

# **MAY FILINGS**



## Comments on draft final proposal

Initiative: Subscriber participating transmission owner model

### Comment period

Apr 18, 2023, 02:00 pm - May 02, 2023, 05:00 pm

### Submitting organizations

California Community Choice Association

## California Community Choice Association

Submitted on 05/02/2023, 12:37 pm

### Contact

Shawn-Dai Linderman (shawndai@cal-cca.org)

### 1. Please provide a summary of your organization's comments on the draft final proposal.

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (ISO) Subscriber Participating Transmission Owner (PTO) Model Draft Final Proposal. CalCCA supports the Subscriber PTO model as an alternative way to develop new transmission with commercial interest without increasing the ISO's transmission access charge (TAC). The ability to develop new transmission through multiple avenues will enable the development of more transmission that is critically needed to support the state's clean energy policy goals.

### 2. Please provide your organization's comments on the proposed use of encumbrances, as described in the draft final proposal.

First and foremost, CalCCA agrees with the principle that the capital and operations and maintenance (O&M) costs of the Subscriber PTO transmission projects should not receive cost recovery through the ISO's TAC. Subscriber PTO projects will not go through the Transmission Planning Process (TPP) to receive approval and, therefore, should not receive cost recovery through TAC. Given the subscribers and their offtakers will fund the project, rather than the TAC, CalCCA agrees the subscribers should receive encumbrances with scheduling rights and the perfect hedge.

### 3. Please provide your organization's comments on the proposed Subscriber Wheeling Charge, as described in the draft final proposal.

CalCCA generally supports the ISO's proposal to charge non-subscribers the TAC or wheeling access charge (WAC) to use the Subscriber PTO line and use the TAC or WAC charges to first pay

for the subscriber WAC developed by the subscriber and approved by the Federal Energy Regulatory Commission (FERC). The ISO should ensure that it is clear in what instances a non-subscriber load-serving entity would be charged the TAC versus the WAC. As long as this information is clear, the non-subscriber can schedule their load in a manner that makes them indifferent from using the subscriber PTO line versus another path.

**4. Please provide your organization's comments on the proposed revision to the revenue recovery of the Subscriber Wheeling Charge, as described in the draft final proposal.**

See response to question 3.

**5. Please provide your organization's comments on the proposed termination of the Subscriber Encumbrance, as described in the draft final proposal.**

The Draft Final Proposal indicates that the decision of whether to continue the subscriber encumbrance after the original encumbrances end will be determined based upon the regulatory requirements at the time and the Subscriber PTO's intentions for the future of its transmission facilities. CalCCA does not oppose this treatment so long as the Subscriber PTO project is fully subscribed, and the Subscriber PTO project will not receive any TAC cost recovery for the original project's costs and associated O&M.

**6. Please provide your organization's comments on the proposed Subscriber PTO project interconnection cost recovery for generator interconnections subsequent to the original build of the Subscriber PTO transmission facilities, as described in the draft final proposal.**

CalCCA supports the Subscriber PTO developing a transmission revenue requirement for network upgrades associated with only subsequent generator interconnection requests that are not a part of the original build of the project. The ISO should only include generator network upgrades identified after the original build and identified through the generator interconnection and deliverability allocation procedures in the TAC.

**7. Please provide your organization's comments on the transmission planning process and transmission issues, as described in the draft final proposal.**

CalCCA agrees that the ISO should add a new Subscriber PTO upgrade to the TAC if the upgrade is incremental to the original build costs and if the ISO has selected the upgrade through the TPP. The ISO must ensure it does not later include the costs associated with the original build of the project in the TAC.

