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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

Evelyn Kahl,
General Counsel and Director of Policy
Lauren Carr,
Senior Market Policy Analyst
Eric Little,
Director of Regulatory Affairs

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94520
Telephone: (510) 980-9459
E-mail: regulatory@cal-cca.org

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SUMMARY OF RECOMMENDATIONS

- 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]

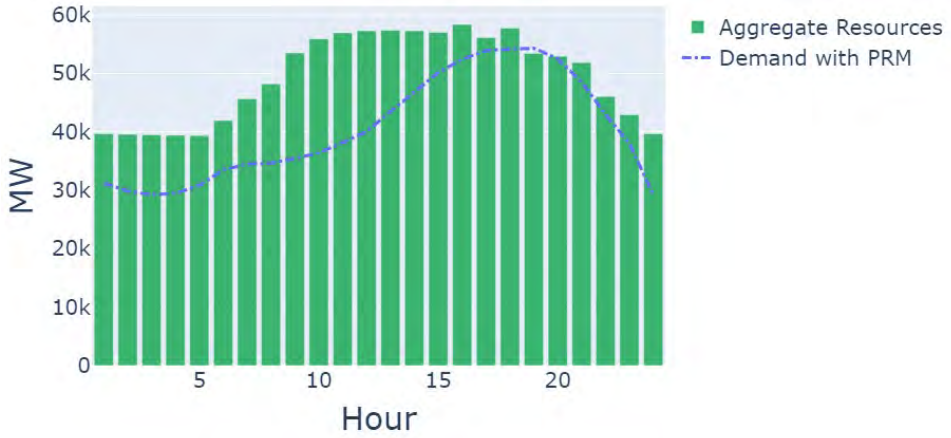
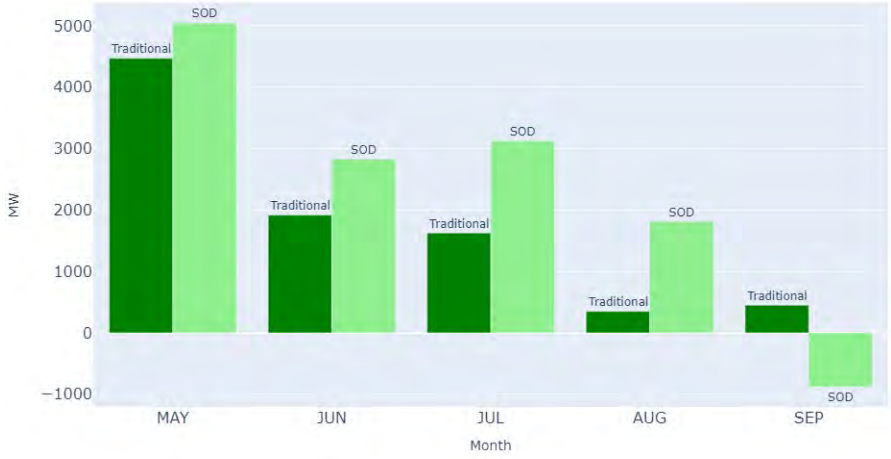


Figure 2 demonstrates how net supply changes from the traditional RA program to the new SOD program. Net supply in September, the most challenging month from an RA compliance perspective, is made worse by switching to SOD.

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.

