), Peninsula Clean Energy (PCE) and SJCE (collectively, the Joint Parties),[33] and supported by CalCCA in its March 24, 2022, comments on the *Future of Resource Adequacy Working Group Report*.[34] Hourly load obligation trading offers an administratively simple way to capture diversity benefits in LSEs' hourly load and generation profiles by allowing LSEs with open positions in some hours to pay other LSEs with long positions to take on their RA obligation. Importantly, trading obligations would *not* shift the responsibility of serving customer load, it would simply allow another way for LSEs to comply with their obligation. Both LSEs involved in an hourly load obligation trade would need to submit RA plans documenting the trade (e.g., the LSE that paid another LSE to take on its obligation would show negative load, the LSE that took on another LSEs' compliance obligation would show positive load associated with the trade and resources to cover such load).

D.22-06-050 expressed concerns with introducing hourly transactability, including concerns around unbundling, added complexity, and impacts on CAISO processes.[35] It also indicated that hourly transactability may not be needed due to the ability to shape storage and perform swaps.[36] CalCCA has addressed these concerns and described the shortcomings the alternatives extensively.[37]

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32 While D.22-06-050 only references the possibility of adopting hourly load obligation trading as a means to resolve transactability concerns, CalCCA continues to advocate for the ability to transact resources, in addition to load obligations, on an hourly basis. Having both options available would expand LSEs abilities to shape their loads and resources, creating further efficiencies.

33 *Future of Resource Adequacy Working Group Report*, Track 3.B2 of the RA Proceeding, R.21- 10-002 (Feb. 2022) at 196-205.

34 California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on the Future of Resource Adequacy Working Group Report, R.21-10-002 (Mar. 24, 2022) (CalCCA March 24, 2022 Comments) at 7-10: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M462/K250/462250112.PDF.

35 D.22-06-050 at 97.

36 *Id.*

37 California Community Choice Association's Comments on the Proposed Decision Adopting Local Capacity Obligations for 2023 - 2025, Flexible Capacity Obligations for 2023, and Reform Track Framework, R.21-10-002 (June 9, 2022) at 7-13:

Hourly load obligation trading is not "unbundling" because it involves only trading of hourly obligations among LSEs and leaves the obligations and requirements of generators unaffected. Hourly load obligation trading does not involve generators (or their requirements) at all, but rather allows LSEs to contract with another LSE to use the second LSEs resources to meet the first LSEs obligations. This eliminates the need to modify CAISO processes like outage substitution or the must offer obligation in any way. It would additionally avoid penalizing a specific LSE(s) when the system as a whole meets the RA needs.

Further, LSEs can show trades using existing showings tools. The LSE paying another to take on its obligation would represent the trade as a MW increase to its RA resource portfolio. The LSE receiving payment to take on the obligation would represent the trade as a MW decrease in its RA resource portfolio. This keeps the process administratively simple for the Commission, the LSEs, and the generators, unlike swaps. At the same time, the Commission would be able to confirm that the reduction in load in one LSE showing is equally offset by an increase in another LSEs showing by the same amount of MWs in the same hours. This is very similar to the manner in which the Commission matches LSE showings to generator supply plans to ensure there is no over claiming of resources.

While swaps could theoretically reduce SOD deficiencies, in reality, there is too much market friction involved for them to provide significant benefits under SOD. Swaps require the involvement of suppliers, and thus increase transaction costs. Swaps may also require multiple steps to reach compliance for all parties involved in the swap. One-for-one swaps between two LSEs and two resources are more likely to simply transfer compliance from one LSE to another, leaving one LSE compliant and the other short. It is more likely that multiple layers of swaps would be required for each LSE to reach compliance. There is also less motivation for those holding resources to conduct swaps because they are already compliant and would take on additional transaction costs (in time and money) and potentially take on risk by reducing their excess portfolio that could otherwise be used for substitution. Conversely, there is more motivation for those holding load to transact with each other because the transaction is targeted at the hour(s) and quantity needed rather than finding complex combinations of resource swaps that fulfill both parties' needs.

For these reasons, the Commission should commit to adopting hourly load obligation trading pending the evaluation of the compliance and efficiency benefits to allowing hourly transactions.

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https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M483/K885/483885726.PDF and CalCCA March 24, 2022 Comments at 4-10.

IV. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

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

January 19, 2024

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ASSIGNED COMMISSIONER'S SCOPING MEMO AND RULING

DECLARATION OF ANDREW MILLS

APPENDIX A

DECLARATION OF ANDREW MILLS
DIRECTOR OF DATA ANALYTICS
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

1. I, Andrew Mills, am Director of Data Analytics at California Community Choice Association (CalCCA). I submit this declaration in support of California Community Choice Association's (CalCCA's) Comments on Assigned Commissioner's Scoping Memo and Ruling in Rulemaking (R.) 23-10-011, being filed on January 19, 2024.

2. As Director of Data Analytics, I manage an analytics and modeling team that provides CalCCA members and decision-makers with data and analysis to ensure a reliable grid at a reasonable cost. Since joining CalCCA in December 2021, I have analyzed resource adequacy (RA) filings from CalCCA members, public data on supply and demand of RA resources in California, and public data on RA transactions in Electronic Quarterly Reports (EQRs) filed with the Federal Energy Regulatory Commission (FERC). I developed and continue to maintain a PLEXOS production cost model for analysis of reliability, costs, and emissions of the Western Interconnection through the planning year of 2035.

3. Prior to CalCCA, I was a Staff Scientist in the Electricity Markets and Policy group at the Lawrence Berkeley National Laboratory. There I led research on the integration of variable renewable energy into the electric power system and impacts on wholesale power markets. I co-authored more than 90 publications including peer-review journal articles, Berkeley Lab reports, and magazine articles. Several of the peer-review journal articles focus on the reliability contribution of variable renewable energy sources and interactions with energy storage.

4. I have a Ph.D. and M.S. in Energy and Resources from the University of California at Berkeley and a B.S. in Mechanical Engineering from the Illinois Institute of Technology.

5. Attached to my Declaration as Exhibit A is a document authored by me entitled "California's Constrained Resource Adequacy Market: Ratepayers Left Standing in a Game of Musical Chairs" (updated January 16, 2024) (hereinafter referred to as RA Whitepaper). The RA Whitepaper includes a description of, and conclusions from, a "stack analysis" I prepared comparing RA requirements with the available RA supply. My conclusions from my analyses are detailed both in the attached RA Whitepaper, and in my Declaration herein.

6. The system RA supply available within the California Independent System Operator (CAISO) balancing authority area (BAA) appears, on a forecast basis, inadequate to meet the RA program compliance requirements in September 2024, with a projected deficiency of 894 MW. In 2023, the available supply was so tight that the available RA supply exceeded demand by only 135 MW in August and 582 MW in September.

7. A wide range of factors have contributed to the current circumstances in which there is insufficient RA supply projected to meet the RA program compliance requirements. These factors include:

- Weather conditions are more extreme, increasing load and reducing generation output.
- Hydro resource availability has declined under drought conditions.
- New resources are delayed due to permitting, interconnection, and supply chain challenges.

- The entire Western region is constrained, reducing the availability of imports to California[1] and risking increased exports of California resources to meet other Western region requirements (e.g., Western Resource Adequacy Program (WRAP)).

- The Commission's reduction in effective load carrying capacity values reduced reliance on wind and solar resources to meet RA requirements.

- The Commission's increase in planning margins (PRMs) to 16 percent in 2023 and 17 percent in 2024, with a 20-22.5 percent "effective" PRM for investor-owned utilities (IOUs), increased RA requirements.

- The Commission's definition of "incremental" procurement to meet the effective PRM encouraged IOUs to cannibalize the existing RA resource stack, reducing supply for other LSEs.

- Unnecessarily restrictive requirements for energy imports under the Commission's RA program reduced the availability of imports to the Commission-jurisdictional RA market.

The result of these contributing factors is shown in Figure 1 below,[2] in which demand for RA is projected to exceed the available supply in 2024 and have razor thin margins in 2025.

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[1] Historical RA import data from the CAISO demonstrates that the September imports in month-ahead RA showings declined from over 8,500 MW in 2019 and 2020 to less than 6,500 MW in 2021, 2022, and 2023. Month-ahead RA imports in August declined even further from 8,804 MW in 2019 to 5,130 MW in 2023. http://www.caiso.com/Documents/HistoricalYearAheadResourceAdequacyAggregateData.xlsx.

[2] Figure 1 was developed using publicly available data sources including the California Energy Commission's (CEC) Integrated Resource Policy Report (IEPR), the Net Qualifying Capacity (NQC) list, CAISO outage data, and the Investor-Owned Utilities' Excess Resource Reports. A detailed list of sources and an explanation of how they were used to develop the stack is included in Exhibit A.

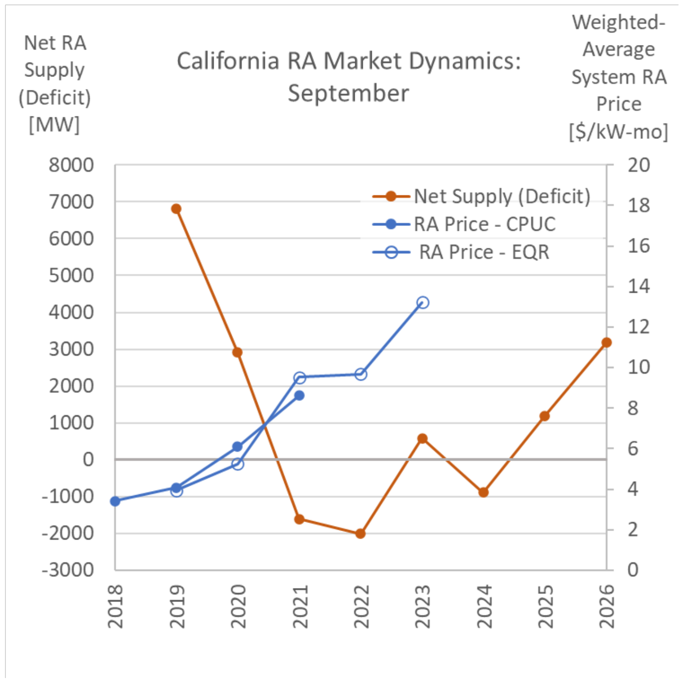
Figure 1

	September NQC	2023	2024	2025	2026
1	CAISO 1-in-2 Load	46,829	47,475	47,987	48,487
2	Reserve Margin (16% in '23, 17% after)	7,493	8,071	8,158	8,243
3	**Total RA Demand**	**54,322**	**55,546**	**56,145**	**56,730**
4	NQC List	49,232	46,137	46,137	46,137
5	Event-Based Demand Response	1,090	980	955	978
6	Imports	6,363	6,000	6,000	6,000
7	Estimate of Contracted Resources	-	7,474	10,189	11,026
8	Thermal Plant Derate	(718)	(761)	(761)	(761)
9	OTC, Retired or Contracted by DWR	-	(2,859)	(2,859)	(2,859)
10	Excess IOU Procurement for Higher Effective PRM	(443)	(1,700)	(1,700)	-
11	Retention for Substitution	(619)	(619)	(619)	(619)
12	**Total RA Supply**	**54,904**	**54,652**	**57,342**	**59,902**
13	Surplus Supply (Deficit)	582	(894)	1,197	3,172

8. The RA supply deficiency in 2024 will prevent collective compliance by CAISO load-serving entities (LSEs) despite their best efforts to procure and willingness to pay exorbitant prices. Some LSEs subject to the Commission's RA program were unable to obtain enough supply to comply with their 2023 RA compliance requirements despite numerous formal solicitations and substantial bilateral outreach.

9. As basic economics would predict, these conditions are ripe to produce exorbitant prices, making reliably serving California's electricity customers more expensive. My analysis of public capacity transaction data in the Federal Energy Regulatory Commission (FERC) Electronic Quarterly Reports (EQR) in Figure 2 shows that the weighted-average price for capacity delivered to the California Load Serving Entities (LSE's) has substantially increased since 2018.

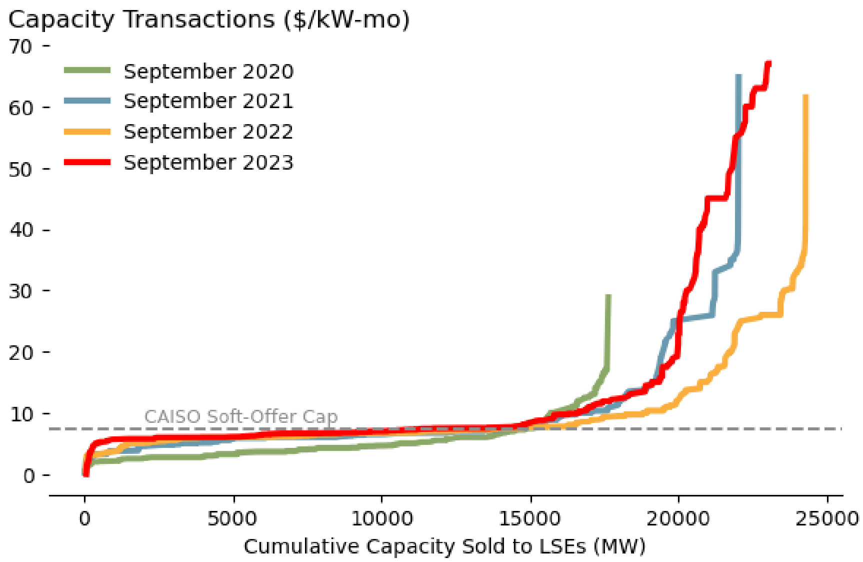
Figure 2



10. Importantly, detailed transaction-level data from the FERC EQRs shows that the rise in average capacity prices is primarily driven by a growing share of transactions at extremely high prices, as shown in Figure 3. In September 2020, a time with excess RA supply relative to the requirement, around 2,800 MW of RA capacity was purchased by California LSEs at prices above \$7.34/kW-month, the CAISO's recently proposed capacity procurement mechanism (CPM) soft-offer cap.[3] In contrast, more than 7,800 MW and 10,600 MW were purchased at prices above \$7.34/kW-month in September 2021 and September 2022, times with an RA deficit. In September 2023, the quantity of RA purchased at prices above the soft-offer cap increased to over 11,700 MW. The highest observed prices rose from \$29/kW-month in September 2020 to over \$60/kW-month in September 2021, 2022, and 2023.

[3] June 30, 2023 straw proposal for CAISO soft offer cap: http://www.caiso.com/InitiativeDocuments/StrawProposal-CapacityProcurementMechanismEnhancementsTrack2.pdf.

Figure 3



11. LSEs faced with a responsibility to meet their RA obligation at any cost are being met with generators only willing to sell at prices eight to nine times higher than the CAISO soft-offer cap. The lack of sufficient capacity available to meet RA needs is clearly driving up costs for California electricity customers.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct to the best of my knowledge and belief.

Executed on January 19, 2024 at Oakland, California.

Andrew D. Mills

Andrew Mills
Director of Data Analytics
California Community Choice Association

EXHIBIT A
TO
DECLARATION OF ANDREW MILLS
DIRECTOR OF DATA ANALYTICS
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

CALIFORNIA'S CONSTRAINED RESOURCE ADEQUACY MARKET: RATEPAYERS LEFT STANDING IN A GAME OF MUSICAL CHAIR
(updated January 16, 2024)

CALIFORNIA'S CONSTRAINED RESOURCE ADEQUACY MARKET:
RATEPAYERS LEFT STANDING IN A GAME OF MUSICAL CHAIRS

Updated January 16, 2024

1. Introduction

The Resource Adequacy (RA) supply available within the California Independent System Operator (CAISO) balancing area for 2023 appears to have left almost no slack to meet the RA program compliance requirements. The "stack" analysis in Figure 1 below, which compares RA requirements with the available RA supply, demonstrates that the margin was razor thin "on paper."[1] The Joint Agency Reliability Planning Assessment by the California Energy Commission (CEC) and California Public Utilities Commission (CPUC), which is based on an hourly analysis of anticipated supply and projected demand, roughly substantiates this conclusion. When the stack analysis is viewed in the context of regulatory dynamics and Western market constraints, the razor-thin margin starts to feel like a material supply deficiency. The tight conditions persist through 2025.

A wide range of factors have contributed to these conditions:

- Weather conditions are more extreme, increasing load and reducing generation output.
- Hydro resource availability has declined under drought conditions.
- New resources are delayed due to permitting, interconnection, and supply chain challenges.
- The entire Western region is constrained, reducing the availability of imports to California[2] and risking increased exports of California resources to meet other Western region requirements (*e.g.,* Western Resource Adequacy Program (WRAP)).
- CPUC revised effective load carrying capacity values reduced reliance on wind and solar resources to meet RA requirements.
- CPUC's increase in planning margins (PRMs) to 16 percent, with a 20-22.5 percent "effective" PRM for investor-owned utilities (IOUs) for 2023, increased RA requirements.
- CPUC's definition of "incremental" procurement to meet the effective PRM allowed IOUs to cannibalize the existing RA resource stack, reducing supply for other LSEs.

1 The stack analysis focuses on the sufficiency of supply to enable load-serving entities to comply with RA program requirements and does not analyze the sufficiency of energy to meet Summer 2023 needs.

2 Historical RA import data from the CAISO demonstrates that the September imports in month-ahead RA showings declined from over 8,500 MW in 2019 and 2020 to less than 6,500 MW in 2021, 2022, and 2023. Month-ahead RA imports in August declined even further from 8,804 MW in 2019 to 5,130 MW in 2023. Historical RA import data: http://www.caiso.com/Documents/HistoricalYearAheadResourceAdequacyAggregateData.xlsx.

- Unnecessarily restrictive requirements for energy imports under the CPUC's RA program reduced the availability of imports to the CPUC-jurisdictional RA market.

The RA supply deficiency may have prevented collective compliance by CAISO load-serving entities (LSEs) even if willing to procure at exorbitant prices. Some LSEs subject to the CPUC's RA program were unable to obtain enough supply to comply with their RA compliance requirements despite numerous formal solicitations and substantial bilateral outreach.

Not all LSEs start the game with the same odds. IOUs hold most "legacy" supplies built prior to the recent growth of community choice aggregation (CCA) and the expansion of Direct Access (DA). As CCA or DA load has departed the IOU portfolio, the IOUs have retained for their remaining bundled load the supply previously procured for the departed load. Consequently, as conditions have changed, the burden of finding new supply to meet requirements has shifted largely to CCA and DA customers. The challenges in getting new steel in the ground thus have had a graver effect on these customers.

Under these conditions, RA program compliance has become a game of musical chairs: some chairs are occupied by the IOUs and some have been grabbed by out-of-state entities, leaving some California LSEs without a chair when the music stops. Until more new resources come online, the race to find a chair in the game will have detrimental consequences for all consumers. The RA shortfall has driven up prices paid by consumers. Prices for resources averaged \$3.63 kilowatt (kW)-month in 2019;[3] summer 2023 has seen individual transactions at prices over \$60 kW-month – the highest for CCAs being \$82.94/kW-month – and resources are increasingly unavailable at any price. Sellers are the only market participants who benefit from this pressure.

RA penalties for LSEs unable to secure supply in a deficient market do nothing to get new resources in the ground; they unnecessarily add to customer costs and indirectly increase the cost of supply. Resource development is properly addressed in the CPUC's Integrated Resource Planning process and procurement mandates.

2. RA Supply/Demand Balance: 2023 RA Stack Analysis

The RA stack analysis in Figure 1 below compares the demand for system RA for peak months in 2023 to the total supply of RA, including RA from resources in the CAISO footprint and reported RA imports. RA supply is primarily derived from the CPUC's net qualifying capacity list, while RA demand is the forecasted median load in the CAISO plus a planning reserve margin.

As shown in Figure 1 below, the available supply of RA exceeded demand for RA by a razor-thin margin of 135 megawatts (MW), even after accounting for observed RA imports, in August 2023. Supply was similarly scarce to meet RA demand in September 2023. The scarcity of supply made it difficult, if not impossible, for every LSE to meet its RA requirements.

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3 *2019 Resource Adequacy Report*, March 2021: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2019rareport-1.pdf, at 22.

Figure 1

		Jun	Jul	Aug	Sep
1	CAISO 1-in-2 Load	42,354	45,510	46,074	46,829
2	Reserve Margin (16%)	6,777	7,282	7,372	7,493
3	**Total RA Demand**	**49,131**	**52,792**	**53,446**	**54,322**
4	2023 NQC List	48,651	49,402	49,108	49,232
5	Event-Based Demand Response	995	1,045	1,077	1,090
6	Imports	4,023	5,746	5,130	6,363
7	Thermal Plant Derate	(718)	(718)	(718)	(718)
8	Excess IOU Resources In IOU Supply Plans	(1,266)	(507)	(396)	(443)
9	Retention for Substitution	(619)	(619)	(619)	(619)
10	**Total RA Supply**	**51,065**	**54,348**	**53,581**	**54,904**
11	Surplus Supply (Deficit)	1,935	1,557	135	582

3. Sources and Explanation of the RA Stack

Figure 1 uses both familiar data in assessing RA supply sufficiency and also integrates information not typically considered in a supply analysis. This information, reflected in rows 8 and 9, stems from regulatory changes implemented by the CPUC that had the effect of eroding supply available to other LSEs. The table below documents the sources of data used in Figure 1.

Row(s)	Source
1	CAISO 1-in-2 Load Forecast. Monthly peak demand forecast for a median (1-in-2) weather year from the CEC's 2022 Integrated Energy Policy Report Planning scenario.[5]
2	Planning Reserve Margin per CPUC D.22-06-050.[6]
4	CPUC 2023 NQC List. The CPUC lists the net qualifying capacity (NQC) for all resources in the CAISO footprint for 2023.[7] CalCCA exclude from the list all resources with a commercial online date later than one month before the applicable RA month. CalCCA found the commercial online date by matching the resource identification number (resource ID) in the NQC list to the resource ID in the CAISO Master Generating List.[8]

5 Monthly maximum managed net load forecast for 2023 from the California Energy Demand 2022 Hourly Forecast for CAISO in the Planning Scenario: https://efiling.energy.ca.gov/GetDocument.aspx?tn=248359&DocumentContentId=82768.

6 D.22-06-050, Decision Adopting Local Capacity Obligations For 2023 - 2025, Flexible Capacity Obligations For 2023, and Reform Track Framework, R.21-10-002 (June 23, 2022): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540633.PDF.

7 2023 NQC List for CPUC Compliance (October 17, 2023 version): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/cpuc-final-net-qualifying-capacity-report-for-compliance-year-2023-17oct23.xlsx

8 CAISO Master Control Area Generating Capability List: oasis.caiso.com.

Row(s)	Source
5	Event-Based Demand Response. Demand response quantities are from the CPUC's Resource Adequacy Compliance Materials.[9] Demand response totals include avoided losses and are from event-based programs at PG&E, SCE, and SDG&E.
6	Imports. Imports are the observed RA imports to the CAISO market.[10] The RA imports reported by the CAISO include both resource specific imports (designated as "TG" by CAISO) and non-resource specific imports (designated "ITIE"), neither of which are included in the 2023 NQC List (row 4).
7	Thermal Plant Derate. Many thermal generators cannot produce maximum output at certain temperatures, leading to plant derates. For this reason, resource owners may not sell their full NQC as RA capacity. For thermal plants whose NQC is listed as equivalent to their Net Dependable Capacity, we apply a technology-specific thermal derate estimated from historical ambient temperature derates within the CAISO.[11] CalCCA's approach parallels recent CPUC discussions regarding the need to include thermal derates in reliability modeling.[12]
8	D.21-12-015 allowed: "excess resources from an IOU's *existing* portfolios may be used to meet or supplement these procurement targets up to the upper end of its contingency procurement target."[13] D.21-12-015 also authorized the IOUs to "continue their procurement efforts and endeavor to meet and exceed their respective incremental procurement targets to achieve the range of additional procurement authorized in this decision for months of concern… As noted previously, a combination of RA eligible and non-eligible resources will be used to meet the contingency procurement target range."[14] While these resources were intended to be incremental to supply available to LSEs to meet their 16 percent requirement, a significant amount appears to erode existing supply.[15] This erosion occurs because many of the resources are qualified to provide RA and, were it not for the IOU procurement, could provide RA to other LSEs to meet their RA compliance requirements. Line 8 represents the

9 2023-2025 Demand Response Totals: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

10 CAISO Historical Resource Adequacy Aggregate Data as of (posted January 12, 2024): https://www.caiso.com/Documents/HistoricalResourceAdequacyAggregateData.xlsx

11 Ambient derate data can be found in the CAISO's daily Curtailed and Non-Operational Generator Prior Trade Date Reports: http://www.caiso.com/market/Pages/OutageManagement/CurtailedandNonOperationalGenerators.aspx.

12 ED Staff Proposal for Derating Thermal Power Plants based on Ambient Temperature: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/r21-10-002/4_ed-proposal-for-phase-3-derates.pdf.

13 D.21-12-015, Phase 2 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 2022 and 2023, R.20-11-003 (Dec. 2, 2021), at 103: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M428/K821/428821475.PDF. .

14 *Id.* at 101-102.

15 The additional resources procured under this authorization are described in the CPUC's RA materials with additional detailed provided in advice letters filed by the IOUs. 2022 IOU Excess Resource reports: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

Row(s)	Source
	subset of the resources shown on the three IOUs' supply plan as filed in the IOU 2023 Excess Resources Report.[16]
9	Retention for substitution. IOUs are entitled to retain RA beyond their bundled needs for substitution during planned outages. While 2022 data are not yet available, this assessment relies on the 2021 resources retained by IOUs as reported in the 2021 IOU Excess Resource reports.[17]

4. Tight Conditions Are Likely to Persist Through 2025

Extending the RA stack for September through 2026, Figure 2 below shows that the tight market conditions continue. The challenge of meeting RA requirements is exacerbated by rising load, increasing planning reserve margins, and retirement or removal from the RA market of resources like several once-through cooling plants. Deployment of new capacity to meet the CPUC's procurement requirements helps, though projects are likely to be delayed at least in the next few years. Though not reflected here, the RA market will undergo a fundamental shift in design, changing to a 24-hour slice of day approach starting in 2025.[19]

The sources and assumptions in this extended stack analysis are similar to the 2023 stack in Figure 1, with the following exceptions:

- The planning reserve margins for 2024-2026 increase to 17 percent;[20]
- Projected imports for 2024 and beyond reflect the CEC's assumed RA imports available to the CAISO market.[21]
- In line with the assumptions of the Joint Agency Reliability Planning Assessment, described in the next section, the remaining once-through-cooling plants are assumed to be procured by DWR;[22]
- Excess IOU procurement for a higher effective PRM continues through 2025;[23] and

[16] Excess Resources Reports from https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

[17] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

[19] D.22-06-050 at 128.

[20] *Id.* at 125 (requiring a 17 percent PRM for 2024, we assume the same for 2025-26).

[21] Joint Reliability Planning Assessment - SB 846 Fourth Quarterly Report, at Table 5: https://efiling.energy.ca.gov/GetDocument.aspx?tn=253425.

[22] The capacity of once-through-cooling plants at risk of retirement is based on the CAISO's Announced Retirement and Mothball List: http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx.

[23] Excess procurement of 1,700 MW for 2024 and 2025 is pursuant to a proposed decision in R.21-10-002, representing the minimum targeted procurement defined by the CPUC. IOUs would be authorized to procure as much as 3,200 MW for those same years, potentially increasing the deficits shown in Figure 2.