**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 REPLY COMMENTS ON  
THE RULING OF THE ASSIGNED ADMINISTRATIVE LAW JUDGE ENTERING  
STAFF PROPOSAL INTO THE RECORD AND NOTICING PUBLIC WORKSHOPS**

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May 5, 2023

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## SUMMARY OF RECOMMENDATIONS

### FSR Calculation

- The California Public Utilities Commission (Commission) must not ignore the hedge value of Power Charge Indifference Adjustment (PCIA) and Cost Allocation Mechanism (CAM) Energy in the financial security requirement (FSR) calculation;
- The Commission should defer consideration of Pacific Gas and Electric Company's (PG&E) two months of energy proposal to Phase 2;
- The Commission should not adopt seasonal Resource Adequacy (RA) costs if it adopts seasonal rates because, unlike seasonal rates, there is no readily available seasonal RA cost measurement;
- The FSR should be reduced for the RA capacity of CAM, Demand Response (DR), and Central Procurement Entity (CPE) allocations because they automatically return to the Provider of Last Resort (POLR) as RA requirements transfer from the deregistering Load Serving Entity (LSE) to the POLR;

### FSR Affordability

- The Commission must discount the FSR to account for the probability that customer return will occur;
- PG&E incorrectly states there were no capacity insufficiencies during previous customer returns to the POLR;

### Financial Monitoring

- The Commission should not require continual financial reporting from community choice aggregators (CCA) that have not triggered financial monitoring;
- 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 should not require CCAs to provide non-confidential financial information to the POLR upon request, as this information is already publicly available for the POLR to access;
- The Commission should not require meetings similar to the Procurement Review Group (PRG) as part of CCA financial monitoring;
- The Commission should not adopt any triggers that are undefined or that introduce subjectivity;

## Summary of Recommendations continued

- The Commission should adopt Staff's Proposal for Financial Monitoring Triggers, as Parties' proposed recommendations to the triggers are excessive, or lead to unintended consequences;

### Contract Assignment

- The Commission should reject The Public Advocates Office at the California Public Utilities Commission's Right of First Refusal proposal and the Solar Energy Industries Association and Large-Scale Solar Association's required contract novation proposal and alternative proposal; and
  - Energy Division should clarify the process for implementing a discount to the FSR/Re-entry Fee based upon the assignment of an RA Contract.
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**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**

The California Community Choice Association<sup>1</sup> (CalCCA) submits these Reply Comments in response to the *Ruling of the Assigned Administrative Law Judge Entering Staff Proposal Into the Record and Noticing Public Workshop*,<sup>2</sup> *E-Mail Ruling Granting Request to Reschedule Workshop and Extend the Deadline For Filing Comments*,<sup>3</sup> and *E-Mail Ruling Granting Request to Reschedule Workshop and Extend the Deadline For Filing Comments*.<sup>4</sup>

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

<sup>2</sup> *Ruling of the Assigned Administrative Law Judge Entering Staff Proposal Into the Record and Noticing Public Workshops*, Rulemaking (R.) 21-03-011 (Jan. 6, 2023) (Ruling): <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M500/K761/500761891.PDF>.

<sup>3</sup> *E-Mail Ruling Granting Request to Reschedule Workshop and Extend the Deadline For Filing Comments*, R.21-03-011 (Feb. 27, 2023): <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M502/K757/502757266.PDF>.

<sup>4</sup> *E-Mail Ruling Granting Request to Reschedule Workshop and Extend the Deadline For Filing Comments*, R.21-03-011 (Mar. 17, 2023): <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M503/K824/503824337.PDF>.

## I. INTRODUCTION

In these reply comments, CalCCA responds to parties' opening comments on the financial security requirement (FSR) proposals presented through the calculators at the April 4, 2023 workshop, and parties' opening comments on the *Energy Division Staff Analysis and Proposal for Phase 1 Issues in the Provider of Last Resort Proceeding*<sup>5</sup> (Staff Proposal). CalCCA continues to support updates to the FSR calculation that better reflect the likelihood of customer return and the actual costs and revenues the Provider of Last Resort (POLR) can expect to receive upon customer return. CalCCA also supports many of the elements in the Staff Proposal with the modifications described in CalCCA's opening comments.<sup>6</sup> CalCCA's reply comments conclude as follows:

