JULY FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill 520 and Address Other Matters Related to Provider of Last Resort.	R.21-03-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING BRIEF

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

- The California Public Utilities Commission (Commission) should continue to provide the Provider of Last Resort (POLR) a six-month runway to prepare for a return of customers;
- The POLR should assume energy procurement from the CAISO (California Independent System Operator) market and Resource Adequacy (RA), Renewable Portfolio Standard (RPS), and Integrated Resource Planning (IRP) compliance obligations for returned customers with the opportunity to waive RA obligations and defer RPS and IRP obligations;
- If the Commission adopts a contract assignment mechanism, it must be one that is mutually agreed upon by the Load Serving Entity (LSE), POLR, and seller;
- The Commission should clarify the process for implementing a discount to the Financial Security Requirement (FSR)/re-entry fee based upon the assignment of an RA contract;
- The Commission must modify the FSR formulation to account for the risk and likelihood of customer return and accurately reflect costs and revenues the POLR can expect to receive;
- Do not deduct revenues associated with the Power Charge Indifference Adjustment (PCIA) cost responsibility of returned customers without also accounting for the hedge value of the PCIA and Cost Allocation Mechanism (CAM) fleet;
- Modify the forecast RA cost components of the FSR calculation to account for CAM, Demand Response (DR), and Central Procurement Entity (CPE) allocations;
- Modify the forecast RPS cost components of the FSR calculation to account for Voluntary Allocations (VA) or Market Offers (MO) and any CAM RPS;
- Rely on the current Energy Resource Recovery Account (ERRA) Market Price Benchmarks (MPB) for RA and RPS products;
- Use average customer rates by class for each Community Choice Aggregator (CCA);
- Reflect seasonal changes in generation rates;
- Incorporate future rate changes that have been approved by the Commission;
- The Commission should not remove the negative procurement cost offset but if it does, it must not use Pacific Gas and Electric Company's (PG&E) current administrative fee;
- The FSR minimum should be updated for inflation;
- Reject PG&E's proposal to require FSR postings to reflect two months of POLR service costs without revenue offset;

- Defer consideration of an insurance pool to phase 2;
- Maintain the ability to use surety bonds as required under statute;
- Continue to update the FSR twice per year;
- Adjust the size of individual FSR postings requirements to account for risk;
- Offer a discount to the FSR amount for LSEs that demonstrate low risk of failure;
- Provide a ramping period for the first FSR posting after the Phase 1 decision and a ramping period for new CCAs;
- The Commission should adopt the Energy Division Staff Proposal on financial monitoring with modifications; and
- As long as the POLR is also a market participant, the Commission must not provide the POLR with confidential information about LSEs who trigger financial monitoring.

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OPENING BRIEF

Pursuant to Rule 13.12 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure, and *Assigned Commissioner's Amended Scoping Memo and Ruling*[1] (Ruling)*,* the California Community Choice Association[2] (CalCCA) submits this opening brief.

I. INTRODUCTION

The objective in this proceeding is to implement Senate Bill 520[3] (SB 520), which established requirements for a Provider of Last Resort (POLR). SB 520 rightly directed the Commission to ensure that a POLR is capable of serving its intended role of providing service to any customer returning to it without undermining reliability and the state's climate goals or shifting costs to other customers. The tone of the proceeding early on was set by a fear of a

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1 *Assigned Commissioner's Amended Scoping Memo and Ruling*, Rulemaking (R.) 21-03-011 (June 19, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M511/K719/511719405.PDF.

2 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 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.

3 Senate Bill 520 (An act to amend Section 218 of the Revenue and Taxation Code, relating to taxation, to take effect immediately, tax levy.), introduced Feb. 14, 2023: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202320240SB520.

"Black Swan" event -- an unpredictable or improbable event with potentially severe consequences. Energy Division Staff explained during the March 7, 2022, workshop:

> If the LSE fails and the POLR is not readily able to secure the resources needed to serve the returning customers, not only will the procurement costs will (sic) spike for returning customers, but the capacity shortfall will continue, impacting the cost for everyone. In a worst-case scenario, the conditions could lead to additional LSE failures. The POLR must be able to perform its responsibilities even in the event of large and/or cascading failures and in extreme market conditions, when the resources are not readily available.[4]

CalCCA does not dismiss these concerns; unpredictable and improbable events can and do occur, and SB 520 does require the Commission to address "potentially large and unplanned" returns.[5] Since the March 7, 2022 workshop, however, Load Serving Entities (LSE) have experienced the "extreme market conditions" Energy Division feared and continued to reliably serve customer load without failure. As of this filing, not a single CCA has filed for an involuntary return due to the extreme market conditions LSEs faced over the course of this proceeding, including:

- **High Summer 2022 Forwards** – On May 10, 2022, Southern California Edison (SCE) submitted Advice Letter (AL) 4789-E which asked for CCAs in the SCE area to submit a financial security requirement (FSR) that totaled just over $123 million in aggregate. The high calculation was based upon forwards prices from the Intercontinental Exchange (ICE) predicting high electric commodity prices in California for the summer period. This coupled with a retail rate from SCE that after summer and through the following winter would trigger an ERRA under collection for which SCE has now requested a rate increase to collect.

- **Extreme Heat Event in September 2022** - In September 2022, California experienced "one of the most challenging events in the history of the ISO grid," - a heat wave that caused a record ten straight days of Flex Alerts and a record peak load of 52,061 megawatts (MW).[6]

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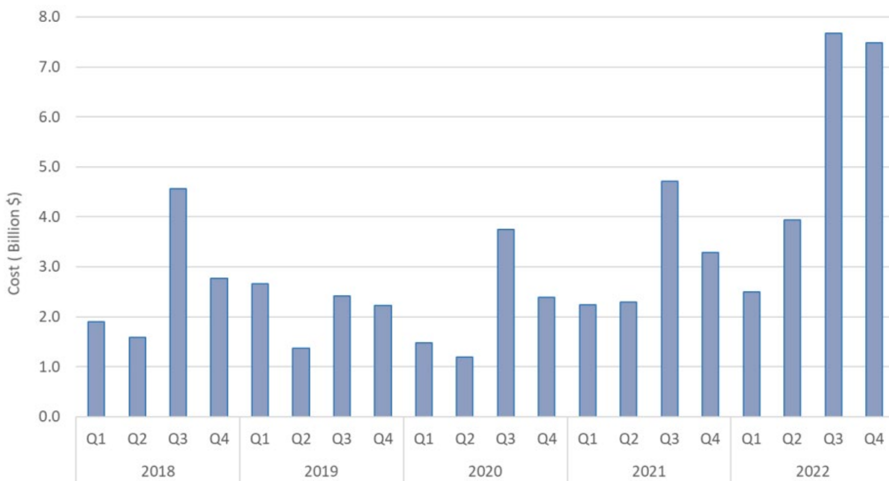
4 Provider of Last Resort (POLR) Workshop #2, Ruling, Mar. 7, 2022 (POLR Workshop #2 Presentations), at Slide 8.

5 Cal. Pub. Util. Code § 387.

6 http://www.caiso.com/Documents/california-iso-posts-analysis-of-september-heat-wave.pdf.

- **High Winter 2022-2023 Actuals** – "Extraordinarily high" natural gas prices in the Western United States impacted California electricity prices and prompted the Commission to issue an Order Instituting Investigation to examine the causes and impacts of these gas price spikes.[7] In December 2022, electricity prices were $3 billion dollars over the norm according to California Independent System Operator (CAISO) estimates.[8] December 2022 wholesale electric costs were about four times higher than in previous years.[9]

Figure 1: Quarterly Wholesale Costs in CAISO Electric Market[10]



- **Prolonged Capacity Shortfalls** –The Commission has acknowledged challenges persist with filling the state's capacity shortfall: "…LSEs and developers are facing exogenous factors such as supply chain impacts on availability of raw materials, import investigations with respect to solar panels, tightening of the economy in the face of inflation, increased demand for clean energy resources throughout the west and globally, and other factors that have material impacts on the development of projects."[11] In 2023, RA capacity in the state continued to be constrained. The stack analysis in Figure 1 of Attachment B demonstrates the RA

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7 *Order Instituting Investigation on the Commission's Own Motion into Natural Gas Prices During Winter 2022-2023 and Resulting Impacts to Energy Markets*, I.________: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M503/K282/503282787.PDF.

8 *Id.* at 3.

9 CAISO, *Gas Conditions and CAISO Markets* (Feb. 6, 2023): http://www.caiso.com/Documents/Gas-Conditions-and-CAISO-Markets-Report-for-Dec2022-Jan2023.pdf.

10 *Id*.

11 *Decision Ordering Supplemental Mid-Term Reliability Procurement (2026-2027) and Transmitting Electric Resource Portfolios to California Independent System Operator for 2023-2024 Transmission Planning Process*, R.20-05-003 (Feb. 28, 2023), at 8: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M502/K956/502956567.PDF.

> supply available within the CAISO balancing authority area was insufficient to meet the RA program compliance requirements.

It is wrong to assume that extreme market conditions will cause a "mass involuntary return"[12] – extreme market conditions have occurred, but they have not driven customer returns from CCAs. While extreme events are possible, they are significantly less likely to cause returns than other factors. In fact, the two customer returns raised during this proceeding - Western Community Energy (WCE) and Baldwin Park Resident Owned Utility District (BProud) – were caused by other circumstances, and their impacts were limited. These two entities represented 2.3 percent of the peak load in the Southern California Edison Company (SCE) Transmission Access Charge (TAC) area.

A more reasonable starting place to evaluate POLR procedures and adequacy is a balanced examination of recent, actual experience of customer returns and an evidence-based examination of the actual risks of returns. Attention should be focused on (1) establishing a workable customer return process and POLR procurement process, (2) updating the financial security requirement (FSR) calculation methodology to make it more accurate and account for the probability of customer return, and (3) adopting a financial monitoring program framework that provides the Commission with sufficiently advanced notice of potential customer returns.

With this experience in mind, the Commission should adopt the following recommendations:

- The Commission should continue to provide the POLR a six-month runway to prepare for a return of customers;
- The POLR should assume energy procurement from the CAISO and Resource Adequacy (RA), Renewable Portfolio Standard (RPS), and Integrated Resource

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12 *Energy Division Staff Analysis and Proposal for Phase 1 Issues in the Provider of Last Resort Proceeding*, R.21-03-011 (Jan. 6, 2023), (Energy Division Staff Proposal) at 2.

Planning (IRP) compliance obligations for returned customers with the opportunity to waive RA obligations and defer RPS and IRP obligations;

- If the Commission adopts a contract assignment mechanism, it must be one that is mutually agreed upon by the LSE, POLR, and seller;

- Energy Division should clarify the process for implementing a discount to the FSR/re-entry fee based upon the assignment of an RA contract;

- The Commission must modify the FSR formulation to account for the risk and likelihood of customer return and accurately reflect costs and revenues the POLR can expect to receive;

- Do not deduct revenues associated with the Power Charge Indifference Adjustment (PCIA) cost responsibility of returned customers without also accounting for the hedge value of the PCIA and Cost Allocation Mechanism (CAM) fleet;

- Modify the forecast RA cost components of the FSR calculation to account for CAM, Demand Response (DR), and Central Procurement Entity (CPE) allocations;

- Modify the forecast RPS cost components of the FSR calculation to account for Voluntary Allocation (VA) or Market Offer (MO) and any CAM RPS;

- Rely on the current Energy Resource Recovery Account (ERRA) Market Price Benchmarks (MPB) for RA and RPS products;

- Use average customer rates by class for each Community Choice Aggregator (CCA);

- Reflect seasonal changes in generation rates;

- Incorporate future rate changes that have been approved by the Commission;

- The Commission should not remove the negative procurement cost offset but if it does, it must not use Pacific Gas and Electric Company's (PG&E) current administrative fee;

- The FSR minimum should be updated for inflation;

- Reject PG&E's proposal to require FSR postings to reflect two months of POLR service costs without revenue offsets;

- Defer consideration of an insurance pool to Phase 2;

- Maintain the ability to use surety bonds as required under statute;

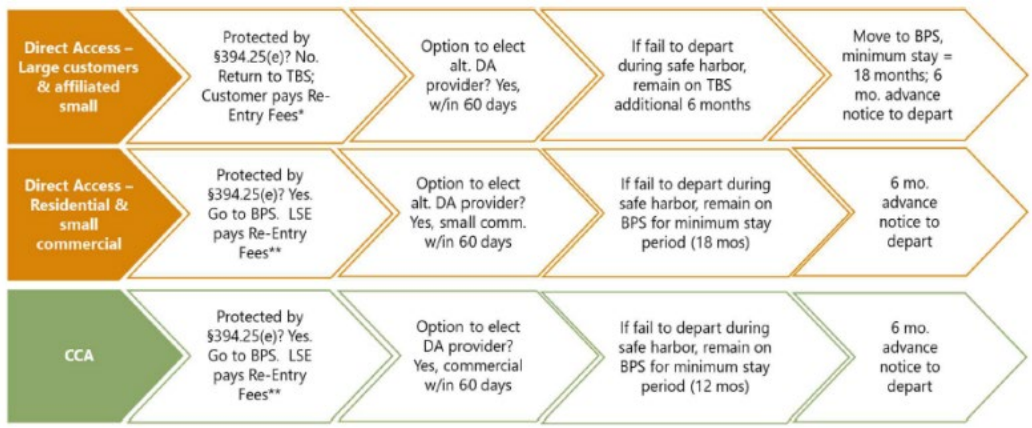
- Continue to update the FSR twice per year;
- Adjust the size of individual FSR postings requirements to account for risk;
- Offer a discount to the FSR amount for LSEs that demonstrate low risk of failure;
- Provide a ramping period for the first FSR posting after the Phase 1 decision and a ramping period for new CCAs;
- The Commission should adopt the Energy Division Staff Proposal on financial monitoring with modifications; and
- As long as the POLR is also a market participant, the Commission must not provide the POLR with confidential information about LSEs who trigger financial monitoring.