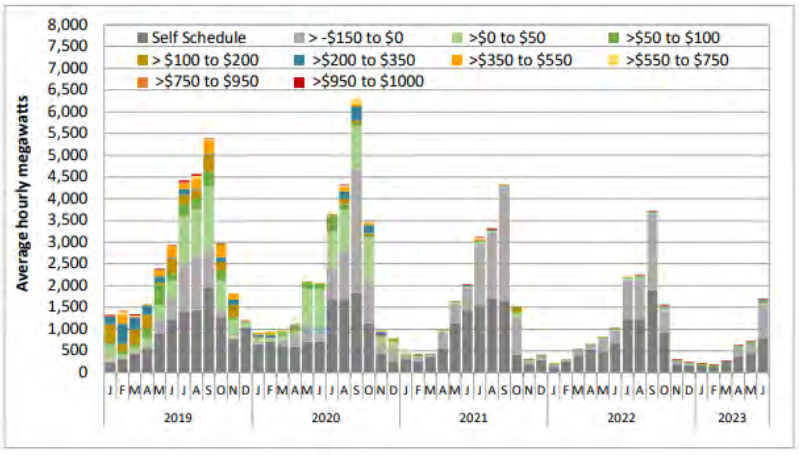
[16] *Id.*

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



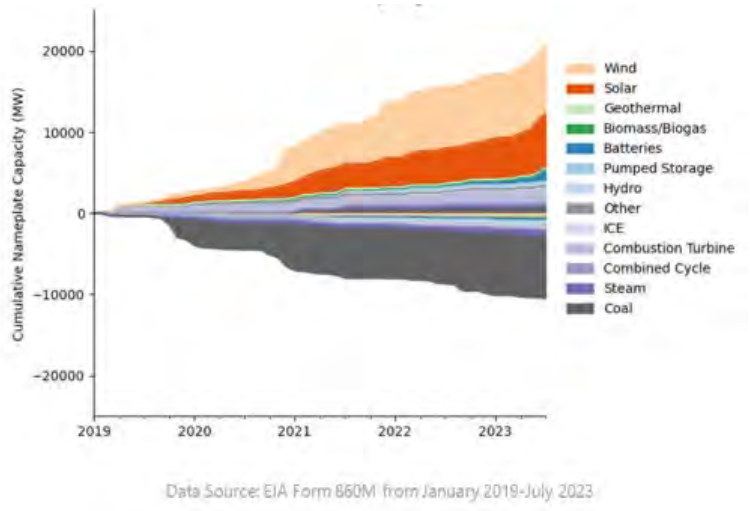
<u>*Second*</u>, LSEs' experiences in the market demonstrate suppliers' unwillingness to transact RA with Commission-jurisdictional LSEs under the current rules. While the Commission's intent with D.20-06-028 was to prevent speculative supply, there is no evidence to conclude that the decline in shown 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

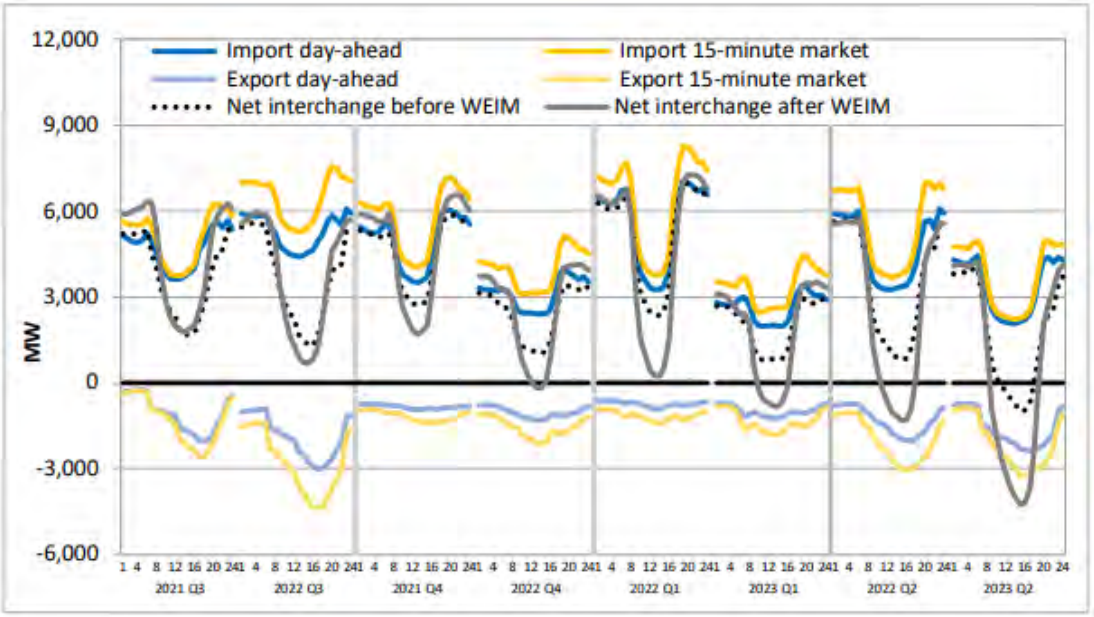


As this shift has occurred, other BAAs have recognized the need to ensure sufficient capacity is available to serve their load through forward commitments and have begun implementing their own RA programs. The Western Resource Adequacy Program (WRAP) had its first non-binding RA showing in October 2022 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