### **FSR Calculation**

- The California Public Utilities Commission (Commission) must not ignore the hedge value of Power Charge Indifference Adjustment (PCIA) and Cost Allocation Mechanism (CAM) energy in the FSR calculation;
- The Commission should defer consideration of Pacific Gas and Electric Company's (PG&E) two months of energy proposal to Phase 2;
- The Commission should not adopt seasonal Resource Adequacy (RA) costs if it adopts seasonal rates because, unlike seasonal rates, there is no readily available seasonal RA cost measurement;
- The FSR should be reduced for the RA capacity of CAM, Demand Response (DR), and Central Procurement Entity (CPE) allocations because they automatically return to the POLR as RA requirements transfer from the deregistering Load Serving Entity (LSE) to the POLR;

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<sup>5</sup> *Energy Division Staff Analysis and Proposal for Phase 1 Issues in the Provider of Last Resort Proceeding*, Rulemaking (R.) 21-03-011 (Jan. 6, 2023): <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M500/K762/500762116.PDF>.

<sup>6</sup> All references to party Opening Comments are to the comments filed in this Docket (R.21-03-011) on April 18, 2023 in response to the Ruling.

## **FSR Affordability**

- The Commission must discount the FSR to account for the probability that customer return will occur;
- PG&E incorrectly states there were no capacity insufficiencies during previous customer returns to the POLR;

## **Financial Monitoring**

- The Commission should not require continual financial reporting from community choice aggregators (CCA) that have not triggered financial monitoring;
- 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 should not require CCAs to provide non-confidential financial information to the POLR upon request, as this information is already publicly available for the POLR to access;
- The Commission should not require meetings similar to the Procurement Review Group (PRG) as part of CCA financial monitoring;
- The Commission should not adopt any triggers that are undefined or that introduce subjectivity;
- The Commission should adopt Staff's Proposal for Financial Monitoring Triggers, as Parties proposed recommendations to the triggers are excessive, or lead to unintended consequences;

## **Contract Assignment**

- The Commission should reject The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) Right of First Refusal (ROFR) proposal and the Solar Energy Industries Association and Large-Scale Solar Association's (SEIA/LSA) required contract novation proposal and alternative proposal; and
- Energy Division should clarify the process for implementing a discount to the FSR/Re-entry Fee based upon the assignment of an RA Contract.

In opening comments, many parties reiterate positions taken in previous comments that CalCCA has already responded to in previous reply comments. Where applicable, these comments cite previous comments that reflect CalCCA's positions on these topics.

## II. FSR CALCULATION

### A. The Commission Must Not Ignore the Hedge Value of CAM and PCIA Energy in the FSR Calculation

While Cal Advocates, PG&E, Southern California Edison Company (SCE), and San Diego Gas & Electric (SDG&E) oppose the notion of reducing the FSR by the amount of energy from CAM and PCIA that is hedging load, none argue that it is not actually hedging consumer costs. SCE argues that CAM energy is billed and collected through distribution rates and the FSR is for Energy Resource Recovery Account (ERRA) related costs.<sup>7</sup> While the distinction may be true, it fails to recognize that like the amount of capacity already purchased by the customer and allocated to their CCA via CAM, the same is effectively true for the energy value and accordingly, should accrue to the CCA and its customers to address FSR needs.

In addition, SCE argues that the returning customers do not pay twice for the hedge value of the PCIA.<sup>8</sup> Without further discussion of the detailed accounting framework used to account for the PCIA over and under collections, CalCCA cannot conclude that SCE is correct in this assertion. Returning customers, in the case that the tariffed rate does not cover current market costs, risk paying more than bundled customers will pay under the current formulation:

<b>Bundled Customer</b>	<b>Returning Customer</b>
Tariffed Rate	Tariffed Rate
N/A	Incremental market value through Reentry Fee
ERRA shortfall amortization to recover incremental market value	ERRA shortfall amortization to recover incremental market value

At the very least, it is clear that the timing of the mechanism is ill suited for the return of customers in that the re-entry fee could calculate a large amount to be funded by the CCA or its

<sup>7</sup> SCE Opening Comments at 16-17.