II. THE OVERALL POLR PROCESS IS NOT BROKEN; THE COMMISSION SHOULD CONTINUE TO PROVIDE THE POLR A SIX-MONTH RUNWAY TO PREPARE FOR A RETURN OF CUSTOMERS

The ultimate objective of POLR service should be to bridge the defaulting LSE and the customer's newly selected LSE, which will perform full functioning procurement meeting long-term objectives (e.g., environmental goals and new generation development) and procuring to hedge the customers' cost exposure within the market. Maintaining a short-duration POLR will help to achieve this objective. CalCCA, therefore, does not propose any change in the existing definition of or general process for POLR service.

POLR service today can be defined as a service provided by the investor-owned utility (IOU) for a specified period when customers are involuntarily returned to the IOU by their LSE. Today, customers are returned consistent with the process shown in Figure 2 below.

Figure 2: Existing Return Process



The "transition period" for most CCA customers who do not have Direct Access (DA) options, is six months, beginning on the date the customers are returned. A DA customer with a 60-day safe harbor period for switching Electric Service Providers (ESP) is effectively eight months: the two months of safe harbor plus the six months of additional POLR service.

Energy Division Staff proposes a schedule that would set a window for "orderly deregistrations" to mitigate financial risks to the POLR of high market price exposure.[13] Under the Energy Division Staff Proposal's schedule, the transition period would occur outside of the summer months so that the POLR would not attempt to meet new load under possible supply constraints and high market prices. The proposed schedule appears to set a reasonable timeline for orderly deregistration that aligns with the existing return process and would likely limit re-entry fees.

Two important dynamics define the POLR period for an involuntary return of customers. *First*, during the six-month period, the POLR must step into the compliance obligations (RPS, RA, and IRP) for the returned customers, a process that is described in Section III below. *Second*, the POLR procurement for the returned customers during this period is supported by

[13] Energy Division Staff Proposal at 4-6.

financial security provided by the returning LSE, which is discussed in Section IV below. While CalCCA proposes changes to these and other dynamics, there is no need to modify the definition or process for an involuntary return of customers to the POLR.

III. POLR PROCUREMENT

A. The POLR Should Assume Energy Procurement from the CAISO Market and RA, RPS, and IRP Compliance Obligations for Returned Customers with the Opportunity to Waive RA Obligations and Defer RPS and IRP Obligations

All LSEs have the primary responsibility for serving the needs of their customers. This includes the provision of energy, capacity for reliability (including both RA and resources necessary to meet the IRP-identified needs), renewable attributes, and green-house gas reduction. The POLR rules should not change this dynamic nor interfere with or complicate existing programs. As described in Section II, the POLR should not be viewed as an LSE but rather as a short-term transitional role for customers returned to the IOU by another LSE. As the IOU POLR assumes responsibility for the returned customers for the future, it must take on procurement and compliance obligations for those customers. The POLR's most urgent role is to provide energy to returning customers. Therefore, during the six months that returning customers are under POLR service, the POLR should procure energy from the CAISO for these customers. This obligation becomes effective upon the date of customer return.

Meeting compliance requirements should be approached more cautiously, considering market conditions and compliance timelines. The POLR should assume RA, RPS, and IRP compliance requirements effective upon the date of the customer return, although actual procurement may be delayed. Compliance requirements for RA, RPS, and IRP procurement mandates should be addressed as follows:

- Depending on the timing of customer return, the POLR may not be able to procure RA for those customers given RA showings are due 45 days prior to the month. The POLR should thus maintain the existing right to an RA waiver when compliance dates have passed, or resources are unavailable at a reasonable price.

- While RPS procurement is critical in the long run, it does not wear the same urgency as energy and RA for reliability. Thus, while the POLR will assume the obligations upon customer return, it should procure any needed resources in a manner that avoids market power exercise or unnecessary costs. If a return falls close to an upcoming compliance date, the POLR should receive a temporary deferral of the RPS obligation.

- Compliance with IRP mandates, like RPS, may be a longer-term concern and present more complication. The IRP mandates are designed to get new resources built, and if the returning LSE has accomplished some or all of its obligations, the POLR should not duplicate these costs. Its obligations should be limited to fulfilling any shortfalls experienced by the returning LSE and a going-forward obligation. Again, the POLR and the Commission should be mindful of market conditions in considering the timing of any "catch-up" procurement to avoid unnecessary costs. If necessary, the POLR should receive a deferral of its obligation to the extent the Commission deems reasonable considering current market conditions.

To avoid speculative and unnecessary costs, the POLR should not be required to "hedge" or procure any product in advance of a notice of customer return. While the concept of advanced hedging and procurement was discussed early on in this proceeding, this issue appears to have gone uncontested for most of the proceeding due to the unnecessary and duplicative costs it would create.[14]

B. If the Commission Adopts a Contract Assignment Mechanism, It Must Be One that is Mutually Agreed upon by the LSE, POLR, and Seller

In this proceeding, Commission staff raised the possibility of assigning contracts of a failing LSE to the POLR upon customer return.[15] SEIA and LSA propose contract novation in

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[14] For a discussion of why the Commission should avoid advanced hedging or procurement requirements for the POLR, see: *California Community Choice Association's Comments on Administrative Law Judge's Ruling Directing Further Party Comment, Requesting Party Proposals, and Amending Procedural Schedule*, R.21-03-011 (Dec. 17, 2021), at 7-12 and 24-25: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M432/K761/432761005.PDF.

[15] *Administrative Law Judge's Ruling Directing Further Party Comment, Requesting Party Proposals, and Amending Procedural Schedule*, R.21-03-011 (Nov. 23, 2021), Attachment 2, at 3: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M425/K517/425517020.PDF.

which the POLR takes on all rights and obligations under the deregistering CCA's contract. Cal Advocates propose the POLR have a right of first refusal (ROFR) over the returning CCA's contracts. Energy Division Staff put forth three options: a ROFR under new contract terms, short-term unilateral assignment, and a mutual assignment clause with re-entry fee credits.[16]

If the Commission adopts a contract assignment mechanism, it should adopt the Energy Division Staff Proposal's third option: mutually agreed upon assignment clauses with re-entry fee credits. Under this option, "if during the deregistration planning process, the LSE and seller agree to assign a contract to the POLR, and the POLR agrees to assume the contract, the amount of the resource contracted for can be used to offset the reentry fee."[17] Option 3 is the most feasible because it is ***voluntary***. Any form of contract assignability must be voluntary for the LSE to avoid the concerns discussed in Section IV.C. below, including the inability to enforce contract assignments in bankruptcy and the adverse impacts forced contract assignments could have on LSE contract negotiations.

C. The Commission Should Reject Mandatory Contract Novation or ROFR Mechanisms

Mandatory contract novation or ROFR mechanisms are unworkable for several reasons. *First*, adopting contract novation or ROFR requirements could have significant cost impacts on existing and future contracts in order to prepare for an event unlikely to occur in the first place. It is unclear whether all generators or market participants would actually transact with the POLR ROFR as a contractual condition. Even if they were willing, all such conditions come at a cost and, in this case, a cost only to the CCA and its customers. The IOU and its remaining customers would be unaffected. The contract will be priced based upon the risk of not only the buyer but of

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16 Energy Division Staff Proposal at 7-8.
17 *Id.* at 8.

the third-party entity as well. This is due, in part, to the need to underwrite the contract based on the credit risk of both counterparties. The party with the weakest credit strength will tend to drive the prices as the chain is only as strong as its weakest link in the eyes of counterparties. A seller entering into a contract with an LSE with a ROFR where the POLR is either in bankruptcy or in financial distress will be disadvantageous to the buyer. This is because the seller will take the risk that in the event of default, the contract may be assumed by an entity (the POLR) in financial distress.

Had this provision been in place over the last 20 years, for a period of 4.5 years, an LSE would have been purchasing RA with a POLR entity in bankruptcy. This historical examination provides empirical support for the overwhelming risk to ratepayers for a large quantity of RA contracts to be overpriced by needing to underwrite them for an insolvent POLR. Further, such a rule would effectively eliminate the value of a CCA's independent financial strength to negotiate favorable prices. As a result, it would undermine the incentives for LSEs to undertake prudent and resilient financial planning. The Commission should avoid a rule that would materially increase RA prices for buyers strictly because the POLR, and not the primary buyer, was not financially solvent. The financial status of the POLR, including its bankruptcy status, credit rating, and other factors, can and will have an impact on any contract entered into by an LSE which has a novation or ROFR provision. Thus, it is inappropriate to require a novation or ROFR for the POLR in LSE contracting.

Second, there are existing contracts that do not contain these provisions, including long-term contracts to meet RPS requirements. To implement a new requirement would potentially mean the re-negotiation of contracts whose terms and conditions may have been set years prior. Any such renegotiation will result in one party or the other seeking additional changes to a contract entered into in good faith and would draw into question the value of long-term contracting in California's complicated energy space.

Third, the IOUs do not support mandatory contract assignments because the POLR would play no role in negotiation. The contract terms and provisions may, therefore, be unacceptable to the POLR and not reviewed for reasonableness by the Commission. The IOUs also note that mandatory contract assignment could increase stranded cost risk given the POLR may not need the contracts from the returning LSE.[18]

Fourth, the Commission does not have clear authority under PU Code 387 to mandate contract novation or a ROFR.[19] Section 387 addresses regulation of the POLR, not LSE procurement – an area exclusively within the domain of the local authorities that regulate the CCA – and does not extend the Commission's authority to procurement jurisdiction over CCAs. Nearly all of the Section 387 subsections focus on the Commission's regulation of POLR, not the LSEs returning customers. They address establishment of an entity as POLR (subsections (b) and (c)), facilitating applications by LSEs to request transfer of responsibility (subsection (d)), transition of obligations from one POLR to another (subsection (e)), additional threshold attributes for POLRs (subsection (f)), POLR cost recovery (subsection (g)), customer billing (subsection (i)), and general oversight of the POLR (subsection (j)). The only language that relates directly to non-POLR LSEs is subsection (h), which allows the Commission to

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[18] *Opening Comments of Southern California Edison Company (U 338-E) on the Administrative Law Judge's Ruling Distributing Workshop Agenda and Providing Questions for Additional Post Workshop Comments*, R.21-03-011 (Mar. 28, 2023), at 3; *Response of San Diego Gas & Electric Company (U 902 E) To Administrative Law Judge's Ruling*, R.21-03-011 (Mar. 28, 2023), at 3; and *Opening Comments of Pacific Gas and Electric Company (U 39 E) on Administrative Law Judge's Ruling Distributing Workshop Agenda and Providing Questions for Additional Post Workshop Comments*, R.21-03-011 (Mar. 28, 2023), at 16.