- For the years 2024 through 2026, the NQC List is based on the 2024 NQC list, though limited to resources built by the beginning of 2023.[24] Expected contracts for new-build resources are added to the list of resources. September new resources build is based on resources online by the end of Q2 in each year.[25]

Figure 2

	September NQC	2023	2024	2025	2026
1	CAISO 1-in-2 Load	46,829	47,475	47,987	48,487
2	Reserve Margin (16% in '23, 17% after)	7,493	8,071	8,158	8,243
3	**Total RA Demand**	**54,322**	**55,546**	**56,145**	**56,730**
4	NQC List	49,232	46,137	46,137	46,137
5	Event-Based Demand Response	1,090	980	955	978
6	Imports	6,363	6,000	6,000	6,000
7	Estimate of Contracted Resources	-	7,474	10,189	11,026
8	Thermal Plant Derate	(718)	(761)	(761)	(761)
9	OTC, Retired or Contracted by DWR	-	(2,859)	(2,859)	(2,859)
10	Excess IOU Procurement for Higher Effective PRM	(443)	(1,700)	(1,700)	-
11	Retention for Substitution	(619)	(619)	(619)	(619)
12	**Total RA Supply**	**54,904**	**54,652**	**57,342**	**59,902**
13	Surplus Supply (Deficit)	582	(894)	1,197	3,172

5. Results Generally Align with Joint Agency Reliability Assessment

The Joint Agency Reliability Planning Assessment, issued on February 9, 2023, assessed hourly supply sufficiency across each year between 2023-2032. Here we focus on the Joint Agency results during critical hours in the month of September 2023-2026 using their assumption that new resources are based on ordered procurement with a delay rate of 40 percent. This assessment differs from the CalCCA assessment above because it focuses on hourly supply sufficiency, rather than RA sufficiency for compliance purposes. Consequently, the Joint Agency assessment:

- Projects a lower completion of new resources for September 2023 than actually observed (1,750 MW vs. 1,905 MW);

[24] 2024 NQC List for CPUC Compliance (December 23, 2023 version): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/cpuc-finalnetqualifyingcapacityreportforcomplianceyear2024-22dec23.xlsx

[25] Expected contracted resources from the Joint Reliability Planning Assessment - SB 846 Fourth Quarterly Report, Tables 3 and 4: https://efiling.energy.ca.gov/GetDocument.aspx?tn=25342

- Uses hourly production of wind and solar on peak demand days, resulting in a contribution of 1,819 MW from wind and solar to meeting demand in Hour 19 of September, compared to the 2,323 MW of wind and solar NQC in the RA stack;
- Uses earlier data for the 2023 NQC list and assumptions for imports (5,500 MW vs. the more recent 6,000 MW assumption);
- Assumes that the Diablo Canyon Power Plant is not included in reliability planning in 2025;
- Uses demand response estimates that may include programs that are not typically used to meet RA requirements;
- Assumes the full contribution of thermal plants are available each hour without accounting for ambient thermal derates associated with high temperatures;
- Does not need to consider the effect of the IOUs' retention of capacity for substitution, since those resources will be available supply unless they are actually substituted for a resource on outage;
- Does not need to consider the effect of the IOUs' incremental "effective" PRM procurement; although the supply may not be available to LSEs to meet their RA requirements, the resources will be a part of the actual supply.

Despite these differences, which in most cases tend to present a more positive view of supply, the assessment shows a very tight supply margin, for Hour 19 in September 2023 – arguably the most challenging hour to meet. The Joint Agency assessment is summarized below in Figure 3, which was prepared by CalCCA using Joint Agency data.[26]

[26] CalCCA created the table from the underlying data used in the Joint Reliability Planning Assessment (https://efiling.energy.ca.gov/GetDocument.aspx?tn=248714&DocumentContentId=83233 consistent with a conversation with CEC staff on Jan. 31, 2023.

Figure 3

	Hour 19 Assessment in the Month of September	2023	2024	2025	2026
1	CAISO 1-in-2 Load	46,827	47,472	47,933	48,424
2	Reserve Margin (16% in '23, 17% after)	7,492	8,070	8,149	8,232
3	**Total Hourly Demand**	**54,319**	**55,542**	**56,082**	**56,656**
4	Existing Resources Except Wind and Solar	44,817	44,817	44,817	44,817
5	Supply from Wind	1,810	1,810	1,810	1,810
6	Supply from Solar	9	9	9	9
7	Estimated Completion of CPUC Mandated Procurement	1,750	6,431	10,381	11,755
8	Demand Response	1,274	1,274	1,274	1,274
9	Imports	5,500	5,500	5,500	5,500
10	Remove Diablo from Planning	-	-	(2,280)	(2,280)
11	OTC, Retired or Contracted by DWR	-	(3,757)	(3,757)	(3,757)
12	**Total Hourly Supply**	**55,159**	**56,084**	**57,753**	**59,128**
13	Surplus Supply (Deficit)	840	542	1,672	2,472
14	Incremental Demand with 2020 Equivalent Event	3,044	2,611	2,636	2,663
15	Add'l. Incremental Demand with 2022 Equivalent Event	1,639	1,662	1,678	1,695
16	Surplus Supply (Deficit) with Extreme Weather	(3,843)	(3,731)	(2,642)	(1,887)

6. The Impact of Weather on Capacity

The changes in precipitation levels from 2022 to 2023 have been an extreme that helps to demonstrate the impact of weather on capacity. As of June 14, 2023, the California Department of Water Resources (CDWR) reports that the water content of snowpack for the State is at 333 percent of normal.[27] On the same day in 2022, CDWR reported that the snowpack had already melted leaving the state at zero percent of normal. In addition to the snowpack, rain has helped to fill reservoirs prior to the snow melt placing many of California's reservoirs above their historical average as early as March.[28]

Using data from the CEC from the past 20 years, 2006 had the highest amount of energy production from hydroelectric generating facilities at 48,559 gigawatt hours (GWh). This high was reached on installed capacity of 13,557 MW of large and small hydro in California at the time for a capacity factor of 40.9 percent. This compares with 2022 where the CEC shows energy generation of 17,612 GWh from an installed capacity of 14,035 MW for a capacity factor of 14.3 percent.[29] Simply put, more water yields more energy. Since the amount of installed capacity in 2023 from large and small hydro is at least as much as it was in 2006, given the amount of available water, it is reasonable to expect that the energy production in 2023 was similar to that in 2006.

27 https://cdec.water.ca.gov/snowapp/sweq.action.
28 https://cdec.water.ca.gov/reportapp/javareports?name=STORSUM.202303.
29 https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-generation-capacity-and-energy.

The RA program counts capacity from resources based on their capability of providing that level of output in a sufficient number of hours to meet system load needs. The RA program will therefore derate the amount of capacity from hydroelectric facilities to account for water available for use at the facility. In 2022, this amount was at historic lows. In fact, the process for RA had the Year-Ahead showing for 2023 occurring in October 2022. At that point in time, CDWR reported snow-pack levels at zero percent of normal. Without knowing that the 2022-2023 precipitation season would be as good as it turned out, the amount of hydroelectric generation for RA was likely assumed to be at very low levels for the Year-Ahead showing process. These expectations likely had a significant effect on the amount of hydro output offered as RA in the Year-Ahead process.

This issue does not only impact California. Hydroelectric generation is prevalent in the Pacific Northwest and there are significant quantities in the Southwest as well. With uncertainty surrounding the amount of precipitation that either of those areas would receive, entities were unwilling to sell significant amounts of import capacity for the Year-Ahead process.

With conditions better known in June, significant amounts of hydroelectric generation in and out of state were likely available, easing the tight capacity market. High hydro conditions were good news for 2023 for California's Month-Ahead RA process but did nothing to cure the lack of capacity for the already complete Year-Ahead RA process. Importantly, it further has little bearing on what the hydroelectric conditions will bring for 2024 onward.

7. The Shortage of RA has Capacity Prices at All Time Highs

As basic economics would predict, these conditions are ripe to produce exorbitant prices, making reliably serving California's electricity customers more expensive. Between September 2019 and September 2021, the net RA supply decreased by 6 GW[30] while the weighted average price for September RA increased by over 100 percent from $4.08/kW-month to $8.62/kW-month (see Figure 4 below).[31] CalCCA analysis of public capacity transaction data in FERC Electronic Quarterly Reports (EQR) shows that the weighted-average price for capacity delivered to the CAISO system continued to rise to over $13/kW-month in 2023.

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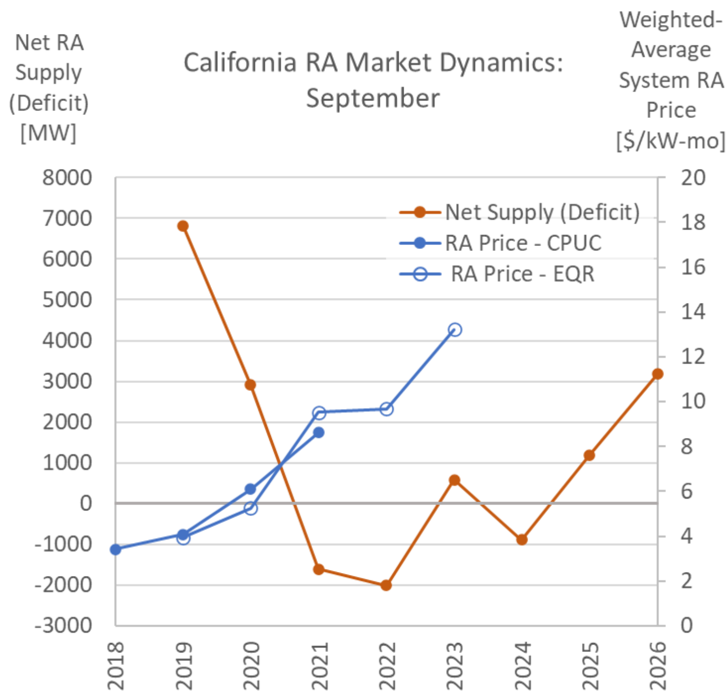
30 CalCCA estimated the net RA supply in September for 2019-2022 using assumptions similar to the 2023 RA Stack in Section 3. Key differences include the use of a 15 percent PRM, load forecasts from the CED 2019 and CED 2021, NQC lists from the relevant year, event-based demand response from the relevant year, historical import RA from the relevant year, and no excess IOU procurement for higher effective PRM.

31 2021 Resource Adequacy Report (Apr. 2023), at 29: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2021_ra_report_040523.pdf.

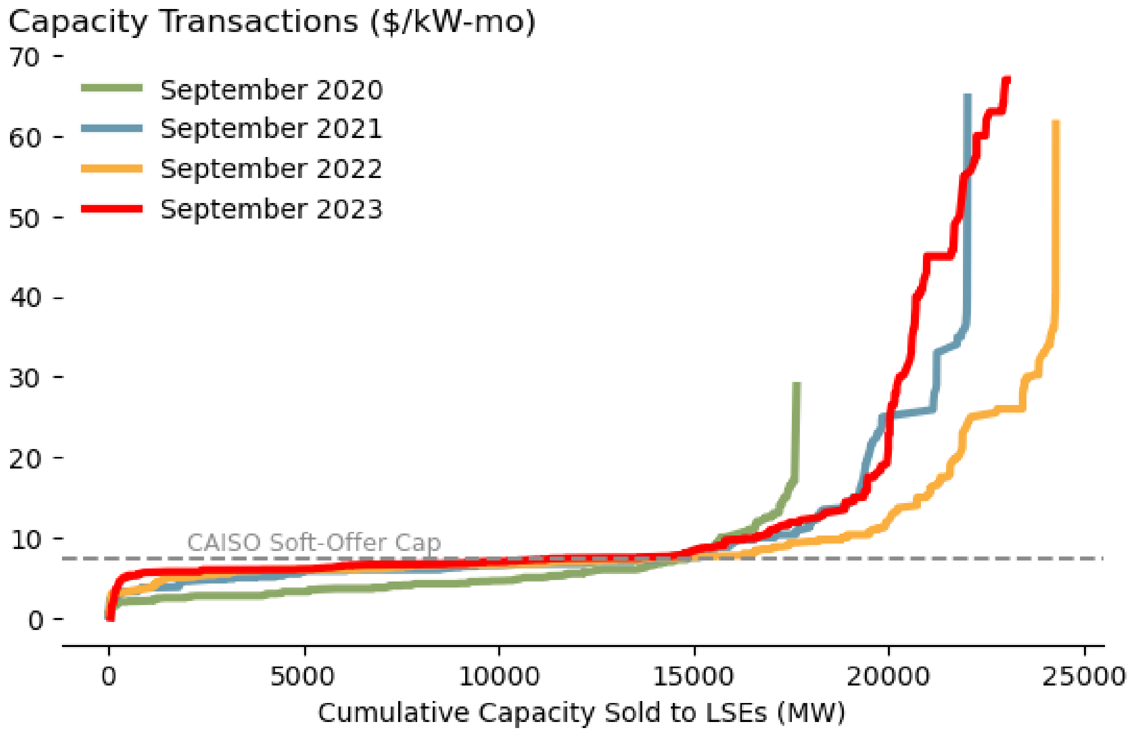
Figure 4



Importantly, detailed transaction level data from the FERC EQRs shows that the rise in average capacity prices is primarily driven by a growing share of transactions at extremely high prices (See Figure 5, below). In September 2020, a time with excess RA supply, around 2,800 MW of RA capacity was purchased by California LSE's at prices above $7.34/kW-mo, the CAISO's recently proposed soft-offer cap for the capacity procurement mechanism (CPM).[32] In contrast, more than 7,800 MW, 10,600 MW, and 11,700 MW were purchased at prices above $7.34/kW-month in September 2021, 2022, and 2023 respectively, times with an RA deficit or extremely tight market. The highest observed prices rose from $29/kW-mo in September 2020 to over $60/kW-mo in September 2021, 2022, and 2023. LSEs faced with a responsibility to meet their RA obligation at any cost are being met with generators only willing to sell at prices eight to nine times higher than the CAISO soft-offer cap. The lack of sufficient capacity available to meet RA needs is clearly driving up costs for California electricity customers.

[32] *Capacity Procurement Mechanism Enhancements*, Track 2 Straw Proposal (June 30, 2023): http://www.caiso.com/InitiativeDocuments/StrawProposal-CapacityProcurementMechanismEnhancements-Track2.pdf.

Figure 5



8. Tight Market Conditions Across the West Limit Availability of RA Imports

The ability of California LSEs to meet their RA obligations in 2023 into future years depends on the availability of RA imports from the rest of the West. Across the West, resource adequacy has become a priority issue as regions experience load growth, retire aging coal plants, and turn to resources like solar for future needs. Demonstrating the importance of RA, utilities across the West supported the development of the Western Resource Adequacy Program (WRAP) as a mechanism to formalize resource counting and to share excess resources when needed in the operational timeframe.[33] Currently, however, no entity regularly quantifies the excess supply of RA in the West that is available for California LSEs to rely on for imports.

We use public reliability assessment data, primarily from the North American Electric Reliability Corporation (NERC), to provide visibility into trends in the availability of RA resources outside of California. We consider both historical data and projections to evaluate the potential implications for California RA markets.

The availability of resources to import into California depends on whether other sub-regions of the Western Electricity Coordinating Council (WECC) have generating capacity that exceeds their peak demand and planning reserve margins. NERC summer reliability assessments (released in May of each year) provide prompt year peak load forecasts and on-peak resource

[33] WRAP: https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

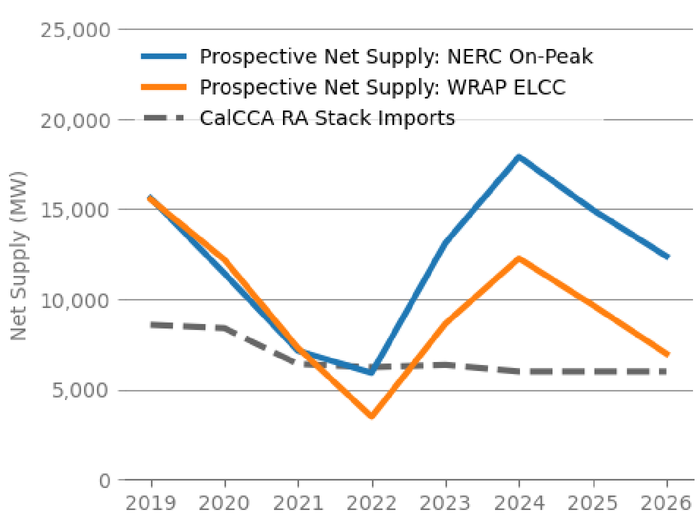
totals for each WECC sub-region. NERC's long-term reliability assessments (released in December each year) provide ten-year projections of loads and resources.

We assume that the resources available to California as RA imports can be calculated as the net supply aggregated across all the non-California WECC sub-regions, where net supply is the amount that the prospective on-peak resource capacity exceeds the peak demand forecast plus a planning reserve needed to meet the Reference Reserve Margin. Due to several limitations in the data and methodology, this net supply calculation is not an exact assessment of available imports, instead it is a proxy whose value over time should reflect trends in the true import availability over the same time horizon. The limitations of this approach include:

- NERC reports non-coincident peaks across WECC sub-regions, meaning that the reported peaks are not expected to be reached at the same time;
- Aggregating resources and demand across all of the WECC sub-region ignores inter-region transmission limits and overstates the availability of supply;
- The approach treats the Reference Reserve Margin as a level of planning reserves that must be met prior to exporting; in reality, California is unique in specifying a mandated planning reserve margin.

Another limitation of the NERC data is that it reports contributions of prospective resources based on their on-peak production. It is apparent in California, that as the share of solar grows, production during the net peak rather than gross peak becomes a more reasonable assessment of the reliability contribution of solar. The WRAP assesses reliability contributions of wind and solar based on effective load carrying capability (ELCC) studies that account for the shifting periods of greatest reliability need. We calculate net supply using the NERC On-peak values and the proposed ELCC values for wind and solar from the WRAP program, based on values applicable to August.

Figure 6



Across the non-CA WECC, the prospective net supply is positive in all years between 2019 and 2026, suggesting RA resources are available to import into California. The amount of available resources, however, appears to change dramatically across years, Figure 6. A 15 GW surplus in resources fell to only 4-6 GW by 2022 because of an increase in load between 2019 and 2020 and a decrease in generation capacity from 2020 to 2022, largely associated with coal plant retirements. The RA imports in the CalCCA RA stack closely tracks the prospective net supply in the Non-CA WECC, suggesting that nearly all of the available resources were imported into California. The CAISO is expected to post 2023 actual data before the end of 2023.

New resources were added after 2022 and additions are expected to continue through 2024 at a rate that exceeds load growth, reducing the tightness in the non-CA WECC region and again freeing up resources to import into California. The major source of new capacity between 2022 and 2024 is solar with some growth in storage, geothermal, and hydropower.

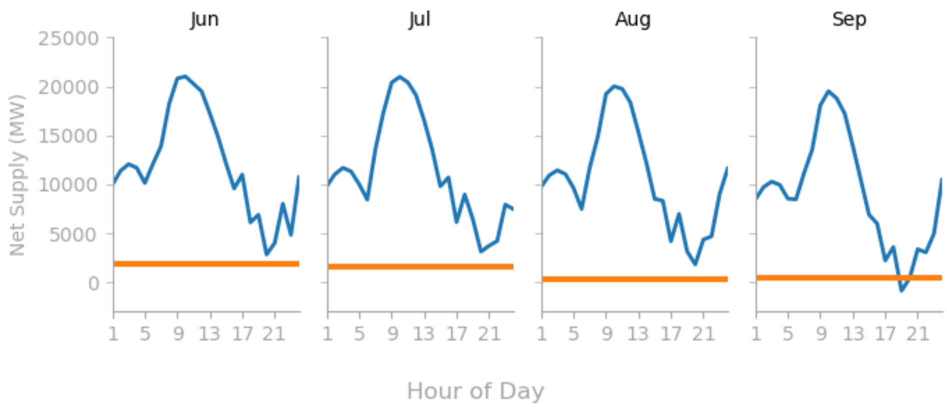
Whether the net supply surplus in the Non-CA WECC region returns to its 2019 levels depends on the capacity accreditation of solar. Using WRAP ELCC values for solar and wind capacity accreditation reduces the net supply surplus by 5.6 GW relative to the surplus calculated with NERC On-Peak values in 2024. The difference in net supply between the two methods continues to be about 5-6 GW through 2032. The lower net supply surplus with the WRAP ELCC values suggests that widespread participation of utilities in the WRAP program may mean that fewer resources are available to import into California.

9. The New CPUC Slice of Day RA Mechanism Will Not Address Thin Supply Margins

In the current Resource Adequacy framework, LSEs procure RA resources for each month of the year to meet their allotted share of the monthly peak demand and planning reserve margin. The contribution of a resource toward the RA obligation is based on its NQC, represented by a single value each month. Beginning in 2025, the Resource Adequacy framework will shift to a new "Slice-of-Day" framework in which the monthly RA obligation is defined for each of the 24 hours in a day and the contribution of a resource can similarly vary by hour of the day. To analyze the implications of this new framework CalCCA developed a "Slice of Day" RA stack analysis for 2023 using data and assumptions similar to the RA stack presented in Section 3. The results show that in critical months, the shift to the Slice-of-Day framework will further tighten the resource adequacy market, Figure 7.

The SOD framework will expose existing constraints currently masked by the annual-peak RA requirements measure. Many hours of the day have significant surplus supply, but not in early evening hours after sunset. In the early evening, the net supply in the SOD stack is at its lowest and, as shown in Figure 7, and can be lower than the net supply calculated with the traditional RA stack for the same set of resources. Months in which the SOD net supply is lower than the traditional net supply will lead to a tighter RA market and greater challenges for LSEs to meet their RA obligations. For the resources and demand in the 2023 RA stack, the most challenging month was September in both the SOD and traditional approach, with hour ending 20 the most critical hour in September.

Figure 7



The differences between the Slice of Day stack and the traditional RA stack include:

- Demand: For SOD, demand is represented by the 24-hourly values on the day with the highest peak load of each month.[34] For the traditional stack, demand is the single highest peak load of each month. The 16 percent planning reserve margin is applied to all 24 hours in SOD and the highest load hour in the traditional stack.
- Wind and Solar: For SOD, the contribution of wind and solar varies by hour and is calculated from exceedance values with historical data.[35] For the traditional stack, the contribution of wind and solar is based on a monthly estimate of the effective load carrying capability (ELCC).
- Energy Storage: For SOD, the contribution of storage to any hour is constrained based on characteristics of the resource, including the power rating, the maximum sustained discharge energy, the maximum number of daily cycles, and the availability of excess capacity to charge the storage.[36] Within these capabilities storage is dispatched to minimize any deficits in net supply, or if none exist, to flatten out the net supply.[37] For the traditional stack, the contribution of storage is based on its full nameplate capacity (or proportionally derated if the maximum discharge duration is less than 4 hours.).

[34] Hourly managed net load forecast for 2023 from the California Energy Demand 2022 Hourly Forecast for CAISO in the Planning Scenario: https://efiling.energy.ca.gov/GetDocument.aspx?tn=248359&DocumentContentId=82768.

[35] CPUC Master Resource Database version 3: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/mrd-draft-2.xlsx. The exceedance profiles for wind and solar vary by technology and location.

[36] Ibid.

[37] LSE's can determine their planned storage dispatch. For this analysis, CalCCA developed a simple optimization model to determine the best way to charge and discharge storage.

- Imports: For the SOD, imports are assumed to be available between hour ending 7 and hour ending 22 following the common "6 X 16" contract schedule. In the traditional stack RA imports are the observed RA imports for 2023 reported by the CAISO..

The primary reason why the SOD net supply in hour ending 20 is lower than the traditional net supply in September is differences in the contribution of solar. In the traditional RA stack, solar resources contribute up to 11 percent of their nameplate capacity toward the RA supply. In the SOD stack, on the other hand, the contribution of solar to supply in hour ending 20 is zero based on the calculated exceedance values. A shift to SOD thus eliminates 1460 MW of RA supply from the September 2023 supply stack in the net peak hours.

Design elements of the SOD framework may further exacerbate the challenges relative to the analysis presented above. In the above analysis, all sources of supply and all demand are pooled prior to calculation of the hourly net supply. In practice, the SOD framework will require that each LSE meet its 24-hour obligations only with resources in its portfolio. Unless there are changes to the proposed SOD framework, resources cannot be subdivided hourly to optimize the LSEs' portfolios. Depending on the composition of individual LSE portfolios and the 24-hour shape of their demand profile, the net supply from first pooling all loads and resources, as assumed in this stack, may be greater than the aggregate net supply without pooling, reflecting the constraints on individual LSE showings. Two examples illustrate this challenge:

- An LSE with a net surplus in one hour cannot allocate that surplus to another LSE with a deficit in the same hour unless they transfer all 24-hours of capability from the resource to the other LSE.
- The charging energy for storage must be met by surplus supply within an LSE's own portfolio, any excess charging energy in another LSE's portfolio is not transferable without trading all 24 hours of the capability of an excess resource.

Even achieving the net supply shown in this SOD stack may require modifications to the framework such as adding transactability of LSE load obligations or individual hours of a resource. Nevertheless, even with these enhancements the transition to the Slice of Day framework alone will not address the tight RA market conditions projected through 2025.

10. Challenges with New Resource Uncertainty

New resources bring new challenges. The RA program allows a new resource to count in the Year-Ahead process from the month of its expected on-line date. However, if the resource fails to reach commercial operation at that date, the resource may not be counted in the Month-Ahead process and the LSE must find a different resource to meet their RA needs. The challenge this presents is that an LSE is unlikely to sell any excess RA in the Year-Ahead process if that excess is contingent on a new resource achieving commercial operation. In addition, it is becoming relatively common for entities to offer sales of capacity contingent on the new resource achieving commercial operation. That is, a seller that is long capacity if the new resource comes online will sell the excess contingent on the resource achieving commercial operation and thus move the non-compliance risk to the buyer.

Much like the hydroelectric discussion in Section 6, the availability of new build expected to come on-line in a compliance year is likely more constrained than the Month-Ahead process when the commercial operation date is known. To the extent the resource has come on-line, the LSE is now willing to sell excess RA so that their customers get the value of the resource without a risk that it will make them non-compliant with their RA requirements.

The only way to ease the current capacity constraints of the RA market is to continue to build new resources. However, this new build is likely to ease constraints in the Month-Ahead RA market and not in the Year-Ahead market due to the uncertainty of achieving commercial operation from the resource.

11. Conclusion

The supply of resource adequacy left only a razor-thin margin to meet 2023 demand, and the thin margins are expected to persist through 2025. The tightness in the market makes it difficult, if not impossible, for all LSEs to comply with year-ahead requirements, and the tight conditions carried into month-ahead compliance. The only durable solution is to bring new resources online, yet new resources continue to face supply chain, interconnection, and permitting challenges. Until those challenges are met holistically, RA supply will remain tight and prices paid by consumers will remain high. In addition, the potential variability of RA supply between Year-Ahead and Month-Ahead RA showings creates a new issue that must be recognized in the RA program.

Seven interim actions should be considered.

1) Expressly evaluate and recognize the tight RA supply conditions and its consequences in the CPUC's next RA decision.
2) Establish a "safety valve," through a discretionary waiver structure for LSEs left deficient in meeting their requirements despite best efforts, to prevent the exercise of market power by suppliers.
3) Consider the potential for waiving Year-Ahead penalties if an LSE meets its obligation in the Month-Ahead showing.
4) Increase the likelihood that California LSEs can secure imports for RA compliance by increasing the CPUC-imposed energy market bid cap on imports – currently set at $0/MWh -- to reduce sellers' risk of financial loss.
5) Prevent erosion of the supply stack available to LSEs to meet their RA requirements by limiting any IOU "effective PRM" procurement to truly incremental, non-RA resources.
6) Increase market transparency by providing aggregated compliance data to reveal (a) trends in the categories of resources (e.g., imports, hydro) used for compliance and (b) the extent of California resource exports.
7) Test and evaluate the new Slice of Day RA model to ensure that:
    a. There are sufficient resources to be able to meet the new RA accounting mechanism. If there are not, then the Commission must examine what must be done to obtain a

fleet capable of meeting the need before implementing penalties for RA deficiencies if the current fleet is incapable of meeting the reliability need.

b. Evaluate the need for transactability adjustments in the Slice of Day mechanism. As discussed in Section 8, the ability to meet the requirements of the entire system from all resources is just the first step. While necessary, it is not sufficient to ensure effective compliance. To be sufficient, the Slice of Day mechanism must consider effective and efficient mechanism to enable parties to transact to meet individual compliance obligations which will also ensure that the total reliability need is met.

PUBLIC APPENDIX B
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ASSIGNED COMMISSIONER'S SCOPING MEMO AND RULING

DECLARATION OF MATTHEW LANGER

PUBLIC APPENDIX B

DECLARATION OF MATTHEW LANGER
CHIEF OPERATING OFFICER
CLEAN POWER ALLIANCE OF SOUTHERN CALIFORNIA

1. I, Matthew Langer, am Chief Operating Officer at Clean Power Alliance of Southern California (CPA). I submit this declaration in support of California Community Choice Association's Comments on Assigned Commissioner's Scoping Memo and Ruling in Rulemaking (R.) 23-10-011, being filed on January 19, 2023.

2. CPA is a community choice aggregator (CCA) serving over 3 million residents and businesses in 32 communities across Los Angeles and Ventura counties. CPA is a member of the California Community Choice Association (CalCCA).

3. I have been CPA's Chief Operating Officer since 2018. I currently lead CPA's energy procurement, customer programs, rates and strategy, regulatory affairs, non-energy contracts, and strategic accounts. In my role, I oversee CPA's procurement of energy, including Resource Adequacy (RA).

4. Prior to CPA, I worked at Southern California Edison for nine years from 2009 to 2018, where I held roles in energy procurement, corporate strategy, transmission and distribution, and customer service. I spent five years in energy procurement where I was involved in the procurement of RA amongst other responsibilities.

5. I earned a Master of Business Administration in 2010 from the University of Southern California, Marshall School of Business, where I was inducted into the Beta Gamma Sigma International Business Honor Society. I received a bachelor's degree in management with a concentration in Finance from Tulane University in 2005.

