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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.21-10-002

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S PROPOSALS IN RESPONSE TO ASSIGNED COMMISSIONER'S AMENDED SCOPING MEMO AND RULING

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

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

- The California Public Utilities Commission (Commission) should modify the local Resource Adequacy (RA) central procurement entity (CPE) structure to provide more certainty to load-serving entities:
    - The Commission should revise the hybrid CPE timeline adopted in Decision 22-03-034 to lock in CPE procurement after year two;
    - The Commission should require the CPE to provide additional information in its annual compliance reports to improve transparency; and
    - The Commission should modify the local capacity requirement - reduction compensation mechanism to enhance the incentives to self-show.
- The Commission should modify the import RA rules to attract additional RA capacity to California:
    - The Commission should revisit the requirement that import RA be from a firm energy import; and
    - The Commission should allow RA imports to bid up to a maximum bid price based upon estimated costs of the typical marginal resource.

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California Community Choice Association[1] (CalCCA) submits these proposals in response to the *Assigned Commissioner's Amended Scoping Memo and Ruling*[2] (Ruling), dated September 2, 2022, on the Implementation Track Phase 3 Schedule (excluding FCR and LCR Issues).

I. INTRODUCTION

Resource Adequacy (RA) procurement for RA compliance year 2023 has revealed two major issues that the California Public Utilities Commission (Commission) must address in the Implementation Track Phase Three of this proceeding. First, the hybrid local RA central procurement entity (CPE) structure has introduced an unworkable level of uncertainty for load serving entities (LSEs) and does not result in the right incentives to show or sell to the CPE.

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

2 *Assigned Commissioner's Amended Scoping Memo and Ruling*, Rulemaking (R.) 21-10-002 (Sept. 2, 2022) (Ruling): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M496/K684/496684932.PDF.

Second, the RA market is extremely scarce and the Commission must begin taking steps now to expand the availability of the existing resource fleet to serve California load as RA. CalCCA makes the following proposals in response to these issues, which are described in detail in sections II and III below:

- The Commission should revise the hybrid central procurement entity (CPE) timeline adopted in Decision (D.) 22-03-034 to lock in CPE procurement after year two;
- The Commission should require the CPE to provide additional information in its annual compliance reports to improve transparency;
- The Commission should modify the Local Capacity Requirement Reduction Compensation Mechanism (LCR-RCM) to enhance the incentives to self-show;
- The Commission should revisit the requirement that import RA be from a firm energy import; and
- The Commission should allow RA imports to bid up to a maximum bid price based upon estimated costs of the typical marginal resource.

The Commission must address these issues promptly to avoid repeating the challenging 2023 RA procurement environment created by the hybrid CPE framework and the scarcity in the RA market.

II. THE COMMISSION SHOULD MODIFY THE LOCAL RA CPE STRUCTURE TO PROVIDE MORE CERTAINTY TO LSES

A. Background

D.20-06-002 established a hybrid CPE structure in the Pacific Gas and Electric (PG&E) and Southern California Edison Company (SCE) areas.[3] The hybrid CPE structure requires PG&E and SCE, as the CPEs, to procure all of the local RA requirements in their areas while individual load-serving entities (LSEs) retain their system and flexible requirements. The CPE

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[3] D.20-06-002, *Decision on Central Procurement of the Resource Adequacy Program,* Rulemaking (R.) 17-09-020 (June 11, 2020): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M340/K671/340671902.PDF.

can meet its obligations by (1) purchasing bundled RA from LSEs or generators and allocating the system and flexible attributes to LSEs, or (2) receiving "self-showings" in which the LSE shows the local attribute of a resource to the CPE while retaining the system and flexible attributes for itself. LSEs that self-show preferred or energy storage resources are compensated at the local RA premium, which currently ranges from $0.00 per kilowatt (kW) /month to $1.48 per kW/month.[4]

In adopting the hybrid CPE structure, the Commission rejected a residual CPE structure advanced in a settlement agreement among community choice aggregators (CCAs), an investor-owned utility (IOU), an electric service provider (ESP), and several generators.[5] The residual CPE structure would have enabled LSEs, at their option, to continue to procure RA resources to meet their share of system, flexible, *and* local RA requirements. The RA CPE would then have the responsibility to procure for the residual procurement obligation after RA resources are "shown" by LSEs to the RA CPE.

In its November 2021 Annual CPE Compliance Report, the PG&E CPE indicated that it was up to 53.4 percent short of its local obligation for RA year 2023,[6] even though the multi-year local RA requirements adopted in D.19-02-022 require 100 percent of the local RA requirement to be met two years forward.[7] In response to the PG&E CPE shortfall, the

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4 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/lcr-rcm-2022.pdf.

5 *Joint Motion of California Community Choice Association, Calpine Corporation, Independent Energy Producers Association, Middle River Power, LLC, NRG Energy, inc., San Diego Gas & Electric Company (U 902-E), Shell Energy North America (US) L.P., and Western Power Trading Forum for Adoption of a Settlement Agreement for a "Residual" Central Procurement Entity Structure for Resource Adequacy*, R.17-09-020 (Aug. 30, 2019).