<sup>8</sup> *Id.* at 18-20.

customers while at the same time, an over-collection in ERRA accrues. If the concern for customer costs is a part of this proceeding, then the re-entry fee process should account for these offsetting effects so that in the instant, customers are not hit with high bills only to be followed later by a reduction when the PCIA values are accounted for. It is the very offset that supports the conclusion that the PCIA and CAM energy are both hedges against customer costs for which the FSR and re-entry fee should account.

Finally, SCE states that they do “not contract for hedges for off-peak hours, so again, the [CalCCA] proposal would overvalue the hedges.”<sup>9</sup> To CalCCA’s knowledge, the PCIA and CAM fleet both contain resources capable of producing energy in both peak and off-peak periods. The question is not whether SCE “contracts” for hedges during off-peak hours; the ownership of the fleet creates a natural physical hedge without contracting. If the energy amounts provided by SCE in response to the CalCCA data request do not provide energy in the off-peak periods, then the CalCCA calculator actually under-values the hedges in that the off-peak forward energy prices are lower than the on-peak forward prices. That aside, since the resources available to SCE in the CAM and PCIA produce energy in both on and off-peak periods, the hedge value is not overstated nor does CalCCA suggest that a true forecast of the energy values should be over or understated for purposes of the FSR calculation. Rather a forecast of output from the resources using the same Intercontinental Exchange (ICE) - forward energy prices should be used to determine when the resources are “in the money”.

**B. The Commission Should Defer Consideration of PG&E’s Two Months of Energy Costs Proposal to Phase 2**

PG&E’s comments state that while it is “well positioned to reliably serve its bundled service customers and meet state policy goals,” it continues to propose an FSR and re-entry fee

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<sup>9</sup> *Id.* at 15.

framework that covers at least 60 days of incremental procurement costs. Its justification for this proposal is that “the financial strength of PG&E should not be hampered by having to bear the incremental costs as the POLR and reserving financial liquidity and using up its own credit capacity to service million of CCAs’ customers on an emergency basis.”<sup>10</sup> The Commission should reject PG&E’s proposal to base the FSR on two months of procurement costs and instead focus on modifications to the individual components of the FSR calculation to make them more accurate.

While PG&E claims to be “well positioned to reliably serve its bundled service customers,” it then goes on to state concerns over serving in the role of POLR unless it can get two months of the California Independent System Operator Corporation (CAISO) energy costs not offset by any customer revenues. Interestingly, neither SCE nor SDG&E seem to share the same concern, or at least do not make the same demand. In particular, SDG&E faces a significant amount of CCA load from a single CCA. PG&E, on the other hand, faces a significant amount of load being served by CCAs but the number of CCAs is significantly higher than that of SDG&E. This would imply that PG&E is concerned with a “black swan” event of a large number of CCAs in its area simultaneously returning load in an unplanned manner.

If PG&E and the Commission see this potential as so significant that it will place the health of the investor-owned utility (IOU) at risk, then the Commission should move expeditiously to the second phase of this proceeding. The second phase must then focus on identifying a non-IOU entity whose financial capability is not threatened in the manner that PG&E is concerned.

Absent that assessment, the Commission should continue with its plans to focus on modifications to the individual components of the FSR calculation to make them more accurate in

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<sup>10</sup> PG&E Opening Comments at 1-2.

this phase. It can then evaluate the need for an insurance pool to address PG&E's concern in the second phase of this proceeding and evaluate whether another entity should serve as the POLR.

**C. The Commission Should Not Adopt Seasonal RA Costs if it Adopts Seasonal Rates Because, Unlike Seasonal Rates, There is no Readily Available Seasonal RA Cost Measurement**

Conceptually, costs and rates that vary by time should be accounted for with such variation. Under the present FSR calculation, the cost of energy from the CAISO market is differentiated in that the IOUs use a forward price forecast of energy for the months the FSR is to cover. The monthly costs of RA are much less clear 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.