6. CPA has experienced increased volatility in the RA market starting in 2020. Part of that volatility is due to the projects that will eventually be available to supply RA but are in development. Consequently, the RA from these projects is only available for "contingent" transacting. Contingent transactions can either take the form of (1) a supplier offering capacity from a project that is in development, and the buyer can use the project's RA capacity only if the project reaches commercial operation by the compliance deadline, or (2) a supplier offering capacity from an online resource to a buyer, but the buyer can only use the capacity if another one of the supplier's projects comes online by a certain date. Contingent transactions place greater risk of non-compliance on buyers. In the event the project is not available by the time the buyer needs it for compliance, the risk falls on the buyer to either find replacement capacity or risk non-compliance and penalties. Thus, contingent transactions provide an inferior product as compared to a non-contingent RA product.

7. Another component of the RA market volatility is the shortage of existing resources, which coupled with the number of projects in development is creating distortions in the RA market. In particular, CPA has experienced difficulty in fulfilling the year-ahead RA (YARA) requirement due to scarcity in the market. My view is that given the shortages of the existing fleet of RA resources or the need for even contingent RA eligible resources, new generation capacity is needed so that LSEs, like CPA, can fulfill their existing YARA compliance obligations. Given the current scarcity, fulfilling especially the YARA obligation is difficult.

8. Issues with contingent transactions and the supply dynamic mentioned above were the subject of CPA's joint opening comments with Peninsula Clean Energy Authority to the Proposed Decision (PD) issued on May 25, 2023, in the predecessor Resource

Adequacy proceeding (R.21-10-002) to the current proceeding. Specifically, CPA requested the PD be changed to only place load-serving entity (LSE) expansion restrictions on those CCAs and/or electric service providers (ESPs) that had a month-ahead RA deficiency because RA volumes tend to become more available in the month-ahead time frame. In addition, contingent volumes tend to become more certain in the month-ahead timeframe that otherwise were not available in the year-ahead timeframe. This increased availability is in part due to the market dynamics related to the uncertainty of new RA resources under development that have greater certainty of reaching COD at each subsequent month-ahead filing. Other factors influencing increased availability as month-ahead filing timelines approach include water availability for hydro resources and greater certainty for maintenance outages on generating resources.

9. CPA has experienced this market dynamic between YARA difficulty and month-ahead RA (MARA) compliance. For example, CPA missed its YARA obligation for July, August, and September 2023, year-ahead filing date of October 31, 2022, because it was unable to secure RA supply even when bidding at prices above those being shown by brokers. However, during the revised filing process CPA was able to cure its YARA deficiency for July 2023 and reduce its YARA deficiency for September 2023. CPA was then able, during the remainder of the year, to cure its entire YARA deficiency *and* meet its additional 10% month-ahead obligation to be 100% compliant for all MARA filings in 2023.

10. The RA market is also transacting differently than in years prior to 2020. First, the number of responses to CPA's requests for offers (RFOs) has decreased but CPA has noticed an increase in the amount of RA sold through investor-owned utility (IOU) RFOs. In the publicly available Excess Resources Report published on the Commission's RA Compliance Materials website the IOUs have, between the summer months of June to October in 2021, 2022

and 2023, shown RA resources within their existing portfolios above the standard Planning Reserve Margin for LSEs. In some months across that timeframe, that excess RA in the IOU portfolios has been as high as 925 megawatts (MW), which averaged across all months is just shy of 400 MW. If such capacity had remained available for all buyers to purchase, prices may have fallen.

11. RA Prices have been increasing rapidly within the past few years. The Power Charge Indifference Adjustment (PCIA) Market Price Benchmark (MPB) for System RA has increased every year for the past five years. In total over that span the MPB has increased over 400 percent, going from $2.77/kilowatt (kW)-month to $14.37/kW-month. It is important to note that while the PCIA MPB is indicative of the RA market in general, it lacks a real-time pricing component. For purposes of understanding current market prices, the MPB quickly becomes stale after it is published given the backward-looking nature of the underlying data.

12. The prices CPA is seeing in the market represent an acute shortage of supply, leading to prices dramatically higher than the underlying cost to provide RA. This shortage presents a challenge from an affordability perspective for customers. As noted previously, the PCIA MPB shows publicly that RA prices have increased significantly in the past five years. Separately, CPA has consistently seen prices surpass the MPB in more real time pricing scenarios through broker quotes and RFOs. CPA has seen prices in the last 12 months range from [redacted] for August 2023, and [redacted] for September 2023. August and September are the two most difficult months to procure. In October of 2023, CPA purchased RA for [redacted] for September 2024 RA.

13. In 2022-2023 timeframe, CPA undertook extensive actions to procure its entire 2023 YARA obligation. In addition to paying extraordinarily high prices, it participated in 13 external RFOs between April 2022 and June 1, 2023. CPA also held eight RFOs for others to bid into from March 2022 to April 2023, for RA volumes delivered in 2023 and future years.

14. As CPA encountered the challenges in the RA market, CPA staff have met with Energy Division staff to keep them apprised of the scarcity of RA, as well as the high prices CPA has been paying to meet its compliance obligations.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct to the best of my knowledge and belief.

Executed on January 18, 2024, at Los Angeles, California.

Matthew Langer
Chief Operating Officer
Clean Power Alliance of Southern
California

PUBLIC APPENDIX C
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ASSIGNED COMMISSIONER'S SCOPING MEMO AND RULING

DECLARATION OF KELLY MORRIS

PUBLIC APPENDIX C

DECLARATION OF KELLY MORRIS
SENIOR POWER RESOURCES SPECIALIST
SAN JOSE CLEAN ENERGY

1. I, Kelly Morris, am the Senior Power Resources Specialist at San José Clean Energy (SJCE). I submit this declaration in support of California Community Choice Association's (CalCCA's) Comments on Assigned Commissioner's Scoping Memo and Ruling in Rulemaking (R.) 23-10-011, being filed on January 19, 2024.

2. SJCE is a community choice aggregator operated by the City of San José that started serving load in 2018. SJCE is a member of CalCCA. I have been employed by SJCE since 2018 and became the lead for SJCE's RA procurement in 2022. In this time, RA has become increasingly scarce, expensive, and difficult to procure.

3. As SJCE has navigated the challenging RA market dynamics described below, SJCE met with Commissioner advisors and conducted ex-parte meetings with Energy Division staff to keep them apprised of the situation. For example, throughout the second half of 2023, SJCE staff regularly met with Commissioner advisors and Energy Division staff to ensure awareness of forward and historical RA market dynamics, product scarcity, and pricing impacts. Additionally, SJCE staff provided feedback to enhance market transactability, affordability, and reliability, while actively seeking input from Energy Division staff on these matters. SJCE has been compliant in meeting its Year Ahead RA (YARA) and Month Ahead RA (MARA) obligations in 2023 and 2024.

4. RA is transacting at prices well above the California Independent System Operator's (CAISO) soft-offer cap, a price the CAISO sets every four years that represents the going-forward fixed costs for marginal resources on the CAISO system. Most recently, the

CAISO has proposed a soft-offer cap of $7.34 kilowatt (kW)-month. For its 2023 RA procurement, SJCE received offers for annual strips of RA over [redacted] times that amount and monthly strips of RA over [redacted] times that amount. SJCE has continued to see prices rise for its 2024 RA procurement. In contracting for 2024 RA, SJCE consistently received quotes for annual strips of RA over [redacted] times the soft-offer cap price and monthly strips of RA over [redacted] times that amount. SJCE is seeing similarly exorbitant RA price trends for 2025 and beyond.

5. SJCE worked diligently to procure sufficient RA to comply with its requirements. Procurement efforts included participating in 11 Investor-Owned Utility and municipal RFOs, performing bilateral outreach to at least 30 potential counterparties, working collaboratively in a joint procurement group with three other CCAs, issuing RFOs, and communicating with brokers.

6. SJCE's procurement experience extends to the bilateral markets, broker markets, and requests for offers (RFOs). Tight market conditions, however, have resulted in a shift in how the market transacts. SJCE has experienced a significant shift away from supplier participation in RFOs to greater supplier participation in the bilateral market. Some sellers forego participation in Load Serving Entities' (LSEs') RFOs entirely, preferring to go directly to the bilateral market to sell their RA supply. While some suppliers do participate in SJCE's RFOs, the offers received are often for products or during time periods that do not align with SJCE's solicitation requests. For example, one RFO hosted by The Energy Authority (TEA), which works with SJCE on joint CCA RA procurement in coordination with three other CCAs, requested offers for RA in the 2024 summer months. TEA received 21 offers from three entities. Of those 21 offers, zero offers included 2024 summer month supply. This is a typical occurrence.

7. The scarcity of RA in summer months and the fear of "unpriced" penalties has created a frenzied market whereby one notification indicating available summer RA supply

creates a race of bids from buyers looking to secure scarce RA capacity needed to meet their compliance obligations. Suppliers are aware of this scarcity and as a result, they seek new market highs, creating a new benchmark for future transactions. In one instance, SJCE observed summer 2024 supply being offered for 20 percent higher than the last known transaction. Because of the significant scarcity of summer 2024 RA supply, many buyers quickly expressed interest in the opportunity to buy this supply. As a result, the market price for these months rose 17 percent in a matter of hours and have stayed elevated since. Similar actions have caused prices to continue to increase.

8. Because of these continually increasing prices, SJCE's expenditures on RA have dramatically increased year over year. Most recently and most significantly, SJCE's total spend on RA [redacted] from 2023 to 2024. In 2023, RA accounted for [redacted] percent of SJCE's total power expenditures. In 2024, that increased to [redacted] percent. This cost increase is a result of SJCE finding supply to meet its RA obligation at today's elevated market prices. SJCE believes prices have elevated to unprecedented highs because of:

a. supply scarcity due to system-wide project delays, stricter requirements to import RA, net qualifying capacity (NQC) that doesn't transact given the need for substitution supply, and removal of once-through-cooling resources from the RA supply stack; and

b. the negative impact of non-compliance on the LSE, such as the non-market standard restriction on LSE expansion, the implications of which extend far beyond RA.

9. This unmitigated rise in RA costs is in direct opposition to the Commission's goal of affordability. Currently, about 20 percent of SJCE's customers are enrolled in SJ Cares, a

CARE/FERA product that offers the same clean electricity other customers receive at a discounted rate. Affordable electricity is crucial to the well-being of San José's residents and businesses.

10. These dramatically high prices reflect the RA supply scarcity market that participants are facing. This scarcity means LSEs must rely on resources that are in development to meet their RA obligations. This puts additional risk on buyers and sellers. For example, SJCE's RA procurement has been impacted by commercial operation date (COD) delays. For its 2024 YARA compliance, SJCE had intended to show an in-development resource for the months of August through December 2024. Seven business days before SJCE's YARA filing deadline, SJCE was notified that the project's online date had been delayed from [redacted] Fortunately, SJCE was able to find enough supply to comply with its YARA requirement by aggressively participating in solicitations and bilateral markets. However, SJCE also planned on using the in-development resource for its [redacted] MARA filings but will be unable to do so.

11. The Commission's requirement set forth in D.20-06-028 that import RA sellers must offer non-resource specific import RA into the CAISO market at a price of $0 per MW-hour or below has reduced the amount of import RA available to Commission-jurisdictional LSEs, further exacerbating tight supply conditions. In 2022, SJCE was unable to obtain any short-term RA imports and in 2023, SJCE had one small contract for short-term import RA in one month. Sellers of import RA have shared their unwillingness to flow power from north to south into California because of the price differential between locations; it is not economically feasible to sell the supply as import RA under the current rules. In 2024, SJCE continued to actively pursue RA import contracts to fulfill its RA obligations. SJCE was able to contract for

imports to aid its RA compliance, but these imports only make up approximately [redacted] percent of SJCE's compliance obligation in its peak month, half of which comes from a long-term out-of-state wind agreement. This number is still low compared to aggregate import RA availability in 2019, in which the CAISO as a whole relied on imports to make up 13 percent of its RA fleet.

12. I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct to the best of my knowledge and belief.

Executed on January 19, 2024 at San José, California.

/s/ Kelly Morris
Kelly Morris
Senior Power Resources Specialist
San José Clean Energy

PUBLIC APPENDIX D
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ASSIGNED COMMISSIONER'S SCOPING MEMO AND RULING

DECLARATION OF DEB EMERSON

PUBLIC APPENDIX D

DECLARATION OF DEB EMERSON
MANAGING DIRECTOR OF POWER PROCUREMENT
SONOMA CLEAN POWER

1. I, Deb Emerson, am Managing Director of Power Procurement at Sonoma Clean Power (SCP). I submit this declaration in support of California Community Choice Association's (CalCCA's) Comments on Assigned Commissioner's Scoping Memo and Ruling in Rulemaking (R.) 23-10-011, being filed on January 19, 2023.

2. SCP is a community choice aggregator (CCA), serving customers in Sonoma County since May 2014 and customers in Mendocino County since June 2017. SCP has participated in the California Public Utilities Commission's (Commission's) Resource Adequacy (RA) program since May 2014.

3. I am SCP's Managing Director of Power Procurement. I oversee all energy and capacity procurement for SCP. I have been employed by SCP since March 2015. I have over 25 years of energy trading experience in Western markets and hold an MBA from the University of Chicago Booth School of Business. Previously, I worked as an energy trader with Constellation Energy where I managed a variety of electricity portfolios in hydropower, natural gas, wind facilities, and capacity markets. Prior to working at Constellation, I was an energy trader at Williams Energy Marketing and Trading. In my role as Managing Director of Power Procurement at SCP, my staff and I forecast SCP's RA obligations and evaluate, research, and procure RA to satisfy SCP's compliance obligations. I have transacted in RA products for SCP for the last 8 years. Prior to that, I transacted in RA products with an Energy Service Provider (ESP) for over 4 years.

4. SCP has a proven track record in meeting all past System RA obligations on a year-ahead RA (YARA) and month-ahead RA (MARA) basis from RA compliance years 2014 to 2022.

5. SCP made reasonable efforts to fulfill its 2023 YARA obligations. For its July 2023 and August 2023 YARA compliance, SCP participated since September 19, 2021, in 123 individual logged Events, consisting of actions related to bilateral conversations and Request For Offers (RFOs) to attempt to procure System RA. Thirty-nine of these Events occurred between SCP's initial 2023 YARA filing on October 31, 2022, and the February 21, 2023, deadline to cure its deficiency, with another six occurring since the February 21, 2023, deadline. Included in this overall effort were two RFOs issued by SCP to procure July 2023 and August 2023 System RA capacity that received no offers in response. These substantial efforts only comprise a portion of the total work completed to meet RA obligations. To initiate deals, SCP takes part in numerous undocumented efforts consisting of frequent phone calls, texts, meetings, and events with other energy procurement entities and entities holding excess RA capacity.

6. Despite these substantial efforts, when SCP filed its YARA compliance filing for RA compliance year 2023 on October 31, 2022, SCP was short its YARA obligation by 19.96 megawatts (MW) for the month of June, 14.50 MW for the month of July, and 43.15 MW for the month of August.

7. Following its October 31, 2022 YARA filing, the Commission's Consumer Protection and Enforcement Division (CPED) gave SCP until February 21, 2023, to cure its YARA deficiency before being subject to the tiered RA penalty structure adopted in D.20-06-031. During the cure period, SCP was in communication with Energy Division to keep them apprised of the efforts SCP was taking to cure its deficiency.

8. On February 17, 2023, SCP submitted revised filings showing that it had completely cured its System RA deficiency for June 2023, and partially cured its System RA deficiency for July 2023 by 9 MW, leaving an additional 5.5 MW that SCP still needed to cure.

9. On April 10, 2023, the Commission's CPED sent SCP a follow-up email notifying SCP that the February 21, 2023, deadline had passed, and the February 17, 2023, revised filings only partially cured SCP's System RA deficiencies. The Commission's CPED requested that SCP provide CPED with proof that it procured necessary capacity to cure its deficiency for July 2023 and August 2023 System RA by the February 21, 2023 deadline. Such proof was to include, but not be limited to, the signed contract, along with a revised RA showing, and a copy of the corrected template by no later than April 17, 2023. SCP spent considerable time and effort to comply with the Commission's RA requirements, and was unable to meet its requirements before the February 21, 2023, deadline.

10. Since the February 21, 2023, deadline, SCP continued its efforts to fill its deficiencies. The most recent Event that resulted in a successfully executed contract arose from Southern California Edison's (SCE) RFO issued on February 6, 2023 (see SCE RFO schedule below). SCE's RFO included the sale of volumes for System RA capacity for the delivery period of May – December 2023. Through the successful execution of a contract that arose from this RFO, SCP was able to cure its entire remaining July 2023 System RA deficiency for 5.5 MW on March 30, 2023, as dictated by the SCE RFO schedule of events. SCP submitted its bid by February 9, 2023, and successfully executed a contract by March 30, 2023. However, between the period when SCP submitted its bid and the execution of the contract, SCP received notice that the Commission required SCP to provide evidence that it had cured its deficiencies by February 21, 2023. The timing of the notice occurred before SCE had selected SCP's bid and

therefore before parties could successfully execute the contract. While SCP did not procure the necessary capacity to cure its July 2023 deficiency by the February 21, 2023, deadline as provided by the Commission's February 13, 2023, email, SCP had been continuously working to do so. The successful transaction which cured SCP's July 2023 deficiency was initiated before SCP received notice from the Commission that it was deficient.

11. There were 50 separate recorded Events that occurred between the time SCP received its final System RA allocation on September 22, 2022, and the February 13, 2023, date when SCP received its notice of deficiency from the Commission. Of those 50 Events, SCP was successful in procuring two times in this period – a bilateral contract originating on January 31, 2023, resulting in 9 MW for July 2023, and the resulting contract from SCE's February 6, 2023, RFO for the outstanding 5.5 MW. [redacted] SCP remained in contact with CPED as it cured the remainder of its July and August shorts.

12. Despite active attempts to cure this deficiency, SCP was unable to cure its deficiency by the time its cure period ended on February 21st, 2023. SCP received a penalty of $442,012.00 for its YARA deficiency on June 6th, 2023. The penalty was paid by SCP.

13. SCP continued its efforts to cure its deficiency after the cure period. SCP cured its remaining July YARA deficiency on March 30th, 2023, by executing its contract with SCE from its RFO described above, and its remaining August YARA deficiency on May 24th, 2023, by procuring excess RA capacity from an investor-owned utility (IOU). [redacted] SCP also met its MARA compliance

obligation for the months of July and August. All of SCP's efforts to contract were communicated timely to the Commission and upon the final MARA obligation being filled, it was at that time that SCP was issued a citation.

14. D.21-12-015 requires the IOUs to make reasonable attempts to sell their excess RA capacity to other LSEs.[1] In SCP's experience transacting in the California RA market, the IOUs typically release public solicitations, in which SCP participated but was not selected prior to the October 31, 2022 YARA deadline. Any subsequent solicitations after the YARA deadline have no timeline regulations around Commission cure periods and, as described below, the IOU's specific timelines did not allow SCP to buy before the citation was issued.

15. In the instance described above in which SCP finally cured its August 2023 deficiency by procuring from an IOU, the process the IOU took to sell its excess RA did not make the RA product readily available to prospective buyers and took a commercially unreasonable amount of time. The IOU thus impeded SCP's ability to meet its YARA obligation. SCP bid on volumes for the same periods in the IOU solicitation closing prior to the YARA deadline, and was not selected. After the YARA deadline, SCP had reached out to the IOU most recently on February 2nd, 2023, to ask if they had any Q3 2023 volumes to sell. The IOU's staff responded that they would issue a solicitation for any excess in February and that SCP could reach out after the solicitation wrapped up to discuss any bilateral agreements. However, the IOU did not make its excess RA available until April 3rd, 2023, over 5 months after the deadline for the YARA compliance filings. After making its excess RA available, the IOU took 18 days to select SCP's bid and over a month between selecting SCP's bid and executing the contract. This

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[1] D.21-12-015, *Phase 2 Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023*, R.20-11-003 (Dec. 2, 2021) at Ordering Paragraph 72.

is significantly longer than it takes other counterparties to contract with SCP. Generally, the time between submittal to a solicitation to contracting is two weeks.

16. The IOU's process for making its excess RA available to the market meant that SCP was unable to fill its YARA position despite reasonable efforts taken both prior to the YARA filing deadline and during the cure period.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct to the best of my knowledge and belief.

Executed on January 19, 2024 at Santa Rosa, California.

<u>/s/ Deb Emerson</u>
Deb Emerson

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service.	R.18-07-006

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ASSIGNED COMMISSIONER'S RULING SEEKING ANNUAL FEEDBACK ON THE IMPLEMENTATION OF THE AFFORDABILITY FRAMEWORK

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January 25, 2024

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SUMMARY OF RECOMMENDATIONS

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

- Describe how it uses the Affordability Metrics to reach decisions that affect affordability;
- Aggregate Affordability Metrics data submitted by investor-owned utilities (IOU) so that the data are more accessible to the public and usable by intervenors;
- Summarize the Cost and Rate Tracker Tool and IOU Quarterly Reports to make them more useful for and accessible to ratepayers;
- Require implementation of the Affordability Framework and Metrics to make them more actionable;
- Integrate use of Affordability Metrics into non-ratesetting proceedings that may have impacts on rates such as Demand Flexibility, Resource Adequacy, and Integrated Resource Planning rulemakings; and
- Augment the Annual Affordability Report to discuss potential further analysis, actions, or solutions for addressing specific affordability challenges identified in the Annual Affordability Report.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service.	R.18-07-006

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ASSIGNED COMMISSIONER'S RULING SEEKING ANNUAL FEEDBACK ON THE IMPLEMENTATION OF THE AFFORDABILITY FRAMEWORK

California Community Choice Association[1] (CalCCA) submits these comments pursuant to the *Assigned Commissioner's Ruling Seeking Annual Feedback on The Implementation of The Affordability Framework*[2] (Ruling), dated December 13, 2023. The Ruling seeks feedback on the use and implementation of the California Public Utilities Commission's (Commission) adopted affordability framework within Commission proceedings and in the Annual Affordability Report.[3] In addition to seeking feedback from parties to this rulemaking, the

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

[2] *Assigned Commissioner's Ruling Seeking Annual Feedback on The Implementation of The Affordability Framework*, Rulemaking (R.) 18-07-006 (Dec. 13, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M521/K479/521479648.PDF.

[3] Decision (D.) 22-08-023 at 71 and Ordering Paragraph (O¶) 13: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K428/496428621.PDF.

Ruling is also seeking feedback from parties to other proceedings where the Affordability Metrics have been introduced and analyzed.[4]

I. INTRODUCTION

As noted in the 2021/2022 Annual Affordability Report, "electric bills started becoming much less affordable in 2022 and will continue on that trend until at least 2026".[5] These growing affordability challenges hit low-income customers the hardest, forcing households to make difficult decisions between paying electricity bills or for other essentials like housing, food, and healthcare. These challenges will grow as California pursues decarbonization and the reliance on the electric grid increase. High rates will slow decarbonization if rising electricity rates cause customers to no longer see an economic benefit to fuel switching. This would slow the adoption of building and transportation electrification and would reduce the capacity for load shifting to help grid management. CalCCA appreciates the opportunity to provide feedback on the Commission's Affordability Framework and Metrics and recommends that the Commission should:

- Describe how it uses the Affordability Metrics to reach decisions that affect affordability;
- Aggregate Affordability Metrics data submitted by investor-owned utilities (IOU) so that the data are more accessible to the public and usable by intervenors;
- Summarize the Cost and Rate Tracker Tool (CRT) and IOU Quarterly Reports to make them more useful for and accessible to ratepayers;
- Require implementation of the Affordability Framework and Metrics to make them more actionable;

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[4] An Administrative Law Judge's Ruling Noticing Related Proceedings of Comments Sought was issued in Applications (A.) 21-06-021; A.23-05-012; A.23-05-010; A. 22-05-015 et. al.; A.22-12-008; A.23-01-008; A.22-10-001 et al.; A.22-10-022; A.22-12-009; A.23-06-008; A.22-01-003; A.23-01-001; and A.23-05-004.

[5] California Public Utilities Commission *2021/2022 Annual Affordability Report* (Oct. 2023): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/affordability-proceeding/2021-2022/2021-and-2022-annual-affordability-report.pdf.

- Integrate use of Affordability Metrics into non-ratesetting proceedings that may have impacts on rates such as Demand Flexibility, Resource Adequacy, and Integrated Resource Planning Rulemakings; and
- Augment the Annual Affordability Report to discuss potential further analysis, actions, or solutions for addressing specific affordability challenges identified in the Annual Affordability Report.

II. CALCCA COMMENTS ON THE IMPLEMENTATION OF THE AFFORDABILITY FRAMEWORK AND METRICS

The Affordability Framework and Metrics are an integral step in addressing affordability concerns for electric utility bills in California. Successful program implementation involves careful planning, execution, evaluation, and subsequent course correction. For evaluation to be utilized and put into action, stakeholders need visibility to ensure they understand what goes into that evaluation.

A. There is a Need for More Transparency to Optimize The Use of Affordability Metrics

The Affordability Metrics allow stakeholders a standardized method to examine impacts to affordability that IOU rate cases may have, but there is a need for more transparency in decision-making to optimize the use and effectiveness of the Affordability Metrics. The Ruling asks a range of questions to stakeholders about how they use the Affordability Metrics; however, stakeholders have no visibility into how the Commission considers the Affordability Metrics while evaluating IOU rate applications or other proposals. To improve visibility, the Commission should take at least two actions. First, the Commission should describe its successes in applying the Affordability Metrics to reach decisions in cases where parties have submitted Affordability Metrics. Second, the Commission should aggregate these data submitted by IOUs and stakeholders so that the data are more accessible to the public and usable by intervenors. These additional steps will further optimize the use of the Affordability Metrics and better inform potential solutions to address affordability concerns.

1. The Commission Should Describe Successes in Applying The Affordability Metrics to Reach Decisions That Affect Affordability

The Commission should describe the successes it has had in applying the Affordability Metrics to reach decisions that affect affordability to allow parties to understand better the weight the Affordability Metrics carry. The Commission's difficult and complex task to evaluate utility rate applications and new policies brings together many factors to consider, one of which is affordability. One purpose of the Affordability Metrics is to be able to measure, in a standardized way, the affordability impacts from proposed changes to revenue requirements. While IOUs and parties may submit the Affordability Metrics in proceedings, neither has visibility into the effect on decision-making those Affordability Metrics have. Since the development and implementation of the Affordability Metrics, rates have continued to increase. It is reasonable to ask how the Affordability Metrics have evaluated and implemented rate changes in a manner to minimize those rate increases. Without an understanding of how the Commission considers the Affordability Metrics, parties cannot know the efficacy of the Affordability Metrics in terms of outcomes on rates.

2. The Commission Should Aggregate Affordability Metrics Data Submitted by IOUS So That The Data Are More Accessible to The Public and Usable by Intervenors

In addition to describing its successes with Affordability Metrics, the Commission should aggregate the Affordability Metrics data submitted by IOUs in rate cases so that the data are more accessible to the public and usable by intervenors. Aggregation of data would improve visibility for all stakeholders, but especially for the public. IOUs submit Affordability Metrics in applications that would increase revenue requirements by one percent or more,[6] representing only a single snapshot in time. Similarly, the Annual Affordability Reports provide the current state of Affordability Metrics for a single year. One important use of the Affordability Metrics is to track changes to affordability over time. Presently, there is not a process in place for Californians to see how IOU applications and Commission decisions impact affordability from the accumulation of these applications and decisions over time. The Commission should aggregate the Affordability Metrics on the Commission Affordability webpage[7] or include time series data in its Annual Affordability Reports. Additionally, the Commission could provide context for ratepayers by comparing trends in the Annual Affordability Reports with the Consumer Price Index's electricity index. This would further operationalize the intents of the Affordability Metrics as described in the Second Scoping Ruling, which includes how to make the measurement of the Affordability Metrics publicly available and accessible.[8]

a. The Commission Should Summarize the CRT and IOU Quarterly Reports to Make Them More Useful for Ratepayers

The Commission should address interactions between the Affordability Metrics and the CRT by summarizing the results of the tool as submitted by the IOUs. The Commission included determining these interactions in the Second Scoping Ruling as issue number seven.[9] The IOUs submit the CRT on a quarterly basis, which contain data the Commission uses as inputs for the Affordability Metrics. Specifically, the average essential usage bill amounts for the IOUs are

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6 D.22-08-023 at 84 and Ordering Paragraph (O¶)

7 https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/affordability.

8 R.18-07-006, *Assigned Commissioner's Second Amended Scoping Memo and Ruling* (Second Scoping Ruling) (Jun 9, 2020), at 3 (Issue #10 in list of scoping issues for Phase II of the proceeding): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M339/K544/339544712.PDF.

9 *See* Second Scoping Ruling, at 3 (Issue #7 in list of scoping issues for Phase 2 of the proceeding).

used as inputs for the Affordability Ratio for the 20th percentile and 50th percentile of income.[10] While these reports and tools may be accessible to intervenors or parties participating in proceedings, they are not accessible to the average ratepayer interested in understanding why their bills are increasing over time. The Commission should take the data reported in quarterly CRT submissions and summarize it so that all IOU information is accessible in one place and clearly described for ratepayers on a regular basis. The Commission webpage on Affordability[11] would provide a publicly accessible place to host this summarized information after each quarterly filing by the IOUs. This will provide ratepayers a view into how pending proceedings may or may not affect their bills, further supporting issue ten of the Second Scoping Ruling.