[19] All subsequent code sections cited herein are references to the California Public Utilities Code unless otherwise specified.

"[e]stablish rules for all load-serving entities in preparation of any potentially large and unplanned customer migration."

While the statute gives the Commission authority to "do all things that are necessary and convenient" to its supervision and regulation of the POLR, that does not mean creating new areas of authority not otherwise clearly provided by the legislature. The legislature made clear that procurement authority lies with the LSE. For example, Section 454.52(b)(3) places oversight for CCA procurement plans with the local authority, and Section 380 subsections (b)(5) and (h)(5) direct the Commission to maximize the ability of CCAs to determine generation resources used to serve their customers. Given the legislature's directives, significantly expanding authority based on the language in Section 387 is unsupportable without clear and express language to the contrary. Additionally, even if Section 387 conferred the needed authority on the Commission, a ROFR requirement is not "necessary" or "convenient", as discussed above.

Finally, a POLR ROFR or mandatory resource assignment presents serious legal questions in the context of bankruptcy, where the provision would have its greatest value. A POLR ROFR provision likely would be unenforceable in a bankruptcy since it would undermine the court's jurisdiction in distributing the estate's assets or reorganizing its obligations. The Supremacy Clause of the Constitution mandates that federal laws, such as those concerning bankruptcy, "shall be the supreme Law of the Land; . . . [the] Laws of any State to the Contrary notwithstanding."[20] "Congress' intent to supersede state law altogether may be found from a "'scheme of federal regulation . . . so pervasive as to make reasonable the inference that Congress left no room for the States to supplement it,' because 'the Act of Congress may touch a

[20] U.S. Const. art. VI, cl. 2.

field in which the federal interest is so dominant that the federal system will be assumed to preclude enforcement of state laws on the same subject."[21]

In describing preemption in the context of federal bankruptcy law, the Ninth Circuit has stated that:

> There can be no doubt that federal bankruptcy law is 'pervasive' and involves a federal interest 'so dominant' as to 'preclude enforcement of state laws on the same subject'--much like many other areas of congressional power listed in Article I, Section 8, of the Constitution, such as patents, copyrights, currency, national defense and immigration. The Bankruptcy Clause, which grants Congress the power to make bankruptcy laws, U.S. Const. art. I, § 8, cl. 4, stresses that such rules must be 'uniform.' Bankruptcy law occupies a full title of the United States Code. It provides a comprehensive system of rights, obligations and procedures, as well as a complex administrative machinery that includes a special system of federal courts and United States Trustees.[22]

A POLR ROFR likely would be preempted under this scheme as an ipso facto provision. The Bankruptcy Code makes a provision terminating or modifying an executory contract upon the commencement of a bankruptcy case generally inoperative:

> Notwithstanding a provision in an executory contract or unexpired lease, or in applicable law, an executory contract or unexpired lease of the debtor may not be terminated or modified, and any right or obligation under such contract or lease may not be terminated or modified at any time after the commencement of the case solely because of a provision in such contract or lease that is conditioned on …the commencement of a case under this title ….[23]

The reasoning underlying this rule goes to the very heart of bankruptcy's purpose. Complementary sections of the Bankruptcy Code empower a debtor in bankruptcy, or the assigned trustee, to "assume," "assume and assign" or "reject" contracts. 11 U.S.C. § 365(a) and

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[21] *Pacific Gas & Electric Co. v. State Energy Resources Conservation & Development Commission*, 461 U.S. 190, 203-04 (1983) (internal citations omitted).

[22] *Sherwood Partners, Inc., v. Lycos Inc.*, 394 F.3d 1198, 1201 (9th Cir. 2005) (internal citations omitted).

[23] 11 U.S.C. § 365(e)(1).

(c). The power to assume, and to assume and assign, valuable contracts is one of the principal benefits of a bankruptcy filing. As the Ninth Circuit court of Appeal explained:

> By invalidating such [ipso facto] clauses, § 365(e)(1) promotes the rehabilitation of the debtor by enabling the bankruptcy trustee to assume (and thus continue in force) beneficial contracts that otherwise would have terminated automatically or would have been terminated by the other contracting party. See H.R. Rep. No. 95-595, at 348-49, reprinted in 1978 U.S.C.C.A.N. 5963, 6304-05 (noting that enforcement of ipso facto clauses "frequently hampers rehabilitation efforts"). In short, the purpose of § 365(e)(1) is to protect the debtor from the enforcement of unfavorable insolvency triggered clauses in executory contracts.[24]

A POLR ROFR thus faces strong legal headwinds. While courts have found in some cases that the Bankruptcy Code is not preempted by a particular state law, those rulings typically conclude that there is no conflict between the state law and the Bankruptcy Code, either because both are capable of being performed or because the ipso facto prohibition is not triggered.[25]

D. Energy Division Should Clarify the Process for Implementing a Discount to the FSR/Re-entry Fee Based upon the Assignment of an RA Contract

If the Commission adopts a mutually agreed upon contract assignment mechanism, the Commission should clarify the process for implementing a discount to the FSR/re-entry fee based upon the assignment of an RA contract. The cost of RA enters into the re-entry fee calculation as the quantity of RA needed to serve the returning load multiplied by the RA

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24 *Spieker Props., L.P. v. MFM The SPFC Liquidating Trust* (In re Southern Pac. Funding Corp.), 268 F.3d 712, 715-716, (9th Cir. 2001). See also In re *Peaches Records and Tapes, Inc.*, 51 B.R. 583, 587, n.6 (B.A.P. 9th Cir. 1985) (Section 365(e)(1) makes ipso facto clauses which result in a breach solely due to a bankruptcy filing of a party unenforceable subject to certain exceptions); In re *Eastman Kodak Co.,* 495 B.R. 618, 623 (Bankr. S.D.N.Y. 2013) ("Section 365 thus advances one of the Code's central purposes, the maximization of the value of the bankruptcy estate for the benefit of creditors.") (internal citations omitted); In re *Enron Corp., 306 B.R.* 465, 473 (S.D.N.Y. 2004).

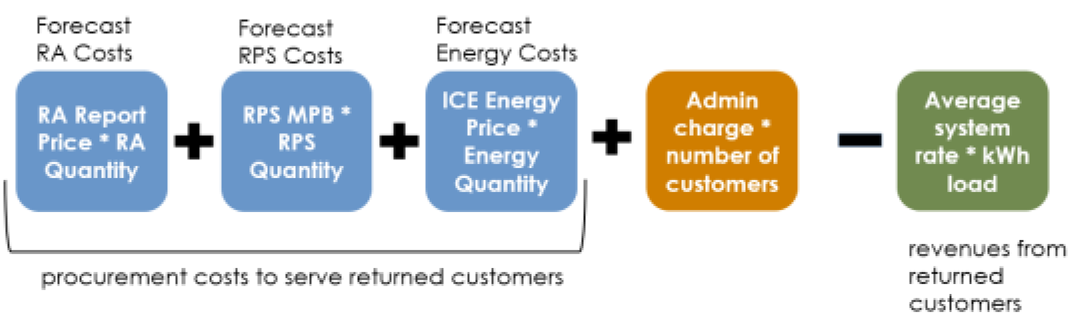
25 See, e.g., *Northwest Wholesale, Inc. v. Pac Organic Fruit, LLC*, 357 P.3d 650 (2015) (holding that Wash. Rev. Code § 25.15.130(1)(d)(ii), which provided for automatic disassociation of LLC members upon a bankruptcy filing, was not preempted by the Bankruptcy Code because the partnership contract was not executory); *Robinson v. Michigan Consolidated Gas Co., Inc.* 918 F.2d 579 (6th Cir. 1990) (Detroit utility termination procedures do not conflict with Bankruptcy Code Section 366 and therefore are not preempted).

benchmark price. The Commission should clarify whether the credit will apply to the quantity or price side of the equation because parties interpreted the discounting process in Energy Division Staff's Proposal differently.[26]

IV. FSR CALCULATION

The FSR is currently calculated every six months for each individual CCA. It is generally designed to cover the costs of providing service to returned customers for six months minus the revenues the POLR can expect to receive from the returned customers. The costs include forecast RA costs, forecast RPS costs, forecast energy costs, and administrative costs. The costs are offset by expected revenues from the returned customers during the same period. The high-level calculation is as follows:

Figure 3: High-Level FSR Calculation



The sections that follow touch on each of these elements and recommend critical changes that will improve the accuracy of the forecast net costs the POLR is expected to incur to serve returned customers.

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[26] CalCCA interpreted the proposal to discount the price side of the equation. It appears that SCE assumed that the credit will be done on the quantity side of this equation. *California Community Choice Association's Reply Comments On The Ruling Of The Assigned Administrative Law Judge Entering Staff Proposal Into The Record And Noticing Public Workshops,* R.21-03-011 (May 3, 2023), at 29: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K084/508084965.PDF.

A. The Commission Must Modify the FSR Formulation to Account for the Risk and Likelihood of Customer Return and Accurately Reflect Costs and Revenues the POLR Can Expect to Receive upon Customer Return

The FSR calculation intends to produce an FSR posting that covers six months of procurement (i.e., RA, RPS, and energy) costs and administrative costs offset by revenues the POLR will receive from returned customers. As currently formulated, however, the FSR does not account for the risk and likelihood of customer return occurring nor accurately reflect costs or revenues the POLR can expect to receive upon customer return. Both problems – risk adjustment and accuracy – must be considered whether the Commission pursues modifications to the FSR calculation.

The Commission must strike the right balance between insuring against risk for bundled customers and setting securitization requirements so high that they unreasonably reduce the LSE's liquidity or credit capacity thereby undermining stable operations, even under an extreme event. To this end, the Commission must consider modifications to the FSR calculation that address both the risks associated with customer return and the likelihood of customer return occurring. Failure to do so would put a disproportionate amount of risk on CCA customers by unnecessarily taking up liquidity and credit capacity that CCAs could use to support operations during high-priced summer periods or to otherwise serve their customers' interests. Modifying the FSR calculation without considering the likelihood of customer return will result in imbalanced and unnecessarily costly FSR postings.

In addition to properly accounting for risk, the Commission must modify the amount of required security to reflect the net costs of customer return more accurately. Accuracy requires a more granular consideration of the costs the POLR will experience in serving the returned customers and the incremental revenues it will receive from those customers. The Commission should prioritize improvements to the FSR accuracy over administrative simplicity because the results of the FSR calculation are highly dependent on certain inputs that can result in significant swings in FSR postings. For example, the May 2022 semiannual update demonstrated that the FSR calculation is very sensitive to the forecast energy cost component. Southern California Edison Company's (SCE's) Advice Letter 4789-E-A would have resulted in an increase in the total FSR posting for SCE's 11 CCAs from approximately $1.5 million to approximately $123 million.[27] The example presented during the April 4, 2023 workshop presents another unique situation with unusually high winter prices that resulted in more postings above the minimum in the winter sensitivities than in the summer sensitivities. Because the final FSR posting amounts will depend heavily on certain inputs to the calculation, select examples like those presented at the workshop cannot fully demonstrate the outcome of each change. Therefore, it is important to focus FSR calculation modifications on improving accuracy by reflecting actual costs and revenues the POLR can expect upon customer return.

When defining accuracy in the context of the FSR calculation, the Commission should aim to (1) reflect in the calculation actual costs and revenues the POLR can expect upon customer return as described in Sections IV.B-H, and (2) account for the probability of a return as described in Section V.

B. Procurement Costs

1. Do not Deduct Revenues Associated with the PCIA Cost Responsibility of Returned Customers without also Accounting for the Hedge Value of the PCIA and CAM Fleet

The IOUs propose to deduct revenues associated with the PCIA cost responsibility of the mass involuntarily returning customers from the revenue component of the FSR calculation.[28] If

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27 SCE Advice Letter 4789-E-A, *Supplement to Advice 4789-E, Southern California Edison Company's Community Choice Aggregator Financial Security Requirement Reports for May 2022* (May 19, 2022): https://cpucadviceletters.org/#/documents/documents/8820/preview/.