6 Advice 6386-E-A, Supplemental: Pacific Gas and Electric Company ("PG&E") Central Procurement Entity ("CPE") Annual Compliance Report (Nov. 19, 2021) at Attachment 1 – PG&E CPE Aggregate Procurement Summary for the 2023 and 2024 RA Compliance Years: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6386-E-A.pdf.

7 D.19-02-022, *Decision Refining the Resource Adequacy Program*, R.17-09-020 (Feb. 21, 2019).

Commission modified the CPE timeline in D.22-03-034 to allow the CPEs until mid-August 2022 prior to the RA year to complete its procurement, leaving LSEs with less than two months between receiving their obligations and the year-ahead filings made on October 31, 2022.[8] Still, the PG&E CPE was up to over 40 percent short of its 2023 local obligation in its September 2022 Annual CPE Compliance Report and PG&E deferred this shortfall to the California Independent System Operator (CAISO) for potential backstop. The PG&E CPE was also up to 40 percent short of its local obligation for 2024, indicating the uncertainty experienced for 2023 procurement will continue through 2024 without reform to the CPE structure.[9]

B. Challenges with the Existing Hybrid CPE Structure

It is clear following the 2023 local RA procurement and compliance processes that the hybrid CPE structure as implemented presents two major challenges. First, it leaves LSEs with substantial uncertainty in their system and flexible RA procurement. Second, under current market conditions, the framework does not provide incentives to LSEs to show their local RA resources.

Allowing CPEs to procure local RA through mid-August prior to the compliance year leaves uncertainty in LSEs' system and flexible RA compliance. When the CPE procures bundled RA supply, it allocates system and flexible RA supply to LSEs in proportion to their load share. Consequently, LSEs must procure only the amount of system and flexible RA not received through CPE or Cost Allocation Mechanism (CAM) allocations. If the CPE is permitted to procure into the August before the compliance year, LSEs remain in the dark about

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8 D.22-03-034, *Decision on Phase 1 of the Implementation Track: Modifications to the Central Procurement Entity Structure*, R.21-10-002 (Mar. 17, 2022): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M460/K580/460580209.PDF.

9 Advice Letter 6706-E, Pacific Gas and Electric Company ("PG&E") Central Procurement Entity ("CPE") Annual Compliance Report 2022 Annual Compliance Report (Sept. 19, 2022) at Attachment A – PG&E CPE Aggregate Procurement Summary (2022 PG&E CPE Compliance Report): https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6706-E.pdf.

the amount of system and flexible allocations they will receive from the CPE. Because LSEs do not receive allocations from self-shown resources, only from resources bought by the CPE, it is not possible for LSEs to assume the amount of allocation they will receive in advance. For example, the 2023 local requirement for the PG&E area was 11,056 megawatts (MW). Had the PG&E CPE procured its total requirements, LSEs could have received anywhere from 0 MW to 11,056 MW of total allocations depending on how much of the 11,056 MW were self-shown versus purchased. The fact that the PG&E CPE was up to over 40 percent short of its 2023 local obligation further exacerbates this uncertainty over the amount of credits LSEs can expect to receive. LSEs have only one to two months before their own year-ahead showings to shore up supply in response. This timeline is unacceptably short given it is not possible for LSEs to reasonably predict their allocations.

In addition to the uncertainty the CPE framework creates, the hybrid CPE structure does not provide sufficient incentive to LSEs to sell or self-show their local RA to the CPE. LSEs may show their unbundled local RA to the CPE while maintaining their system and flexible RA for compliance. While the Commission intended to structure incentives to encourage this self-showing, the incentives are absent under the current market conditions. Scarcity in the system RA market has intensified in recent years, making it critically important for LSEs to maintain their system and flexible RA rather than bidding them to the CPE. Moreover, there is no clear benefit to an LSE who elects to show its local RA to the CPE. Financial benefits through the LCR RCM are virtually non-existent. The most recent LCR-RCM, which is based on the delta between system and local RA resources, currently ranges from $0.00 per kW/month to $1.48 per kW/month and only applies to new preferred or storage resources.[10] It appears increasingly

[10] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/lcr-rcm-2022.pdf.

likely that LSEs would not receive compensation for resources they self-show to the CPE given the combination of the lack of a premium price and the application of the LCR-RCM to a subset of resources in the local area.[11] The LCR-RCM is not available to all resources in the local area, only to new preferred or energy storage resources. If an LSE self-shows another type of resource, it would not receive any compensation even if there were a local RA premium in the local area.

Given the CPE procurement results and flaws in the hybrid CPE structure, the Commission must take steps now to further refine the local RA CPE framework. These revisions should provide LSEs with more certainty further in advance about the amount of local RA the CPE has procured on their behalf and enhance the self-showing incentives to improve the CPE's ability to meet its local RA obligations.