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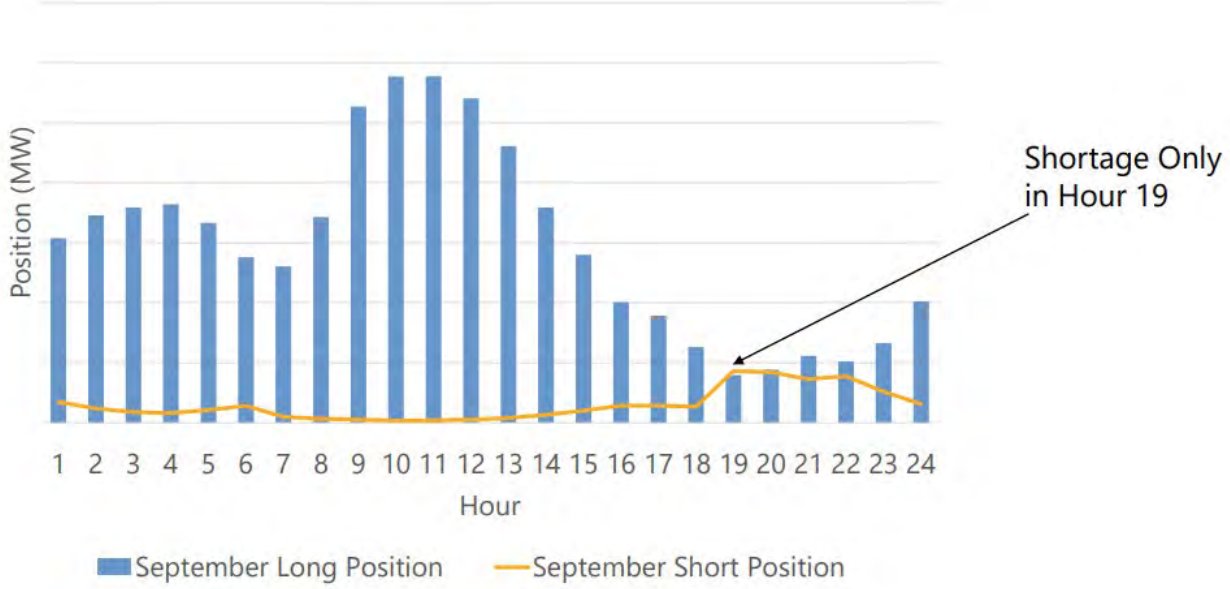
30 D.22-06-050, *Decision Adopting Local Capacity Obligations for 2023-2025, Flexible Capacity Obligations for 2023, and Reform Track Framework*, R.21-10-002 (June 23, 2022), at 55: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540633.PDF.

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.