III. THE COMMISSION SHOULD REQUIRE IMPLEMENTATION OF THE AFFORDABILITY FRAMEWORK AND METRICS TO MAKE THEM MORE ACTIONABLE

Increased transparency will enable stakeholder understanding of the evaluation steps used to address affordability concerns. There is a need to move beyond evaluation and into the course correction phase. Phase 2 of the Affordability proceeding developed and implemented the Affordability Metrics and Phase 3 will address actions to mitigate further rate increases. To bridge the gap between Phases 2 and 3, the Commission should require implementation of the Affordability Framework and Metrics to make them more actionable. The Commission described issues under consideration in Phase 3 of the Affordability proceeding in the *Assigned Commissioner's Fifth Amended Scoping Memo and Ruling*.[12] This includes actions the

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10 R.18-07-006, *Affordability Metrics Implementation Workshop* (Nov. 15, 2021), at 36: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/affordability-proceeding/affordability-phase-2-workshop-slidedeck_11152021.pdf.

11 https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/affordability.

12 R.18-07-006, *Assigned Commissioner's Fifth Amended Scoping Memo and Ruling* (Jan 1, 2022), at 6-7 (listing the issues to be determined or otherwise considered): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M442/K734/442734815.PDF.

Commission should take to limit and/or mitigate future increases to ratepayer bills, the creation of processes to compare cumulative impacts of proposals, and how the Commission can ensure rate impact tools are used and useful for programs and applications. Implementing the Affordability Metrics in a way that makes them more actionable addresses these issues. These comments identify two examples of ways to do this. First, the Commission should use the Affordability metrics in non-ratesetting proceedings that may have impacts on rates. Second, the Commission should augment the Annual Affordability Report to discuss potential actions for addressing specific affordability challenges identified.

A. The Commission Should Integrate Use of Affordability Metrics into Non-Ratesetting Proceedings That May Have Impacts on Rates Such As Demand Flexibility

The Commission should implement the Affordability Metrics into non-ratesetting proceedings that may impact energy affordability, such as the Demand Flexibility proceeding (R.) 22-07-005, to compare impacts on affordability from proposals being considered by the Commission. CalCCA recommended this in its comments after reviewing ED Staff's Proposal on Implementation of Affordability Metrics, and pointed out that rate-setting applications are not the only proceedings that lead to actions that affect affordability.[13] The Demand Flexibility proceeding is a prime example of such a proceeding. The Commission is developing an income-graduated fixed charge (IGFC) to improve affordability for low-income customers, which would restructure how and from whom IOU fixed costs are recovered. In addition, the rulemaking is investigating dynamic rates to incentivize customers to use electricity when it is more beneficial for the grid. Both of these initiatives have had multiple proposals for stakeholders to consider and

[13] R.18-07-006, *California Community Choice Association's Comments on Assigned Commissioner's and Assigned Administrative Law Judge's Ruling Inviting Comments on Staff Proposal on Implementation of Affordability Metrics* (Jan 10, 2022), at 4 (describing that rate-setting applications are not the only place where actions are taken that affect revenue requirements).

on which to comment. Those proposals were not required to include the Affordability Metrics despite substantially changing rate structures and therefore potentially changing affordability for ratepayers. While the IGFC bill impact tool developed by Energy and Environmental Economics contained bill impacts for submission with IGFC proposals, it did not translate those impacts into the Affordability Metrics. This missed an opportunity to use the standardization offered by the Affordability Metrics to compare proposals and understand not just bill impacts in terms of magnitude, but also how they impact a ratepayer's ability to afford their bills as the Affordability Metrics measure.

The Demand Flexibility proceeding is not the only non-ratesetting proceeding in which the Affordability Metrics would provide value. Proceedings such as the new Resource Adequacy proceeding, R.23-10-011, or the Commission's Integrated Resource Planning proceeding, R.20-05-003 have the potential to substantially impact the cost of resources, which directly impact rates. The Commission's policies in these areas can affect the energy market and exacerbate or mitigate rising costs. The Commission should seek to understand the affordability impacts of various procurement policies so they can select policies that meet state goals for build out of clean energy resources while minimizing the risk of driving up prices. The Commission could use the Affordability Metrics to compare proposals submitted by parties or staff in these proceedings. Integrating the Affordability Metrics in more than rate-setting applications makes them more useful to the Commission, stakeholders, and ratepayers.

B. The Commission Should Augment The Annual Affordability Report to Discuss Potential Further Analysis, Actions, or Solutions for Addressing Specific Affordability Challenges Identified in The Annual Affordability Report

The Commission should include a discussion of potential further analysis, actions, or solutions for addressing specific challenges identified in the Annual Affordability Reports.

Currently, the Annual Affordability Report provides summaries and descriptions of Affordability Metrics for electric, gas, and water customers in California. It reports on each Affordability Metric and includes tables and maps to illustrate the state of affordability, including listing Areas of Affordability Concern (AAC). The AAC are locations in which a given utility service constitutes a certain percentage of a customer's disposable income. For electric service, the AAC is set at 15 percent. The Annual Affordability Reports also provide a listing of IOU ratesetting proceedings that include the Affordability Metrics and ends with a timeline of future reports. The Commission should include an additional section that discusses potential strategies to address specific findings. For example, what else could be learned about AACs that could alleviate energy burdens? Are there localized programs the Commission can recommend or pursue to provide some relief for AACs? What existing programs could be a resource to low-income customers or AACs struggling to pay bills? The Commission dedicates significant resources to programming that supports affordability for low-income customers such as the California Alternative Rate for Energy (CARE) or the Disconnections and Reconnections proceeding, R.18-07-005. The Commission should use the affordability metrics to integrate efforts to address affordability using existing programs like CARE and the Disconnections and Reconnections proceeding to meet affordability goals and equity goals as laid out by the Commission's Environmental and Social Justice Action Plan.[14] The Commission should seek to maximize the visibility of these types of programs, which includes discussing them in the Annual Affordability Reports.

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[14] See *California Public Utilities Commission Environmental and Social Justice Action Plan* (Apr. 7, 2022), at 22-24 (Goals 1, 5, and 9): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/documents/news-office/key-issues/esj/esj-action-plan-v2jw.pdf.

IV. CALCCA RESPONSES TO QUESTIONS

A. CalCCA Comments on The Annual Affordability Reports

See section 3.B. The Commission should add discussions of strategies to address specific findings of the Annual Affordability Reports as well as new and existing programs that would help low-income customers afford their electricity bills.

B. CalCCA Responses to The Questions in Section 5.3 of D.22-08-023[15]

1. AR Calculator and Calculations

a. Are there technical changes to the metrics or the methodologies that can be made to make them more effective/useful? For example, is the Affordability Ratio at the 20th income percentile capturing low-income customers eligible for the CARE/FERA or ESA programs? Eligible for the Affordable Connectivity Program (ACP)? For Lifeline? Is AR20 capturing customers that are low-income but do not necessarily qualify for an assistance program such as CARE/FERA, ESA, ACP, or Lifeline?

CalCCA has no comment at this time.

b. Should the AR Calculator add production of metrics at other geographic levels such as city, county, or geographic level, such as zip code?

CalCCA has no comment at this time.

c. Is the administrative burden involved in the production of the metrics worth the extra work, for the utilities? For the Commission?

CalCCA has no comment at this time.

2. Forecasting

a. Do nationwide CPI metrics accurately forecast the Affordability Ratio inputs for customers outside the metropolitan statistical areas (MSAs) or is it necessary to develop an alternate approach?

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15 D.22-08-023 at 71-73.

CalCCA has no comment at this time.

b. Are there more regionally based metrics of inflation for regions outside of MSAs?

CalCCA has no comment at this time.

c. Are there weaknesses to the staff method of forecasting income and housing costs for the metrics?

CalCCA has no comment at this time.

d. Has any utility used the Global Insights inflation rates as an alternative to forecast increases in costs/rates/bills?

CalCCA has no comment at this time.

e. As contemplated in this decision, have parties been able to get access to the source data for essential bills in the AR Calculator?

CalCCA has no comment at this time.

f. Are the energy and water trackers good mechanisms to provide a view of current and prospective cumulative revenues from which forecasted rates are derived and from which projected essential usage bills are derived?

CalCCA has no comment at this time.

3. Implementation

a. Is affordability testimony being required for the right types of proceedings?

See section 3.A. CalCCA recommends the Commission utilize the Affordability Metrics in non-ratesetting proceedings that impact affordability such as Demand Flexibility, Resource Adequacy, and Integrated Resource Planning.

b. What has been gained from any implementation of the metrics in past proceedings or final decisions?

See section 2. The Affordability Metrics have provided standardization in measuring affordability impacts, however the benefits of these metrics and their use in proceedings or final decisions for the Commission should be made more transparent.

c. Is updated affordability testimony being required at the right points in time during a proceeding?

CalCCA has no comment at this time.

d. Is the revenue requirement threshold (more than one percent revenue requirement increase over total system-level revenue requirement in current rates for water and energy proceedings) appropriate?

CalCCA has no comment at this time.

e. Are the demarcations designating AACs set at a useful and relevant level?

CalCCA has no comment at this time.

f. Is analysis of AACs a useful component in affordability testimony?

CalCCA has no comment at this time.

g. Are the annual Affordability Reports a good forum to present the forecast of cumulative revenues for future years?

See section 3.B. The Affordability Reports are a good forum to present forecasts of revenues for future years. The Commission should add content to the Affordability Reports which discuss how the findings will lead to further actions.

h. Have the metrics been applied to small water utilities or Small LECs?

CalCCA has no comment at this time.

i. Has implementation allowed the Commission to better fulfill its statutory duties expressed in various Public Utilities Code sections, including Section 739(d)(2), Section 382, Section 739.8(a), and Section 871.5?

CalCCA has no comment at this time.

j. Has implementation allowed the Commission to enhance its role in closing the digital divide as expressed in various Public Utilities Code sections, including Section 709, Sections 280281, Section 275.6, and the Moore Act?

CalCCA has no comment at this time.

C. CalCCA Comments on The Public Advocates Office at The California Public Utilities Commission's (Cal Advocates) Proposal to Define "Last Adopted Revenue Requirement" As The Revenue Requirement from The Last Adopted General Rate Case (GRC)

CalCCA has no comment at this time.

D. CalCCA Comments on section 4 of The Ruling "Assessing Implementation"

1. Does the affordability framework (metrics, maps, calculator, quarterly revenue reports, and annual affordability reports):

a. Make utility rates and bills meaningful or useful for the type of decision[16] being made?

See section 2. This is unclear without more transparency from the Commission.

b. Make utility rates and bills representative for types of customers based on where they live and their costs of living?

CalCCA has no comment at this time.

c. Help describe the choices before the Commission as more or less affordable?

See section 3.A. Without utilizing the Affordability Metrics to compare proposals the Commission is considering outside of ratesetting proceedings, the Affordability Metrics cannot describe the choices in either direction.

d. Advance the Commission's environmental and social justice goals?

See section 3.B. Without a discussion of how to act on affordability impacts, the Affordability Metrics will not advance Commission environmental and social justice goals.

e. How have non-utility parties utilized the affordability framework to inform their participation and/or develop their positions? If not at all, is it due to difficulty understanding the affordability tools/metrics, difficulty incorporating the tools/metrics into parties' positions, or some other reason?

[16] Examples of choices under consideration in the related proceedings: A.21-06-021; A.23-05-012; A.23-05-010; A.22-05-015 et al.; A.22-12-008; A.23-01-008; A.22-10-001 et al.; A.22-10-022; A.22-12-009; A.23-06-008; A.22-01-003; A.23-01-001; A.23-05-004.

See section 2. CalCCA utilizes the Affordability Metrics to track bill affordability for customers over time in IOU rate cases. However, the IOU filings containing Affordability Metrics are disaggregated which makes it difficult to understand the total impact on rates throughout the year. As section 2 describes, the Commission should work to aggregate the Affordability Metrics in separate filings to show how all proposed changes to rates affect affordability together.

2. With regard to the Water Tracker:

a. Should the definition of "Last Adopted Revenue Requirement" mean a utility's authorized revenue requirement from the adopted GRC or start fresh on January 1 of the year before the year in which the Water Tracker is filed?

CalCCA has no comment on the Water Tracker.

b. Should the Water Tracker provide incremental revenue requirement and bill impacts changes between last adopted GRC and next adopted GRC or continue using a continuous forward-looking tracker?

CalCCA has no comment on the Water Tracker.

c. If the Water Tracker is changed to capture incremental changes between GRCs, should these changes be implemented post-adoption of each water utility's next GRC revenue requirements, or sooner?

CalCCA has no comment on the Water Tracker.

3. Describe with specificity how you have used the annual Affordability Report (any year(s)), including identifying the industry for which it was used.

a. If at all, how does the Affordability Report provide value beyond the metrics, maps, calculator, and quarterly revenue reports?

See section 3.B. Beyond the value provided by the metrics, maps, calculator, and quarterly reports, the Annual Affordability Report does not provide strategies or discussions of further ways to address affordability.

b. Do the recommendations for how to present affordability metrics in the 2021/2022 Affordability Report[17] help distill relevant information?[18]

See section 2.B. The Commission should aggregate Affordability Metrics data throughout the year to allow ratepayers to see potential changes to Affordability Metrics rather than just the retrospective look the Annual Affordability Reports take.

V. CONCLUSION

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

Respectfully submitted,

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

January 25, 2024

17 The presentation of the affordability metrics in applications is required by O¶s 5 and 6 of D.22-08-023.
18 2021 and 2022 Annual Affordability Report (Attachment 1 of the Ruling), at 56.

DOCKETED	
Docket Number:	23-DECARB-01
Project Title:	Inflation Reduction Act Residential Energy Rebate Programs
TN #:	254199
Document Title:	Marin Clean Energy Comments on the Request for Information RE Inflation Reduction Act Home Efficiency Rebate Program (HOMES)
Description:	N/A
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Organization:	Marin Clean Energy (MCE)
Submitter Role:	Public Agency
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Comment Received From: Marin Clean Energy (MCE)
Submitted On: 1/26/2024
Docket Number: 23-DECARB-01

Marin Clean Energy on the Request for Information RE Inflation Reduction Act Home Efficiency Rebate Program (HOMES) Docket

Additional submitted attachment is included below.

January 26, 2024

California Energy Commission
Docket Office
715 P Street
Sacramento, CA 95814-5512
Docket@energy.ca.gov

RE: Marin Clean Energy on the Request for Information RE: Inflation Reduction Act Home Efficiency Rebate Program (HOMES) Docket No. 23-DECARB-01

Dear Commissioners, Board Members and Staff,

I. Introduction

Marin Clean Energy ("MCE") strongly supports the goals of the Inflation Reduction Act ("IRA") Home Efficiency Rebate program ("HOMES") to advance the transition to clean, affordable, efficient, resilient, equitable and beneficial energy access in households across the United States. MCE specifically supports the HOMES program goals to support greater innovation on efficiency programs, lowering energy burdens in low-income households and disadvantaged communities, and reducing pollution from buildings.

MCE is a community choice aggregator ("CCA") who provides clean electricity service and cutting-edge energy programs to more than 1.5 million residents and businesses in 37 member communities across Contra Costa, Marin, Napa, and Solano counties.[1] MCE's mission is to confront the climate crisis by eliminating fossil fuel greenhouse gas emissions, producing renewable energy, and creating equitable community benefits.

Since 2013, MCE is a dedicated program administrator ("PA") of a host of energy efficiency ("EE"), demand response ("DR") and decarbonization focused programs. MCE programs serve residential, commercial, agricultural and industrial customers. MCE also specifically administers Equity-focused residential direct install programs, workforce education and training programs, and pay-for-performance efficiency programs with many shared goals of the HOMES program.[2]

[1] *See* MCE, About Us, available at: https://www.mcecleanenergy.org/about-us/ (detailing additional information on MCE and CCAs).
[2] MCE's Equity segment programs include its Home Energy Savings Program, Multifamily Energy Savings Program and Commercial Equity Program. MCE's Workforce Education and Training program include the Green Workforce Pathways program. MCE's marketplace pay-for-performance programs include Residential Efficiency Market Program, Commercial Efficiency Market Program and its Peak FLEXMarket program. *See* MCE, FLEXmarket Programs, available at: https://www.mcecleanenergy.org/flexmarket/.

MCE's EE programs have reduced over 14,609 metric tons of carbon dioxide equivalent and distributed over $7.9 million dollars in rebates to date.

MCE offers substantive comments on braiding HOMES program funds into the Equitable Building Decarbonization ("EBD") program, best practices and considerations for layering different funding sources in efficiency programs, pay-for-performance program design recommendations, and income verification methods. MCE supports braiding HOMES funds into the EBD Direct Install program, as well as layering HOMES funds with additional local and state funding sources to deliver greater program benefits. MCE offers lessons learned from administering its pay-for-performance marketplace efficiency programs,[3] and residential equity-focused programs serving low-income households.

II. Responses to Input Request

1) Braiding HOMES with the Equitable Building Decarbonization Direct Install Program.

MCE supports braiding HOMES funds with EBD Direct Install program funds to deliver deeper benefits to more households in underresourced communities. MCE sees the alignment between the HOMES program and the EBD Direct Install programs' shared goals to reduce greenhouse gas emissions from buildings and lower energy burdens for historically underserved households.[4] Layering the HOMES funds into the EBD Direct Install program provides the critical financial resources for EBD to serve more households with additional measures. This braiding approach also allows the CEC to streamline the administration of HOMES by leveraging the existing administrative infrastructure of the EBD Direct Install program.[5] Braiding likely reduces overall administrative costs and supports a faster program launch timeline. Since EBD Direct Install program participants experience both higher pollution and energy burdens in addition to facing barriers to accessing clean energy programs more broadly,[6] delivering meaningful investments is urgently needed. MCE sees merit in braiding HOMES funds with EBD Direct Install program funds in two distinct scenarios: **Partial Integration** or **Full Integration**.[7]

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[3] MCE's marketplace pay-for-performance programs include its Residential Efficiency Market Program, Commercial Efficiency Market Program and its Peak FLEXMarket program. *See* MCE, FLEXmarket Programs, available at: https://www.mcecleanenergy.org/flexmarket/.

[4] Inflation Reduction Act, Public Law 117–169 Section 50121 (2022); Assembly Bill 209, Chapter 251, Statutes of 2022.

[5] *See* California Energy Commission, Equitable Building Decarbonization Direct Install Program Guidelines, October 2023, available at: https://www.energy.ca.gov/programs-and-topics/programs/equitable-building-decarbonization-program.

[6] California Energy Commission, *SB 350 Barriers Study*, 2016, available at: https://assets.ctfassets.net/ntcn17ss1ow9/3SqKkJoNIvts2nYVPAOmGH/fe590149c3e39e51593231dc60eeeeff/TN214830_20161215T184655_SB_350_LowIncome_Barriers_Study_Part_A__Commission_Final_Report.pdf.

[7] MCE recognizes the Department of Energy possesses the authority under the Inflation Reduction Act to approve, modify or reject the California Energy Commission's application and proposals for HOMES funding on behalf of California. MCE offers recommendations to the

- **Scenario 1 - Partial Integration**: In this scenario, the CEC would apply some HOMES funds to stack on some EBD Direct Install program projects when beneficial to simultaneously advance each programs' goals for greater participant benefit.
    - The CEC applies EBD funds to cover 100% of direct installation decarbonization project costs for eligible households per EBD Direct Install program Guidelines regardless of their energy savings. For a fuller discussion of balancing EBD Direct Install program goals and energy savings requirements of HOMES while braiding funds, *See* **Considerations for Braiding HOMES funds into EBD Direct-Install Program** Energy Savings Goals and Energy Equity Goals discussed below.
    - EBD Direct Install program funds cover the costs of electrification upgrades, including ancillary measures that allow the electrification measures to be installed like light construction, pest and mold remediation, and panel/wiring upgrades that may not produce energy savings in isolation. The CEC additionally stacks HOMES funds onto some of those projects to provide additional efficiency measures that meet its required modeled or measured energy savings thresholds.[8] This approach lowers the overall cost of an EBD project by covering costs with two funding streams (EBD and HOMES) and delivers greater benefits to the participant or allows the treatment of more households.
    - The CEC correspondingly applies HOMES program requirements only to the selection of EBD Direct Install program projects that receive stacked HOMES funding. The CEC could retain some separate reporting requirements for EBD projects that do and EBD projects that do not receive stacked HOMES funds.

- **Scenario 2 – Full Integration**: Subject to the authority of the Department of Energy and consistent with the controlling provisions of the Inflation Reduction Act, the CEC fully integrates all HOMES funding into the EBD Direct Install program.
    - The CEC leverages its existing EBD administrative rules and structure to add HOMES funds to all EBD projects. This allows greater funding for each EBD Direct Install project and therefore more decarbonization and efficiency measures or higher costing measures for each participating household.
    - The CEC must apply all the HOMES regulatory requirements to all EBD Direct Install projects including the required energy savings thresholds.
    - The CEC along with EBD Direct Install program regional PAs must develop streamlined participation and reporting requirements for EBD participants. This approach requires potentially complex program infrastructure design to ensure dual compliance with EBD and HOMES on the front end. However, once the CEC and PAs reconcile program rules within a single implementation structure, program participation, tracking, reporting and implementation could be significantly more efficient.

Commission with awareness of DOE's decision-making authority in this context and IRA's required corresponding processes.

[8] Department of Energy, State Community & Energy Programs, INFLATION REDUCTION ACT HOME ENERGY REBATES – Program Application Requirements & Instructions, October 2023, available at: https://www.energy.gov/sites/default/files/2023-10/home-energy-rebate-programs-requirements-and-application-instructions_10-13-2023.pdf at pp. 34-36.

Considerations for Braiding HOMES funds into EBD Direct-Install Program

- **Energy Savings Goals and Energy Equity Goals:** HOMES requires modeled or measured energy savings to qualify for a rebate varying by methodology, property type and income.[9] Notably, the EBD Direct Install program does not require projects to achieve energy savings. EBD projects strive to deliver the health, safety, comfort and affordability non-energy benefits ("NEBs") that advance energy equity regardless of energy savings.[10] EBD specifically requires electrifying two end uses in a household which, even when paired with other efficiency measures, may increase the corresponding electrical load.[11] Stacking all EBD eligible measures with HOMES eligible measures may not achieve the energy savings thresholds required by HOMES in every household, but may provide valuable NEBs or achieve EBD's program goals. Finding the right EBD and HOMES measure mix for each household requires thoughtful design to avoid putting the energy savings goals of HOMES in tension with the energy equity goals of EBD. MCE believes the CEC may work with the Department of Energy and stakeholders especially community-based organizations ("CBOs") in this docket to design specific guidance to avoid any such tensions thereby mutually advancing both important sets of goals.

- **Defining a "Project" – Segmentation within a Household:** MCE encourages the Commission to explore, with the supervision of the Department of Energy, methods to define and segment a HOMES "project" and EBD Direct Install "project" within the same served household.[12] If possible, MCE recommends segmenting HOMES and EBD projects within the same household. This approach would permit two projects under different rules and requirements within the same household. For example, the CEC could define the HOMES measures and installation costs on one household a separate "project" under its corresponding rules and then stack the EBD funds and rules on to only the EBD measures within that same household. The PAs could partner with the Commission to ensure a streamlined participation experience for participants. The combination of EBD and HOMES funds would allow deeper financial investment in a household while allowing for a more individualized, community-led project design.

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[9] Department of Energy, State Community & Energy Programs, INFLATION REDUCTION ACT HOME ENERGY REBATES – Program Application Requirements & Instructions, October 2023, available at: https://www.energy.gov/sites/default/files/2023-10/home-energy-rebate-programs-requirements-and-application-instructions_10-13-2023.pdf at pp. 12-14.
[10] CEC, EBD Direct Install Program Guidelines, October 2023, at pp. 2, 9 (outlining program goals and initial community focus area criteria).
[11] DNV, MCE Low-Income Families & Tenants Pilot Program Evaluation, August 2021 at pp. 25-30 (outlining the diversity of electric load impacts of a variety of decarbonization, electrification and efficiency measures for low-income tenants).
[12] DOE, SCEP,I NFLATION REDUCTION ACT HOME ENERGY REBATES – Program Application Requirements & Instructions, October 2023, available at: https://www.energy.gov/sites/default/files/2023-10/home-energy-rebate-programs-requirements-and-application-instructions_10-13-2023.pdf at p. 45 (consistent with requirements on combining rebates).

MCE looks forward to partnering with the Commission and stakeholders on partial or full braiding of HOMES funds into the EBD Direct Install program in advancement of energy equity. Following recent and significant proposed funding cuts to the EBD program, MCE believes braiding state and federal resources are vital to achieving its goals and delivering meaningful decarbonization benefits to underresourced communities.[13]

a. Share any best practices for braiding federal and state funds for highly effective rebate, incentive, and/or direct install programs aimed at households in disadvantaged communities or meeting low-income guidelines.

Through the administration of its programs and related research, MCE observes and administers several decarbonization focused programs that layer state and federal funds aimed at low-income households and disadvantaged communities. MCE finds great success in layering when collaborating with common implementers on several programs or layering its own programs. For example, MCE administers two direct-install decarbonization focused[14] programs serving low-income multifamily households: the Low-Income Families and Tenants Pilot program ("LIFT"), and the Multifamily Energy Savings program ("MFES"). Similar to EBD and HOMES, the LIFT and MFES programs have different requirements and priorities. However, MCE was able to braid these funds together for each project in a way that advanced the goals of both programs without the need to compromise. MCE designed its program offerings to stack and offer complementary measures to potential participants. Through this thoughtful and narrow program design, MCE and implementers of both programs may cover lower cost efficiency measures of a household through MFES and the same household's electrification costs through LIFT. Experienced PAs with knowledge of existing programs and implementers with working and trusted relationships are essential to support a streamlined administration of the programs that shields a participant from burdensome processes.

MCE recommends designing program stacking rules to complement known gaps and barriers of existing programs. MCE successfully layers its direct install Home Energy Savings program ("HES") with the TECH Quick Start grants to offer greater benefits to participants and advance each program's distinct program goals. HES provides home energy retrofits at no cost to low-income single-family households in disadvantaged communities. Franklin Energy, on behalf of MCE, designed its TECH Quick Start grant to overcome known barriers in the administration of HES such as home conditions that prevented participants from receiving heat pump incentives like subfloor resizing and small electrical repairs.[15] Stacking the TECH Quick Start funding on to the HES program allowed deeper retrofit projects to occur and thus the participation of low-income

[13] Department of Finance, Governor's Proposed Budget, January 2024, available at: https://ebudget.ca.gov/ (proposing a reduction of $283 million General Fund dollars and a shift of $87 million dollars to the Greenhouse Gas Reduction Fund, representing a $370 million dollar change).
[14] In advancement of decarbonization goals beyond energy savings, MCE's direct install programs offer electrification measures.
[15] TECH Clean California, 2021 Quick Start Grant Recipients – Franklin Energy, available at: https://techcleanca.com/quick-start-grants/2021-quick-start-grant-recipients/franklin-energy/.

households with greater needs who would have been otherwise excluded from participation. MCE similarly recommends the CEC approach program design and stacking rules for HOMES to complement existing programs and overcome their known barriers for low-income and disadvantaged community participants.

MCE also recommends leveraging existing marketing, outreach, implementation and quality assurance teams when braiding funds. In addition to stacking TECH Quick Start Grant incentives to overcome program gaps and fund ancillary measures, MCE also layers federal funds received from the Housing and Urban Development Department[16] ("HUD") to provide health, safety and comfort remediation services as well as electrification funds into its existing direct install programs. By braiding those funds with MCE's existing efforts to curb barriers to electrification, MCE can stretch its program reach even farther by using the same marketing and outreach, implementation, and quality assurance teams. Braiding federal funds into MCE's existing programs required additional administrative and documentation steps. However, MCE programs deliver deeper, diversified and more measures. As a result, additional residents in MCE's service area will be served and the implementation will be more efficient.

MCE recommends the Commission support the leadership of CBOs and CBO partnerships when braiding state and federal funds. CBOs are locally trusted entities with many skills and the knowledge necessary to support successful implementation of braided programs for low-income households in disadvantaged communities. MCE, for example, partners with GRID Alternatives through a Transformative Climate Communities grant in the City of Richmond.[17] Through this partnership, GRID Alternatives helped many low-income customers in MCE's service area become eligible for electrification and ancillary measures. CBOs can play an integral role in ensuring low-income households in disadvantaged communities receive attuned support to beneficial participation in braided programs.

2) In the situation where CEC does not incorporate/braid HOMES program funding into the EBD Direct Install Program, respond to the following questions to inform CEC's HOMES program design and application to DOE.

(a.) Overall Program Design

iv. Leveraging and Stacking

b) Are there considerations for stacking pay-for-performance rebates with existing programs?

MCE supports stacking pay-for-performance rebates with existing programs. MCE currently administers the Residential Efficiency Market program that provides pay-for-performance

[16] In 2023, MCE received authorization to use $750,000 in federal budget funds for its Marin Clean Energy Healthy Homes program; final program design and funding disbursement is pending final approval by HUD.