C. A Residual CPE Structure Avoids the Shortcomings of the Hybrid CPE Structure

CalCCA continues to support the residual CPE model proposed in the Settlement over the hybrid CPE model adopted by the Commission. The residual CPE model would enable LSEs, at their option, to procure RA resources to meet their share of system, flexible, *and* local RA requirements. After LSEs complete procurement of their share of the three requirements, the RA CPE would then have the responsibility to procure for the residual procurement obligation after RA resources are "shown" by LSEs to the RA CPE. LSEs that defer procurement to the CPE would then have costs allocated to them for their share of procurement done by the CPE on their

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[11] As recently as 2019, the RA report showed weighted average system RA prices of $3.46/kW-month. In September 2022, the Commission issued its calculation of market price benchmarks for the Power Charge Indifference Adjustment (PCIA) with both a true-up for 2022 at $8.11/kW-Month, and a 2023 forecast at $7.39/kW-month. Each of which represents a more than a 100 percent increase in the cost of RA in just three years. Because system RA is scarce, so is the local RA premium. In addition, the PCIA market price benchmarks for 2022 show both on a final 2022 and a forecast 2023 basis that local RA is transacting at a discount to system.

behalf. The residual CPE structure avoids the shortcomings of the hybrid CPE structure. This is because it differs from the hybrid structure in that it:

- Removes uncertainty for LSEs by allowing them to conduct their procurement first, with the option to defer to the CPE and have CPE procurement costs allocated to those who defer;
- Obviates the need for a self-showing process because LSEs that hold local RA could use it towards their own share of the local requirement or sell it to the CPE;
- Aligns with the statutory requirement that the Commission permit CCAs to maximize their self-procurement;[12] and
- Retains a CPE to shore up RA procurement to the extent necessary.

The only remaining issue – leaning – may not be solved by the residual method; however, this issue should not be the sole driver for an RA compliance framework. Therefore, the Commission should reconsider its rationale behind rejecting the residual model. The Commission rejected the residual model in part on the basis that without further breaking down local areas based upon resource effectiveness at addressing the local transmission contingencies, the residual procurement would result in leaning. That is, entities would procure the least expensive and least effective resources and be provided full credit for meeting local RA. Those that did not procure would then be forced to pay higher prices through the CPE and thus the procuring LSEs would lean on the CPE to procure the better resources.

In the local area procurement for 2023, despite the CPE in the PG&E area being up to 40 percent short of the local obligation, the CAISO has yet to issue any notice of backstop procurement. While the CAISO may be waiting for the monthly showings, it is also possible that the CAISO did not find a local deficiency because in their efforts to meet the system obligations, LSEs showed sufficient local resources to meet the CAISO's needs even though those LSEs chose not to self-show to the CPE. Given the current market conditions in which local is not

[12] Cal. Pub. Util. Code § 380(b)(5), (h)(5).

trading at a premium to system, those LSEs did not incur costs specific to a local value that others should have incurred. Under these conditions then, it appears that leaning is not an issue.

While leaning may not be an issue at the present time, the difficulties faced by LSEs in the obligations that they take on by self-showing a resource (e.g. constraining their portfolio flexibility in the month it was shown in the Year-Ahead process) are real and can provide incentive for LSEs to not self-show.

D. The Commission Should Revise the Hybrid Local RA CPE Structure to Enhance the Timeline, Transparency, and Incentives

Should the Commission continue to forego a residual CPE model in favor of the hybrid CPE model, the Commission must at minimum consider timeline, transparency, and incentive enhancements proposed in sections II.D., 1-3. These enhancements will ensure the hybrid CPE model does not significantly disrupt the RA procurement of LSEs, does not prolong uncertainty in the amount of system and flexible RA credits LSEs will receive, and does not lack proper incentives to self-show to the CPE.

1. The Commission Should Revise the Hybrid CPE Timeline Adopted in D.22-03-034 to Lock in CPE Procurement After Year Two

Given the uncertainty created by the existing timeline, the Commission should modify the timeline to move up the CPE's final showing requirement by one full year. In other words, the CPE would make its final showing two years – rather than the current two months -- in advance of the compliance year, consistent with the 100 percent local RA requirement for year two.[13] For example, for compliance year Y, the CPE would complete its local procurement by mid-August Y+2 rather than mid-August Y+1. The Commission should require CPEs to finalize

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[13] It is worth noting that it is possible for the Local RA need to change year to year. If there is an increase of Local RA need after Y+2, it is reasonable to allow the CPE to procure only for this incremental need. Based upon history, the change in Local RA needs is typically small and such incremental procurement by the CPE will have minimal impact on LSE allocations.

their procurement in year 2 beginning for RA compliance year 2025. This change would result in the following deadlines:[14]

Local RA CPE Timeline Assuming RA Year 2025

- **April-May 2023:** The CAISO files draft and final Local Capacity Requirement (LCR) one- and five-year ahead studies. The LCR studies will include any CAISO-approved transmission upgrades from the Transmission Planning Process LCR study. Parties file comments on draft and final LCR studies.

- **No Later Than Mid-May 2023:** LSEs in SCE and PG&E transmission access charge (TAC) areas make self-shown commitments of local resources to the CPE for the applicable RA years.

- **No Later than June 2023:** The Commission adopts multi-year local RA requirements for the applicable compliance years as part of its June decision.

- **No Later Than Early July 2023:** CPE receives total jurisdictional share of multi-year local RA requirements for the applicable compliance years.