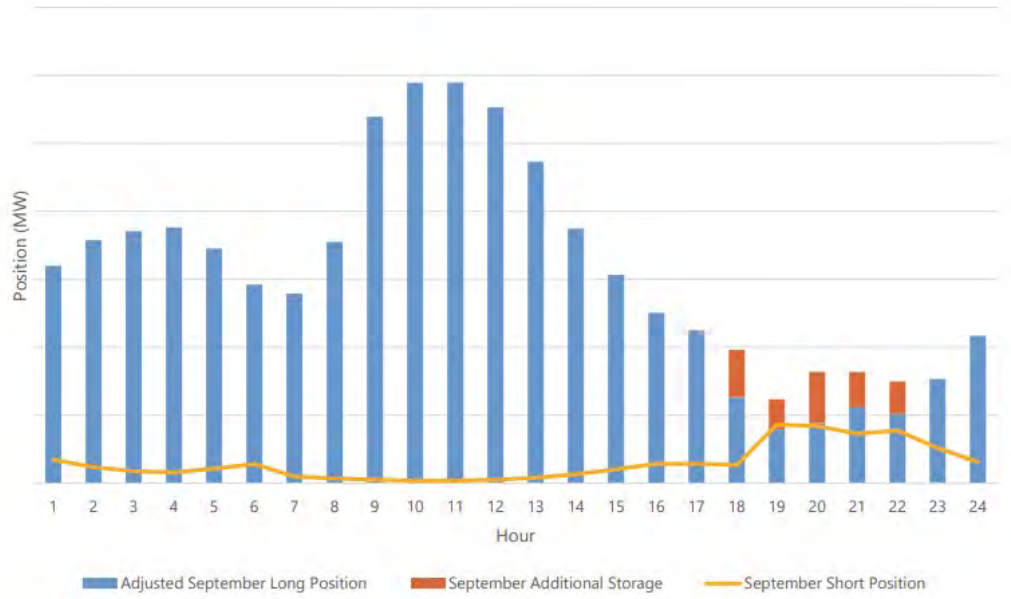
Figure 6 - Aggregate CCA Short and Long SOD Positions for September, As Filed



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,
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.

[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.

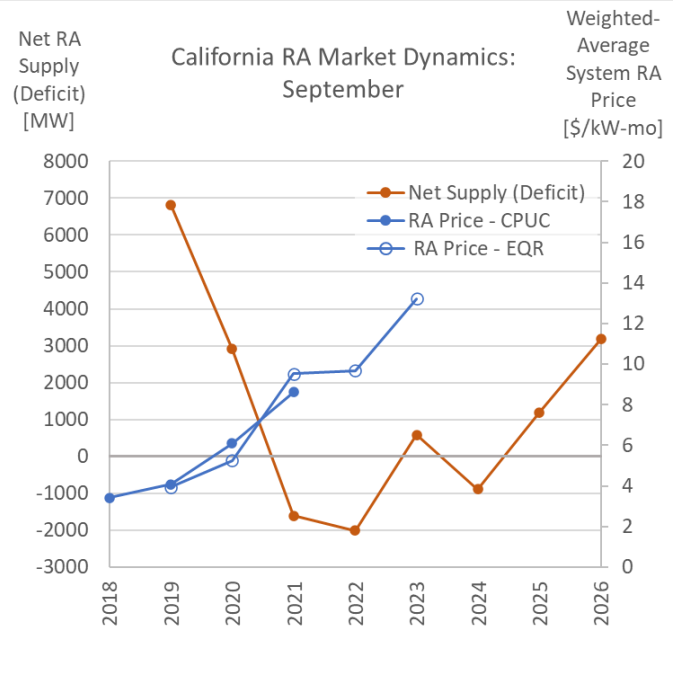
Figure 1

	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.

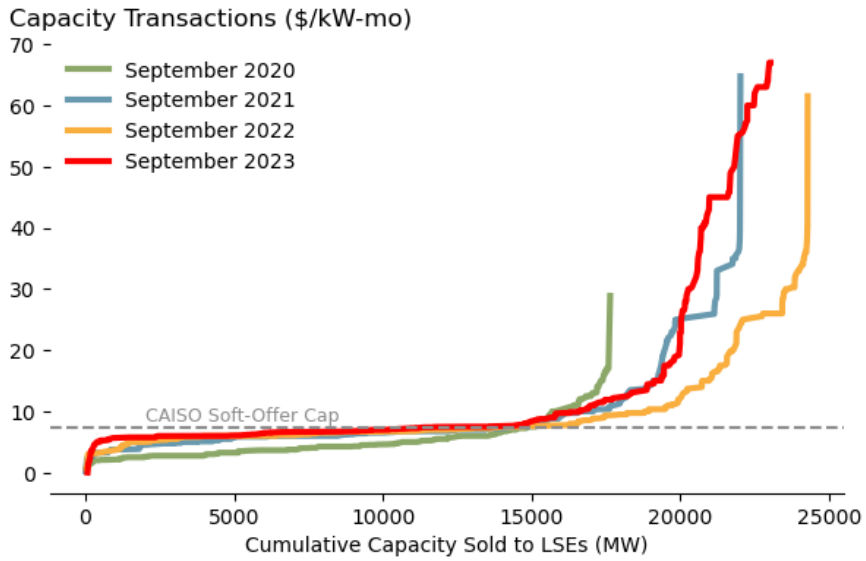
Figure 2



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 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)

CALCCA
ADVANCING LOCAL ENERGY CHOICE

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.