In its comments, SCE states, “[i]f the FSR and Re-Entry Fee calculations move away from an annual average generation rate to seasonal average generation rates to forecast the POLR’s revenues available to pay the cost of new generation, the cost of new procurement needs to fairly account for seasonality as well.”<sup>11</sup> CalCCA disagrees. Directionally, greater granularity in reflecting costs and revenues, where possible, improves the accuracy of the FSR posting. Moreover, SCE does not recognize that the current calculation already has a mismatch between non-seasonal retail rates and seasonal energy cost forecasts which are 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, 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

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<sup>11</sup> SCE Opening Comments at 12.

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. SCE suggests that the tail should wag the dog. Failing to seasonally differentiate revenues because matching RA costs are not available would allow the RA cost, representing approximately 10 percent of the summer costs, to drive greater misalignment of 100 percent of the revenues.

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 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 and should not do so where those values are not supported by evidence sufficient to provide a reasonably accurate value.

**D. The FSR Should be Reduced For the RA Capacity of CAM, DR, and CPE Allocations Because They Will Automatically Return to the POLR as RA Requirements Transfer from the Deregistering LSE to the POLR**

SCE and SDG&E indicate they support reducing the RA cost component by CAM, DR, and CPE credits only if the credits are immediately reallocated to the IOU POLR.<sup>12</sup> As CalCCA

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<sup>12</sup> SCE Opening Comments at 2, 12-13, and SDG&E Opening Comments at 19-20.

explained in its August 5, 2022 reply comments to SDG&E, there is no reason these credits would not be immediately transferred from the deregistering LSE to the IOU once the IOU takes on the RA obligations associated with the returning customers.<sup>13</sup>

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 resources already resides with the IOU as do the resources. There is no potential that the IOU will 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. Therefore, the Commission should modify the FSR calculation to reduce the amount of forecasted RA procurement the POLR will need to perform on behalf of returned customers.

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<sup>13</sup> *California Community Choice Association’s Reply 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 (Aug. 5, 2022), at 4-5: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M496/K416/496416748.PDF>.

### **III. FSR AFFORDABILITY**

#### **A. The Commission Must Discount the FSR to Account for the Probability That Customer Return Will Occur**

Cal Advocates and the IOUs do not support the Staff Proposal to provide a ramping period to increase the FSR posting amount to its required level over time; nor do they support reducing a CCA's FSR if the CCAs can demonstrate adequate hedging contracts, demonstrate compliance with RA and Integrated Resource Plan (IRP) obligations, and are not considered to be at financial risk.<sup>14</sup> These parties cite concerns around potential cost shifts to customers and uncertainty around the effectiveness of the criteria in mitigating the risk of deregistration. For the reasons described below, the Commission should reject the arguments made by Cal Advocates and the IOUs, and adopt the Staff Proposal with the modifications proposed by CalCCA.

As CalCCA explained in its July 5, 2022 comments on the FSR calculation,<sup>15</sup> it is universally accepted in energy markets that collateral requirements should be considered in light of risk factors. Cal Advocates and the IOUs ignore this principle in their arguments. Keeping the calculation as is without a risk adjustment, as these parties suggest, would set the FSR to cover 100 percent of the incremental procurement costs minus the expected revenues of the returning customers. 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.

Modifying the FSR calculation without considering the likelihood of customer return, as Cal Advocates and the IOUs recommend, will result in imbalanced and unnecessarily costly FSR postings. The Commission must strike the right balance between protecting bundled customers

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<sup>14</sup> Cal Advocates Opening Comments at 23, PG&E Opening Comments at 17-18, SCE Opening Comments at 27-29, and SDG&E Opening Comments at 13-15.

<sup>15</sup> *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 19-21.

and setting the FSR so high that it unreasonably reduces a CCA's liquidity or credit capacity, undermining stable operations at the expense of the CCA and its customers. 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.

When determining the likelihood of customer return, the Commission must evaluate CCAs based on attainable standards that consider market conditions at the time. The Staff Proposal makes positive steps towards accounting for risk by discounting the FSR if a CCA can demonstrate metrics that point to a low probability of failure. Under the Staff Proposal, if a CCA receives an FSR discount, the Commission has determined that the CCA's risk of involuntary customer return is low, and therefore the risks of customers having to pay re-entry fees are also low.