[17] Office of Governor Gavin Newsom, California Awards $96 Million for Climate Projects in 10 Frontline Communities, October 2022, available at: https://www.gov.ca.gov/2022/10/27/california-awards-96-million-for-climate-projects-in-10-frontline-communities/.

incentives for measured savings from energy efficiency projects.[18] This program pays the incentives on metered energy savings based on the previous year's energy consumption compared to the metered value after the measures are installed. The Residential Efficiency Market increases energy efficiency and peak load shifting specifically by offering extra incentives for periods of high demand during summer peak hours in support of greater grid reliability. This type of program model aligns closely with the HOMES program's "Measured Home Efficiency Rebates" pathway and the CEC may leverage MCE's existing administrative infrastructure and mechanisms for implementation and measurement of the HOMES measured pathway. Stacking HOMES incentives into MCE's existing Residential Efficiency Market program reduces the administrative burdens of HOMES implementation. The additional HOMES incentives would enable MCE's Residential Efficiency Market program to serve many more customers with deeper retrofit projects and support immediate impacts, versus the risked delays from starting another independent pay-for-performance program.

(b.) Rebate determination approach and rebate values.

i. What are the advantages and drawbacks of program design using the fixed costs versus pay-for-performance method? Can the pay-for-performance method effectively serve low-income households?

MCE finds merit in both fixed costs and pay-for-performance methods. As discussed throughout this response, MCE administers several programs that use fixed costs and pay-for-performance methods.[19] Pay-for-performance methods encourage projects to fully achieve meaningful energy savings. These programs reduce potential financial risk to funders and administrators by paying only for achieved results. However, programs serving low-income households have other important climate, equity, and policy goals beyond reducing financial risk and achieving energy savings like improving health, safety and comfort within a household. Pay-for-performance methods in isolation may not achieve those non-energy savings-based goals. However, MCE believes that pay-for-performance methods when paired with additional measures and protections, and stacked with additional programs, can deliver both meaningful energy savings and NEBs to low-income households. For example, stacking HOMES pay-for-performance rebates with MCE's Residential Efficiency Market could offer deeper and more beneficial investments to participating low-income households. Beyond stacking, it is essential for any pay-for-performance method designed to serve low-income households to eliminate any potential project risks for a participant. A participating low-income household should not be penalized or assume any financial risk associated with participation if the energy savings thresholds are not achieved. If the CEC is pursuing a pay-for-performance pathway for low-income households the program, PAs or an aggregator must assume any risks associated with energy savings performance. Transferring any risk to a low-income household is unethical and runs counter to the HOMES program goals. Finally, upfront payments for projects and financial protections are also critical to effectively serve low-income households.

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[18] MCE, MCE Launches $6 Million Residential Efficiency Market Program, April 2022, available at: https://www.mcecleanenergy.org/mce-news/mce-launches-6-million-residential-efficiency-market-program/.

[19] MCE Response Question 1; MCE Response Question 2.

ii. What are the options to manage and allocate performance risk and financing costs during the 9 to 12-month post-installation period prior to issuing the rebate? Options should consider at a minimum that: low-income households are not required to utilize personal funds to pay for rebated work, the inability for many contractors, installers, or small businesses to "float" rebate costs, and the cost of capital for aggregators (or some designated entity) to float those costs.

Stacking HOMES pay-for-performance rebates with other complementary programs and funds while requiring an upfront payments mechanism can protect low-income households from any financial risks or responsibilities as discussed above. If the CEC blends HOMES funds with other programs, as discussed in **MCE Response to Question 1,** a program could provide up-front and progress payments to contractors to offset the capital costs of projects with alternate funding sources and then the HOMES funds would replenish the program funds once the measurement and verification period is complete.

In the current Residential Efficiency Market, for example, MCE distributes an up-front payment of 20% of the forecasted energy savings value and then issues performance payments quarterly based on the measured results until the 12-month measurement and verification period is complete.

By following a similar structure to MCE's Residential Efficiency Market, and blending the HOMES funds, this method protects a low-income customer, or participating contractor, from financial risks and allows for multiple funding sources to collaboratively deliver greater results to a participant.

iv. What is the best way for the CEC to obtain consistent and sufficient documentation for contractors, such as itemized cost breakdowns, while remaining consistent with contractor business practices?

MCE recommends the CEC develop a clear program invoice template for contractor documentation. MCE requires the aggregators (contractors) in its Residential Efficiency Market program to submit written invoices. An invoice template protects against documentation gaps and confusion for contractors and participants.

(d.) Income Verification

i. *What approaches should CEC consider to verify individual household income that are efficient and accurate, safeguard information, and create a minimal burden for residents? Please provide examples of other programs and why you consider them effective models?*

MCE supports limiting the income verification requirements and burdens for program participants. Complex and burdensome income verification requirements often result in the exclusion of low-income program participants from programs intended to serve them. Therefore, MCE supports the use of self-attestation to demonstrate income eligibility for the HOMES program.[20] MCE uses self-

[20] Disadvantaged Communities Advisory Group, Re: Comments on Rulemaking 20-05-012 Assigned Commissioner's Ruling (ACR) on Improving Self Generation Incentive Program

attestation for its Home Energy Savings ("HES") program with great success. MCE observes several programs including, but not limited to the California Alternate Rates for Energy ("CARE") energy bill discount program and the Family Electric Rate Assistance Program ("FERA") energy bill discount program also successfully use self-attestation to establish income eligibility and selective post-enrollment verification processes. Beyond energy programs, Medi-Cal and Covered California both accept self-attestation of income to demonstrate eligibility for low-income participants via a written statement.[21]

ii. The EBD Direct Install Guidelines established a list of federal and state assistance programs that can be accepted to qualify a resident as low income (i.e., "Categorical Eligibility"). Should the CEC utilize the same list of programs for Categorical Eligibility for a program(s) developed with HOMES funding? In addition to the programs found in Section E.3. of the Guidelines, are there additional programs CEC should consider?

Yes, MCE supports using the EBD Direct Install Program Guidelines established list of federal and state assistance programs, "Categorical Eligibility," to qualify a resident as low-income for the HOMES program.[22] MCE believes utilizing the same Categorical Eligibility list of low-income programs decreases the potential burdens of participation for a low-income resident to demonstrate their eligibility and decreases the risk of excluding low-income residents from the HOMES program altogether. Additionally, applying the same Categorical Eligibility criteria for income verification to both the HOMES and EBD Direct Install programs further streamlines the dual implementation of both programs by the CEC especially under a braided funds scenario as discussed in **MCE Response to Question 1.** This approach produces greater administrative efficiencies for the CEC and PAs while simultaneously decreasing the risks of confusion for potential program participants.

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Equity Outcomes and Assembly Bill 209 Implementation, available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M499/K629/499629300.PDF at p. 2 (Where providing proof of income and/or residing in deed-restricted housing are necessary to qualify for participation, these conditions often result in unnecessary barriers to participation. Consider enabling self-attestation of income to reduce these barriers, which can be verified through random audits of a small subset of customers, or at a minimum enable customers who qualify for CARE or FERA to participate without additional paperwork.").

[21] Department of Health Care Services, Medi-Cal, https://www.dhcs.ca.gov/Get-Medi-Cal/Pages/confirm-eligibility.aspx (case by case basis for those that may lack proof of income and/or receive cash wages); Covered California is the health insurance marketplace in California established under the federal Patient Protection and Affordable Care Act. Covered California, Attestation of Income, No Documentation Available, available at: https://www.coveredca.com/pdfs/Attestation-Form-Income-No-Documentation-Available-English.pdf .

[22] CEC, EBD Direct Install Program Guidelines, October 2023, at p.11 (notably including Medi-Cal which allows the use of self-attestation).

III. Conclusion

MCE respectfully submits these comments to **Docket No. 23-DECARB-01** and looks forward to ongoing collaborations with the CEC and stakeholders to advance energy efficiency, greenhouse gas reductions from buildings, non-energy benefits and energy equity in its service area and throughout California.

Thank you for your consideration and attention.

Sincerely,
/s/__________
Wade Stano
wstano@mcecleanenergy.org
Senior Policy Counsel
MCE

DATED: January 26, 2024.

**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.	R.18-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION APPROVING COMMUNITY-BASED ORGANIZATION ARREARS CASE MANAGEMENT PILOT PROGRAM

Evelyn Kahl,
General Counsel and Director of Policy
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January 29, 2024

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SUMMARY OF RECOMMENDATIONS

California Community Choice Association (CalCCA) provides the following recommended modifications to the Proposed Decision to ensure both bundled investor-owned utility (IOU) customers and community choice aggregator (CCA) unbundled customers benefit through participation and/or information collection from the Community-Based Organization (CBO) Arrears Case Management Pilot Program (CBO Pilot):

- Incorporate CCA customer considerations into the CBO Pilot implementation, including requiring the referral by the IOUs of eligible IOU *and* CCA customers to the CBOs, providing adequate information to the CBOs regarding CCAs, and requiring the CBOs to provide information on CCA customer participation in the pilot to the CCAs; and

- Require the evaluation metrics to identify IOU *and* CCA customers in the data to understand the impact of the CBO Pilot on bundled and unbundled customers.

In addition, CalCCA recommends adoption of the Proposed Decision's requirement to allow input by the Pilot Implementation Working Group in the selection of the evaluator and the evaluation scope.

**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.	R.18-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION APPROVING COMMUNITY-BASED ORGANIZATION ARREARS CASE MANAGEMENT PILOT PROGRAM

The California Community Choice Association (CalCCA)[1] submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[2] on the proposed *Decision Approving Community-Based Organization Arrears Case Management Pilot Program*[3] (Proposed Decision), dated January 9, 2024.

I. INTRODUCTION

CalCCA supports the Proposed Decision's approval of the Community-Based Organization Arrears Case Management Pilot Program (CBO Pilot). Many California residential energy customers, including unbundled customers served by community choice aggregators

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

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

[3] Proposed *Decision Approving Community-Based Organization Arrears Case Management Pilot Program*, Rulemaking (R.) 18-07-005 (Jan. 9, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M523/K071/523071353.PDF.

(CCAs), continue struggling to remain current on their bills and avoid service disconnections. The two-year CBO Pilot is designed to fund case management services through community-based organizations (CBOs) for 12,000 customers to reduce residential disconnections by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E), (collectively, the IOUs). Through accurate documentation and evaluation, the CBO Pilot can provide valuable data to assess whether such case management services should be implemented on a larger scale.

All residential customers, including IOU bundled and CCA unbundled customers, will fund the $11.24 million CBO Pilot.[4] As CCA customers are distribution customers of the IOUs, certain CCA customers will be eligible to participate in the CBO Pilot. As required by Decision (D.) 22-04-037, one CCA from each IOU service territory participated in a CBO Pilot Working Group which refined the eligibility parameters for customers to participate in the CBO Pilot.[5] The zip codes ultimately chosen to be served under the CBO Pilot do not include any zip codes within CCA territories in PG&E's service territory (and therefore no customers from CCAs in PG&E's service territory will participate in the CBO Pilot).[6] However, CCA customers in certain zip codes in SCE's and SDG&E's service territories will be eligible to participate.[7]

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4 Proposed Decision, at 13, 28, Conclusion of Law 17 (COL), at 33 ("It is reasonable for the case management services to be funded by ratepayers because the CBOs will help enroll eligible customers in arrearages management programs, to help customers remain in the program, reduce their energy bills and arrearages over time, and reduce the risk of service disconnection").

5 D.22-04-037, *Decision Requiring Development of Community Based Organization Case Management Pilot Program to Reduce Arrearages Associated with the Covid-19 Pandemic,* R.21-02-014 (Apr. 7, 2022): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M468/K801/468801115.PDF.

6 Proposed Decision at 11-12, Finding of Fact (FOF) 4, at 31.

7 *Id.* at 11, FOF 3, at 31.

Aside from the potential benefits of participation, *all* CCAs are interested in ensuring robust and comprehensive data collection regarding all aspects of the CBO Pilot, including CCA customer participation. Such data will enable the assessment of the value of rolling out such CBO case management on a widespread basis at the end of the CBO Pilot. CalCCA accordingly provides the following recommended modifications to the Proposed Decision to ensure both bundled and unbundled customers benefit through participation and/or information collection:

- Incorporate CCA customer considerations into the CBO Pilot implementation, including requiring the referral by the IOUs of eligible IOU and CCA customers to the CBOs, providing adequate information to the CBOs regarding CCAs, and requiring the CBOs to provide information on CCA customer participation in the pilot to the CCAs; and

- Require the evaluation metrics to identify IOU and CCA customers in the data to understand the impact of the CBO Pilot on bundled and unbundled customers.

In addition, CalCCA recommends adoption of the Proposed Decision's requirement to allow input by the Pilot Implementation Working Group in the selection of the evaluator and the evaluation scope.

II. THE COMMISSION SHOULD ADOPT THE PROPOSED DECISION WITH MODIFICATIONS TO ENSURE BOTH BUNDLED AND UNBUNDLED RESIDENTIAL CUSTOMERS BENEFIT FROM THE CBO PILOT

A. CCA Customer Considerations Should be Incorporated into the CBO Pilot Implementation

The CBO Pilot Design should be updated to ensure CCA customer considerations are incorporated into the Pilot. CalCCA appreciates the Proposed Decision's requirement that CCAs be invited to participate in the Pilot Implementation Working Group to assist with the creation of standard informational and training materials.[8] However, the Commission should also require incorporation of the needs of unbundled versus bundled customers both for participation in the

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[8] *Id.*, at 16, COL 9, at 32.

Pilot as well as reaping the benefits of the evaluation. As such, the following should be incorporated into the CBO Pilot Design, Marketing, Education and Outreach (ME&O), and enrollment specifications:

- IOUs should be required to refer eligible IOU *and* CCA customers, and therefore "provide selected CBOs with customer contact information for [both IOU *and* CCA] eligible customers";[9]
- CBOs should be provided standard information regarding CCAs to enable the CBOs to adequately advise CCA customers regarding their options for assistance from the CCA and/or the IOU;
- SCE and SDG&E should not only be required to provide CCAs the customer accounts participating in the pilot, but also customers who have unenrolled;[10] and
- Attachment A of the Proposed Decision should be amended to incorporate requirements concerning CCA customers, including SCE and SDG&E providing marketing materials and customer enrollment data to CCAs.[11]

In addition to the above, the CCAs look forward to participating in the Pilot Implementation Working Group to ensure (1) CCA information is represented in ME&O materials, (2) that all CBOs participating are equipped with information to adequately support both bundled and unbundled customers, and (3) that the information is standardized to allow adequate evaluation of both bundled and unbundled customer success under the program.

B. Pilot Metrics and Evaluation Should Incorporate Data Regarding CCA Customer Pilot Participation

In addition to enabling effective CCA customer participation in the Pilot, CalCCA recommends that the evaluation metrics be modified to ensure data distinguishes between IOU

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9 *Id.*, at 10 (listing the pilot design elements).

10 In addition, the Commission should amend Attachment A to incorporate its requirements for SCE and SDG&E.

11 *See* Proposed Decision, at 12, and COL 3, at 32 ("It is reasonable to require SCE and SDG&E to provide the following information to each CCA that serves pilot zip codes: (a) pilot marketing materials and contact information for the CBOs that serve pilot zip codes in the CCA's service territory at least 10 business days before pilot enrollment commences, and (b) a list of the customer accounts that are participating in the pilot within 10 business days of the end of the pilot enrollment period.").

and CCA customers (as well as the specific organization serving each customer). As experienced with the Arrearage Management Plan success rates and evaluation process, certain "best practices" of organizations work better than others.[12] Keeping careful track of the success rates of customers not only according to the metrics set forth in the Proposed Decision but also by organization (IOU or CCA) will ensure the robust evaluation necessary to determine what was effective. Therefore, CalCCA requests that the Commission incorporate into the metrics a categorization regarding not only for pilot and non-pilot customers, but also whether such customers are IOU or CCA customers.

C. The Commission Should Adopt the Proposed Decision's Requirement that the Pilot Implementation Working Group Provide Guidance on the Evaluation Contractor and Key Deliverables

The Commission should adopt the Proposed Decision's requirement that:

> [t]he Pilot Implementation Working Group, excluding the CBO Pilot Program contracts, meet with Energy Division to discuss the selection of the evaluation contractor, the evaluation scope of work, the evaluation plan, the reporting metrics, and the evaluation report.[13]

Allowing members of the Pilot Implementation Working Group to guide the selection of the evaluation contractor and provide input on the evaluation scope will ensure the broad input of interested load-serving entities and stakeholders. The Proposed Decision's requirement to include the Pilot Implementation Working Group in the evaluation process should be adopted.

[12] *See, e.g.,* R.18-07-005, *Administrative Law Judge's Ruling Directing Utilities to Provide Data and Requesting Comments on Pilot Questions* (Feb. 13, 2023) (detailing the difficulties of evaluating success under the AMP Program when the IOUs utilized different parameters to measure success under the program): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M502/K200/502200451.PDF.

[13] Proposed Decision, at 25, COL 16, at 33.

III. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

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General Counsel and Director of Policy
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

January 29, 2024

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION APPROVING COMMUNITY-BASED ORGANIZATION ARREARS CASE MANAGEMENT PILOT PROGRAM

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

Proposed text deletions show as ~~**bold and strikethrough**~~
Proposed text additions show as **<u>bold and underlined</u>**

FINDINGS OF FACT

No proposed changes.

CONCLUSIONS OF LAW

3. It is reasonable to require SCE and SDG&E to provide the following information to each CCA that serves pilot zip codes: (a) pilot marketing materials and contact information for the CBOs that serve pilot zip codes in the CCA's service territory at least 10 business days before pilot enrollment commences, and (b) a list of the customer accounts that are participating in the pilot within 10 business days of the end of the pilot enrollment period~~**.**~~**<u>, and a list of the customer accounts that unenroll from the pilot.</u>**

6. It is reasonable for a Pilot Implementation Working Group to meet to discuss the development of standard informational materials about the pilot and standard training materials for providing case management services**<u>, including information on CCAs and regarding IOU and CCA assistance programs,</u>** before the CBO Pilot Program commences.

11. It is reasonable to adopt the CBO Pilot Program metrics and reporting requirements in Attachment A~~**.**~~**<u>, which will require the Large Utilities to refer eligible IOU and CCA customers to CBOs for services under the CBO Pilot Program.</u>**

13. It is reasonable to adopt the CBO Pilot Program evaluation plan in Attachment A~~**.**~~**<u>, which will require information on CBO participation to be categorized according to whether a participant is a customer of an IOU or CCA.</u>**

ORDERING PARAGRAPHS

No proposed changes.

New Order:

No proposed changes.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION TO EXPAND SYSTEM RELIABILITY PILOTS OF PACIFIC GAS AND ELECTRIC COMPANY AND SOUTHERN CALIFORNIA EDISON COMPANY

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January 4, 2024

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TABLE OF AUTHORITIES

California Public Utilities Commission Rules of Practice and Procedure

SUMMARY OF RECOMMENDATIONS

California Community Choice Association supports the Proposed Decision and offers the following recommendations for the California Public Utilities Commission (Commission) to further define and clarify community choice aggregator (CCA) participation in real time pricing (RTP) pilots:

- Adopt the Proposed Decision's cost recovery framework because it avoids cost shifts between bundled and unbundled customers;
- Adopt the Proposed Decision's timeline for CCA participation in pilots, allowing CCAs to initiate enrollment by June 1, 2025;
- Allow CCAs to notice intent to participate after IOU advice letters are submitted;
- Adopt the Proposed Decision's recommendation to direct Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) to jointly host a workshop to discuss, with CCAs, plans to prevent dual enrollment with excluded demand response (DR) programs;
- Revise the Proposed Decision to provide more detail about how the Commission envisions CCA participation in IOU-administered RTP pilots;
- Clarify roles and responsibilities of CCAs and IOUs for RTP pilot implementation; and
- Provide the calculation methodology in the Proposed Decision for the CCA incentive of $20/kilowatt-year.

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

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION TO EXPAND SYSTEM RELIABILITY PILOTS OF PACIFIC GAS AND ELECTRIC COMPANY AND SOUTHERN CALIFORNIA EDISON COMPANY

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[2] on the proposed *Decision to Expand System Reliability Pilots of Pacific Gas and Electric Company and Southern California Edison Company*[3] (Proposed Decision), dated December 15, 2023, and *Procedural Email Re: Rule 11.6 Motion for Extension of Time (SCE, PG&E, and SDG&E)*, dated December 22, 2023: Opening comments on the proposed decision are now due on January 5, 2024, and reply comments are now due on January 12, 2024.

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

[2] State of California, California Public Utilities Commission, *Rules of Practice and Procedure* (May 1, 2021).

[3] Proposed *Decision to Expand System Reliability Pilots of Pacific Gas and Electric Company and Southern California Edison Company*, Rulemaking (R.) 22-07-005 (Dec. 15, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M521/K479/521479791.PDF.

I. INTRODUCTION

CalCCA applauds the Commission for swiftly incorporating stakeholder feedback and proposing balanced approaches for implementing expanded real time pricing (RTP) pilots. The Proposed Decision recognizes the need to expand testing of RTP rates across customer and rate classes to improve grid reliability in the near term and ahead of the California Energy Commission's Load Management Standard deadlines for load-serving entities to establish RTP rates by 2027. The Proposed Decision establishes three primary elements which strike a reasonable balance based on stakeholder feedback in this proceeding. First, the Proposed Decision establishes a cost recovery framework that avoids cost shifts. Second, the Proposed Decision proposes an enrollment-based incentive of $20/kilowatt (kW)-year for participating community choice aggregators (CCAs). Third, the Proposed Decision, if adopted, would allow CCAs to opt into pilots through June 2025. While the Proposed Decision establishes several important characteristics for implementing expanded pilots, the Proposed Decision should be revised to provide more clarity to CCAs to maximize CCA participation in pilots administered by investor-owned utilities (IOUs). Therefore, CalCCA recommends that the Commission do the following:

- Adopt the Proposed Decision's cost recovery framework because it mitigates cost shifts between bundled and unbundled customers;
- Adopt the Proposed Decision's timeline for CCA participation in pilots, allowing CCAs to initiate enrollment by June 1, 2025;
- Allow CCAs to notice intent to participate after IOU advice letters are submitted;
- Adopt the Proposed Decision's recommendation to direct Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) to jointly host a workshop to discuss, with CCAs, plans to prevent dual enrollment with excluded demand response (DR) programs;
- Revise the Proposed Decision to provide more detail about how the Commission envisions CCA participation in IOU-administered RTP pilots;
- Clarify roles and responsibilities of CCAs and IOUs for RTP pilot implementation; and

- Provide the calculation methodology in the Proposed Decision for the CCA incentive of $20/kw-year.

II. THE COMMISSION SHOULD ADOPT THE PROPOSED DECISION'S COST RECOVERY FRAMEWORK BECAUSE IT MITIGATES COST SHIFTS BETWEEN BUNDLED AND UNBUNDLED CUSTOMERS

The Proposed Decision strikes a reasonable and fair position with regard to the expanded pilot cost recovery framework by proposing to recover expanded pilot implementation costs through the existing Dynamic and Real Time Pricing Memorandum Account (DRTPMA). For cost recovery of the generation portion of shadow bill credits, the Proposed Decision proposes to use the Energy Resource Recovery Account (ERRA) for PG&E, and the Base Revenue Requirement Balancing Account Generation subaccount (BRRBA-G) for SCE.[4] The Commission should adopt the Proposed Decision's cost recovery framework for two reasons. First, it mitigates the potential for cost shifts between bundled and unbundled customers. Since bundled and unbundled customers can benefit from participating in the expanded pilots, it is reasonable to collect implementation costs through the existing DRTPMA, which is a distribution account and therefore collected from all customers. Second, the Proposed Decision's cost recovery framework for shadow bill credits avoids dealing with the complexity of, or potential cost shifts due to cost recovery through the latest Power Charge Indifference Adjustment (PCIA) vintage of the Portfolio Allocation Balancing Account (PABA), which PG&E proposed.[5] Collecting shadow bill credit cost recovery for bundled customers through the ERRA and BRRBA-G, which are

4 *See* Proposed Decision Finding of Fact 30 and 31, at 75-76.

5 R.22-07-005. *Submission of GridX, Inc., Polaris Energy Services, Gridtractor, Inc., and Pacific Gas and Electric Company's Comments and Responses to the Administrative Law Judge's Ruling on Track B Staff Proposal to Expand Existing Pilots* (Sept. 25, 2023), at 26 ("PG&E believes that recovery through the last PCIA vintage year of PABA for PG&E generation rate shadow billing credits is the most appropriate method of recovery for the generation component because it will recover the revenue shortfall from those customers").

collected from PG&E and SCE bundled customers respectively, will mitigate cost shifting between departed load customers and bundled customers.

III. THE COMMISSION SHOULD ADOPT THE PROPOSED DECISION'S FLEXIBILITY IN ALLOWING CCAS TO INITIATE ENROLLMENT OF CUSTOMERS BY JUNE 1, 2025

CalCCA appreciates the Proposed Decision's acknowledgement of the importance of CCA customer participation in the expanded RTP pilots by allowing CCAs to initiate enrollment up to June 1, 2025. This will allow CCAs that are ready to participate the ability to enroll customers for the summer of 2024, and give more time to CCAs that are not ready. Providing an additional year for CCAs to determine whether participation in expanded pilots is right for their customers as well as how participation may interact with other existing CCA programs will maximize the overall number of CCAs participating and minimize any conflicts.

IV. THE COMMISSION SHOULD ALLOW CCAS TO NOTICE INTENT TO PARTICIPATE AFTER IOU ADVICE LETTERS ARE SUBMITTED

For CCAs that are ready to participate for the summer of 2024, the Proposed Decision should require CCAs to file their Tier 1 advice letter providing notice to the Commission that they will participate in the pilots after the IOUs have submitted their Tier 2 implementation plan advice letters and the advice letters have been approved. Understanding the details of how the IOUs plan to implement the pilots is a fundamental part of a CCA's decision-making process for determining whether to participate in the pilots. Given that the IOU implementation advice letters are due 60 days after the effective date of this decision, most likely late March 2024 if the decision is voted out at the end of January 2024, CCAs that are ready to participate in the pilot by summer of 2024 should be required to file their Tier 1 advice letters only after the disposition of the IOU implementation advice letters.[6]

[6] *See* Proposed Decision, Ordering Paragraphs (O¶) 1-2, at 77-78.

V. THE COMMISSION SHOULD ADOPT THE PROPOSED DECISION'S DIRECTION FOR PG&E AND SCE TO HOST A WORKSHOP TO DISCUSS HOW TO WORK WITH CCAS TO PREVENT DUAL ENROLLMENT IN EXCLUDED DR PROGRAMS

The Commission should adopt the Proposed Decision's recommendation to direct PG&E and SCE to host a workshop to discuss with CCAs how to prevent dual enrollment with RTP pilots and expand the scope of the workshop to include a discussion of how CCAs will be able to modify their generation rates throughout the duration of the pilots. As part of PG&E and SCE planning for implementing expanded pilots, the Proposed Decision directs both IOUs to include a joint plan to prevent dual enrollment that includes input from CCAs.[7] A benefit of the expanded pilots will be to see how RTP rates work or do not work well with other programs that incentivize load shifting, but in different ways. Finding synergies or conflicts between existing programs and RTP rates will ensure that full RTP rates offered to customers in the future provide the most value and incent the most load shifting. This applies to CCA customers as well, so CCA input to PG&E and SCE dual enrollment prevention plans is equally important for maximizing CCA customer enrollment in pilots. However, as the Commission rightly points out, prohibiting dual participation in DR programs may reduce participation in the expanded pilots, thereby limiting their potential impact. [8] As such, CalCCA urges the Commission to acknowledge that any limits on dual participation adopted in the Final Decision are not precedential and any future decisions on dual enrollment in daily load shifting and event-based DR programs will not be prejudiced by this decision. To ensure broad participation in demand flexibility rates, CalCCA

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7 *Ibid.*

8 *See* Proposed Decision, at 62 ("We acknowledge that prohibiting dual participation in DR programs may reduce participation in the expanded pilots and limit their potential to meet the 50-MW enrollment targets for each pilot.").

recommends that the Commission expeditiously create a working group process to address dual enrollment issues either in this or another proceeding as referenced in the Proposed Decision.[9]

VI. THE PROPOSED DECISION SHOULD PROVIDE MORE DETAIL ABOUT HOW CCAS WILL PARTICIPATE IN IOU-ADMINISTERED RTP PILOTS TO PROVIDE CERTAINTY AND MAXIMIZE CCA PARTICIPATION

CalCCA appreciates the Commission's willingness to consider ways to optimize CCA participation in the expanded RTP pilots administered by PG&E and SCE, including the discussions in Sections 3 and 4, and the $20/kw-year incentive for CCAs based on enrolled load from CCA customers.[10] In this same vein, the Proposed Decision should include further details on how CCA participation will work in IOU administered RTP pilots to provide certainty for CCAs to participate.