28 Joint IOU FSR Workshop Presentation, Apr. 4, 2023.

the Commission adopts this proposal, the Commission must also adopt accompanying changes made by CalCCA to account for the hedge value of the PCIA fleet and CAM fleet.

a. Hedge Value of PCIA Fleet

The PCIA portfolio includes IOU retained generation and contracts. The IOU pays for energy based on the price for the contracted resources (established through a general rate case (GRC) and/or Commission-approved power purchase agreements (PPAs)) and receives the market revenues for the generation produced. If actual energy prices are higher than, e.g., the contract costs, the hedge offsets portfolio costs, compared to an unhedged position, or is "in the money." If the actual energy prices are lower than the contract costs, the hedge increases costs or is "out of the money." The PCIA is set annually on a forecast basis and then trued-up in the following year. If actual energy prices exceed the forecast costs, the generation in the PCIA portfolio will produce more revenues than expected. These excess revenues will accrue as an overcollection in the Portfolio Allocation Balancing Account (PABA) for return the following year. Importantly, if the customer returns to the POLR, the "hedge" value does not disappear. It remains in the PABA.

The PCIA operates as an energy price "hedge" by reducing price exposure in all price-spike scenarios, including those in which departed customers return to IOU service. In a price spike scenario, when bundled rates are too low, the PCIA is too high. As a result, while the IOU is paying more to procure for returned customers than bundled rates cover, the IOU is also taking in more cash from its PCIA portfolio than it needs to cover the stranded costs because PCIA rates are too high. In effect, the PCIA operates as an energy price "hedge" that must be accounted for in the FSR calculation, as explained below.

The FSR calculation currently relies on a forecast of how much the POLR will need to pay to supply returned customers for six months assuming completely unhedged positions. In particular, the FSR's forecast energy cost assumes the POLR will pay the unmitigated forecast energy price for 100 percent of the energy it procures for the returned customer. The costs the POLR incurs for energy are in fact hedged (or offset) by the PCIA portfolio.

Without an adjustment, the IOUs' proposal would require returning customers to pay twice for PCIA energy hedge value; once through the FSR/Re-Entry Fee and a second time through ERRA. In addressing the intersection of the PCIA and FSR, the Commission must reflect this "hedge" effect. The calculation can *either*:

- Adjust the FSR cost to incorporate PCIA hedge value; or
- Reduce the energy volumes used in the FSR calculation to remove amounts hedged through the PCIA portfolio.

By ignoring the hedge value, SCE proposes an unlawful cost shift from bundled customers to returning customers in the event of an involuntary return. Failing to recognize the value of the hedge in the FSR calculation and corresponding reentry fee, means that returning customers are paying the unhedged price for power that has already been hedged, while still being responsible for the inevitable under-collection that will accrue to bundled customers if prices settle at or near the inflated market forwards. Essentially, returning customers are asked to double pay for the energy; once through the re-entry fee and again in the following year through an under-collection balance accrued by bundled customers that is then socialized amongst returning customers.

The Commission should therefore adjust the IOUs' proposed exclusion of PCIA rates by either adjusting the energy cost or the energy volume to account for the hedge value the PCIA portfolio provides to the POLR. If the Commission chooses to adjust the energy costs, this would be accomplished by reducing the total cost by the returned customer's share of the forecast PABA balance that would accrue over the FSR posting period if prices matched the FSR forecast. The PABA share could be calculated as the difference between the PCIA forecast Energy Index and the FSR forecast energy price multiplied by the returned customer's load share of the PABA. Alternatively, the Commission could adjust energy volumes by reducing the departed customer's FSR generation amounts by a pro rata share, determined by dividing the total generation by the total MWh for which returned customers pay the PCIA rate.

b. Hedge Value of CAM Fleet

Similarly, CAM resources provide an energy price hedge by netting energy market revenues against the cost of the contract. The principle of CAM is that the IOU procures on behalf of all benefitting customers and all customers pay for and benefit from the resource. While CAM allocates the RA capacity associated with the procurement, energy is netted against the costs of the contract. That is, any market revenue from dispatch is used to pay off the costs of operation and to the extent there are excess revenues, these pay down the cost of the CAM contract. Thus, while the CAM does not directly allocate the megawatt-hour (MWh) of energy to LSEs, those MWhs are dispatched on the grid and hedge the costs that would be incurred via the CAM. The IOU then plans its bundled load portfolio on the need for capacity and energy net of CAM. Ignoring this impact would lead to over-procurement.

When a customer returns to bundled service, CAM costs and benefits, including offsetting energy revenues, follow the customer, providing the POLR with an additional energy hedge. Therefore, much like the RA capacity associated with CAM capacity discussed in Section 3 below, the IOU will not be at risk for the cost of energy associated with the CAM portfolio used to serve the returning customer load.

To address this calculation change, CalCCA recommends the following where the bold components represent the change from the current calculation:

FSR Energy Cost = [(CCA On Peak load forecast (MWh) ***– CAM On Peak energy forecast (MWh))*** ** IOU Specific Line Loss] * ICE On Peak forward quote + [(CCA Off Peak load forecast (MWh)* ***– CAM Off Peak energy forecast (MWh))*** ** IOU Specific Line Loss] * ICE Off Peak forward quote*

Adopting the IOUs' proposal to deduct revenues associated with the PCIA cost responsibility of returned customers without CalCCA's proposal will result in an imbalance in accounting for the PCIA and essentially ask returning customers to pay twice for energy they pay for through PCIA and CAM. The Commission must therefore only adopt the IOUs' proposal with the accompanying proposals from CalCCA to account for the hedge values from PCIA and CAM.

2. Modify the Forecast RA Cost Components of the FSR Calculation to account for CAM, DR, and CPE Allocations

Currently, the forecast RA costs are calculated by multiplying the CCA's RA requirement by the RA price multiplied by six months. This calculation omits the RA value of CAM, DR, and CPE procured system allocations that will return to the POLR with the involuntarily returned customers, thus overstating the RA costs the POLR can expect to incur. The Commission must adjust the RA cost calculation to accurately reflect the costs incurred by the POLR upon a customer's return and avoid duplication of costs.

CAM, DR, and CPE procured System RA credits would be immediately transferred from the deregistering LSE to the IOU once the IOU takes on the RA obligations associated with the returning customers. The IOU procures CAM, DR, and CPE resources on behalf of all customers - bundled and unbundled. LSEs receive "RA credits" through a reduction in their RA requirements for their portion of CAM, DR, and CPE resources procured on their behalf by the IOU. If a CCA returns its customers to the IOU, the Commission and the IOU will already know how many RA credits were allocated to the returning customers and thus how much is reverting to the IOU to serve the returned customers. In practice, the Energy Division accomplishes this by transferring the RA requirement associated with the CAM, DR, and CPE resources from the

CCA to the IOU. The IOU then has the resource in its portfolio to use to serve the transferred RA requirement.

By definition, the IOU will immediately have the resources since the RA requirement associated with CAM, DR, and CPE procured system RA resources already resides with the IOU as do the resources. There is no potential for the IOU to not immediately have the RA resources to use to satisfy the returning customers' obligations in this case. If a CCA deregisters, the RA credit associated with IOU procurement performed on the CCA's behalf will not disappear. Instead, these credits will follow the returning customers from the CCA to the IOU. While this appears to be the status quo, if doubt remains the Commission should simply clarify in its final decision.

To avoid duplication and accurately reflect the POLR's return costs, CAM, DR, and CPE procured system RA quantities should be netted out of the RA quantity priced by the calculation, as outlined in the examples below. The value of the CAM and DR resources follows the load and therefore will return to the IOU upon customer return, reducing the RA costs the POLR will incur. In other words, these resources will provide a portion of the RA capacity needed to serve a returning customer.

Current RA Cost Forecast Calculation

The RA cost forecast component of the FSR calculation without accounting for CAM, CPE, or DR would result in the following FSR posting (the current calculation):

RA Cost Forecast = [(CCA's Local RA Requirement (MW) x Local RA Price ($kW-mo))
+ (CCA's Net System RA Requirement (MW) x System RA Price ($/kw-mo))] x 6 x 1000

RA Cost Forecast Calculation with CAM Adjustment (Non-CPE Areas Only)

To account for CAM, the RA cost forecast component of the FSR calculation should be modified as follows:

RA Cost Forecast = [((CCA's Local RA Requirement (MW) – ***CCA's Local CAM allocations (MW))*** *x Local RA Price ($kW-mo)) + ((CCA's Net System RA Requirement (MW)* ***- CCA's System CAM allocations (MW))*** *x System RA Price ($/kw-mo))] x 6 x 1000.*

RA Cost Forecast Calculation with CAM Adjustment and CPE Adjustment

As of RA year 2023, all local RA in the SCE and PG&E areas will be procured by the Central Procurement Entity. For any FSR calculation that includes the period beginning January 2023, SCE and PG&E should only include system RA within their RA Cost Forecast. To the extent the CPE purchases RA, the system RA is allocated to all LSEs within the CPEs area. It is exactly this allocated system RA that must be accounted for in the FSR. CPE allocations for the SCE and PG&E area CCAs can be accounted for the same way as system RA CAM allocations are accounted for, by subtracting the CPE System RA allocations in MW from the CCA's System RA requirement.

RA Cost Forecast = [(CCA's ~~Net~~ System RA Requirement (MW) ***- CCA's System CAM allocations (MW) - CCA's System RA CPE allocations (MW))*** *x System RA Price ($/kw-mo))] x 6 x 1000.*

RA Cost Forecast Calculation with CAM Adjustment and DR Adjustment

The same approach should be applied to DR allocations. Assume the same illustrative CCA now also has five MW of DR located in a local capacity area allocated to it in addition to its CAM allocations. To account for the DR allocations, the RA cost forecast component of the FSR calculation should be further modified as follows:

RA Cost Forecast = [((CCA's Local RA Requirement (MW) – ***CCA's Local CAM allocations (MW) – CCA's Local DR allocations (MW))*** *x Local RA Price ($kW-mo)) + ((CCA's Net System RA Requirement (MW)* ***- CCA's System CAM allocations (MW) - CCA's System DR allocations (MW))*** *x System RA Price ($/kw-mo))] x 6 x 1000.*

3. Modify the Forecast RPS Cost Components of the FSR Calculation to Account for Voluntary Allocations or Market Offers and any CAM RPS

The POLR will have RPS available to serve returned customers from three possible sources: (1) the customer's portion of a Voluntary Allocation of RPS resources from the PCIA portfolio, (2) Market Offers purchased by the CCA, and (3) the customer's portion of CAM RPS, if any. The RPS VAMO process, established in the PCIA proceeding, similarly allows the output of RPS resources transferred from the IOUs to CCAs to revert back to the IOU upon an event of default.[29] The RPS costs the POLR would incur to serve the returned customers would be reduced given the IOU would again use those resources for RPS compliance on behalf of the returned customers. Therefore, in the event of an LSE bankruptcy, the primary concern within the context of POLR, the IOU would suspend VAMO deliveries pursuant to the applicable VA contract and the resources would be available to the IOU.[30] This reversion of RPS compliance value to the IOU should be reflected in the FSR calculation as a reduction in the forecast RPS cost, outlined in the formula below. While the RPS value of VAMO resources logically follows the returning customers to the POLR within the context of the IOU as POLR, this would need to be reevaluated in the context of a non-IOU POLR. The RPS portion of the FSR calculation also must reflect the share of RPS resources, if any, in the CAM portfolio. CalCCA acknowledges that the vast majority of CAM resources are not RPS eligible resources. To the extent they are, however, or if future CAM procures significant amounts of RPS eligible resources, this same issue will cause an over-estimate of the FSR. The FSR thus should be reduced by these amounts.