- **July 2023:**

  - For the SCE and PG&E TAC areas, LSEs receive initial RA allocations, including CAM credits from CPE-procured system and flexible capacity from the prior year and any bilateral contracts.

  - For the San Diego Gas and Electric Company (SDG&E) TAC area, LSEs receive initial RA allocations (system, flexible, local requirements) and CAM credits.

- **Mid-August 2023:** CPE makes local RA showing to the Commission.

- **End of August 2023:** LSEs in the SCE and PG&E TAC areas receive updated CAM credits for multi-year system/flexible capacity that was procured by the CPE as a result of the CPE's multi-year local RA showing to the Commission in Mid-August.

- **September 2023:**

  - For PG&E and SCE's TAC areas, LSEs are allocated final year-ahead system and flexible RA allocations, including CAM credits from CPE-procured system and flexible RA capacity based on revised year-ahead load forecast load ratios.

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[14] The timeline described here follows the format for the CPE including the changes made in D.22-03-034 and simply moves the deadlines forward one year. If necessary, the Commission may consider pushing the due dates for CPE procurement to late September, as adopted in D.20-06-002, or December 31st each year. Doing so would provide additional time for the CPE to complete their process but still afford the LSEs sufficient forward notice of their allocations.

    - For the SDG&E TAC area, LSEs receive final RA allocations (system, flexible, local requirements) and CAM credits.

- **End of October 2023:**
    - LSEs in the SDG&E TAC make system, flexible, and three-year local RA showing.
    - LSEs in PG&E and SCE TACs make year-ahead system and flexible showings, and provide justification statements, if applicable, for local resources not self-shown or bid to the CPE.
    - The CPEs and LSEs that committed to self-show make year-ahead showing to CAISO.

- **November 1, 2023:** Annual CPE Compliance Report

This timeline would reduce LSE uncertainty but not completely eliminate it. This is because the CAISO assesses the need for backstop year ahead only and, therefore, LSEs will be uncertain about the allocations they will receive from CAISO backstop when doing their procurement. Still, it is a significant improvement to the 2023 timeline because it allows LSEs to conduct their own system and flexible procurement knowing their CPE allocations.

Because the Commission will not issue the June 2023 Decision on these proposals in time to follow this proposed timeline for RA year 2024, the Commission should direct the CPE to stop procurement upon issuance of the June 2023 Decision and allocate CPE credits by the end of June 2023. This would provide LSEs with two more months than they had for RA year 2023 to finalize their 2024 system and flexible RA procurement. While not ideal, any small improvements for RA year 2024 are worthwhile as the Commission transitions to the timeline proposed here for RA year 2025.

2. The Commission Should Require the CPE to Provide Additional Information in Its Annual Compliance Reports to Improve Transparency

D.22-03-034 took positive steps toward improving the transparency of CPE procurement by requiring CPEs to include the following information in their Annual Compliance Reports:

- Total local Resource Adequacy (RA) allocation for the CPE from the Commission;
- Total local demand response (DR) resources allocated for the CPE by the Commission;
- Total local Cost Allocation Mechanism resources (non-DR) applied towards CPE requirements;
- Total local resources procured by the CPE;
- Total load-serving entity self-shown local resources;
- Net total position associated with the CPE;
- Total capacity of preferred resources that were bid or shown to the CPE;
- Total capacity of preferred resources selected and not selected by the CPE; and
- Total capacity of MW procured by the CPE from generation facilities located in Disadvantaged Communities.[15]

Additionally, D.22-12-028 encouraged parties to submit proposals that would provide additional transparency on CPE procurement efforts to "help LSEs understand the local RA capacity that is not shown or not offered to the CPE."[16] The Commission should require the following additions to the Annual Compliance Report reporting requirements adopted in D.22-03-034:

- If any offers or self-showings were not selected by the CPE, why were they not selected (price, inability to negotiate contract terms, other); and

- Total Net Qualifying Capacity (NQC) of local RA not offered or self-shown.

These additional data points will help provide a more comprehensive view of CPE procurement efforts, including why the CPE did not opt to procure resources offered to it and how much

15 D.22-03-034, Ordering Paragraph (O¶) 17.

16 D.22-12-028, *Decision Denying Petition for Modification of Decision 22-03-034 by California Community Choice Association*, R.21-10-002 (Dec. 15, 2022), at 10.

capacity that could have provided RA was not offered to the CPE. In order to be useful, the CPEs must provide this information along with the timeline changes proposed in section II.D.1 above. Otherwise, it will be provided too late to be useful.

3. The Commission Should Modify the LCR-RCM to Enhance the Incentives to Self-Show

As described in section II.B., the current LCR-RCM has been ineffective because: 1) it is not available to all resources in the local area, and 2) the amount paid is based upon a local premium which was very low in 2022 and expected to be low or non-existent in 2023. The Commission should recognize that a self-showing of a local resource places constraints upon an LSE portfolio. Once an LSE self-shows a resource as local, the LSE must show that resource in each month-ahead showing for which it was shown in the year-ahead self-showing. This means that the resource is no longer available in the LSEs portfolio for sales or substitution of another resource if needed. Taking on such an obligation and placing constraints on an LSEs portfolio without compensation is not realistic. While the Commission developed the LCR-RCM to compensate LSEs for buying resources that they theoretically procured at a premium or that had a premium value due to their location, it is also important to compensate the LSEs for the constraints it places on their portfolio.