A. The Proposed Decision Should Clarify Roles and Responsibilities for CCA Participation in an IOU-Administered RTP Pilot

The Proposed Decision directs PG&E and SCE to administer the expanded RTP pilots and provides the ability for CCAs to opt in to participation with their respective utility. While the Proposed Decision provides direction to PG&E and SCE on developing implementation plans,[11] it does not provide details on what the Commission expects CCA participation in pilots to look like or guidance on how CCAs will be able to modify the components of the dynamic rate for which they are responsible. The Proposed Decision should include more details clarifying the roles and responsibilities of CCAs and IOUs in IOU-administered RTP pilots given that IOUs will interact with customers with whom CCAs have existing relationships. This particularly applies to larger customers such as agricultural, commercial, and industrial customers.

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9 *See* Proposed Decision, at 63 ("The Commission may create a process to address these issues in Phase 2 of this proceeding or in another proceeding to promote widespread enrollment in demand flexibility rates.").

10 *See* Proposed Decision, Conclusion of Law (COL) 12, 13, and 25, at 72-74.

11 *See* Proposed Decision, O¶ 1-2, at 77-78.

CCAs have built relationships with customers across all rate classes by servicing their generation needs. The expanded RTP pilots should be structured in a way that allows CCAs and IOUs to collaborate effectively, enhancing the experience for all parties involved, including customers. CCA customers who participate in the program will expect their generation provider to be knowledgeable about all generation components of the pilots, including, but not limited to information related to hourly generation rates and their formation. It is essential to recognize that allowing the IOU to manage the entire pilot, with no role for CCAs in the customer journey, *ipso facto* detracts from the generation-related experience of CCA customers, could introduce inconsistencies, and potentially undermines the trust and expertise that CCAs have cultivated with their customer base. Thus, the Proposed Decision should explicitly outline the expectations and responsibilities for CCAs as partners in managing the customer relationships within the context of IOU-administered RTP pilots. This clarity will not only safeguard the interests of CCA customers but also contribute to the overall success and effectiveness of the RTP pilots.

CalCCA's recommendations for CCA participation include but are not limited to:

- Clarification of the process through which CCAs will be able to modify the generation component of the dynamic rate for their unbundled customers and how CCAs will be able to interact with the pilot platform to modify the cost components for which they are responsible.
- CCAs should have the ability, to the extent necessary, to manage customer relationships with CCA customers enrolled in expanded pilots.
- IOU administrators should provide CCAs access at all times to the hourly generation rate and the methodology and data used to create the combined hourly rate.
- IOUs should provide CCAs with all monthly shadow bills for their participating customers.
- CCAs should have the option to include messaging to customers when customers receive their annual savings derived from the shadow bills. At minimum, customer messaging should acknowledge the portion of savings paid by the CCA vs. the IOU.

- PG&E and SCE should provide CCAs with their implementation plans so CCAs can understand how CCA customers will be marketed and contacted.

- CCAs should have the option to co-host educational webinars marketed towards shared customers.

- CCAs should receive access to expanded pilot technology and platforms to the extent necessary to effectively communicate with customers.

- IOU administrators should keep CCAs apprised of how CCA customers are performing in pilots.

- CCAs should have the option to develop co-branding with their IOU administrator if electing to participate in expanded pilots.

- SCE should provide criteria as to how it will select the first CCA to participate. The selected CCA should have the ultimate authority to determine its participation in the expanded pilot.

B. The Proposed Decision Should Clarify The Methodology The Commission Used to Calculate The CCA Incentive

The Proposed Decision offers participating CCAs $20/kw-year of capacity enrolled in RTP pilots up to $1.8 million per pilot,[12] but it should clarify the methodology the Commission used to calculate this incentive level. CalCCA appreciates the Commission's recognition of the value of CCA customer participation in RTP pilots for grid reliability by offering an incentive to CCAs. CCAs would benefit from understanding how the Commission calculated this incentive level for two reasons. First, understanding the inputs to calculating the incentive level would help CCAs understand what the Commission envisions for CCA participation and how that vision may align with efforts required by CCAs to participate. Second, if the Proposed Decision establishes a specific methodology, CCAs can use that same methodology to determine whether the incentive is sufficiently compensating CCAs for their participation and the cost of connecting to the third-party vendor to provide their generation rates. CCAs will need to dedicate resources

[12] *See* Proposed Decision, COL 12, 13, and 25, at 72-74.

to monitor customer participation in IOU administered pilots, including at a minimum managing customer relationships, responding to customer inquiries, uploading generation rates, verifying CCA customer shadow bills and annual payments, and analyzing customer performance to inform future CCA RTP rate development. With the incentive calculation methodology from the Commission, CCAs can make more informed choices on participation in RTP pilots.

VII. CONCLUSION

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

Respectfully submitted,

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

January 4, 2024

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION TO EXPAND SYSTEM RELIABILITY PILOTS OF PACIFIC GAS AND ELECTRIC COMPANY AND SOUTHERN CALIFORNIA EDISON COMPANY

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

Proposed text additions show as **<u>bold and underlined</u>**
Proposed text deletions show as **~~bold and strikethrough~~**

CONCLUSIONS OF LAW

<u>38. It is reasonable to allow CCAs that participate in the PG&E pilots to modify the generation component of the dynamic rate for their unbundled customers before commencing enrollment and throughout the entire duration of the pilots.</u>

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

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION TO EXPAND SYSTEM RELIABILITY PILOTS OF PACIFIC GAS AND ELECTRIC COMPANY AND SOUTHERN CALIFORNIA EDISON COMPANY

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January 12, 2024

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS

- The Proposed Decision should enable community choice aggregators (CCAs) to have the option for access to participating CCA customer communications equal to that of investor-owned utility (IOU) administrators.
- The Proposed Decision should require IOU administrators to share relevant demand response program data to CCAs participating in pilots.
- The California Public Utilities Commission (Commission) should provide more information consistent with comments from the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) regarding operational details of CCAs' participation so CCAs can understand what participation in pilots entails.
- The commission should reject Cal Advocates' recommendation to require participating CCAs to file unnecessary advice letters to ensure consistent pilot rate design.
- The Commission should reject Cal Advocates' recommendation to require CCAs to provide copies of funding applications before receiving ratepayer funding as it is unnecessarily burdensome.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION TO EXPAND SYSTEM RELIABILITY PILOTS OF PACIFIC GAS AND ELECTRIC COMPANY AND SOUTHERN CALIFORNIA EDISON COMPANY

The California Community Choice Association (CalCCA)[1] submits these reply comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[2] on the proposed *Decision to Expand System Reliability Pilots of Pacific Gas and Electric Company and Southern California Edison Company* [3] (Proposed Decision), dated December 15, 2023, and *Procedural Email Re: Rule 11.6 Motion for Extension of Time (SCE, PG&E, and SDG&E)*, dated December 22, 2023: Opening comments on the proposed decision were due on January 5, 2024, and reply comments are now due on January 12, 2024.

I. THE PROPOSED DECISION SHOULD ENABLE CCAS TO HAVE THE OPTION FOR ACCESS TO PARTICIPATING CCA CUSTOMER COMMUNICATIONS EQUAL TO THAT OF IOU ADMINISTRATORS

To the extent that Pacific Gas and Electric Company (PG&E) or Southern California Edison Company (SCE) reach out to CCA customers directly for expanded pilot recruitment, the investor-owned utility (IOU) should keep the participant's community choice aggregator (CCA) informed of that communication. In opening comments, PG&E proposes to work directly with customers rather than primarily having automation service providers (ASPs) market to customers.[4] CCAs do not necessarily object to this proposal, however CCAs should have equal access to their own customers in the context of implementing real time pricing (RTP) pilots and have input on how IOU administrators will communicate with CCA customers. CCA staff, including call center staff, should have knowledge of pilot implementation, eligibility, and other

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

[2] State of California, California Public Utilities Commission, *Rules of Practice and Procedure* (May 1, 2021).

[3] Proposed *Decision to Expand System Reliability Pilots of Pacific Gas and Electric Company and Southern California Edison Company*, Rulemaking (R.) 22-07-005 (Dec. 15, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M521/K479/521479791.PDF.

[4] *See* PG&E Opening Comments, at 3.

details so they can answer CCA customer questions as well as IOU call center staff. Additionally, CCAs have deep knowledge of their customers and communities, which can enhance an IOU administrator's recruitment efforts, so IOU and CCA partnership in recruiting customers and CCAs being kept up to date on messaging will benefit the pilots overall.

II. THE PROPOSED DECISION SHOULD REQUIRE IOU ADMINISTRATORS TO SHARE RELEVANT DR PROGRAM DATA TO CCAS PARTICIPATING IN PILOTS FOR DUAL ENROLLMENT PREVENTION

The Proposed Decision should require IOUs to share CCA customer enrollment data for prohibited Demand Response (DR) programs with participating CCAs. CCAs that choose to participate in RTP pilots will want their customers to enroll and will be invested in their customers benefitting from the pilot. In order to support enrollment in the pilot, CCAs may contribute to marketing efforts. Without CCA customer DR enrollment data, CCAs would not know which customers are eligible for RTP pilots, muddling the enrollment process for the customer. To avoid customer confusion and wasting marketing resources, the IOUs should share DR enrollment data of CCA customers with participating CCAs. PG&E has argued that PG&E's 2024-2027 Demand Response Application (A.22-05-002) is the more appropriate place for CCAs to discuss unbundled customer DR participation data,[5] and more recently put forth a similar position in opening comments by pointing to R.22-11-013[6] as a better venue for these data access issues.[7] Given the enrollment disorder that preventing CCA access to unbundled customer DR participation data may cause, the Commission should direct the IOUs to share the DR participation data for CCA customers with CCAs participating in the expanded RTP pilots, isolated to the programs for which the Commission prohibits dual enrollment.

III. THE COMMISSION SHOULD PROVIDE MORE DETAIL CONSISTENT WITH CAL ADVOCATES' COMMENTS REGARDING OPERATIONAL DETAILS OF CCAS PARTICIPATION SO CCAS CAN UNDERSTAND WHAT PARTICIPATION IN PILOTS ENTAILS

The Commission should provide details on what it expects the role for CCA participation to be in the expanded pilots administered by IOUs. Cal Advocates recommended the Proposed

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5 R.22-07-005, *Reply Comments of Pacific Gas and Electric Company* to Administrative Law Judge Wang's September 13, 2023 email ruling (Oct 9, 2024), at 17 (Explaining why unbundled customer DR participation data policy should not be in scope in the Demand Flexibility Rulemaking R.22-07-005).

6 R.22-11-013 is the Rulemaking to Consider Distributed Energy Resource Program Cost-Effectiveness Issues, Data Use and Access, and Equipment Performance Standards.

7 *See* PG&E Opening Comments, at 6.

Decision provide operational details such as allocation of incentives, and CCA-IOU rate design compatibility so that pilot results are not diluted or distorted by inconsistencies.[8] This type of detail would benefit CCAs interested in participating in expanded pilots. As CalCCA argued in its opening comments, CCAs must have a role in the customer journey and generation rate component for CCA customers enrolled in an RTP pilot administered by an IOU to prevent degradation of the customer experience and maintain CCA rate autonomy.[9] While CalCCA appreciates the Commission recognition of the importance of CCA participation, CCAs are still unclear as to what participation will entail for them and their customers, including the system costs to integrate generation rates into the pilot platforms, the administrative costs, and the marketing costs associated with participation. CCAs will be able to make more informed decisions to benefit their customers if the decision explicitly defines the role and expectations for CCAs. To expand on Cal Advocates' recommendation for more details, CalCCA provides a list of recommendations in Appendix A, attached herein.

IV. THE COMMISSION SHOULD REJECT CAL ADVOCATES' RECOMMENDATION TO REQUIRE PARTICIPATING CCAS TO FILE UNNECESSARY ADVICE LETTERS TO ENSURE CONSISTENT PILOT RATE DESIGN

The Commission should reject the proposal from Cal Advocates to require CCAs to file a Tier 2 advice letter associated with changes to pilot rate design because the process is unnecessary. Cal Advocates believes that a participating CCA should be required to file a Tier 2 advice letter in order to allow party input and Commission review to ensure CCA generation rates are consistent with bundled service customers' rates.[10] This requirement is not necessary because CCA generation rates can inherently differ from bundled generation rates. CCAs have rate autonomy and unbundled generation rates are set by individual CCA boards. Both CCAs and IOUs are invested in the integrity of the evaluation of RTP pilots ahead of the 2027 Load Management Standard deadline for implementing dynamic rates from the California Energy Commission. However, the RTP pilots will be available to customers being served by two different generation service providers and may inherently have differing results. The Commission should have oversight of proposed changes to the structure of RTP pilots and has

8 *See* Cal Advocates Opening Comments, at 4.
9 *See* CalCCA Opening Comments, at 7.
10 *See* Cal Advocates Opening Comments, at 5.

oversight over bundled generation rates. The responsibility of taking those changes to the Commission is that of the IOU as the administrator of the pilot, not a participating CCA.

V. THE COMMISSION SHOULD REJECT CAL ADVOCATES' RECOMMENDATION TO REQUIRE CCAS TO PROVIDE COPIES OF FUNDING APPLICATIONS BEFORE RECEIVING RATEPAYER FUNDING AS IT IS UNNECESSARILY BURDENSOME

The Commission should not require CCAs to provide copies of funding applications and determinations before receiving the proposed CCA incentive as Cal Advocates proposed because it would hinder CCAs participating in the pilot.[11] Though non-ratepayer funding sources are desirable to minimize costs to ratepayers, it is unnecessarily burdensome and subjective to require only CCAs to demonstrate, and the CPUC to determine whether or not exhaustive funding efforts were made to pursue other funding sources. This is particularly true given the short timeline of the expanded pilots. Cal Advocates' recommendation would serve as a disincentive to CCA participation, reducing both the load shifting potential in the short term and the amount of customer data available to evaluate at the end of the pilots. Given the magnitude of California's load served by CCAs and to maximize the potential of this and future rates and pilots, the Commission must ensure a level playing field between IOUs and CCAs, especially when those rates or pilots are funded by all ratepayers. As such, the Commission should reject Cal Advocates' proposal.

VI. CONCLUSION

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

Respectfully submitted,

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

January 12, 2024

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11 *Ibid.*

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION TO EXPAND SYSTEM RELIABILITY PILOTS OF PACIFIC GAS AND ELECTRIC COMPANY AND SOUTHERN CALIFORNIA EDISON COMPANY

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

Proposed text deletions are in ~~bold and strikethrough~~
Proposed text additions are in <u>bold and underlined</u>

CONCLUSIONS OF LAW

<u>38. It is reasonable for CCAs to have the option to manage customer relationships with CCA customers enrolled in expanded dynamic rate pilots.</u>

<u>39. It is reasonable for PG&E and SCE to provide CCAs with implementation plans so CCAs can understand how CCA customers will be marketed and contacted.</u>

<u>40. It is reasonable for PG&E and SCE to keep CCAs informed of communications with CCA customers related to expanded dynamic rate pilots.</u>

<u>41. It is reasonable for PG&E and SCE to share with CCAs the demand response enrollment status of CCA customers for demand response programs prohibited for dual enrollment with expanded dynamic rate pilots, including all supply-side DR resources (economic or emergency), including all DR programs and contracts counted toward resource adequacy, DRAM, Flex Market Pilot, DAHRTP, and other event-based load-modifying programs or pilots operated by the utilities or CCAs.</u>

<u>42. It is reasonable for PG&E and SCE to provide all monthly shadow bills to CCAs for participating CCA customers.</u>

43. It is reasonable for CCAs to have the option to include messaging to customers when customers receive their annual savings derived from the shadow bills. At minimum, customer messaging should acknowledge the portion of savings paid by the CCA and paid by the IOU.

44. It is reasonable for CCAs to have access to expanded dynamic rate pilot technology and platforms to the extent necessary to modify CCA generation rates and effectively communicate with customers.

45. It is reasonable for PG&E and SCE to keep CCAs apprised of how CCA customers are performing in pilots.

46. It is reasonable for CCAs to have the option to develop co-branding with their IOU administrator if electing to participate in expanded dynamic rate pilots.

ORDERING PARAGRAPHS

1. Pacific Gas and Electric Company shall file a Tier 2 advice letter within 60 days of the effective date of this decision to propose an implementation plan for expanding the dynamic rate pilot authorized in Decision 21-12-015 into two pilots that will commence enrollment on June 1, 2024 in accordance with this decision. The advice letter shall include (a) an implementation strategy for achieving the 50-megawatt enrollment target for each pilot, and (b) a joint proposal with Southern California Edison Company for addressing dual participation issues and a description of how the proposal addresses input from the dual participation workshop~~.~~**, and (c) a plan for collaborating with CCAs that opt to participate that includes at a minimum how PG&E will comply with the items listed below:**

(a) Establish a process through which CCAs will be able to modify the generation component of the dynamic rate for their unbundled customers;

(b) Allow CCAs the ability, to the extent necessary, to manage customer relationships with CCA customers enrolled in expanded pilots;

(c) Provide participating CCAs access at all times to the hourly generation rate and the methodology and data used to create said the combined hourly rate;

(d) Provide CCAs with all monthly shadow bills for their participating customers;

(e) Provide CCAs the option to include messaging to customers when customers receive their annual savings derived from the shadow bills;

(f) Provide CCAs with their implementation plans so CCAs can understand how CCA customers will be marketed and contacted;

(g) Allow CCAs the option to co-host educational webinars marketed towards shared customers;

(h) Provide CCAs access to expanded pilot technology and platforms to the extent necessary to effectively communicate with customers;

(i) Keep CCAs apprised of how CCA customers are performing in pilots.;

(j) Allow CCAs the opportunity for co-branding with PG&E if electing to participate in expanded pilots; and

(k) Provide CCA customer participation data for demand response programs prohibited from dual enrollment with PG&E's Expanded Pilots.

2. Southern California Edison Company shall file a Tier 2 advice letter within 60 days of the effective date of this decision to propose an implementation plan to expand the dynamic rate pilot authorized in Decision 21-12-015 and to apply all modifications to the pilot authorized in this decision on June 1, 2024. The advice letter shall (a) include an implementation strategy for achieving the 50-megawatt enrollment target for the pilot, (b) propose which CCA customers will initially be permitted to enroll in the SCE Expanded Pilot, and (c) propose jointly with Southern California Edison Company how to address dual participation issues and input from the

dual participation workshop~~.~~**, and (c) a plan for collaborating with CCAs that opt to participate that includes at a minimum how SCE will comply with the items listed below:**

> **(a) Establish a process through which CCAs will be able to modify the generation component of the dynamic rate for their unbundled customers;**
>
> **(b) Allow CCAs the ability, to the extent necessary, to manage customer relationships with CCA customers enrolled in expanded pilots;**
>
> **(c) Provide participating CCAs access at all times to the hourly generation rate and the methodology and data used to create said the combined hourly rate;**
>
> **(d) Provide CCAs with all monthly shadow bills for their participating customers;**
>
> **(e) Provide CCAs the option to include messaging to customers when customers receive their annual savings derived from the shadow bills;**
>
> **(f) Provide CCAs with their implementation plans so CCAs can understand how CCA customers will be marketed and contacted;**
>
> **(g) Allow CCAs the option to co-host educational webinars marketed towards shared customers;**
>
> **(h) Provide CCAs access to expanded pilot technology and platforms to the extent necessary to effectively communicate with customers;**
>
> **(i) Keep CCAs apprised of how CCA customers are performing in pilots.; and**
>
> **(j) Allow CCAs the opportunity for co-branding with SCE if electing to participate in expanded pilots.**
>
> **(k) Provide CCA customer participation data for demand response programs prohibited from dual enrollment with SCE's Expanded Pilots.**

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S MOTION TO OFFER EXHIBITS INTO EVIDENCE AND ADMIT INTO THE RECORD

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S MOTION TO OFFER EXHIBITS INTO EVIDENCE AND ADMIT INTO THE RECORD

The California Community Choice Association[1] (CalCCA) submits this Motion to Offer Exhibits into Evidence and Admit into the Record (Motion to Admit) pursuant to Commission Rules of Practice and Procedure 11.1, 13.8(a), 13.8(c) and the Administrative Law Judge's (ALJ) January 16, 2024 Ruling Modifying the Proceeding Schedule.[2] Through this Motion to Admit, CalCCA requests the Commission admit the following CalCCA exhibits[3] into the record of this proceeding:

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

[2] A.23-02-018, Administrative Law Judge's Ruling Modifying the Proceeding Schedule (Jan. 16, 2024).

[3] CalCCA notes certain of its discovery requests to PG&E remain pending (CalCCA Set 6 discovery requests to PG&E, issued on January 11, 2024). Following review of PG&E's responses to those discovery requests once received, CalCCA may identify one or more of those responses as hearing exhibits, and may seek to offer one or more of those hearing exhibits into evidence during the evidentiary hearing.

Exhibit No.	Sponsor/Witness	Exhibit Title and Date(s)	Link to E-Filing as Supporting Document
CalCCA-01	Shuey, Brian	Prepared Direct Testimony of Brian Shuey on Behalf of the California Community Choice Association, dated September 22, 2023	https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2302018/6977/523563443.pdf
CalCCA-01-C	Shuey, Brian	[Confidential] Prepared Direct Testimony of Brian Shuey on Behalf of the California Community Choice Association, dated September 22, 2023	N/A
CalCCA-02	PG&E / Stipulated	PG&E's Response to CalAdvocates MDR 108	https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2302018/6977/523565456.pdf
CalCCA-03	PG&E / Stipulated	Attachment to PG&E's Response to CalAdvocates MDR 108 (Appendix S to PG&E's Bundled Procurement Plan effective March 31, 2022)	https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2302018/6977/523557288.pdf
CalCCA-03-C	PG&E / Stipulated	[Confidential] Attachment to PG&E's Response to CalAdvocates MDR 108 (Appendix S to PG&E's Bundled Procurement Plan effective March 31, 2022)	N/A

In accordance with Rule 13.8, CalCCA's testimony was timely served on all parties on the service list. The public exhibits in the table above have been uploaded to the Commission's Supporting Documents website.

CalCCA's exhibits focus on Pacific Gas and Electric Company's (PG&E) Resource Adequacy (RA) activities during the summer of 2022, a time during which many of California's load-serving entities (LSEs) faced a capacity shortage. During that period, PG&E transferred nearly a gigawatt of excess RA capacity—capacity in excess of its bundled customers' RA compliance needs—from its Power Charge Indifference Adjustment (PCIA) resource portfolio to the System Reliability Incremental Procurement subaccount (Reliability OIR) of its New System Generation Balancing Account (NSGBA, recovered through the Cost Allocation Mechanism or

"CAM").[4] Decision (D.) 21-12-015, the Commission's Phase 2 Summer Reliability decision, allows PG&E to count its existing RA resources towards its incremental system reliability procurement targets (and transfer the corresponding capacity from the PCIA to CAM), but only after PG&E makes reasonable attempts to sell its excess RA capacity to other LSEs.[5] CalCCA witness Shuey identifies a substantial and unexplained gulf between the RA position reports that formed the basis for PG&E's RA sales solicitations in 2022 and the excess capacity PG&E ultimately transferred to CAM mere months later—which suggests PG&E did not make reasonable attempts to sell its excess RA capacity to other LSEs prior to counting that capacity toward its incremental system reliability procurement targets.[6] As witness Shuey notes, PG&E's attempts to sell excess RA have important implications for all LSEs, who faced a constrained RA market during the summer of 2022 and paid fines where they failed to meet RA compliance requirements.[7]

A key disputed issue in this proceeding, therefore, is whether PG&E indeed made reasonable attempts to sell its excess RA capacity to other LSEs in the summer of 2022 before counting that capacity towards its incremental system reliability procurement targets. PG&E's witness claims the utility did so, whereas CalCCA's witness Shuey argues PG&E did not.[8] The Commission, however, need not and should not resolve this substantive dispute between CalCCA

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[4] Pacific Gas & Electric Company Prepared Testimony at 12-15 (PG&E Prepared Testimony).

[5] Rulemaking (R.) 20-11-003, *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*, Phase 2 Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company to take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023, D.21-12-015 at 183-184 (permitting PG&E to count excess resources in its existing portfolios toward its incremental system reliability procurement targets "provided it has made reasonable attempts to sell this excess capacity to other LSEs").

[6] Prepared Direct Testimony of Brian Shuey on behalf of CalCCA at 5-7 (CalCCA Direct Testimony).

[7] *Id*. at 11-14.

[8] *Id*. at 4.

and PG&E at this stage of the proceeding; it will do so following the close of the record and the parties' submission of legal briefing. Instead, at this stage, the Commission need only determine the evidence that should be admitted to the record.

CalCCA's testimony should be admitted to the record because that testimony falls well-within the definition of "relevant evidence" under California Evidence Code section 210, which is evidence "having any tendency in reason to prove or disprove any disputed fact that is of consequence to the determination of the action."[9] The facts adduced in CalCCA's testimony tend to disprove the reasonableness of PG&E's attempts to sell its excess RA capacity in 2022 prior to transferring that capacity to CAM, which, again, is a disputed issue of consequence to this proceeding. More specifically, CalCCA's testimony is relevant to Scoping Issues 1, 3 and 5,[10] as the first page of that testimony explains.[11] Those Scoping Issues are as follows:[12]

- **Scoping Issue 1**: Whether PG&E, during the record period, prudently administered and managed, in compliance with all applicable rules, regulations and Commission decisions, including but not limited to Standard of Conduct No. 4 (SOC 4), the following:

  a. Utility-Owned Generation Facilities, except for the Elkhorn Battery Energy Storage System and Pit 1 Powerhouse outages which will be reviewed in the 2023 ERRA Compliance proceeding;

  b. Qualifying Facilities (QF) Contracts; and

  c. Non-QF Contracts

  If not, what adjustments, if any, should be made to account for imprudently managed or administered resources?

- **Scoping Issue 3**: Whether the entries recorded in the ERRA and the Portfolio Allocation Balancing Account are reasonable, appropriate, accurate, and in

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9 Cal. Evid. Code sec. 210.

10 A.23-02-018, Assigned Commissioner's Scoping Memo and Ruling at 2-3 (June 2, 2023) (Scoping Memo).

11 CalCCA Direct Testimony at 1-2.

12 Scoping Memo at 2-3.

compliance with Commission decisions.

- **Scoping Issue 5**: Whether PG&E administered resource adequacy procurement and sales consistent with its Bundled Procurement Plan.

With respect to Scoping Issue 1, CalCCA's testimony tends to prove PG&E did not prudently manage its RA resources (utility-owned generation (UOG) and contracted resources) during the record period. With respect to Scoping Issue 3, CalCCA's testimony tends to prove PG&E's RA-related entries recorded to the PABA are not appropriate or in compliance with Commission decisions. With respect to Scoping Issue 5, CalCCA's testimony tends to prove PG&E did not administer RA sales consistent with its Bundled Procurement Plan (BPP). CalCCA's testimony is therefore relevant to multiple scoping issues in this proceeding, is competent evidence in all other respects, and should be admitted to the record.

On October 6, 2023, PG&E filed a Motion to Strike portions of CalCCA witness Shuey's prepared testimony.[13] PG&E's Motion to Strike argues Mr. Shuey's testimony is irrelevant, out of scope, and unfairly prejudicial. CalCCA filed a Response opposing PG&E's Motion to Strike on October 23, 2023.[14] Far from being irrelevant to this proceeding as PG&E contends, Mr. Shuey's testimony *must be submitted* in this proceeding—there simply is no other proceeding in which the Commission might scrutinize whether PG&E's inadequate attempts to sell its excess RA capacity during the summer of 2022—a time of significant capacity scarcity—harmed customers.

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[13] A.23-02-018, Motion to Strike Portions of the Prepared Direct Testimony of Brian Shuey on behalf of the California Community Choice Association by Pacific Gas and Electric Company (U 39-E) (Oct. 6, 2023) (Motion to Strike).

[14] A.23-02-018, California Community Choice Association's Response to Pacific Gas and Electric Company's Motion to Strike (Oct. 23, 2023) (CalCCA Response to PG&E MTS). Because PG&E continues to take the position that portions of Mr. Shuey's testimony are irrelevant to this proceeding (*see* A.23-02-018, Joint Report of Meet and Confer by Pacific Gas and Electric Company (U 39 E), Public Advocates Office, and the California Community Choice Association at 3, 4 (Jan. 8, 2024)) CalCCA references PG&E's Motion to Strike in this Motion to Admit.

I. ARGUMENT

A. California Law Supports a Broad Interpretation of Relevancy.

In its Motion to Strike, PG&E claims portions of CalCCA's testimony related to the utility's management of its RA portfolio in 2022, including its attempts to sell excess RA capacity before counting that capacity towards its incremental system reliability procurement targets, are irrelevant to this proceeding.[15] PG&E does not so much as mention—let alone apply—the correct legal standard.