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[29] *See* D.21-05-030, *Phase 2 Decision on Power Charge Indifference Adjustment Cap and Portfolio Optimization*, Rulemaking (R.) 17-06-026 (May 20, 2021) (establishing the RPS VAMO process). The first VAMOs are being conducted in 2022, and monitored in the RPS proceeding, R.18-05-03. The IOUs submitted, and Energy Division approved, pro forma Voluntary Allocation contracts with provisions governing CCA defaults (such as failure to pay or bankruptcy). *See* Resolution E-5216 (June 23, 2022) (approving the IOUs' standard VA pro forma contracts). In an event of default by a CCA that is a signatory to one of the IOU's pro forma VA contracts, the IOU can declare an early termination of the contract and suspend performance. See, e.g., Section 5.2 of EEI Master Power Purchase and Sale Agreement (incorporated by PG&E Pro Forma Master Power Purchase and Sale Agreement - Renewables Portfolio Standard Energy Allocation Confirmation Letter, SDG&E Confirmation for Allocation of Bundled Energy and Renewable Energy Credits, and SDG&E Confirmation for Unbundled Energy and Renewable Energy Credits); Section 5.2(a) of SCE Pro Forma Voluntary Allocation Agreement.

[30] CalCCA opposes automatic assignment of third-party contracts to the POLR in the event of bankruptcy in earlier comments. These circumstances differ, however, because they involve a regulatory allocation and reversion to the IOU originally allocating the products.

Current RPS Cost Forecast Calculation

The RPS cost forecast is currently calculated without an adjustment for the return of RPS VAs.

The formula is as follows:

RPS Cost Forecast = REC Value ($/MWh) x Annual RPS Target (%) x CCA Annual Usage Forecast x IOU-Specific Line Loss Factor

RPS Cost Forecast Calculation with VA and MO Adjustment

The RPS cost forecast calculation should be updated to include an adjustment for VAs as follows:

RPS Cost Forecast = [REC Value ($/MWh) x (Annual RPS Target (%) x (CCA Annual Usage Forecast (MWh)) ***– (Voluntary Allocation and Market Offer (MWh) + CAM RPS (MWh)]*** *x IOU-Specific Line Loss Factor*

4. Rely on the Current Energy Resource Recovery Account (ERRA) MPBs for RA and RPS Products

The current FSR calculation draws the price of RA from Energy Division's most recent RA report. These prices lag behind current market prices, meaning they are out of date when used for this purpose. This lag could be reduced by relying on recent ERRA market price benchmarks as proxies for forecast RA costs. There appears to be consensus among parties that this change should be made to improve the accuracy of the FSR calculation. The RPS price in the FSR calculation should likewise rely on the ERRA MPB for RPS.[31]

C. Revenues

Currently the forecast retail revenue component of the FSR calculation is calculated by multiplying the POLR's system average bundled generation rate by the returning LSE's load forecast. This overly simplified approach has the potential to misrepresent the characteristics of

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31 Rule 23 for all three utilities states, "In the absence of a robust index, a forward quote, or durable methodology for regularly estimating the value of a Renewable Energy Credit (REC), [IOU] will use the $10/MWh REC value adopted by the Commission in D.16-05-006 as an estimate of the incremental cost of satisfying the Renewable Portfolio Standard (RPS) requirement for the involuntarily returned CCA load." Since D.16-05-006, the Commission has issued annually a PCIA MPB that has been used as a more robust methodology.

returning customers and the expected rates the POLR can expect to receive depending on the time of return. To improve the accuracy of the FSR calculation, the Commission should make the modifications outlined here to better reflect actual revenues the POLR can expect to receive upon customer return.

1. Use Average Customer Rates by Class for each CCA

Customer rates vary by class, with small residential customers experiencing the highest rates and large industrial customers experiencing relatively lower rates. Calculating expected revenues using the IOU's system average rates, as is done for the FSR calculation today, may over or underestimate the actual revenues the IOU will receive from returning customers. This is because system average bundled rates that reflect the IOU's mix of customer classes will almost certainly not reflect the same mix of returning customers. In many if not most cases, the customer mix for a CCA will be more heavily weighted toward residential rates, which yields a relatively higher revenue offset than is reflected in today's FSR calculation. Therefore, the Commission should reflect average customer rates by class for each CCA in the forecast revenue component of the FSR calculation to better reflect anticipated revenues for any individual CCA return.

Rate classes are generally segmented into four high-level categories: residential > commercial and industrial > agricultural > street lighting. Recognizing that incorporation of each customer class may be administratively burdensome, the IOU POLR should at least incorporate residential and non-residential rates in its FSR calculation. To incorporate these rate classes in the calculation, the Commission should require forecast revenues to be calculated by multiplying the class-specific rate by the load forecast of the customers in that rate class as follows:

Forecast Revenues = (Residential Rate*Residential Customer Load Forecast) + (Non-Residential * Non-Residential Customer Load Forecast)

2. Reflect seasonal changes in generation rates

"Seasonality" is reflected in the most significant component of the FSR calculation – energy costs – by updating prices each season to correspond to the period covered by the FSR. Typically, energy costs will be higher in summer and lower in winter. This same seasonality exists within the IOU generation rates, with higher rates in summer periods and lower prices in winter periods. Like energy costs, rate seasonality has a significant influence on the outcome of the FSR calculation. However, the forecast revenue component of the current FSR calculation uses an annual average generation rate, rather than reflecting the seasonality that exists within the IOU generation rates. This creates a seasonal misalignment: while the forecast energy cost component of the calculation will reflect the seasonal differences through ICE forward price quotes, the revenue component does not. Accounting for seasonality on the cost side but not the revenue side will result in an FSR/re-entry fee calculation that is artificially high in the summer and artificially low in the winter. Therefore, the Commission should seasonally differentiate average generation rate revenues to match the seasonal differentiation of forecast energy costs.

To do this, the Commission should require the POLR to use the rate that applies for the season in which the FSR calculation is being calculated. If the rate seasons do not align exactly with the FSR posting period, each utility should provide the monthly energy forecast within the FSR. Instead of using a single rate multiplied by the sum of the energy for the months adjusted for the IOU-specific line losses, the IOU should instead calculate the retail revenues for each month at the seasonal price for the rate classes and adjust that for the IOU-specific line losses. Doing so will place the revenue calculation on par with the energy cost calculation.

Some parties have suggested that if the Commission adopts seasonal rates, it should also adopt seasonal RA costs.[32] However, monthly costs of RA are much less clear than the seasonal energy costs and seasonal rates, since there is no centralized capacity market and no monthly forward curve for RA. Instead, the Commission develops a benchmark based upon historical contracts. The contracts reported to produce this benchmark are a mix of contracts covering anything from one month to multiple years. The data simply do not provide sufficient granularity to determine a seasonal differential.

Within this proceeding, parties have not proposed a seasonal RA benchmark with supporting evidence of its accuracy. Without sufficient opportunity to examine such data and present evidence to the contrary, the Commission cannot adopt a seasonal value for RA. While the annual RA report provides monthly values for the average and weighted average prices of RA, in the POLR proceeding, there has been a general consensus that the RA report information is too old to be of use in setting the cost of RA. Parties instead appear to be supportive of using the PCIA benchmark to establish the cost of RA. However, the PCIA benchmark reflects an annual RA price and does not provide monthly or seasonal information. In addition, with many contracts procured at a single strip price covering both summer and winter periods or for multi-year periods, the data do not provide confidence that they reasonably represent a seasonal RA price.

The current mismatch between non-seasonal retail rates and seasonal energy cost forecasts has a far larger impact than the inclusion of seasonality in the RA cost forecast. Using the current FSR calculation as provided by the IOUs in their calculator from the April 4, 2023,

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32 *Opening Comments of Southern California Edison Company (U 338-E) on The Ruling of The Assigned Administrative Law Judge Entering Staff Proposal into The Record and Noticing Public Workshops*, R.21-03-011 (Apr. 18, 2023) at 11: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M506/K523/506523045.PDF.

Workshop,[33] of the total forecasted costs of new procurement, approximately 85 percent in the summer comes from the energy cost forecast. With 85 percent of the cost forecast being differentiated by season using forward ICE quotes, it is unreasonable to ignore the offsetting revenues which are also differentiated by season in the IOUs rates. RA costs represent approximately 10 percent of the summer procurement costs. The Commission should not forego seasonally differentiating revenues because matching RA costs are not available. This would allow the RA cost, representing approximately 10 percent of the summer costs, to drive greater misalignment of 100 percent of the revenues.

The Commission should reflect seasonal values where such information is readily available and reasonably accurate, such as in the cost of energy and the retail rate revenues. It should not do so where those values are not supported by evidence sufficient to provide a reasonably accurate value.

3. Incorporate Future Rate Changes That Have Been Approved by the Commission

Approved future rate changes that will take effect during the FSR posting period should be accounted for in the calculation of forecast revenue. This should occur for both semi-annual updates to account for any new changes during the six months of the FSR posting. This modification will ensure the FSR accounts for the most likely rates the returned customers will be paying based on the most current information available.

33 The IOU Calculator is attached to the *Comments of San Diego Gas & Electric Company (U 902 E) in Response to Administrative Law Judge Ruling Entering Staff Proposal into the Record and Noticing Public Workshops*, R.21-03-011 (Apr. 18, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M506/K523/506523513.PDF.

D. Administrative Fees

1. The Commission should not Remove the Negative Procurement Cost Offset but if It Does, It Must Not Use PG&E's Current Administrative Fee

Administrative costs are calculated by multiplying the administrative fee and the number of customers returning. Negative procurement costs offset incremental administrative costs, per Decision (D.) 18-05-022.[34] This decision followed the same approach adopted for ESPs in D.13-01-021,[35] where the Commission found:

> The negative incremental procurement costs shall be allowed to offset up to 100% of the calculated incremental administrative costs. Since both administrative costs and procurement costs are incurred in connection with an involuntary return of DA customers to bundled service, it is reasonable to consider the net effect of both elements of costs in determining the amounts, if any, necessary to compensate the IOU and to avoid cost shifting to other customers.[36]

The Commission should reject the IOUs proposal to remove the negative procurement cost offset from the FSR calculation. The Commission should retain the negative procurement cost offset, as the FSR calculation is the sum of the anticipated energy, RA, RPS, and administrative costs, minus the anticipated revenues. If anticipated revenues fully cover the sum of all costs, there is no rational reason to select a single cost element as the basis for an FSR minimum.

However, if the Commission does decide to remove the negative procurement cost offset, it must use the average of SCE's and SDG&E's administrative fee as the value used in the FSR calculation, and not rely on PG&E's administrative fee. PG&E's administrative fee is

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[34] D.18-05-022, *Decision Establishing Reentry Fees and Financial Security Requirements for Community Choice Aggregators*, R.03-10-003 (May 31, 2018), at 12: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M215/K726/215726275.PDF.

[35] D.13-01-02, *Decision Granting Applications for Demand Response Aggregator Managed Portfolio Agreements*, Application (A.) 12-09-004 and A.12-09-007 (Jan. 24, 2013): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M046/K233/46233814.PDF.

[36] *Id.* at 31.

significantly higher than the other IOUs' and has not been adequately justified.[37] SCE and SDG&E's administrative costs are roughly $0.50 per customer service account, while PG&E's administrative costs are $4.24 per customer service account. This issue was previously raised in R.03-10-003. The resulting D.18-05-022, declined to examine this difference. Instead, D.18-05-022 directed the utilities to identify the administrative fee as a separate item in their next GRCs, describing its components, how it is calculated, and a comparison of its fee with that of the other major California utilities.[38] While PG&E's GRC[39] and Advice Letter 5359-E provides a generic accounting of how the cost is estimated, the comparison with other major California utilities has not been offered. Indeed, while PG&E's documentation in the GRC and Advice Letter offered categories of costs and an estimated four minutes per account processing time, in response to a Joint CCA data request,[40] PG&E indicated that they have no work papers to describe how they arrived at the processing time which is the driver of the cost. Given this, while the Commission should not net the negative procurement cost offset from the FSR calculation, if it does, it should not rely on PG&E administrative fees.

2. The FSR Minimum Should be Updated for Inflation

Parties who support updates to the FSR minimum generally base their arguments around the need to cover administrative costs. For the reasons described below, the Commission should not adopt SCE's proposal to remove the negative procurement offset that applies to both procurement costs and administrative costs. Instead, the Commission should update FSR

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37 *California Community Choice Association's Comments on Ruling of the Assigned Commissioner and Assigned Administrative Law Judge Requesting Comments on Financial Security Requirements and Reentry Fees, and Modifying the Proceeding Schedule*, R.21-03-011 (July 5, 2022), at 34-6: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M490/K740/490740399.PDF.