To address this disincentive to self-show, the Commission should allow self-shown resources that are either not receiving the LCR-RCM or who choose to forfeit the LCR-RCM to self-show without the current restrictions placed upon the self-showing LSE which require the self-showing LSE to show the resource in all months. Based upon the fact that the CAISO has not performed any backstop, it would appear the year-ahead showing process provided sufficient local area resources even though they were not shown by LSEs to meet a local obligation in the SCE and PG&E areas. It appears that the CAISO is relying upon its ability to backstop after the month-ahead process if those resources shown in the year-ahead process are not available in the month-ahead showing.

Allowing LSEs to self-show without taking on significant incremental obligations could result in more self-showing. This would then give a better indication year-ahead on the contractual status and likely availability of local area resources as the CPE completes its local procurement obligation.

III. THE COMMISSION SHOULD MODIFY THE IMPORT RA RULES TO ATTRACT ADDITIONAL RA CAPACITY TO CALIFORNIA

D.20-06-028 modified eligibility rules for imported resources under the Commission's RA program. Previously non-resource-specific RA imports could bid up to the bid cap in the day-ahead market and had no further obligation to bid into the real-time market if not scheduled in the day-ahead market. The decision modified the bidding requirements for non-resource-specific imports to count towards RA such that the energy from non-resource-specific imports must be bid in at levels between negative $150/ megawatt-hour (MWh) and $0/MWh or self-scheduled into the CAISO day-ahead and real-time markets at least during the availability assessment hours.[17] While the information is not publicly available, CalCCA suspects that the changes to the import rules, combined with the changing face of the Western market, has made it more difficult for LSEs to procure import RA. To maximize the availability of imports to the RA program, the Commission should modify the bid price for the must-offer requirement.

A. Background

Non-resource-specific imports, imports that are not associated with a specific resource or dynamically scheduled, are eligible under the Commission's RA program. Unlike other imports,

[17] D.20-06-020, *Decision Adopting Resource Adequacy Import Requirements*, R.17-09-020 (June 25, 2020), at O¶ 2: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF.

however, non-specific resources must bid into the CAISO day-ahead market and into the real-time market *only if scheduled in the day-ahead market*. Also unlike other imports, non-resource specific imports do not have consistent physical unit parameters driving their costs included in bid prices because they are not associated with a specific unit.

Prior to the adoption of D.20-06-028, non-resource-specific RA imports could bid up to the bid cap in the day-ahead market and had no further obligation to bid into the real-time market if not scheduled in the day-ahead market. The energy bid cap in the CAISO market may be set between \$1000/MWh and \$2,000/MWh depending on market conditions. D.20-06-028 modified non-resource specific RA import bidding rules based upon the concern that those bidding rules could allow a significant portion of RA to be met by "speculative" imports (*i.e.*, no true physical resource or contractual obligation backing the RA showing) that have limited availability during critical conditions. D.20-06-028 modified the bidding requirements for non-resource-specific imports to count towards RA such that the energy from non-resource-specific imports must be bid in at levels between negative \$150/MWh and \$0/MWh or self-scheduled into the CAISO day-ahead and real-time markets at least during the availability assessment hours.[18] The Commission adopted this change with the belief that it "addresses speculative supply concerns and reasonably ensures that self-schedules and/or bids into the day-ahead and real-time markets will be backed by adequate physical supply."[19]

While well intended, the change in eligibility requirements for imports may have dampened sellers' interest in making these sales. The change created a situation in which an entity supporting an import RA may be forced to operate even if the CAISO market clearing

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[18] D.20-06-020, *Decision Adopting Resource Adequacy Import Requirements*, R.17-09-020 (June 25, 2020), at O¶ 2: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF.

[19] *Id.* at 46.

price for energy is below the entity's marginal cost. Using June through September, CalCCA calculated the estimated generation cost of an example peaker that could be used as an import.[20] CalCCA then compared the CAISO marginal cost of energy for the months of June through September during the availability assessment hours (AAH) to the calculated cost of the example import peaker to generate. Since a non-resource specific import RA resource must bid no higher than $0 during the AAH, the market clearing price is what the import RA resource will be awarded by the CAISO. CalCCA found that at best, the example import peaker would not have recovered its costs in 5 percent of the AAH during August and at worst would not have recovered its costs in 91 percent of the AAH in June and July.[21] The results are contained in the table below.

Table 1: Percent of AAH Where CAISO marginal cost of energy (MCE) is Less than Estimated Example Peaker Generating Costs

Percent of AAH Where CAISO MCE is Less Than Estimated Example Peaker Generating Cost				
	June	July	August	September
Low Gas Price	47%	48%	5%	29%
High Gas Price	91%	91%	56%	65%

An entity opting to sell an import to a California LSE must consider how likely and how frequent such an event may occur and will have to place that cost risk in their RA capacity cost. Alternatively, the seller can look for others that need capacity for the growing capacity constraints that exist throughout the Western Electricity Coordinating Council (WECC) as discussed in section II.B.2.