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[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.

[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.

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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.

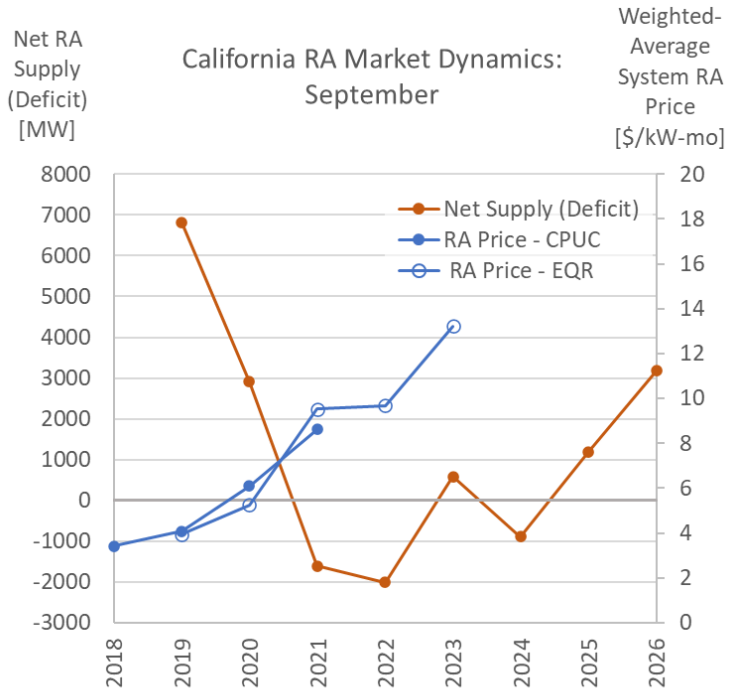
7. The Shortage of RA has Capacity Prices at All Time Highs

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.

[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.