38 D.18-05-022 at 5.

39 PG&E Application (A.) 18-12-009, Exhibit PG&E-6, at 2-28.

40 Attachment A.

minimum for inflation, as it did in D.18-05-022. The FSR minimum should not be revised to equal the administrative costs.

To avoid an FSR of $0 when the negative procurement costs totally offset incremental procurement and administrative costs, the Commission adopted a minimum FSR of $100,000 in D.13-01-021, and increased the minimum to $147,000 for CCAs in D.18-05-022 to account for inflation.[41] D.18-05-022 correctly allowed the negative procurement to offset both procurement costs and administrative costs. The revenues the POLR receives from returned customers will offset all costs the POLR incurs on behalf of the returned customers, including administrative costs in the event revenues exceed procurement costs. Therefore, the FSR minimum does not need to be revised to equal administrative costs by removing the negative procurement offset.

The Commission correctly allowed revenues to offset administrative costs when establishing the CCA FSR and must continue to do so. The Commission should, therefore, only adjust the FSR minimum to account for inflation between when the FSR minimum was established in D.18-05-022 and now.

E. Reject PG&E's Proposal to Require FSR Postings to Reflect Two Months of POLR Service

PG&E proposes that the minimum FSR amount reflect two months of POLR service without a revenue offset rather than $147,000 because PG&E "requires upfront liquidity to provide reliable service in a short amount of time."[42] The Commission should reject this proposal for the following reasons.

The Commission has made clear that the purpose of the FSR is to provide basic financial security, not liquidity, to cover the costs incurred by the POLR, offset by the generation revenues

[41] D.18-05-022 at 12.
[42] Joint IOU FSR Workshop Presentation, Apr. 4, 2023.

received by the POLR. In D.18-05-022, the Commission found that, "[t]he purpose of the [FSR] statute appears to be more about basic financial security – ensuring that money is available – rather than liquidity."[43] Nothing in the operation of the FSR has changed since that decision was issued.

Moreover, while it is possible the POLR may not have the money in hand to cover the re-entry costs immediately, this will not always be the case. When it is the case that the POLR does not have the liquidity to cover the re-entry costs immediately, the liquidity crunch will be relatively short-lived. In a period of rising energy prices, the IOU will have increased liquidity, rather than reduced liquidity, resulting from higher energy prices it receives for its resources than are reflected in customer rates. The CAISO charges market participants for load and pays market participants for supply at the same time, meaning as PG&E pays CAISO charges for returning customers, it concurrently receives revenues from its PCIA and CAM fleet. In other circumstances, the IOU will need to rely – as it does in many other cases – on short-term borrowing.

Addressing liquidity by removing the revenue offset to POLR costs would have a material effect on the FSRs a CCA needs to post. Removing such revenue would significantly increase the FSR posting. When evaluating the impacts of PG&E's proposal, the Commission must keep in mind that the example presented in the workshop did not demonstrate its full magnitude. The example presented at the workshop used an LSE that represented roughly 2.5 percent of load in PG&E territory. Even using an LSE with a very small portion of PG&E load, PG&E's proposal would have resulted in a $38 million final FSR in the May filing period with a zero percent pricing sensitivity. Currently, roughly one third of the load in PG&E's service area is served by CCAs. Scaling up the results from an example LSE serving 2.5 percent of PG&E's

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43 D.18-05-022 at 8.

load to the total load being served by CCAs, an estimated $517 million would need to be posted in total to satisfy PG&E's proposal under the same set of assumptions used in the example. Modifying the FSR calculations in this manner will have substantial impacts on CCAs' liquidity and/or credit capacity and should be avoided given the purpose of the FSR is to provide basic financial security rather than liquidity.

While the issue driving PG&E's need for liquidity is the immediate CAISO energy costs of serving returning customers, PG&E has not demonstrated (1) that it is incapable of borrowing in the short term to temporarily finance costs until customers are billed or (2) that CAISO market revenues from the IOUs fleet of resources (PCIA and CAM) will be insufficient to cover these costs. If PG&E is still unable to resolve its liquidity concerns considering its ability to borrow and its revenues that it expects to receive from the CAISO market, then the Commission must expeditiously commence Phase 2 of this proceeding, where parties will consider the POLR framework with an entity other than the IOU acting as the POLR.

F. Defer Consideration of an Insurance Pool to Phase 2

PG&E proposed an "insurance pool" as a potential alternative to posting individual financial security instruments. In response to PG&E's proposed pool, CalCCA put forth its own insurance pool proposal that would be more appropriately sized to a reasonable level of risk.[44] The Energy Division Staff Proposal states that "[t]o the extent the creation of an insurance pool is considered in this proceeding Staff Proposes that this issue be considered as part of Phase 2 of this proceeding."[45] The Commission should adopt the Energy Division Staff Proposal's

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44 *California Community Choice Association's Comments on Ruling of the Assigned Commissioner and Assigned Administrative Law Judge Requesting Comments on Financial Security Requirements and Reentry Fees, and Modifying the Proceeding Schedule*, R.21-03-011 (July 5, 2022) at 21-26: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M490/K740/490740399.PDF.

45 Energy Division Staff Proposal at 11.

recommendation to defer consideration of an insurance pool to Phase 2 of the proceeding. The Commission should defer consideration of an insurance pool to Phase 2, as more consideration is needed to determine whether to develop a pool.

G. Maintain the Ability to Use Surety Bonds as Required Under Statute

SCE proposes to remove surety bonds as an instrument that can be used to meet a CCA's FSR based on the supposition that "they [surety bonds] are expected to be litigious, just as insurance claims typically are, and can potentially take months or years for the IOU to recover on its Re-Entry Fee claim and impact the IOUs' liquidity during this period of dispute."[46] However, the Commission expressly rejected this argument when implementing the statute with respect to CCAs:

> The Joint Utilities describe the problem with surety bonds as follows: Collecting on a surety bond is similar to collecting on an insurance claim, where a litigious and delayed process for resolving a claim is not unusual.... The purpose of the statute appears to be more about basic financial security – ensuring that money is available – rather than liquidity. The fact that surety bonds may not be commonly used for other purposes in the energy procurement business does not control in this context, where there is express statutory language. Accordingly, we approve the use of surety bonds as FSR for CCAs.[47]

The governing statute permitting a bond - section 394.25(e) – has not changed and continues to permit the use of a bond. SCE's supposition was not sufficient when raised before the Commission previously, and it is not sufficient now to remove surety bonds as an option. The Commission must maintain the ability to use surety bonds as required by statute.

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[46] *Opening Comments of Southern California Edison Company (U 338-E) on the Administrative Law Judge's Ruling Distributing Workshop Agenda and Providing Questions for Additional Post Workshop Comments*, R.21-03-011 (March 28, 2023) at 16: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M463/K620/463620374.PDF.

[47] D.18-05-022 at 8-9.

H. Continue to Update the FSR Twice Per Year

The Commission should maintain the current FSR update schedule of every six months. Updating the FSR amount every six months strikes the right balance by avoiding potential large swings in FSR posting amounts over a short time period, providing stability for CCAs who need to post the FSR, and incorporating energy price differences between the summer and winter season. Updating the FSR more frequently, such as quarterly or monthly, would increase the volatility in the amount of FSR CCAs have to post and further exacerbate the misalignment between FSR forecast costs and the revenue forecast in customer rates. While the FSR is updated every six months, the PCIA is updated annually. Updating the FSR more frequently without also triggering a PCIA change increases the likelihood of divergence between the prices used when the PCIA was set, and the prices used in the FSR calculation. This is especially true if SCE's proposal to reduce the PCIA component of the FSR revenue offset is adopted and the hedge value of the PCIA ignored.

The semi-annual update in SCE AL 4789-E indicates the FSR posting amount can swing drastically, from the $147,000 minimum to over millions of dollars, from one update to another based on the month chosen to do the calculation.[48] If changes of similar magnitude were to occur on a monthly or quarterly basis, it would take up CCAs' liquidity and credit for longer than necessary given the typical length of the financial instruments that CCAs use to provide the security. For these reasons, the Commission should maintain the FSR update frequency of every six months to strike the right balance of maintaining stability in the FSR posting amounts and accounting for seasonal differences between costs and revenues expected in the summer and winter seasons.

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[48] *Community Choice Aggregator Financial Security Requirement Reports for May 2022* (SCE Advice Letter 4789-E), May 10, 2022, at 3.

V. FSR AFFORDABILITY

A. Adjust the Size of Individual FSR Postings Requirements to Account for Risk

Risk is commonly expressed as the probability of a failure event occurring multiplied by the consequences of failure. The current FSR calculation as framed within this proceeding considers only the consequences of failure and does not account for the probability of failure. The current calculation covers 100 percent of the incremental cost of procurement minus the expected revenues of the returning customers to set the FSR amount. This results in a CCA securitizing the full expected costs of a customer return in advance, even if the probability of that return is slim. Similarly, within this proceeding, Energy Division frames the discussion by assuming a mass involuntary customer return to the POLR is inevitable, then explores how to securitize on that basis.[49] Framing the discussion in this way omits an important factor: the risk of large-scale customer returns is very small. It is important to incorporate risk-weighting into the FSR calculation to avoid over-securitization that takes up LSEs' liquidity and credit capacity that could be better used to preserve affordability. The current posting mechanisms, including a letter of credit (LOC), cash, or a surety bond, each have cost and liquidity or credit consequences for the CCA and its customers.[50] Excessively high FSRs take up liquidity or credit capacity that could be used to purchase hedges to mitigate price risk during high priced summers or procure clean energy resources to meet state policy and promote reliability by building the resource stack.

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[49] "While they may be able to absorb individual or small CCA failures, the failure of larger LSEs, or the possibility of multiple concurrent LSE failures due to a major market shortage, may potentially contribute to a reliability crisis that would be challenging for the POLR to absorb." CPUC Energy Division Staff Presentation, Oct. 29, 2021, at 93.

[50] *California Community Choice Association's Reply Comments on Administrative Law Judge's Ruling Distributing Workshop Agenda and Providing Questions for Additional Post Workshop Comments*, R.21-03-011 (Apr. 15, 2022), at 7-8.

The Commission should not continue to ignore the probability of involuntary customer return, as the result is increased costs to customers for an event that is unlikely to occur. To incorporate the risk of involuntary customer return into the FSR calculation, the Commission should discount the FSR amount for LSEs that demonstrate low risk of failure as described in section V.B below.

B. Offer a Discount to the FSR Amount for LSEs that Demonstrate Low Risk of Failure

To ensure the FSR posting amounts reflect the risk of customer return, the Commission should discount the FSR amount for LSEs that demonstrate low risk of failure. Energy Division Staff proposes a mechanism for discounting that the Commission should adopt with modifications. First, the Energy Division Staff Proposal would only allow discounts to LSEs that demonstrate they "hold fixed price contracts with a collateralized counterparty to meet at least 80 percent of their load forecast."[51] The Commission should not limit acceptable hedges to fixed-price contracts only. There are many other effective hedging mechanisms LSEs can use to hedge energy price risk, including call option contracts, swaps, and tolling agreements, among others. LSEs are in the best position to determine which types of hedges are the most effective for their unique situations. The Commission should modify this element of the Energy Division Staff Proposal to allow LSEs to demonstrate all types of hedges the IOUs are allowed to use in their bundled procurement plans, at minimum.[52] The Commission should also clarify that CCAs would need to demonstrate hedges that cover the forecasted load for the same six months the FSR will cover.

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[51] Energy Division Staff Proposal at 12.

[52] See PG&E Bundled Procurement Plan Appendix A, and SCE Bundled Procurement Plan Appendix C.

Second, the Energy Division Staff Proposal would require that LSEs "have substantially met" month-ahead and year-ahead RA requirements and IRP requirements as a condition to receive the discount.[53] The Commission should strike this condition from the proposal given current RA and IRP market conditions making it difficult, if not impossible for all LSEs to comply with these obligations. The RA supply available within the CAISO balancing authority area for 2023 through 2026 appears inadequate to meet the RA program compliance requirements. A wide range of factors have contributed to the current circumstances in which there is insufficient RA supply 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;
- Reduction in Effective Load Carrying Capability values reduced reliance on wind and solar resources to meet RA requirements;
- Increases in Planning Reserve Margins (PRM) to 16 and 17 percent, with a 20-22.5 percent "effective" PRM for 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; and
- 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 4 below, in which demand for RA is projected to exceed the available supply through 2025, with only a very minor surplus in 2026.