SCE states that if the Commission adopts a discount to the FSR, the Commission should "notify potential CCA customers well in advance of their automatic enrollment in a CCA program of the attendant risks, including the results of any risk assessment by the Commission, and on a regular basis during the pendency of any FSR discounting."<sup>16</sup> The Commission should reject SCE's recommendation. Customers served by an IOU take on risk associated with the IOU's service. The IOUs and the Commission regularly make decisions that will affect bundled customers' risk profiles, and the IOUs have no requirement to report those decisions and associated risks to their customers in a manner similar to what SCE proposes.

Notifying customers of risks associated with an FSR discount is unnecessary. If the Commission offers an FSR discount to a CCA under the Staff Proposal, the Commission has determined that the CCA's risk of involuntary customer return is low. The Commission should reject SCE's proposal to notify CCA customers of risks associated with an FSR discount.

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<sup>16</sup> SCE Opening Comments at 29.

**B. PG&E Incorrectly States There Were No Capacity Insufficiencies During Previous Customer Returns to the POLR**

PG&E states “...the most recent deregistration or withdrawal of the following CCAs happened outside of capacity market constraints: Butte Clean Energy (June/July 2020), Western Community Energy (June 2021), and the City of Baldwin [*sic*] (October 2021).”<sup>17</sup> The Commission should ignore PG&E’s claims that there were no capacity market constraints in 2020, 2021, and 2021 when evaluating the conditions for qualifying for an FSR adjustment to account for the probability of customer return.

PG&E’s assertions that the recent CCA deregistrations “happened outside of capacity market constraints” are factually incorrect. While market participants may disagree about the degree of constraint, there is scant, if any, evidence to support PG&E’s conclusion. The 2021 Resource Adequacy Report states:

The weighted average price of system RA for both seasons has increased each year, and at an accelerating pace. Average August prices were \$3.13/kW-month in 2017 but increased each year thereafter. By 2021 the average price had risen to \$8.07 kW/month, an increase of 158 percent over just 5 years. January RA prices increased a more modest 112 percent between 2017 and 2021, from \$2.52/kW-month to \$5.35/kW-month. These price increases appear to be driven by issues related to supply and demand balances due to resource retirements, load forecast increases, and changes in counting conventions for certain resources.<sup>18</sup>

CalCCA’s stack analysis in Table 1 compares total RA supply to RA requirements from 2021-2023 and indicates supply deficits each of those years.<sup>19</sup>

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<sup>17</sup> PG&E Opening Comments at 4 (footnote omitted).

<sup>18</sup> 2021 Resource Adequacy Report at 28 (emphasis added): [https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2021\\_ra\\_report.pdf](https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2021_ra_report.pdf).

<sup>19</sup> See Appendix A for data sources.

Table 1: 2021-2023 Stack Analysis

	<i>September NQC (MW)</i>	<i>2021</i>	<i>2022</i>	<i>2023</i>
1	CAISO 1-in-2 Load	45,966	46,319	46,829
2	Reserve Margin (15%)	6,895	6,948	7,493
<b>3</b>	<b>Total RA Demand</b>	<b>52,861</b>	<b>53,267</b>	<b>54,322</b>
4	NQC List	44,843	46,923	47,304
5	Event-Based Demand Response	1,212	1,136	1,090
6	Imports	6,409	5,500	5,500
7	Thermal Plant Derate	(557)	(650)	(717)
8	Excess IOU Resources Above PRM (D.21-12-015)	-	(206)	(206)
9	Supply-Side Emergency Reliability Procure (D.21-12-015)	-	(1,125)	(1,125)
10	Retention for Substitution	(619)	(619)	(619)
<b>11</b>	<b>Total RA Supply</b>	<b>51,289</b>	<b>50,959</b>	<b>51,227</b>
12	Surplus Supply (Deficit)	(1,572)	(2,308)	(3,094)
13	Expected New Resources	-	-	1,695
14	Surplus Supply (Deficit) with New Resources	(1,572)	(2,308)	(1,399)

In opening comments, CalCCA also demonstrated that capacity market constraints are expected to persist through at least 2026.<sup>20</sup> The Commission should ignore PG&E’s erroneous claims that there were no capacity market constraints in 2020 and 2021.