The California Evidence Code defines "relevant evidence" as evidence "having *any* tendency in reason to prove or disprove *any* disputed fact that is *of consequence* to the determination of the action."[16] That definition does not create a precise formula for relevancy.[17] Rather, California courts have held that evidence is relevant if it "logically, naturally and by reasonable inference tends to establish some fact."[18] Further, the definition of "relevant evidence" is "manifestly broad," and evidence is relevant "no matter how weak it tends to prove a disputed issue."[19]

Commission rules also support a broad interpretation of relevance to ensure CalCCA has a meaningful opportunity to rebut PG&E's evidence. Under Commission Rule 13.6 (a), California's "technical rules of evidence . . . need not be applied in hearings" before the Commission, and the Commission need not exclude evidence "merely by application of rules governing admissibility, competency, weight or foundation."[20] However, "the rights of parties to meaningfully participate

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15 Motion to Strike at 4-7.

16 Cal. Evid. Code sec. 210 (emphasis added).

17 *People v. Simms*, 10 Cal. App. 3d 299, 311 (1st Dist. Aug. 6, 1970).

18 *Id*.

19 *See, e.g. People v. Tauber*, 56 Cal. Rptr. 2d 656, 660 (4th Dist. Sept. 18, 1996).

20 Rule 13.6(a).

in the proceeding and to public policy protections shall be preserved."[21] CalCCA's testimony falls within the Commission's broad relevancy standard and should be admitted such that CalCCA can participate meaningfully in this proceeding.

B. CalCCA's Testimony Is Relevant To The Scope Of This Proceeding.

ERRA Compliance proceedings typically involve a review of the investor-owned utility's (IOU) RA activities during the record year. The facts of those activities, therefore, are facts of consequence to the Commission's determination of an ERRA Compliance proceeding.

In the instant proceeding, one of the specific issues of consequence to the Commission's determination is the reasonableness of PG&E's attempts to sell its excess RA capacity to other LSEs during the summer of 2022 prior to transferring that capacity to CAM. That issue is of consequence to three separate scoping issues in this proceeding: Scoping Issue 1, which generally asks whether PG&E prudently managed and administered its resources; Scoping Issue 3, which generally asks whether PG&E's accounting entries to the PABA were appropriate; and Scoping Issue 5, which generally asks whether PG&E complied with its BPP.

CalCCA's testimony scrutinizes PG&E's RA activities during the record year. CalCCA witness Shuey discusses the nearly one gigawatt of excess RA PG&E transferred from the PABA to the NSGBA over the course of five summer months;[22] the dramatic differences in PG&E's RA position between the time it made those transfers and the RA sales solicitations PG&E conducted just a few months prior;[23] PG&E's attempts (or lack thereof) to sell its excess RA to other LSEs;[24] the RA market constraints all LSEs face; and the implications of PG&E's failure to make

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[21] *Id*.

[22] CalCCA Direct Testimony at 3-4.

[23] *Id*. at 4-6.

[24] *Id*. at 6-11.

reasonable attempts to sell its excess RA to other LSEs.[25] Those facts collectively tend to disprove the reasonableness of PG&E's attempts to sell its excess RA capacity in 2022 prior to transferring that capacity to CAM and therefore CalCCA's testimony falls within the broad definition of relevance applied in Commission proceedings. The Commission should therefore admit CalCCA's testimony to the record.

1. CalCCA's testimony is relevant to whether PG&E prudently managed its RA portfolio (Scoping Issue 1).

Scoping Issue 1 of the *Assigned Commissioner's Scoping Memo and Ruling* asks "[w]hether PG&E, during the record period, prudently administered and managed the following, in compliance with all applicable rules, regulations, and Commission decisions, including but not limited to Standard of Conduct (SOC) 4: a) Utility-Owned Generation Facilities, except for the Elkorn Battery Energy Storage System and Pit 1 Powerhouse outages which will be reviewed in the 2023 ERRA Compliance proceeding; b) Qualifying Facilities (QF) Contracts; and c) Non-QF Contracts. If not, what adjustments, if any, should be made to account for imprudently managed or administered resources?"[26]

At a high level, Scoping Issue 1 requires the Commission to evaluate whether PG&E prudently administered and managed its generation portfolio (UOG and contracted resources) in 2022. As a part of that broad evaluation, the Commission must assess whether PG&E administered and managed its RA resources prudently. That prudence assessment, in turn, includes assessing whether PG&E made reasonable efforts to ensure it received value for all its RA resources, a key consideration in determining whether PG&E has prudently managed its generation portfolio.

The Commission applies several standards to assess the prudence of PG&E's management

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25 *Id*. at 11-14.

26 Scoping Memo at 2.

and administration of its generation portfolio, including SOC 4, the Commission's Good Utility Practice standard and the "reasonable manager" standard.[27] SOC 4 requires utilities to prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner.[28] The Commission has stated that prudent contract administration consistent with SOC 4 requires the utility "dispose of economic long power"—in other words, sell excess resources—among other activities.[29] In a similar vein, the "Good Utility Practice" standard requires utilities act consistent with:

> "[A]ny of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition."[30]

Lastly, the broad "reasonable manager" standard requires utilities act in a manner that "comport[s] with what a reasonable manager of sufficient education, training, experience and skills using the tools and knowledge at his disposal would do when faced with a need to make a decision and act."[31] Each of these standards permit the Commission to review whether the utility maximized the value of its RA resources for the benefit of its customers during the record period.

In addition, as referenced in Scoping Issue 1, the Commission must determine whether PG&E managed its resource portfolio in compliance with all applicable Commission decisions, including D.21-12-015. D.21-12-015 requires PG&E make reasonable attempts to sell its excess

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[27] *See, e.g.* A.19-05-007, D.20-12-036 at 9 (in SDG&E's 2018 ERRA Compliance proceeding, finding SDG&E complied with the Good Utility Practice and reasonable manager standards).

[28] D.02-10-062, Conclusion of Law 11 (Oct. 24, 2002).

[29] D.02-12-074 at 54 (Dec. 19, 2002); *see also* D.05-04-036 at 24.

[30] D.02-12-069, Attachment A at 5 (Dec. 19, 2002).

[31] D.90-09-088 at 499.

RA capacity to other LSEs before counting that capacity towards its incremental system reliability procurement targets.[32] PG&E's efforts to sell its excess RA during the summer of 2022 and realize the value of those resources for the benefit of its customers, therefore, is relevant to the assessment the Commission must make under Scoping Issue 1.

In its Motion to Strike, PG&E argues D.21-12-015 "does not create a separate or additional requirement beyond Appendix S" and asserts Appendix S "is the upfront reasonableness standard by which PG&E's compliance is measured for the management and sale of RA in this proceeding."[33] In support, PG&E points to Commission Resolution 4998-E approving Appendix S and the Commission's subsequent disposition of PG&E's Advice Letters 6306-E and 6306-E-A (collectively, "Appendix S Justification ALs"), claiming that disposition "affirms that Appendix S contains the CPUC-approved upfront reasonableness standard for conducting RA sales, including in connection with the Emergency Reliability OIR procurement orders."[34] In essence, PG&E suggests the Commission cannot scrutinize its RA sales activities during the record period in an ERRA Compliance proceeding beyond confirming PG&E complied with Appendix S.

PG&E overstates the effect of Resolution 4998-E and the Commission's disposition of the Appendix S Justification ALs. Nothing in Resolution 4998-E or the Commission's disposition of the Appendix S Justification ALs narrows the scope of ERRA Compliance proceedings or precludes parties (and the Commission) from investigating whether PG&E prudently managed its RA sales during the record period. Finally, even if the Commission's scrutiny of PG&E's 2022 RA activities in this proceeding were limited to confirming PG&E complied with Appendix S (and

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[32] D.21-12-015 at 183-184.

[33] Motion to Strike at 4.

[34] *Id*. at 6.

CalCCA does not agree it is), CalCCA's testimony is nevertheless relevant to the Commission's scrutiny of that issue (*see infra* I.B.3.).

Ultimately, PG&E's management of its generation portfolio—and specifically the efficiency of PG&E's sales of excess RA—directly contributes to the rates customers pay. That is because PG&E's sales of RA from its PCIA portfolio drive the quantity of Sold and Unsold RA it records, which in turn impacts PG&E's PABA balance—a key component of the PCIA rates PG&E's customers (bundled and unbundled) pay.[35]

In addition, the reasonableness of PG&E's attempts to sell excess RA has larger implications for other LSEs in its service territory, as CalCCA witness Shuey explains in his testimony. During the summer of 2022, LSEs faced a severely constrained RA market, which led to difficulty procuring sufficient RA to meet compliance obligations.[36] Under these market conditions, PG&E's efforts to maximize its sales of excess RA are especially relevant to whether PG&E prudently managed its resource portfolio—not only to lower costs to customers but also to ensure excess capacity is available to meet regional RA needs.

Finally, this is not only the appropriate proceeding for the Commission to review the prudence of PG&E's management of its RA portfolio during the summer of 2022—it is the *only* proceeding in which the Commission can do so. Section 454.5(d)(2) expressly permits the Commission to "establish a regulatory process to verify and ensure that each contract was administered in accordance with the terms of the contract[.]"[37] That process is the ERRA Compliance process. In an ERRA Compliance proceeding, parties can contest whether PG&E

[35] *See also infra* I.B.2., discussing the relevance of CalCCA's testimony to Scoping Issue 3.

[36] CalCCA Direct Testimony at 11-14.

[37] Cal. Pub. Util. Code § 454.5(d)(2).

followed SOC 4 and prudently managed its resources in making RA sales during the record year. Because the question involves actions PG&E should have taken, but did not pursue (*i.e.*, a retrospective review of PG&E's actions during the record year), the ERRA Compliance application and review process is the only available forum for parties to probe that question.

2. <u>CalCCA's testimony is relevant to whether PG&E's entries recorded in the PABA are reasonable, appropriate, accurate, and in compliance with Commission decisions (Scoping Issue 3)</u>

Scoping Issue 3 asks "[w]hether the entries recorded in the ERRA and the [PABA] are reasonable, appropriate, accurate, and in compliance with Commission decisions."[38] The Commission has broad latitude to consider PG&E's activities impacting those entries.

Among the myriad activities informing Scoping Issue 3 is PG&E's transfer of 923 MW of excess RA capacity from the PCIA to CAM in 2022, and associated accounting entries, which PG&E describes in its Prepared Direct Testimony.[39] The reasonableness of PG&E's attempts to sell excess RA during the summer of 2022 is well-within the scope of this proceeding because that issue ultimately impacts the entries PG&E made to its balancing accounts, including the Portfolio Allocation Balancing Account (PABA) during the 2022 record period. Those entries directly contribute to the rates PG&E's customers ultimately pay.

To be more specific, PG&E's attempts to sell its excess RA impact not only the magnitude of PG&E's credit to PABA resulting from the transfer of excess RA to CAM, but also the actual amount of RA capacity PG&E sold during the record year. Ultimately, PG&E's Actual Sold RA (compared to the amount of Sold RA it had forecasted it would sell) is a key factor driving whether an over- or under-collection exists in the PABA, which in turn drives the revenue requirement for

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[38] Scoping Memo at 2-3.

[39] PG&E Prepared Testimony at 12-15.

the following year's PCIA rates that PG&E's customers pay.[40]

The facts of PG&E's attempts to sell excess RA during the summer of 2022 therefore go to whether PG&E's PABA entries are "reasonable, appropriate, accurate, and in compliance with Commission decisions." Put differently, should the Commission find PG&E's attempts to sell its excess RA capacity were *not* reasonable, it might determine PG&E's PABA entries were not "reasonable, appropriate, accurate and in compliance with Commission decisions." CalCCA's testimony is replete with the facts of PG&E's attempts to sell excess RA during the summer of 2022, including (but not limited to) the following specific portions:

- At page 4, lines 2-11 of CalCCA witness Shuey's direct testimony, discusses the amount of excess RA that PG&E counted towards its incremental system reliability procurement targets between June and October 2022.
- At page 5, lines 4-13 of CalCCA witness Shuey's direct testimony, discusses the RA sales requirements in PG&E's BPP.
- At page 5, lines 14-19 of CalCCA witness Shuey's direct testimony, discusses PG&E's calculation of its RA position for the purposes of its RA sales solicitations.
- At page 6, lines 1-6 of CalCCA witness Shuey's direct testimony, summarizes PG&E's System RA Positions calculated for solicitations with delivery in 2022.
- At page 6, lines 6-11 of CalCCA witness Shuey's direct testimony, discusses the discrepancy between PG&E's Excess Resources Report and its RA Positions calculated for the purposes of RA sales solicitations.
- At page 6, line 12 to page 7, line 8 of CalCCA witness Shuey's direct testimony, discusses the timing of PG&E's RA sales solicitations, PG&E's preparation of an RA Position for the purposes of that solicitation, and PG&E's identification of excess RA capacity counted towards meeting incremental system reliability procurement targets.
- At page 7, lines 12-20 of CalCCA witness Shuey's direct testimony, discusses PG&E's responses to certain CalCCA discovery requests scrutinizing the attempts

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[40] PG&E's PCIA rates are set in the ERRA Forecast proceeding based on: (1) the Indifference Amount (the difference in the forecast year between the cost of PG&E's supply portfolio and the market value of that portfolio); and (2) the year-end balance in the PABA. The Indifference Amount and the year-end PABA over- or under-collection are added together to form the PABA revenue requirement underlying PCIA rates.

(or lack thereof) PG&E made to sell its excess capacity during the summer of 2022.

- At page 7, line 21 to page 8, line 6 of CalCCA witness Shuey's direct testimony, discusses the terms of PG&E's RA sales under its BPP.

- At page 8, line 7 to page 11, line 3, discusses RA offered for sale in each RA sales solicitation with delivery periods from June through October 2022, the bids PG&E received, as well as the outcomes of those solicitations.

- Attachment B (PG&E responses to CalCCA Data Requests) to CalCCA witness Shuey's direct testimony includes discovery responses addressing:

    - PG&E's sold, unsold and retained RA; its RA positions; and its operational constraints (PG&E response to CalCCA data request 1.08);

    - PG&E's evaluation of the bids it received in response to its RA sales solicitations (PG&E responses to CalCCA data requests 2.21 and 2.23);

    - PG&E's attempts to sell any portion of its excess RA capacity to any other LSEs prior to transferring that capacity out of PABA (PG&E response and supplemental response to CalCCA data request 2.54);

    - PG&E's receipt of offers from other LSEs to purchase any portion of its excess RA capacity (PG&E response to CalCCA data request 2.55);

    - PG&E's response to offers from other LSEs to purchase any portion of its excess RA capacity (PG&E response to CalCCA data request 2.56);

    - PG&E's efforts to make excess capacity available in RA solicitations before counting that capacity toward PG&E's incremental system reliability procurement target (PG&E response to CalCCA data request 2.57);

    - When PG&E knew it had excess RA capacity available (PG&E response to CalCCA data request 3.26);

    - Circumstances that caused changes to PG&E's RA position such that PG&E had excess RA capacity available for use to meet summer reliability needs in 2022 (PG&E responses to CalCCA data request 3.27, 3.33CONF, 4.14CONF, 4.15);

    - The System RA volumes PG&E offered for sale in its RA solicitations for delivery between June and October 2022 (PG&E response to CalCCA data request 3.31CONF); and

    - PG&E's efforts to communicate the availability of its excess RA capacity to other LSEs (PG&E response to CalCCA data request 3.28).

CalCCA's testimony is therefore relevant to Scoping Issue 3, and this, on its own, is sufficient to support the admission of CalCCA's testimony to the record.

3. CalCCA's testimony is relevant to whether PG&E administered resource adequacy sales consistent with its BPP (Scoping Issue 5)

Scoping Issue 5 asks "[w]hether PG&E administered resource adequacy procurement and sales consistent with its [BPP]."[41] Facts related to PG&E's RA sales in 2022—including PG&E's RA positions; the calculation of its RA positions; the timing of PG&E's calculation of its RA position; the timing and outcomes of its RA solicitations; and PG&E's attempts to sell its excess RA capacity—are each relevant to Scoping Issue 5, because those facts go to whether PG&E conducted RA sales consistent with Appendix S of its BPP. CalCCA witness Shuey's testimony adduces several of these facts, including in particular:

- At pages 5-7, discusses PG&E's System RA Positions calculated for each RA sales solicitation with delivery during 2022;
- At pages 7-11, discusses PG&E's attempts to sell excess RA capacity in 2022, including the timing of PG&E's RA solicitations; the RA volumes PG&E offered for sale by solicitation; and the bids PG&E received and rejected; and
- In Attachment B (PG&E's responses to CalCCA data requests), includes several of PG&E's responses to CalCCA data requests seeking information regarding the RA volumes PG&E offered for sale by solicitation (PG&E response to CalCCA data request 3.31CONF); PG&E's calculation of its RA position for the purposes of its RA sales solicitations (PG&E response to CalCCA data request 1.08); and the outcomes of PG&E's RA sales solicitations (PG&E responses to CalCCA data requests 2.21, 2.23, 2.55, 2.56 and 2.57).

While CalCCA witness Shuey does not reach a conclusion regarding PG&E's compliance with its BPP, the facts adduced in his testimony nevertheless inform the Commission's evaluation of Scoping Issue 5, and CalCCA may address PG&E's compliance with its BPP in legal briefing following further record development during the evidentiary hearing. CalCCA's testimony is therefore relevant to Scoping Issue 5, and this, on its own, is sufficient to support the admission of

41 Scoping Memo at 3.

CalCCA's testimony to the record.

C. The ALJ in SDG&E's 2022 ERRA Compliance case recently ruled that information related to SDG&E's excess RA sales was relevant to the scope of that case, and the Commission should not deviate from that Ruling here.

The evidentiary question before the Commission—whether CalCCA's testimony regarding PG&E's attempts to sell its excess RA during the summer of 2022 is relevant to the scope of this ERRA Compliance proceeding—mirrors a question that was recently resolved in San Diego Gas & Electric Company's (SDG&E) 2022 ERRA Compliance proceeding. As the table below demonstrates, Scoping Issues 1 through 3 of the SDG&E proceeding are exceedingly similar to Scoping Issues 1 and 3 of the instant proceeding:

<table>
<tr><th>Scoping Issue</th><th>A.23-02-018, PG&E 2022 ERRA Compliance proceeding[42]</th><th>Scoping Issue</th><th>A.23-06-002, SDG&E 20222 ERRA Compliance proceeding[43]</th></tr>
<tr><td rowspan="2">Scoping Issue 1</td><td rowspan="2">Whether PG&E, during the record period, prudently administered and managed, in compliance with all applicable rules, regulations and Commission decisions, including but not limited to Standard of Conduct No. 4 (SOC 4), the following:

a. Utility-Owned Generation Facilities, except for the Elkhorn Battery Energy Storage System and Pit 1 Powerhouse outages which will be reviewed in the 2023 ERRA Compliance proceeding;
b. Qualifying Facilities (QF) Contracts; and
c. Non-QF Contracts

If not, what adjustments, if any, should be made to account for imprudently managed or administered resources?</td><td>Scoping Issue 1</td><td>Whether SDG&E administered and managed its own generation resources prudently, to include the management of outages and associated fuel costs, according to Standard of Conduct ("SOC") 4</td></tr>
<tr><td>Scoping Issue 2</td><td>Whether SDG&E administered and managed its Qualifying Facility ("QF") and non-QF contracts for generation and power purchase agreements in accordance with the contract provisions and otherwise followed Commission guidelines relating to those contracts and their amendments according to SOC 4.</td></tr>
</table>

42 *Id*. at 2-3.

43 A.23-02-018, CalCCA Motion for Official Notice, Exhibit A at 2-3.

Scoping Issue 3	Whether the entries recorded in the ERRA and the Portfolio Allocation Balancing Account are reasonable, appropriate, accurate, and in compliance with Commission decisions.	Scoping Issue 3	Whether the entries recorded during the record year in the following accounts are correctly stated and in compliance with Commission directives: [. . .] b. Portfolio Allocation Balancing Account [. . .].

In the SDG&E proceeding, certain community choice aggregators (collectively, the Joint Community Choice Aggregators or "Joint CCAs") sought a ruling compelling SDG&E to produce information fully responsive to data requests seeking to scrutinize SDG&E's attempt to maximize its RA sales during the record period.[44] The Joint CCAs explained that between June and October of 2022, SDG&E relied on excess RA capacity from its existing resources to count toward its incremental system reliability procurement targets[45]—mirroring PG&E's treatment of excess RA during the summer of 2022. Joint CCAs asserted, therefore, that "[a]n important question for the Commission to consider in [SDG&E's 2022 ERRA compliance] proceeding is whether SDG&E should have offered more RA for sale in 2022 given this substantial excess RA capacity, *i.e.*, whether SDG&E prudently managed its portfolio during the record year that is the focus of this proceeding."[46] That question parallels the key disputed issue between CalCCA and PG&E in this proceeding: whether PG&E made reasonable attempts to sell its excess capacity to other LSEs during the summer of 2022 before transferring that capacity to CAM.

In order to help the Commission address that question in SDG&E's proceeding, the Joint CCAs issued data requests seeking information regarding SDG&E's RA solicitation materials, RA positions, and bid outcomes of SDG&E's sales of excess RA.[47] As the CCAs explained, SDG&E's

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44 A.23-02-018, CalCCA Motion for Official Notice, Exhibit B.

45 *Id.*, Exhibit B at 5.

46 *Id.*, Exhibit B at 6.

47 *Id.*, Exhibit B at 2-3.

attempts to maximize its RA sales "[go] directly to the heart of whether [SDG&E] prudently managed its generation portfolio during the 2022 compliance period. SDG&E's efforts in this regard ultimately impact the entries it made into its balancing accounts, including the [PABA], which is subject to a compliance review in this proceeding."[48] Similarly, here, CalCCA's testimony adduces facts regarding PG&E's attempts to sell its excess RA, including PG&E's RA positions and solicitations, because those facts go to whether PG&E prudently managed its resource portfolio (Scoping Issue 1); whether PG&E's entries to the PABA were appropriate (Scoping Issue 3); and whether PG&E complied with its BPP (Scoping Issue 5).

SDG&E objected to the Joint CCAs' data requests.[49] It contended any information regarding its attempts (or lack thereof) to sell excess RA was not relevant to its ERRA Compliance proceeding.[50] In response to the CCAs' motion to compel, while acknowledging intervening parties in an ERRA Compliance proceeding "may make a threshold inquiry as to whether SDG&E sold excess RA in the record year", SDG&E asserted intervenors "are not allowed to review or examine the specifics of those activities for the purposes of contesting their reasonableness."[51] SDG&E also argued it had already "justified its methodology for determining how much of its PCIA-eligible RA is reserved in its BPP" and the Commission "recently confirmed that SDG&E's methodology for determining how much of its [PCIA]-eligible RA is reserved in its BPP is reasonable."[52] SDG&E further argued its RA transactions in compliance with an approved BPP

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48 *Id.*, Exhibit B at 3.

49 *Id.*, Exhibit B at 6-7.

50 *Id.*, Exhibit B at 6-7.

51 *Id.*, Exhibit C at 12.

52 *Id.*, Exhibit C at 12-13.

are not subject to any additional "after-the-fact" reasonableness review.[53]

The substance of SDG&E's arguments echoes the substance of the arguments PG&E advances in this proceeding, even if the form of each utility's argument differs (*i.e.* SDG&E sought to deny Joint CCAs' the opportunity to review its RA activities by objecting to discovery, whereas PG&E seeks to deny CalCCA the opportunity to meaningfully dispute its RA activities by moving to strike portions of its testimony after objecting to discovery). Like SDG&E, PG&E argues CalCCA's data and arguments on PG&E's RA activities during the summer of 2022 "are not relevant to the scope of this proceeding";[54] asserts its BPP establishes an "upfront reasonableness standard" by which the Commission evaluates PG&E's RA sales;[55] and asserts the Commission's review of PG&E's RA activities during the record year is limited to a review of PG&E's compliance with its BPP.[56]

The ALJ in SDG&E's proceeding ruled in favor of the Joint CCAs. The Ruling concludes the Joint CCAs "showed that SDG&E's responses to [their] Data Requests are relevant to the scope of this proceeding."[57] Given the substantial similarity between: (1) the scope of this proceeding and the SDG&E proceeding, and (2) the evidentiary dispute before the Commission in each proceeding (*i.e.*, whether facts regarding the IOU's efforts to sell its excess RA during the record year are relevant to the scope of an ERRA Compliance proceeding), the Commission should not deviate from the ALJ's Ruling in SDG&E's proceeding. The Commission should admit CalCCA's testimony to the record.

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53 *Id.*, Exhibit C at 11.

54 Motion to Strike at 1.

55 *Id.* at 4.

56 *Id.* at 6-7.

57 A.23-02-018, CalCCA Motion for Official Notice, Exhibit D at 2-3.

II. CALCCA'S TESTIMONY IS NOT PREJUDICIAL TO ANY PARTY AND THEREFORE THE COMMISSION SHOULD ADMIT THAT TESTIMONY TO THE RECORD.

According to PG&E's Motion to Strike, Section V of CalCCA witness Shuey's testimony "impl[ies] that PG&E is responsible for 'substantial fines' incurred by Load Serving Entities", and asserts that testimony is "unfairly prejudicial to PG&E because it incorrectly implies that PG&E is a contributing cause to the LSE's RA compliance fines."[58] PG&E misrepresents Mr. Shuey's testimony. In the first sentence in Section V of his testimony, Mr. Shuey asserts PG&E's unreasonable attempts at selling its excess RA capacity "cannibalize[] an already constrained RA market and increase costs to all customers."[59] In the remaining portion of Section V, Mr. Shuey presents a series of (undisputed) facts illustrating RA market constraints.[60]

PG&E reads into Mr. Shuey's testimony an allegation that PG&E caused LSEs' RA compliance fines, but Mr. Shuey's testimony does not make that allegation. Moreover, to the extent Mr. Shuey's testimony demonstrates a relationship between PG&E's RA practices and fines paid by LSEs, PG&E fails to explain why that demonstration causes any "prejudicial impact" to PG&E, beyond its bare assertion that such an implication is "incorrect." PG&E had an opportunity to respond substantively to Mr. Shuey's description of the challenges that LSEs face related to the RA market in rebuttal testimony, but chose not to do so. The Commission should disregard PG&E's hollow claims that any portion of Mr. Shuey's testimony causes unfair prejudice to PG&E and admit CalCCA's testimony in its entirety.

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58 Motion to Strike at 8.

59 CalCCA Direct Testimony at 11.

60 *Id*. at 11-14.

III. CALCCA'S RECOMMENDATIONS ARE PROPER AND THEREFORE THE COMMISSION SHOULD ADMIT THAT TESTIMONY TO THE RECORD IN ITS ENTIRETY.

As discussed above, CalCCA's testimony is relevant to multiple scoping issues in this proceeding and therefore should be admitted to the record of this proceeding. Based on the facts adduced in his testimony, and his conclusions following from those facts, Mr. Shuey makes a series of recommendations to the Commission on the final page of his testimony, including that "PG&E's BPP should be updated to ensure excess capacity is made available to the market, either through refined adjustments to available capacity in RA position reports or through market offers outside of the scheduled solicitation process."[61]

PG&E moves to strike this recommendation, along with other related sections of Mr. Shuey's direct testimony, arguing that testimony seeks to "amend or relitigate the BPP[.]"[62] PG&E asserts the structure of the BPP can and should be litigated in the Integrated Resources Plan (IRP) proceeding, or in the IOUs' BPP-related advice letter filings, but modifications to that structure should not be considered in this proceeding.[63]

CalCCA agrees the Commission does not rewrite the structure of the BPP in ERRA Compliance proceedings. However, should the Commission determine that PG&E's RA-related actions warrant further scrutiny based on the record of this proceeding, it may direct—in this proceeding—revisions to the BPP to occur in a separate proceeding (which is the type of determination the Commission frequently makes in ERRA proceedings), such as the IRP proceeding.[64] Mr. Shuey's recommendations are therefore proper and his testimony should be

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61 *Id*. at 18.

62 Motion to Strike at 7-8.

63 *Id*. at 7.

64 *See, e.g.,* D.21-07-013, *Decision Resolving Phase One of Pacific Gas and Electric Company's*

admitted in its entirety.

Moreover, CalCCA's recommendations to the Commission are essentially requests for relief—they are not themselves facts. PG&E will have the opportunity to oppose CalCCA's requests for relief, or make alternate requests for relief, and explain the grounds for its position in legal briefing. The Commission should not, however, foreclose consideration of CalCCA's recommendations at this stage.

IV. CONCLUSION

For the reasons described in this Motion, CalCCA requests the Commission grant this Motion and admit CalCCA's exhibits into the record in their entirety.