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53 Energy Division Staff Proposal at 12.

Figure 4: 2023-2026 Stack Analysis

	September NQC	2023	2024	2025	2026
1	CAISO 1-in-2 Load	46,819	47,475	47,987	48,487
2	Reserve Margin (16% in '23, 17% after)	7,491	8,071	8,158	8,243
3	**Total RA Demand**	**54,310**	**55,546**	**56,145**	**56,730**
4	2023 NQC List	47,304	47,304	47,304	47,304
5	Event-Based Demand Response	1,090	1,105	1,111	1,111
6	Imports	5,500	5,500	5,500	5,500
7	Estimate of Incremental Authorized Procurement	1,695	6,505	9,725	10,325
8	Thermal Derates from 2023 NQC List	(726)	(726)	(726)	(726)
9	Remove Diablo from Planning	-	-	(2,280)	(2,280)
10	OTC, Retired or Contracted by DWR	-	(3,692)	(3,692)	(3,692)
11	Excess IOU Procurement for Higher Effective PRM	(1,331)	(1,424)	(1,440)	-
12	Retention for Substitution	(619)	(619)	(619)	(619)
13	**Total RA Supply**	**52,913**	**53,953**	**54,883**	**56,922**
14	Surplus Supply (Deficit)	(1,397)	(1,593)	(1,262)	192

LSEs procuring RA for 2023 likely experienced even greater levels of market tightness than this analysis suggests because the entire Western region is constrained, reducing the availability of imports to California and risking increased exports of California resources to meet other Western region requirements (e.g., Western Resource Adequacy Program). A detailed description of current RA market conditions including a list of sources used to develop the stack analysis in Figure 4 can be found in Attachment B incorporated herein. When it comes to IRP compliance, the Commission has acknowledged "…LSEs and developers are facing exogenous factors such as supply chain impacts on availability of raw materials, import investigations with respect to solar panels, tightening of the economy in the face of inflation, increased demand for clean energy resources throughout the west and globally, and other factors that have material impacts on the development of projects."[54] While LSEs have been able to meet their IRP

[54] D.23-02-040, *Decision Ordering Supplemental Mid-Term Reliability Procurement (2026-2027) and Transmitting Electric Resource Portfolios to California Independent System Operator for 2023-2024 Transmission Planning Process*, R.20-05-003 (Feb. 28, 2023), at 8: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M502/K956/502956567.PDF.

compliance obligations to date "due to excess procurement by the CCAs and ESPs[,]"[55] the bulk of procurement ordered by the Commission has compliance dates of 2024 and later, so these exogenous factors may still have impacts on LSEs' abilities to meet their IRP procurement obligations in future years.

Asking LSEs to be compliant with RA requirements and IRP procurement orders to receive an FSR discount may be realistic when there is sufficient excess RA capacity to produce a competitive RA market and when procurement is ordered in a programmatic and predictable manner. At present, however, RA capacity appears inadequate to meet the RA program's compliance requirements and exogenous factors are complicating efforts to develop new projects in response to IRP procurement orders that require compliance in a short timeframe. The Commission should therefore modify Energy Division's proposal to ensure that it is not too limiting in its qualifications for obtaining the discount by striking the requirement that the LSEs have substantially met their RA and IRP requirements.

In adopting the FSR discounting mechanism, the Commission should also clarify how the FSR will be discounted. Energy Division Staff suggested calculating the FSR "assuming winter market conditions" if a CCA qualifies for the discount,[56] but a number of open questions remain about how this would be done.[57] Alternatively, CalCCA recommends the Commission instead use the lower of the current FSR and the last FSR. This would essentially allow the CCA to post

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55 *Summary of Compliance with Integrated Resource Planning (IRP) Order D.19-11-016 and Progress Toward Mid Term Reliability (MTR) D.21-06-035 Procurement*, (Feb. 2023), at slide 24: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/d1911016andd21.pdf.

56 Energy Division Staff Proposal at 13.

57 *California Community Choice Association's Comments on the Ruling of the Assigned Administrative Law Judge Entering Staff Proposal into the Record and Noticing Public Workshops*, R.21-03-011 (Apr. 18, 2023) at 16: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M506/K523/506523253.PDF.

the lower of the most recent summer FSR and most recent winter FSR. Using winter conditions may not always result in a smaller FSR posting if the winter energy price forwards are unusually high, as observed in the example FSR calculations presented by CalCCA and the IOUs at the April 4, 2023, workshop.

C. Provide a Ramping Period for the First FSR Posting After the Phase 1 Decision and a Ramping Period for New CCAs

Upon adoption of a Phase 1 decision, CCAs may be required to post FSR amounts very different than they have posted in the past. To address this, the Energy Division Staff proposal includes a ramping period for any FSRs that are above a certain amount for the first FSR posting after a Phase 1 Decision. The Energy Division Staff proposal would also allow a ramping period for new CCAs' first posting.[58] CalCCA supports a ramping period for the first FSR postings after the Phase 1 final decision and a ramping period for new CCAs. The Commission should design the ramping period such that the ramping period covers the CCA's first two FSR postings after the final decision or its first two postings as a new CCA. This would ensure the ramping period covers at least one summer FSR posting, which is more likely to require a larger posting amount. During the ramping period, the CCA should be required to post half the calculated amount or the minimum, whichever is greater.

VI. FINANCIAL MONITORING

A. The Commission Should Adopt the Energy Division Staff Proposal on Financial Monitoring Proposal with Modifications

A financial monitoring framework should be aimed solely at providing the Commission advance notice of potential customer returns. In addition, the financial monitoring framework should result in an administratively simple approach that does not introduce any subjectivity

[58] Energy Division Staff Proposal at 12.

around when to report, does not require any premature action by the Commission or by the POLR, and does not require continual reporting by CCAs in good financial standing. The Commission should adopt the Energy Division Staff Proposal with modifications to accomplish these objectives.

Energy Division Staff proposes a financial monitoring framework that would require a CCA to report financial information upon meeting the following triggers:

- Downgrade below investment grade credit rating, or
- Days Liquidity on Hand (DLOH) is less than 45 days and Debt Service Coverage Ratio falls below 1.0, or
- Cash reserves is below 5% of annual expenses, or
- Default on procurement contract required to meet Resource Adequacy requirements or to the CAISO scheduling coordinator due to non-payment
- Insolvency or bankruptcy.

After meeting one of these triggers, the Energy Division Staff Proposal would require the CCA to submit a confidential letter to Energy Division within 10 days, meet with Energy Division as requested up to once per month, and provide Energy Division with information regarding contracting, financials, and plans for correction and/or market exit.[59] The Commission should adopt the Energy Division Staff Proposal's proposed list of conditions that would trigger financial reporting with the following modifications.

First, after submitting the confidential letter to the Director of Energy Division and before requiring the up to once per month meeting to provide the CCA's financial information, the Commission should require the CCA who triggered financial reporting to have an initial consultation with Energy Division to explain the reasoning behind their trigger. This initial

[59] Energy Division Staff Proposal at 9-10.

consultation would include the CCA providing information regarding any counterbalancing factors and/or projected timelines to meet target levels. If after the initial consultation, the CCA can demonstrate that its triggering event was not indicative of poor financial health, then the Commission would not require additional financial reporting. The Commission should adopt this approach because not all situations leading to a CCA hitting one of the triggers are indicative of poor financial health that would require continual monthly meetings and financial reporting.

Second, the Commission must define criteria that, once met, would allow a CCA to stop financial reporting. These criteria should allow the CCA to demonstrate that it has corrected the financial conditions that initially caused it to be required to report its financials. CalCCA recommends the following criteria, meant to mirror the criteria that would trigger reporting:[60]

- DLOH of 45 days or more or Debt Service Coverage Ratio 1.0 or above;
- Cash reserves of five percent of annual expenses or above;
- Resolving or replacing any RA contract defaults for the immediate RA compliance year (e.g., either by paying the counterparty or by procuring sufficient RA contracts to replace the defaulted contract) or resolving any non-payments to the CAISO scheduling coordinator; or
- Emerging from insolvency/bankruptcy.

CalCCA recommends the Commission require CCAs to evaluate the metrics that would trigger ending financial reporting on a monthly basis to avoid the need for the CCA to report, and the Commission to monitor, on a continuous basis.

Third, the Commission should modify the fourth trigger from "Default on procurement contract required to meet Resource Adequacy requirements or to the CAISO scheduling coordinator due to non-payment" as follows. First, modify the fourth trigger to incorporate the

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60 Given the time it takes for the rating agencies to modify credit ratings, CalCCA recommends that if a CCA receives a downgrade below investment grade, it not be required to continue to report once the other four other criteria are met.

following language: “Event of Default with respect to a buyer’s payment obligations under a procurement contract required to meet Resource Adequacy requirements, provided that a CCA is entitled to any applicable cure periods under such procurement contract.” Contractual breach may occur for a number of reasons unrelated to CCA financial condition. The proposed modification above clarifies that the fourth trigger does not include an Event of Default unrelated to a CCA's financial condition, such as Events of Default caused by a seller or with respect to a buyer's non-financial performance obligations. Second, add a fifth trigger as follows: “Failure to pay a CAISO scheduling coordinator.” CalCCA recommends use of the term “Event of Default” because it is a standard defined term in RA contracts that has written notice requirements and that can result in contract termination if not cured. The term “default” is typically not defined in RA contracts and will result in too much uncertainty for the Commission and LSEs about when the trigger has in fact occurred.

Fourth, the Commission should make the following clarifications relative to the “Downgrade below investment grade credit rating” trigger. The Commission should clarify that it would not require LSEs without a credit rating to report – it would only require reporting if a rated LSE went from an investment grade rating to a noninvestment grade rating. This clarification is necessary to avoid overly burdening CCAs without credit ratings by continually requiring them to report until they get a credit rating, even if all their other financial information points to good financial health. For CCAs that share jurisdiction with a city, the credit rating of the City should apply to the CCA itself for the financial monitoring requirements. This is the methodology the CAISO uses for a CCA sharing a jurisdiction with a city when it evaluates credit ratings for its purposes.

Finally, the Commission must clarify how DLOH and Debt Service Coverage Ratios will be calculated. CalCCA recommends the following:

Days Liquidity on Hand:

- Numerator: CCA's available unrestricted cash and investments and eligible unused bank LOCs and capacity under commercial paper programs, multiplied by 365
- Denominator: CCA's annual operating and maintenance expenses, excluding depreciation and amortization

Adjusted Debt Service Ratio:

- Numerator: Annual recurring revenue plus interest income plus withdrawals from a Rate Stabilization Fund; minus recurring annual cash operating expenses and General Fund Transfers
    - Recurring revenue and recurring expenses exclude special, one-time items
    - Annual operating expenses excluding depreciation and amortization expenses
- Denominator: Aggregate annual debt service (principal, interest, and fees)

The Commission should adopt the Energy Division Staff proposal with these modifications. The resulting financial monitoring framework would result in an administratively simple approach that does not introduce any subjectivity around when to report, does not require any premature action by the Commission or by the POLR, and does not require continual reporting by CCAs in good financial standing.

B. As Long as the POLR is also a Market Participant, the Commission must not Provide the POLR with Confidential Information about LSEs who Trigger Financial Monitoring

The Commission must keep a CCA's financial reporting, including both the triggering of financial reporting and the reported information, confidential to protect the CCA's market sensitive information. This includes keeping the information confidential from the POLR, given the POLR is also a market participant and an entity triggering financial reporting will not always result in the entity returning load to the POLR. The Commission should make it explicit that (1) an event that triggers CCA financial reporting and (2) information submitted by a CCA pursuant to its financial reporting requirement is confidential from the POLR.

Providing confidential financial information about one LSE to another LSE and/or counterparty will put the LSE receiving the financial information at a competitive advantage. The IOU acts as both a POLR and an LSE. In its LSE role, the IOU directly competes with CCAs in the same markets to procure capacity, energy, and GHG-free attributes to serve their customers. Additionally, CCAs and IOUs may contract with each other to buy and sell these products. If the POLR, as an LSE, possesses non-public information about a financial reporting trigger, they may take actions in buying from and/or selling to the CCA that they would not have if they were positioned similar to any other market participant. A CCA triggering financial reporting will not always mean the CCA will return load to the POLR, and, therefore, it is too early for Energy Division to report to the POLR upon a CCA triggering financial monitoring.