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[20] CalCCA used as its basis a 12,000 Btu/kwh peaker. Natural gas prices in the west ranged from $5.50 to $10.50 depending on the month and location according to EIA data. CalCCA assumed a greenhouse gas (GHG) cost of $15 and a Variable operation and maintenance (O&M) of $5.

[21] As a sensitivity, CalCCA performed the same analysis for a 10,000 Btu/kwh resource and found that only in the low gas price scenario in the month of August would such a resource have recovered its generation costs in all AAH. Even so, a 10,000 Btu/kwh resource would have found that under high gas costs, it would not have recovered its costs in 75% of the AAH in June and July.

B. The RA Market is Scarce

Current RA market conditions warrant reconsidering the RA import bidding rules adopted in D.20-06-028 to ensure California LSEs can secure import RA capacity to meet their RA obligations. Scarcity in the RA market has intensified for RA compliance year 2023 for a number of reasons, including:

1. Declining effective load carrying capability (ELCC) values for solar and wind – the September NQC values of all fully operational solar plants was 379 MW less in 2023 than in 2022;
2. Reduced hydro availability likely due to expected prolonged drought conditions – the September NQC for hydro was 19 MW less in 2023 than in 2022;
3. Supply chain issues, permitting delays, transmission and interconnection delays - all of these factors can contribute to delays in new projects coming online; and
4. An increase in the planning reserve margin (PRM) from 15 percent to 16 percent for RA year 2023.

To capture the impacts of these contributing factors on RA market scarcity, CalCCA developed a stack analysis comparing 2023 system RA requirements with 2023 RA supply.

Table 2: 2023 Summer Supply Stack

		Jun	Jul	Aug	Sep
1	Owned by Calpine[22]	5,874	5,864	5,861	5,867
2	Owned by AES[23]	3,657	3,657	3,655	3,655
3	Owned by NRG[24]	2,321	2,317	2,315	2,322
4	Owned by Other[25]	35,956	36,402	35,690	34,973
5	Removed from NQC list by D.21-12-015[26]	(478)	(478)	(478)	(478)

22 Totals by generator owner established using CAISO 2023 NQC List at: https://www.caiso.com/Documents/Final-Net-Qualifying-Capacity-Report-For-Compliance-Year-2023.xls, and CAISO Master Control Area Generating Capability List at: oasis.caiso.com.

23 *Id.*

24 *Id.*

25 *Id.*

26 D.21-12-015 requires the IOUs to procure 2,000-3,000 MWs of capacity in addition to their RA requirements in 2023. An assessment of various IOU advice letters indicates 478 MW of capacity was on the NQC list but used to meet D.21-12-015 requirements, and therefore unable to meet RA requirements.

		Jun	Jul	Aug	Sep
6	Thermal Plant Derate[27]	(726)	(726)	(726)	(726)
7	Imports[28]	4,413	5,477	5,704	6,409
8	Event-Based Demand Response[29]	995	1,045	1,077	1,090
9	**Total RA Supply**	**52,012**	**53,557**	**53,098**	**53,112**
10	CAISO 1-in-2 Load[30]	42,056	45,397	45,922	46,819
11	Reserve Margin (16%)[31]	6,729	7,264	7,347	7,491
12	Retention for Substitution[32]	619	619	619	619
13	**Total RA Demand**	**49,405**	**53,280**	**53,888**	**54,929**
14	Surplus Supply (Deficit)	607	277	(791)	(1,817)
15	Expected New Resources[33]	-	-	1,695	1,695
16	Surplus Supply (Deficit) with New	2,607	277	904	(122)

Table 2 shows that the RA supply margin is very small in the summer months of 2023, and even goes negative in September. As described in the paragraphs below, the actual supply

[27] Many thermal generators cannot produce at maximum output at certain temperatures, leading to plant derates. For this reason, resource owners may not sell their full NQC as RA capacity. 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.

[28] Assumes that 2021 aggregate RA imports are available in the same quantity by month in 2023. Aggregate import data is from the CAISO Historical Resource Adequacy Import Aggregate Data: (http://www.caiso.com/Documents/HistoricalResourceAdequacyImportAggregateData.xlsx).

[29] Demand response quantities are from the CPUC's Resource Adequacy Compliance Materials (https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials). Demand response totals include avoided losses and are from event-based programs at PG&E, SCE, and SDG&E.

[30] Peak demand forecast from the CPUC's 2023 Forecast Summary Tables (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/ra-2023-forecast-summary-tables.xlsx).

[31] Planning reserve margin requirement of 16% is based on the CPUC's D.22-06-050 (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540633.PDF).