Respectfully submitted,

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Dated: January 18, 2024

ERRA Compliance Application for the 2019 Record Year, A.20-02-009 (July 15, 2021), at 21 (emphasis added) (stating "The Commission's currently open proceeding, Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment, R.17-06-026, is more appropriate for considering how the Commission should address contract vintages for the utilities in the future, ***and we intend to explore these matters in that proceeding***.); D.20-12-028, at OP 4, 22 ("We recognize the importance of approving a consistent method for returning balances to customers but will not adopt PG&E's going-forward proposal at this time. We will consider a long-term solution when we address PCIA framework issues in the appropriate proceeding."); D.20-02-047 at 13-16 (resolving PG&E's 2020 ERRA Forecast case and stating "A tracking framework within PABA and mechanisms to value banked RECs at the end of the compliance period may help resolve these issues. These issues are however, more appropriately addressed by the Commission in the PCIA proceeding."); D.22-12-044 at 22; and D.22-12-012 at 61-62 (stating "… the current scope of the PCIA proceeding includes consideration of whether to modify or clarify the calculation of the PCIA for VAMO transactions, so we do not address SoCal CCAs' request here.").

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company and Pacific Generation LLC to Recover Helms Uprate Costs (U 39 E)	Application No. 23-12-014

PROTEST OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION TO APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY AND PACIFIC GENERATION LLC TO RECOVER HELMS UPRATE COSTS

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On behalf of
California Community Choice Association

January 22, 2024

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PROTEST OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION TO APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY AND PACIFIC GENERATION LLC TO RECOVER HELMS UPRATE COSTS

Pursuant to Rule 2.6 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the California Community Choice Association[1] (CalCCA) submits this protest to the *Application of Pacific Gas and Electric Company* (PG&E) *and Pacific Generation LLC To Recover Helms Uprate Costs* (Application).

Through this Application, PG&E is requesting approval to recover $462 million worth of capital investments in its Helms Pumped Storage Facility (Helms)[2]—a massive re-investment that would both increase the total nameplate generating capacity at Helms by 150-180 megawatts (MW) and extend the life of this asset for decades. The impact of this project would be substantial: it would replace nearly obsolete asset components and extend the useful life of the asset—currently set to end in 2026—by 38 years;[3] it would trigger the need for a Federal Energy Regulatory

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

[2] Application (A.) 23-12-014, *Application of Pacific Gas and Electric Company and Pacific Generation LLC To Recover Helms Uprate Costs (U 39 E)*, p. 2 (Dec. 20, 2023) (Application).

[3] *Id*., pp. 7, 11.

Commission (FERC) license amendment;[4] and it could necessitate the replacement or installation of substation and transmission related components.[5]

If approved, the costs associated with this project must be fairly allocated between PG&E's bundled and unbundled customers such that each customer set is only paying for those costs it caused PG&E to incur. CalCCA intervenes in this proceeding to further investigate PG&E's cost allocation proposal and ensure that it would not shift costs between bundled and unbundled customer groups. CalCCA respectfully requests the Commission set this matter for hearing to fully examine these issues identified thus far, as well as others that may arise during the course of the proceeding.

I. CALCCA'S INTEREST

CalCCA represents 24 community choice electricity providers in California, including 11 in PG&E's service territory.[6] Community choice aggregator (CCA) customers receive generation services from their local CCA, and receive transmission, distribution, billing, and other services from their investor-owned utility (IOU). As such, CCA customers in PG&E's service territory pay the same electric distribution, transmission, and non-bypassable charges (NBCs) as PG&E's bundled customers, including the Power Charge Indifference Adjustment (PCIA). CCA customers pay CCA-specific generation rates, which vary and are partially influenced by local mandates to procure and maintain clean electricity portfolios that in many cases exceed state requirements for renewable generation.

CCA customers have an interest in ensuring any approved cost recovery mechanism for the $462 million worth of costs at stake in this Application is just and reasonable and represents a

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4 *Id.*, p. 8.
5 *Id.*, p. 12.
6 *See supra* n. 1.

fair allocation between bundled and unbundled customers. PG&E is proposing to recover the above-market costs associated with the Helms Uprate Project through PCIA rates, via two separate PCIA vintages: the Legacy Utility-Owned Generation (UOG) Subaccount (for the costs associated with the existing capacity of Helms)[7] and a new vintage subaccount (for the costs associated with the proposed incremental capacity).[8] In this proposal, the costs would be allocated based on the proportion of generation capacity within each vintage.[9]

The Commission's determinations in this proceeding on cost recovery and allocation will directly impact the rates that CalCCA members' customers pay. CCA customers pay PG&E's PCIA rates, and subsets of CCA customers are assigned to different PCIA vintages in accordance with their date of departure from bundled service. Therefore, the Commission's conclusions on whether the costs associated with the Helms Uprate Project should be recovered via the PCIA, and if so, through which vintages, will dictate whether any subset(s) of CCA customers should pay for this significant capital investment.

CalCCA has an interest in ensuring the costs associated with the Application are properly categorized, and that the Application does not give rise to illegal cost shifts between bundled and unbundled customers. More broadly, CalCCA has an interest in ensuring the cost recovery mechanism approved for this Application is consistent with best practices for allocating costs associated with significant re-investments in UOG. For all these reasons, CalCCA has a real, present, tangible, and pecuniary interest in PG&E's proposals in this proceeding.

II. GROUNDS FOR PROTEST

This Application raises critical PCIA vintaging issues that have been at the center of

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7 Application, p. 15.
8 *Id*.
9 *Id*.

several Commission proceedings in recent years. The PCIA cost recovery approach for this Application has the potential to both increase the specific PCIA rates CCA customers pay and significantly impact the Commission's evolving vintaging policy for utility re-investments in UOG. CalCCA's review of PG&E's Application is ongoing, and CalCCA also reserves the right to analyze, address, and protest additional issues that may arise.

A. Background on PCIA Vintaging

California law prohibits cost shifts between groups of bundled and unbundled customers. In particular, Section 366.2 of the California Public Utilities Code provides that "[t]he implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation."[10] Similarly, Section 365.2 mandates that the Commission ensure both that bundled customers do not experience any cost increases as a result of other customers electing to receive service from other providers, and that "departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load."[11] The Commission generally refers to these requirements as a statutory mandate to ensure ratepayer indifference.[12]

The Commission's foundational policies on PCIA vintaging evolved out of these clear statutory directives prohibiting cost shifts between bundled and unbundled customers and requiring compliance with the indifference principle.[13] The Commission adopted the PCIA to ensure that when customers of IOUs depart from bundled service and receive their electricity supply from a non-IOU provider, such as a CCA, "those customers remain responsible for costs

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[10] Cal. Pub. Util. Code § 366.2(a)(4).
[11] Cal. Pub. Util. Code § 365.2. *See also id.* § 366.3.
[12] *See, e.g.*, Decision (D.) 16-09-044, p. 11.
[13] Cal. Pub. Util. Code § 366.2(a), (f); Cal. Pub. Util. Code §§ 365.2, 366.3.

previously incurred on their behalf by the IOUs — but only those costs."[14] Decision (D.) 08-09-012 provides the basis for the current cost responsibility policies for departing load customers, and specifically, the policies associated with vintaging IOU generation costs. The decision limits a departing load customer's cost responsibility to resource commitments made by the IOU up until the time of the customer's departure, finding that "departing customers should bear *no* cost responsibility for . . . commitments the IOU makes after their departure."[15] This directive helps ensure that each customer will "pay its fair share of the costs the IOU incurred on [its] behalf[,]" which "is an integral part of the principles of bundled customer indifference and prevention of cost-shifting."[16]

Based on these underlying principles, unbundled customers are assigned to a vintage year based on their departure date.[17] PG&E assigns each UOG resource to a specific vintage based on the year the generation resource commitment was originally made (*i.e.*, the original date of Commission approval of UOG construction), and all ongoing costs at that facility are recorded to the same initial vintage.

The PCIA rates ultimately paid by customers are derived from the utility's Indifference Adjustment, which is updated annually in each IOU's Energy Resource Recovery Account (ERRA) forecast proceeding. The Indifference Adjustment is the difference in the target year between the cost of the IOU's supply portfolio and the market value of the IOU's supply portfolio, as shown in the graphic below.

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

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

16 *Id.*, Finding of Fact 2.

17 *Id.*, Finding of Fact 38 and Conclusion of Law 14.

Figure 1: Indifference Calculation

Total Portfolio Cost includes the variable power supply costs, which are also determined in the IOU's annual ERRA forecast proceedings,[18] *plus* the UOG capital investment recovery and fixed maintenance costs determined in a general rate case (GRC).[19]

An Indifference Adjustment is calculated for each vintage, and customers are responsible for the cumulative costs included in all vintages prior to and including their assigned vintage year.[20] The total Indifference Adjustment is collected through PCIA rates, ensuring that PG&E receives full recovery of the generation-related revenue requirement approved in GRCs and other proceedings.[21]

In this Application, PG&E is requesting continued cost recovery via the Legacy UOG Vintage for most of the costs associated with Helms, and cost recovery via a new vintage only for the costs associated with the proposed incremental capacity. Since all CCA customers pay the Legacy UOG Vintage, this would result in all unbundled customers bearing the vast majority of

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[18] Variable power supply costs include purchased power such as that from power purchase agreements (PPAs), fuel costs for UOG and PPAs with tolling agreements, and California Independent System Operator (CAISO) grid charges and revenues, net of any sales.

[19] D.11-12-018, pp. 8-9.

[20] *Id.*, p. 9.

[21] Prior to D.18-10-019, the 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 unbundled customers. This true-up now occurs via the Portfolio Allocation Balancing Account (PABA), a rolling true-up between the forecasted Indifference Adjustment and the actual costs and revenues PG&E realizes during the year related to its PCIA eligible resource portfolio.

the costs associated with what essentially amounts to a re-procurement of an aging asset that would otherwise be nearing the end of its useful life.

B. The Commission Has Considered Establishing Clear Limits On Cost Recovery From An Asset's Original Vintage Assignment Across a Range of Proceedings.

Over the past several years, a range of Commission proceedings have begun to grapple with the question of how to best ensure that the IOUs' allocation of UOG costs to CCA customers is fair and consistent with these foundational principles of cost causation underlying the Commission's PCIA policy. Specifically, these cases have focused on the cost shifting that can occur when the IOUs undertake new investments in UOG and propose to allocate all associated costs to the asset's original vintage assignment.

The problem arises when utilities undertake new investments in older UOG assets on behalf of their current bundled customers, and propose to assign *all* future costs at that facility, *even these new investments that serve only bundled customers*, to the asset's original vintage. This approach means that even when an IOU decides to significantly reinvest in an older generation asset to extend the useful life of that asset, expand the capacity of that asset, or fundamentally change the function of the asset, *all* costs associated with these new investments are allocated to the asset's original vintage assignment. The result is that customers that have departed bundled service remain responsible for the costs associated with any and all expansions or extensions to UOG, in perpetuity, in violation of the Commission directive that "departing customers . . . bear no cost responsibility for . . . commitments the IOU makes after their departure."[22]

The CCAs have urged the Commission in the PCIA rulemaking and across all the IOUs' GRC proceedings to apply the Commission's foundational cost causation principles to these situations and recognize that certain types of significant new investments in UOG should be

[22] D.08-09-012, p. 59.

understood as *entirely new resource commitments* for purposes of PCIA vintaging.[23] This policy would be an extension of existing Commission precedent. For example, the Commission has endorsed this approach of reconsidering an asset's original vintage assignment in the context of power purchase agreement renewals/extensions and amendments.[24]

The Commission first acknowledged the validity of CCA concerns regarding the perpetual recovery of ongoing costs and re-investments in UOG in 2018, in D.18-10-019.[25] There, the Commission found that full or partial re-vintaging may be necessary under certain circumstances. Specifically, the Commission acknowledged:

> It is possible that new investments in an old power plant may represent such a significant overhaul of the facility as to justify a "re vintaging" of the facility. Likewise, it is possible that plant investments for certain upgrades may justify a different vintage treatment for those investments than for the underlying facility.[26]

The Commission concluded that "any such analysis must be fact-specific to the plants and spending in question."[27]

CCAs' vintaging recommendations in recent GRC proceedings were responsive to this directive. In these cases, the CCAs have argued that when a utility decides to re-invest in its older UOG to extend the life, expand the capacity, or change the function of the asset, that new investment should trigger a reconsideration of the default vintage assignment for the asset.[28] When

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[23] *See* D.18-10-019, pp. 134-135; D.23-11-069, pp. 508-511; A.22-05-015, *Opening Brief of SDCP and CEA*, pp. 10-35 (Aug. 14, 2023); A.23-05-010, *Protest of CPA and CalChoice to the Application of SCE*, pp. 5-7 (Jun. 14, 2023).

[24] *See* Resolution E-5095, p. 9 (Aug. 27, 2020) (approving Southern California Edison's re-vintaging of renewed contracts); Resolution E-4841, pp. 9-10 (May 11, 2017) (considering whether amendments to PPAs should result in re-vintaging, and concluding that because the amendments at issue did not affect material contract terms, such as price, re-vintaging was not appropriate (thus implying that changes to material contract terms may merit re-vintaging)).

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

[26] *Id*.

[27] *Id*.

[28] *See* D.23-11-069, pp. 508-511; A.22-05-015, *Opening Brief of SDCP and CEA*, pp. 10-35 (Aug. 14, 2023).

the IOU is undertaking those kinds of new investments on behalf of its bundled customers, those investments should be understood as new resource commitments for purposes of PCIA vintaging.

In response to this advocacy, in its final decision in PG&E's most recent GRC, the Commission ordered that in future GRCs, PG&E must justify its proposed vintaging treatment for UOG whenever it proposes to undertake certain new investments—new asset life extensions, incremental capacity additions, or changed functions—in any of its UOG assets.[29] The CCAs' arguments on these issues in the other IOUs' most recent GRCs are still under development and Commission review.

C. The Commission Must Ensure That The Costs Associated With This Investment In Helms Are Allocated In Line With Cost Causation.

This Application implicates these same issues surrounding cost allocation for sizable new investments in UOG. PG&E's proposal to allocate the vast majority of the costs associated with this massive investment in Helms to all bundled and unbundled customers via the Legacy UOG Vintage assignment must be thoroughly scrutinized in this proceeding.

PG&E proposes to recover the above-market costs associated with the Helms Uprate Project through the Legacy UOG Subaccount (for the costs associated with the existing capacity of Helms)[30] and a new vintage subaccount (for the costs associated with the proposed incremental capacity).[31] This would result in all bundled and unbundled customers paying for approximately 89 percent of these project costs.[32]

Requiring unbundled customers to pay for the bulk of these project costs may not be appropriate given the magnitude of this project and PG&E's objectives in undertaking it. The

[29] D.23-11-069, p. 511.
[30] Application, p. 15.
[31] *Id*.
[32] *See* A.23-12-014, *PG&E Prepared Testimony*, at 4-10:28 to 4-11:3 (Dec. 20, 2023) (Testimony).

relevant principle in determining the appropriate PCIA cost recovery is that customers should pay their "fair share of the costs the IOU incurred on [their] behalf"; they should not, however, be charged for costs *not* incurred on their behalf.[33] The Application makes clear that PG&E is undertaking this substantial project—which will both increase the capacity of Helms by approximately 15 percent and extend its useful life for 38 years[34]—in order to serve various needs of its bundled customers. PG&E explains that the project will help fulfill bundled customers' clean energy and reliability requirements generally,[35] and specifically, that it will help satisfy certain Local Area capacity requirements.[36] Thus PG&E has noted that the project is geared toward serving these bundled customer needs, and has specifically claimed that "the Uprate will be an important resource in PG&E's future bundled portfolio."[37] Allocating most of the associated project costs to *all* customers—including unbundled customers—seems inconsistent with these explanations.

The Application also raises the question of how cost allocation should be impacted by the fact that, through this Uprate Project, bundled customers will be able to benefit from low cost incremental capacity that is only available *because* of the initial Helms investment—an investment shouldered by all unbundled customers. Bundled customers only have access to this low cost procurement option because of CCA customers' investments to date in Helms. The Commission should consider whether unbundled customers should receive some form of compensation for bundled customers' avoided procurement costs associated with this incremental capacity.

PG&E attempts to justify its proposed PCIA treatment by claiming this new investment

33 D.08-09-012, Finding of Fact 2.
34 Application, pp. 4, 7.
35 Testimony at 3-13:17-18.
36 *Id*. at 3-16:13 to 3-18:8.
37 *Id*. at 3-15:13-14.

will "not only secure the reliability and energy needs of its bundled customers, but also . . . support important systemwide state policy and planning objectives."[38] PG&E requests a Commission finding that the project "provides additional, non-quantifiable benefits to the State, including through diversification of the energy storage capacity portfolio."[39] These amorphous "statewide" benefits referenced throughout the Application and testimony necessitate further review.[40] For example, PG&E's suggestion that the uprated Helms asset's ability to satisfy or backstop Commission procurement orders should be understood as an important contribution to *state* policy goals[41] does not square with the fact that PG&E generally only procures generation assets on behalf of its *bundled* customers—a fact that PG&E itself acknowledges repeatedly in testimony.[42] CalCCA intends to further investigate PG&E's justifications for its proposal to recover the majority of project costs via the Legacy UOG vintage to ensure that PG&E is only charging CCA customers for costs actually incurred on their behalf.

III. CATEGORIZATION OF PROCEEDING, NEED FOR HEARINGS, AND PROPOSED PROCEDURAL SCHEDULE

CalCCA supports categorization of the proceeding as "ratesetting" and agrees hearings may be needed.[43]

In place of PG&E's proposed schedule, CalCCA recommends the following in order to allow parties and the Commission adequate time for discovery and review of PG&E's extensive testimony:[44]

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38 Application, p. 4.
39 *Id*., pp. 32-33.
40 *See Id*., pp. 18, 32-33.
41 *Id*., pp. 3-5, 17-18; Testimony at 3-8:2 to 3-13:15.
42 Testimony at 3-13:16 to 3-14:4.
43 Application, p. 24.
44 *Id*., pp. 25-26.

Activity	PG&E Proposed Date	CalCCA Proposed Date
Prehearing Conference	January 31, 2024	Mid-February 2024
Scoping Memo	February 7, 2024	February 29, 2024
Intervenor Testimony	February 28, 2024	May 15, 2024
Rebuttal Testimony	March 20, 2024	June 28, 2024
Evidentiary Hearings	April 17, 2024	Week of July 22, 2024
Opening Briefs	May 1, 2024	August 23, 2024
Reply Briefs	May 22, 2024	September 13, 2024
Proposed Decision	By August 20, 2024 [Rule 14.2(a)]	End of October 2024
Opening Comments on Proposed Decision	September 9, 2024 [Rule 14.3(a)]	In accordance with Rule 14.3
Reply Comments on Proposed Decision	September 16, 2024 [Rule 14.3(d)]	In accordance with Rule 14.3
Final Decision	First Voting Meeting Following September 16, 2024	End of November 2024

IV. COMMUNICATIONS

CalCCA consents to "email only" service and requests that the following individuals be added to the service list for A.23-12-014 on behalf of CalCCA:

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V. CONCLUSION

For the foregoing reasons, CalCCA requests the Commission set this matter for hearing to fully examine the preliminary issues discussed above.

Respectfully submitted,

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January 22, 2024

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 THE PROPOSED DECISION ADOPTING 2023 PREFERRED SYSTEM PLAN AND RELATED MATTERS, AND ADDRESSING TWO PETITIONS FOR MODIFICATION

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January 30, 2024

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SUMMARY OF RECOMMENDATIONS

California Community Choice Association (CalCCA) supports the Proposed *Decision Adopting 2023 Preferred System Plan and Related Matters, and Addressing Two Petitions for Modification* (Proposed Decision), with the following limited comments and a request for clarification:

- ✓ The Final Decision should resolve the Proposed Decision’s inconsistent documentation of Community Choice Aggregator Integrated Resource Planning (IRP) plan certifications;
- ✓ The Proposed Decision’s procurement encouragement provides welcomed clarifications on the future of IRP procurement;
- ✓ The California Public Utilities Commission (Commission) should adopt the Proposed Decision’s 25 million metric tons Core portfolio and High Gas Retirement sensitivity;
- ✓ The Commission should adopt long lead time resource procurement process outlined in the Proposed Decision; and
- ✓ The Commission should authorize funding for continued consulting support in IRP as specified in the Proposed Decision.

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 THE PROPOSED DECISION ADOPTING 2023 PREFERRED SYSTEM PLAN AND RELATED MATTERS, AND ADDRESSING TWO PETITIONS FOR MODIFICATION

The California Community Choice Association (CalCCA)[1] submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[2] on the proposed *Decision Adopting 2023 Preferred System Plan and Related Matters, and Addressing Two Petitions For Modification*[3] (Proposed Decision), mailed January 10, 2024.

I. INTRODUCTION

CalCCA supports the Proposed Decision, which was issued after extensive effort by load serving entities (LSEs) to develop their individual integrated resource planning (IRP) plans,

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1 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

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

3 Proposed *Decision Adopting 2023 Preferred System Plan and Related Matters, and Addressing Two Petitions For Modification*, Rulemaking (R.) 20-05-003 (Jan. 1, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M523/K201/523201875.PDF.

important work by Energy Division to conduct the modeling and planning activities necessary to develop the preferred system plan (PSP), and engagement by stakeholders to thoroughly vet the results. The outcome of these efforts is a PSP that will keep the state on track to meet its reliability and climate goals through 2035.

The Proposed Decision also provides much needed clarifications on the structure of future procurement directives that may come from the Commission. There is room for further clarification by expeditiously developing the reliable and clean power procurement program (RCPPP), so that LSEs have certainty about the procurement framework they will need to comply with going forward.

Finally, the Proposed Decision extends the compliance deadline for long lead time (LLT) resource procurement, allowing LSEs more time to fulfill LLT procurement requirements without compromising on the capacity needed in the interim. This extension recognizes that maintaining the current deadline could negatively impact customer affordability and adopts a preemptive solution that addresses current market constraints and potential project delays without disadvantaging LSEs that can meet the current deadline.

In summary, CalCCA supports the Proposed Decision, with the following limited comments and a request for clarification:

- ✓ The Final Decision should resolve the Proposed Decision’s inconsistent documentation of Community Choice Aggregator (CCA) IRP plan certifications;
- ✓ The Proposed Decision’s procurement encouragement provides welcomed clarifications on the future of IRP procurement;
- ✓ The Commission should adopt the Proposed Decision’s 25 million metric tons (MMT) Core portfolio and High Gas Retirement sensitivity;
- ✓ The Commission should adopt the LLT resource procurement process outlined in the Proposed Decision; and

- ✓ The Commission should authorize funding for continued consulting support in IRP as specified in the Proposed Decision.

II. THE PROPOSED DECISION SHOULD BE ADOPTED WITH CLARIFICATIONS

A. The Final Decision Should Resolve the Proposed Decision's Inconsistent Documentation of CCA IRP Plan Certifications

The Proposed Decision lists CCA IRP plans that are "certified" and "not yet certified" in Table 1, section 2.5.2, Ordering Paragraph (O¶) 5, and O¶ 6.[4] There are inconsistencies in the list that appears in Table 1 compared to the lists that appear in the rest of the document. The Final Decision should ensure consistency between Table 1, section 2.5.2, O¶ 5, and O¶ 6 so that it is clear which CCA IRP plans are certified, and which are not yet certified.

B. The Proposed Decision's Procurement Encouragement Provides Welcomed Clarifications on the Future of IRP Procurement

The Proposed Decision encourages LSEs to continue to conduct timely procurement of the resources identified in their IRP plans.[5] Along with its encouragement, the Proposed Decision makes two important pieces of information clear:

First, the Proposed Decision states:

> We do not require strict compliance with the plans, since we understand that plans can change, particularly over a period of a decade or more, and that pricing may be different in actual bids than anticipated ahead of time.[6]

Second, the Proposed Decision affirms:

> We state affirmatively that procurement conducted in advance of the adoption of a programmatic approach will be counted towards the LSE's obligations under whatever program is adopted. In addition, if the Commission needs to adopt any more "interim" procurement orders, new resources procured and built will also count towards any incremental requirements of the individual LSEs and that the

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[4] Proposed Decision Table 1, section 2.5.2, O¶ 5, and O¶ 6.
[5] *Id.* at 43-44.
[6] *Id.* at 43.

> procurement baseline will not be further updated from the baseline for D.21-06-035.[7]

CalCCA agrees with the Commission that “steady and continued addition of clean energy resources to the electric system will be required by all LSEs”[8] to meet grid reliability targets and green-house gas (GHG) emissions reduction goals. To do this in the most orderly, reliable, and cost-effective manner, LSEs require flexibility to adjust their plans to account for new and better information that becomes known closer to the planned year, such as forecasts, estimated resource costs, transmission costs, interconnection costs and timelines, etc. They also need certainty that the procurement they do now will benefit them when it comes to compliance with future IRP procurement orders and procurement programs. For these reasons, CalCCA supports these two important clarifications provided in the Proposed Decision.

While CalCCA welcomes these important clarifications, the Commission should continue to move forward with the development of the RCPPP expeditiously. A clearly defined procurement framework will help ensure LSE procurement balances reliability, GHG-reduction, and customer affordability through orderly and predictable procurement as opposed to ad hoc procurement orders.

C. The Commission Should Adopt the Proposed Decision’s 25 MMT Core Portfolio and High Gas Retirement Sensitivity

The Commission should adopt the Proposed Decision’s O¶s 10 and 11, which adopt the 25 MMT Core portfolio as the PSP and transmits it to the California Independent System Operator (CAISO) for use in its 2024-2025 Transmission Planning Process (TPP) as the reliability and policy-driven base case portfolios.[9] The 25 MMT Core portfolio maintains GHG and reliability targets through 2035 and considers the preferences of LSEs expressed in their

7 *Id.* at 44.
8 *Id.* at 43.
9 *Id.* O¶s 10 and 11.

individual IRPs.[10] CalCCA applauds the Commission for adopting a portfolio that will keep the state on track with its climate and reliability goals.

The Commission should also adopt the Proposed Decision's O¶ 12 transmitting the High Gas Retirement sensitivity as a policy driven sensitivity portfolio to the CAISO for it to analyze in its 2024-2025 TPP.[11] As noted in the Proposed Decision, planning for potential future natural gas plant retirements is an important step for California to meet its Senate Bill 100[12] requirements and GHG emissions reduction goals.[13] The ability to reduce reliance on natural gas-powered resources will depend on the ability to reliably serve load in local areas in other ways, either through transmission expansion or new resource development. The Proposed Decision recognizes the CAISO's ability to do a granular and detailed analysis of local reliability needs through the study of this sensitivity.[14] Such work is necessary to begin identifying the most cost-effective and feasible solutions that will result in a combination of new resources and new transmission needed to reduce operations of natural gas capacity in local areas. For these reasons, the Commission should adopt the Proposed Decision's High Gas Retirement sensitivity for transmittal to CAISO for its 2024-2025 TPP cycle.

D. The Commission Should Adopt LLT Resource Procurement Process Outlined in the Proposed Decision

The Proposed Decision adopts an extension for the LLT resource procurement obligation ordered in Decision (D.) 21-06-035[15] in response to a petition for modification filed by the

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10 *Id.* at 67.
11 *Id.* O¶ 12.
12 Senate Bill (SB) 100, (Stats. 2018, Ch. 312)
13 Proposed Decision at 76.
14 *Id.* at 77.
15 D.21-06-035, *Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026)*, R.20-05-003 (issued June 30, 2021): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF.

California Energy Storage Alliance and the Western Power Trading Forum.[16] To support its conclusion that an extension is warranted, the Proposed Decision states:

> We find it legitimate for the LSEs to seek extensions on the basis of high, non-competitive, or unreasonable pricing in the bids received in their solicitations. Our intent was never to require procurement of LLT resources at all costs, which must be borne by ratepayers, but rather to encourage their development on a reasonable and steady timetable.

CalCCA applauds the Commission for recognizing that regulatory decisions can impact customer affordability and for considering preemptive solutions to address the current market constraints and potential project delays.

The Proposed Decision structures the extension such that LSEs that utilize the extension must procure the balance of its unmet LLT requirements through generic resource adequacy capacity procurement that otherwise meets the requirements of D.21-06-035. LSEs that meet their LLT procurement requirements by June 1, 2028, and therefore do not utilize the extension, would not have to procure additional capacity to meet their LLT requirement.

The Commission should structure the extension as outlined in the Proposed Decision, as it allows LSEs more flexible timelines to fulfill LLT procurement requirements, without compromising on incremental capacity needed in the interim. It also does not disadvantage LSEs that do not require an extension. Several LSEs have made significant progress on their LLT resource procurement obligations, while others may require more time. Those who remain on track to meet their 2028 compliance deadline should not have their procurement requirements modified. For these reasons, the Commission should adopt the LLT resource procurement process as outlined in the Proposed Decision.

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[16] Proposed Decision at 96-98.

E. The Commission Should Authorize Funding for Continued Consulting Support in IRP as Specified in the Proposed Decision

The Proposed Decision authorizes an additional $18 million in consulting funds over the next six years to fund consulting that supports the IRP process.[17] CalCCA supports this authorization. The IRP proceeding necessarily relies heavily on resource-intensive planning activities and modeling to identify the resource portfolios and associated infrastructure needed to support a reliable, affordable, and decarbonized grid.

III. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

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

January 30, 2024

[17] Proposed Decision at 107.