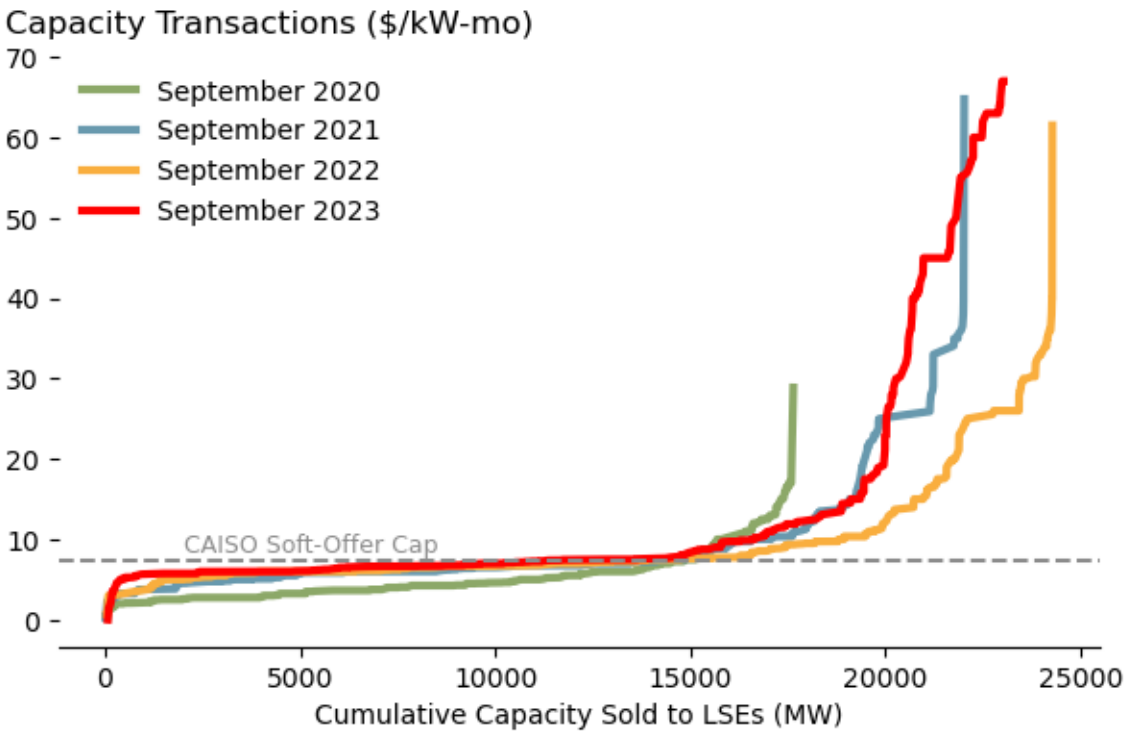
Figure 4



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

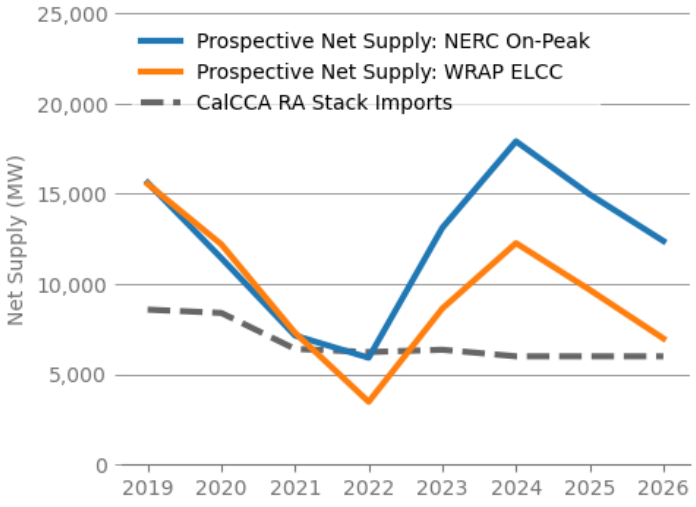
totals for each WECC sub-region. NERC's long-term reliability assessments (released in December each year) provide ten-year projections of loads and resources.

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.

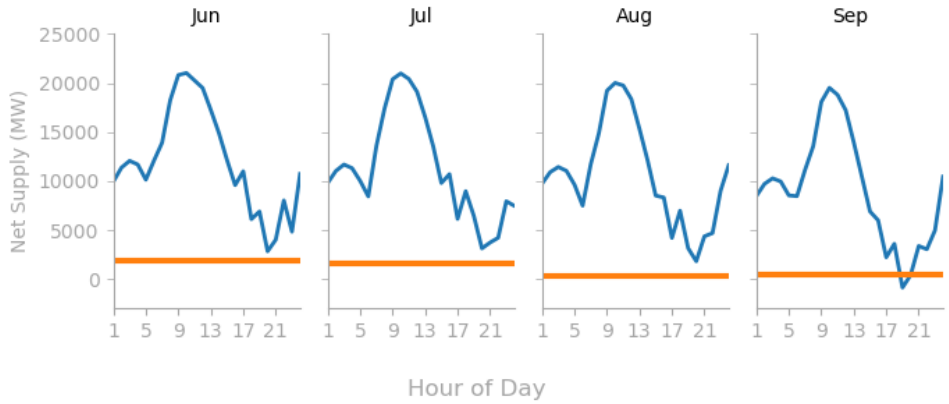
Whether the net supply surplus in the Non-CA WECC region returns to its 2019 levels depends on the capacity accreditation of solar. Using WRAP ELCC values for solar and wind capacity accreditation reduces the net supply surplus by 5.6 GW relative to the surplus calculated with NERC On-Peak values in 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

[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.

/s/ Deb Emerson
Deb Emerson