[32] 2021 IOU Excess Resource reports: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

[33] Follows PG&E's approach in its *Response of Pacific Gas and Electric Company (U 39 E) to California Community Choice Association's Petition for Modification of Decision 22-03-034*, R.21-10-002 (Oct. 11, 2022) at 10 which assumes that 60 percent of 2023 Commission-mandated IRP procurement becomes available for RA in 2023: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M497/K621/497621743.PDF.

margin is likely even smaller than this analysis shows, given this analysis assumes all generators sell all of their NQC minus a small reduction in thermal capacity to account for thermal derates (row 6), all NQC is sold within the CAISO footprint ignoring west-wide constraints, and the same level of RA imports available in 2021 are available in 2023 (row 7).

First, NQCs on the CAISO's NQC list may overstate the capacity that suppliers are actually willing to sell as RA into the Commission's RA program. Thermal derates or other types of outages may impact the resources' ability to offer into the CAISO market. Therefore, resource owners may opt to sell less than the full NQC of the resource as RA.

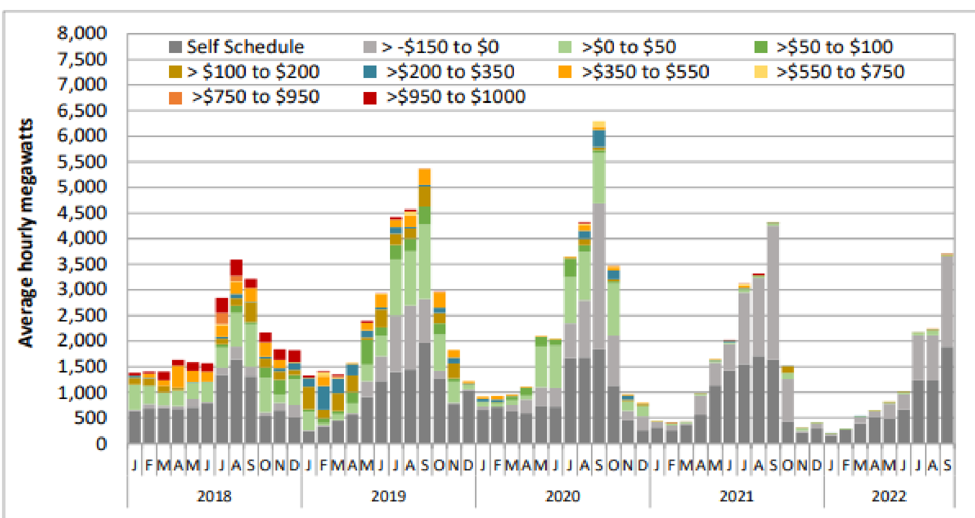
Second, as California continues to face scarce capacity conditions, so do other regions across the west. As the WECC's August 2020 Heatwave Event Analysis Report finds, increased demand during summer months across the Western Interconnection has created more competition for available generation. The Report also finds that seasonal demand differences between balancing authority areas (BAAs) that once allowed excess generation in the north to supply demand in the south in the summer (and vis versa) appear to be diminishing, as BAAs that previously peaked in the winter months now peak in summer or in both summer and winter. [34] This increases demand for available generation in the summer when California's RA needs are highest. 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

[34] Western Electricity Coordinating Council, *August 2020 Heatwave Event Analysis Report*, March 19, 2021, at 2-3.

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.[35]

Finally, requirements on RA imports to bid zero dollars during the net peak hours could limit the ability for California LSEs to competitively contract with imports given opportunities for imports to contract elsewhere in western regions without such bidding requirements. While this requirement is intended to ensure the imports are supported by a physical resource that will deliver when dispatched, it may reduce the pool of suppliers willing to offer imports to California. CAISO's Department of Market Monitoring's (DMM) Third Quarter Report on Market Issues and Performance demonstrates a decline in the quantity of RA import bids beginning in 2021 and continuing into 2022.[36] Figure 1 below taken from DMM's report demonstrates this point, showing the quantity and price of RA import bids into the CAISO market through the third quarter of 2022:

Figure 1: Average Hourly Resource Adequacy Imports by Price Bid



[35] 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.

[36] CAISO Department of Market Monitoring, *Q3 2022 Report on Market Issues and Performance* (Dec. 14, 2022).

While the graph shows an increase in imports when compared to 2018 particularly from those bid below high energy price levels (e.g. $750 and above), the graphic also demonstrates that imports from resources meeting the self-schedule or bid at or below $0 have declined steadily from 2020 through 2022. In addition, so has capacity from import RA that bid at or below $50 in 2020 which is not indicative of a "speculative" RA resource. At a time when the RA market is scarce west-wide, the Commission should not inhibit California LSEs' ability to competitively contract with imports given imports can contract elsewhere in western regions without such bidding requirements.

C. The Commission Should Revisit the Requirement that Import RA be from a Firm Energy Import

The Commission has long held that firm energy imports should count as RA.[37] Over the time horizon that RA has existed, the markets, resources, and needs of LSEs have changed. While allowing firm energy import to count for RA should continue, the Commission should review whether *only* firm energy imports can count as RA or if other imports with sufficient requirements to provide energy to the CAISO market instead of directly to the LSE are appropriate.