Finally, there is not a clearly defined need for providing the POLR with a CCA's financial information, given the POLR would not conduct procurement in anticipation of customer return. If the Commission notifies the POLR that a CCA has triggered financial reporting, would the POLR take any concrete steps to prepare for customer return that is not guaranteed to occur? If there are steps the POLR would take after a CCA triggers financial reporting, the Commission must weigh the benefits and impacts of taking action. That is, what benefit is provided through providing this information to the POLR and what is the impact of intervening in a market with the provision of otherwise confidential information affecting the competitiveness of the CCA. If the Commission must inform the POLR of the potential to receive returned load, the Commission must do so without identifying the entity that may return load. Doing so would provide the POLR, in this case the IOU, with information about a potential counterparty that is not otherwise available to the market.

If, however, the Commission does allow Energy Division to share financial information with the POLR and identify the entity that triggered financial reporting, then the Commission must require the POLR to establish rules that dictate how the POLR will protect confidential, market sensitive information received from Energy Division or the CCA. It must also develop procedures to prevent the sharing of confidential, market sensitive information from IOU employees serving in a procurement function, risk management function, or any functions beyond the IOU's POLR function.

VII. CONCLUSION

CalCCA appreciates the Commission's consideration of the recommendations set forth herein.

Respectfully submitted,

Evelyn Kahl

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

July 10, 2023

ATTACHMENT A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
OPENING BRIEF

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	JointCCAs_014-Q004		
PG&E File Name:	GRC-2023-PhI_DR_JointCCAs_014-Q004Supp01		
Request Date:	April 28, 2022	Requester DR No.:	014
Date Sent:	May 13, 2022 (Original) May 27, 2022 (Supplemental)	Requesting Party:	City and County of San Francisco/ East Bay Community Energy/ Marin Clean Energy/ Peninsula Clean Energy Authority/ Pioneer Community Energy/ San José Clean Energy/ Silicon Valley Clean Energy Authority/ Sonoma Clean Power Authority
PG&E Witness:	Ed Fertuna	Requester:	Jacob Schlesinger

QUESTION 004

Referring to PG&E's response to Joint CCA Data Request 12 Q5 and PG&E Advice Letter 5359-E, p. 2, please explain the basis for the 4 minute processing time referenced in the Advice Letter, and provide all calculations and assumptions that went into that estimate.

ANSWER 004

PG&E responds that Advice Letter 5359-E describes the basis for the 4 minute processing time. Please see PG&E-6, Chapter 2, pp. 2-28 through 2-29, filed in PG&E's 2020 GRC, for the underlying calculations of this estimate.

ANSWER 004 SUPPLEMENTAL 01

PG&E responds that it has no workpapers with the calculations underlying the four minute processing time. CSR handling was manually timed to determine the duration of the required average processing time. The assumptions therein (as discussed in Advice Letter 5359-E and PG&E's 2020 GRC), amounting to the four minutes, include:

- *Notice To Return To PG&E Bundled Service, PG&E Form 79-1011, (Notice) received and processed by Mail Room.*
- *Customer Service Representative verifies information on Notice is valid and complete.*
- *If Notice is valid and complete, CCASR (electronic switching request) created in PG&E's Billing System.*
- *If Notice is not valid and complete, call placed to customer to get needed information.*
- *Electronic storage of customer Notice*

ATTACHMENT B
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
OPENING BRIEF

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

Updated March 20, 2023

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

Updated March 20, 2023

1. Introduction

The Resource Adequacy (RA) supply available within the California Independent System Operator (CAISO) balancing area for 2023 appears inadequate 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 is razor thin "on paper."[1] The recent 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, however, the razor-thin margin becomes a material supply deficiency.

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 reduction in 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%, with a 20-22.5% "effective" PRM for investor-owned utilities (IOUs), increased RA requirements.
- CPUC'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 CPUC's RA program reduced the availability of imports to the CPUC-jurisdictional RA market.

The RA supply deficiency 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 CPUC's RA program were unable to obtain enough supply to comply with their

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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 likely sufficiency of energy to meet Summer 2023 needs.

2 Historical RA import data from the CAISO demonstrates that the amount of imports in year-ahead RA showings declined from 5,900 MW in 2020 to 3,600 MW in 2022. RA imports from unspecified declined from 4,300 MW to 1,300 MW over the same period. Historical year-ahead RA data: http://www.caiso.com/Documents/HistoricalYearAheadResourceAdequacyAggregateData.xlsx.

year-ahead RA compliance requirements despite numerous formal solicitations and substantial bilateral outreach. Recent experience suggests the problem will only grow in the month-ahead RA compliance process absent a substantial increase in hydro output, imports, or expedited deployment of new resources.

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. 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 estimated RA imports. RA supply is primarily derived from the CAISO'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, demand for RA exceeds the available supply of RA, even after accounting for imports and expected addition of resources, in three of the four peak summer months. The projected deficit is nearly 1,400 megawatts (MW) in September 2023. The scarcity of supply makes it difficult, if not impossible, for every LSE to meet its RA requirements.

[3] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2019rareport-1.pdf, at 22.

CALCCA ADVANCING LOCAL ENERGY CHOICE

Figure 1

		Jun	Jul	Aug	Sep
1	CAISO 1-in-2 Load	42,056	45,397	45,922	46,819
2	Reserve Margin (16%)	6,729	7,264	7,347	7,491
3	**Total RA Demand**	**48,786**	**52,661**	**53,269**	**54,310**
4	Owned by Calpine	5,874	5,864	5,861	5,867
5	Owned by AES	3,657	3,657	3,655	3,655
6	Owned by NRG	2,321	2,317	2,315	2,322
7	Owned by Other	36,426	36,843	36,124	35,460
8	Event-Based Demand Response	995	1,045	1,077	1,090
9	Imports	5,500	5,500	5,500	5,500
10	Thermal Plant Derate	(726)	(726)	(726)	(726)
11	Excess IOU Resources Above PRM (D.21-12-015)	(794)	(925)	(664)	(206)
12	Supply-Side Emergency Reliability Procure. (D.21-12-015)	(883)	(933)	(824)	(1,125)
13	Retention for Substitution	(619)	(619)	(619)	(619)
14	**Total RA Supply**	**51,751**	**52,023**	**51,699**	**51,218**
15	Surplus Supply (Deficit)	2,966	(638)	(1,570)	(3,092)
16	Expected New Resources	-	-	1,695	1,695
17	Surplus Supply (Deficit) with New	2,966	(638)	125	(1,397)

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 11 through 13, 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 CPUC.[4]
2	Planning Reserve Margin per CPUC D.22-06-050[5]
4-7	California ISO NQC List. The CAISO lists the net qualifying capacity (NQC) for all resources in the CAISO footprint for 2023.[6] We identify the plant owner by matching the resource identification number (resource ID) in the NQC list to the resource ID in the CAISO Master Generating List.[7] Three companies (Calpine, AES, and NRG) and their affiliates own nearly 12 GW (over 20%) of NQC.

4 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.

5 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.

6 CAISO 2023 NQC List: https://www.caiso.com/Documents/2023-net-qualifying-capacity-values-for-resource-adequacy-resources.html.

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

Row(s)	Source
8	Event-Based Demand Response. Demand response quantities are from the CPUC's Resource Adequacy Compliance Materials.[8] Demand response totals include avoided losses and are from event-based programs at PG&E, SCE, and SDG&E.
9	Imports. Imports reflect the CEC's assumed RA imports available to the CAISO market.[9]
10	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.[10] Our approach parallels recent CPUC discussions regarding the need to include thermal derates in reliability modeling.[11]
11	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."[12] Line 11 represents the total of the three IOUs' excess resources from their portfolios as filed in the IOU 2022 Excess Resources Report.[13]
12	D.21-12-015 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% 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.[16]

8 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.

9 Joint Agency Reliability Planning Assessment - SB 846 Quarterly Report and AB 205 Report, at 43: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-ESR-01.

10 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.

11 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.

12 D.21-12-015 at 103

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

14 D.21-12-015 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.

16 CalCCA used the amounts in the IOU reports and removed those resources that would not otherwise qualify for RA (*e.g.*, Emergency Load Reduction Program). The resources included in row 12 include firm energy imports, additional RA contracts, tolling agreements, extension of existing contracts that are RA eligible, and contracts for increased output where the efficiency upgrades likely could have been financed by an RA contract with an LSE.

Row(s)	Source
13	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]
16	Expected new-build resources online by 8/1/23. Resources mandated by the CPUC pursuant to D.19-11-016 and D.21-06-035 assuming a 40% delay and/or failure rate.

4. Tight Conditions Are Likely to Persist Through 2026

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 Diablo Canyon Power Plant (DCPP) and 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.[18]

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

- The load forecast for 2024-26 is based on the CEC's 2022 Integrated Energy Policy Report Planning scenario;[19]
- The planning reserve margins for 2024-2026 increase to 17%;[20]
- In line with the assumptions of the Joint Agency Reliability Planning Assessment, described in the next section, DCPP is retired in 2025 and the remaining once-through-cooling plants are assumed to be procured by DWR;[21] and
- Excess IOU procurement for a higher effective PRM continues through 2025.[22]

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17 https://www.cpuc.ca.gov/industries-and-topics/electricalenergy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliancematerials.

18 D.22-06-050 at 128.

19 CEC's California Energy Demand 2022 Hourly Forecast for the CAISO region with the Planning Scenario, based on the monthly maximum of the CAISO Managed Net Load: https://efiling.energy.ca.gov/GetDocument.aspx?tn=248359&DocumentContentId=82768.

20 D.22-06-050 at 125 requires a 17% PRM for 2024, we assume the same for 2025-26.

21 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.

22 R.21-10-002, Appendix A, *Energy Division Proposals for Proceeding R.21-10-002* (Jan. 20, 2023), at 7: As part of Proposal 1, Energy Division staff propose to retain the 17% PRM while also extending the effective PRM through 2025 at a level of 3% of the forecasted peak load. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M501/K407/501407493.PDF.

Figure 2

	September NQC	2023	2024	2025	2026
1	CAISO 1-in-2 Load	46,819	47,475	47,987	48,487
2	Reserve Margin (16% in '23, 17% after)	7,491	8,071	8,158	8,243
3	**Total RA Demand**	**54,310**	**55,546**	**56,145**	**56,730**
4	2023 NQC List	47,304	47,304	47,304	47,304
5	Event-Based Demand Response	1,090	1,105	1,111	1,111
6	Imports	5,500	5,500	5,500	5,500
7	Estimate of Incremental Authorized Procurement	1,695	6,505	9,725	10,325
8	Thermal Derates from 2023 NQC List	(726)	(726)	(726)	(726)
9	Remove Diablo from Planning	-	-	(2,280)	(2,280)
10	OTC, Retired or Contracted by DWR	-	(3,692)	(3,692)	(3,692)
11	Excess IOU Procurement for Higher Effective PRM	(1,331)	(1,424)	(1,440)	-
12	Retention for Substitution	(619)	(619)	(619)	(619)
13	**Total RA Supply**	**52,913**	**53,953**	**54,883**	**56,922**
14	Surplus Supply (Deficit)	(1,397)	(1,593)	(1,262)	192

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%. 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 higher percentage of completion of new resources by August 1, 2023 (1,750 MW vs. 1,695 MW);
- 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 2,359 MW of wind and solar NQC in the RA stack;
- 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 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. The Joint Agency assessment is summarized below in Figure 3, which was prepared by CalCCA using Joint Agency data.[23]

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. Conclusion

The supply of Resource Adequacy is insufficient to meet 2023 demand. This insufficiency made it impossible for all LSEs to comply with year-ahead requirements, and the insufficiency likely will carry into month-ahead compliance requirements absent a significant increase in hydro RA availability. 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.

Five interim actions should be considered.

1) Recognize the RA supply insufficiency and its consequences in the CPUC's next RA decision.

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23 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.

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) 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.
4) 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.
5) Increase market transparency by providing aggregated compliance data to reveal (a) trends in the categories of resources (e.g., imports, storage) used for compliance and (b) the extent of California resource exports.