Currently, the Commission requires imports to deliver during the AAH in addition to meeting, at a minimum, Maximum Cumulative Capacity (MCC) Bucket 1 requirements. However, the combination of delivering during all of the AAH creates structural energy hedging concerns that place hedging at odds with RA needs. For 2023, the AAH for May through October includes 4PM – 9PM.[38] In the month of August for example, there is still a significant

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37 RA from firm imports has been discussed in D.04-10-035, D.05-10-042, and most recently D.20-06-028.

38 CAISO Reliability Requirements Business Practices Manual at 88-89. https://bpmcm.caiso.com/BPM%20Document%20Library/Reliability%20Requirements/BPM%20for%20Reliability%20Requirements%20Version%2069.docx.

amount of solar generation occurring up to 5PM. It is therefore likely that an LSE will have less need for a firm energy hedge in the 4 and 5 PM hours than it will in the 6 through 9 PM hours.

The needs for firm energy imports have changed and will continue to change as the resources in the market continue to evolve. Since the primary objective of the RA program is to ensure the CAISO has sufficient resources to reliably operate the grid, the requirement that import RA is only countable if it is a firm energy sold and delivered to the LSE is not necessary. Rather, the Commission can achieve resource availability to the CAISO market, similar as it does for CAISO connected resources, from imports through other mechanisms including the proposal in section III.D below.

Based on this, the Commission should re-examine within this proceeding the requirement from D.20-06-028, O¶ 3 that for a non-resource specific import to count as RA, "The counterparty of the energy contract must be the load-serving entity (LSE) and the energy must be delivered and sold to the LSE". The reference decision made such a requirement under the basis that:

> Some parties oppose import energy contracts (and the attendant self-schedule or delivery requirement) as limiting the pool of import suppliers or leading to increased costs. As discussed above, eliminating inexpensive speculative supply and requiring LSEs to procure reliable RA imports may necessarily result in increased costs and may discourage certain suppliers from participating in the market. [39]

However, the Commission must recognize that it is no longer simply a case of the cost of the RA but the ability of LSEs to attract such resources who have competing offers to provide capacity to other states through programs like the Northwest Power Pool's WRAP. In addition, speculative supply can be addressed through bidding requirements. LSEs already have a requirement that their non-resource specific import RA to bid into the CAISO market at or below

[39] D.20-06-028 at 40.

a specified price.[40] This mechanism could continue and would ensure the energy is made available to the CAISO to reliably operate the grid while enabling LSEs to best meet their energy hedging needs and RA needs in a cost-effective manner.

D. The Commission Should Allow RA Imports to Bid up to a Maximum Bid Price Based Upon Estimated Costs of the Typical Marginal Resource

In order to attract additional RA import offers to California LSEs, the Commission must modify the bidding requirements adopted in D.20-06-028. To do so, the Commission should investigate a "Goldilocks" maximum bidding level. The requirement should not be so low that it requires generators to operate at a loss nor so high that it allows providers to willingly take the risk that the resource will not be called upon to provide energy to the CAISO market by continually bidding high prices in the day-ahead market.

This can be accomplished by basing the maximum import RA bid price on the costs of the typical marginal resource in the market. Typically, the resource on margin during the availability assessment hours is a Combustion Turbine (CT). Costs for a CT can be reasonably estimated based upon heat rate, natural gas prices and penalties, variable O&M, and GHG costs.[41] 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.

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[40] *Id. at* O¶ 2.

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

Heat Rate

The California Energy Commission (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.[42] 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

The next piece of information necessary is the price of natural gas. There are a number of sources the Commission could use to obtain gas prices. The Commission should use an average of the SoCal Border price and the PG&E Citygate price for natural gas. While this is not the precise gas price an RA import provider will face, obtaining information to make the gas price index exact would be onerous as the imports can come from anywhere in the Pacific Northwest and Desert Southwest. To avoid setting the prices for import bids excessively frequently, the Commission should use a monthly forward quote for these points and establish the parameters on a monthly basis to determine which tier of the maximum import RA energy price the current market conditions allow.

Variable O&M

The next cost for consideration is the variable O&M. The Energy Information Administration (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.[43] 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 $5.50 currently.

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

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

GHG

The California Air Resources Board (CARB) provides information about the auction prices, allowance floor prices, and secondary market prices that can be used to estimate GHG costs.[44] The EPA lists natural gas as having a GHG content of 53.06 kilogram (kg) / Million British Thermal Units (MMBtu).[45] Assuming a heat rate of 12,000 British thermal units (Btu) / kilowatt-hour (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 CARB 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 $17.50/MWh.[46]

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 $5.50/MWh and $17.50/MWh, respectively. Therefore, before considering the cost of natural gas to produce a MWh, variable O&M and GHG represent a cost of $23.00 /MWh. Next, the Commission should establish tiers based upon natural gas price levels up to $10/MMBtu, $20/MMBtu, and $30/ MMBtu.[47] The Commission would determine which tier resources can bid to each month based upon gas price forwards. With a 12,000

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

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

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

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

Btu/kWh heat rate, these correspond to generation costs of $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:

- $10/MMBtu - $143/MWh
- $20/MMBtu - $263/MWh
- $30 or more /MMBtu - $383/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.

IV. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl,
General Counsel to the
CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

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