Setting the criteria for an FSR discount based upon compliance with the RA program will mean that some LSEs would be ineligible for a discount regardless of their efforts to comply with the program, their financial health, and their probability of failure.

Given these capacity market constraints, the Commission should adopt the Staff Proposal on FSR affordability with modifications that consider current capacity market conditions. The Staff Proposal would require that CCAs “[h]ave substantially met their month ahead during the

<sup>20</sup> CalCCA Opening Comments at 14.

past year and year ahead RA requirements for the following year, in compliance with IRP procurement requirements.” Setting the criteria for an FSR discount based upon compliance with the RA program, in a capacity constrained market, will ensure that some LSEs would be ineligible for a discount regardless of their efforts to comply with the program, their financial health, and their probability of failure. The Commission should remove this requirement for a CCA to be eligible to receive an adjustment to their FSR given CalCCA’s analysis of estimated available net qualifying capacity (NQC) appears insufficient to meet RA requirements.<sup>21</sup> In addition, the Commission has yet to demonstrate that the new RA structure, including requirements in all 24 hours, will not exacerbate this capacity insufficiency. Without knowing whether the fleet is sufficient to meet needs, including in a more granular and complex RA mechanism, it would be unreasonable to implement this provision.

#### **IV. FINANCIAL MONITORING**

When establishing financial reporting requirements, the Commission must ensure it (1) respects the authority of local governing boards over CCA financial oversight, (2) protects CCAs’ confidential information they report to Energy Division, (3) considers the financial position of each LSE, and (4) to the greatest extent possible, avoids immediate customer returns by an LSE coming as a surprise to the Commission or the POLR. The Staff Proposal, with the modifications proposed by CalCCA,<sup>22</sup> best meets these four objectives because it requires financial reporting dependent upon clearly defined financial metrics and clearly defines a pathway to end financial reporting, keeps reported information confidential, and allows Energy Division to gain greater insight into a CCA’s financial health upon a CCA triggering financial reporting. The Commission should adopt the Staff Proposal with CalCCA’s recommended

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<sup>21</sup> CalCCA Opening Comments at 13-16.

<sup>22</sup> *Id.* at 7-11.

modifications and reject party recommendations described below. These proposals would require reporting regardless of the CCAs' financial positions, expose confidential information to other market participants/counterparties, impose onerous reporting requirements of information already available, or usurp the CCA governing board's authority.

**A. The Commission Should Not Require Continual Financial Reporting from CCAs That Have Not Triggered Financial Monitoring**

The IOUs recommend the Commission adopt regular financial reporting for CCAs, rather than financial reporting upon meeting certain triggers. PG&E recommends the Commission require all CCAs to report on each of the triggers proposed in the Staff Proposal on a quarterly basis.<sup>23</sup> CalCCA generally supports the triggers in the Staff Proposal with modifications,<sup>24</sup> but does not support requiring CCAs to continually report on the metrics, even if a CCA has not triggered reporting. Requiring quarterly reporting for all CCAs regardless of whether a CCA has experienced a triggering event would be unnecessary.

SCE suggests that the Staff Proposal "relies too much on the honor system" regarding the reporting of triggering events.<sup>25</sup> CalCCA disagrees. Unlike profit-motivated LSEs, CCAs make their financial circumstances public, both in their Board packets and through links on the CalCCA website. In addition, the Commission has important existing enforcement mechanisms that it could apply to financial reporting. As CalCCA describes in its Opening Comments, failure to report a triggering event could be considered a Rule 1 violation, meaning CCAs would be obligated to report a triggering event or face the consequences of a Rule 1 violation. Relying on

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<sup>23</sup> PG&E Opening Comments at 13. The triggers CCAs would be required to report on quarterly are: downgrade below investment grade credit rating, Days Liquidity on Hand (DLOH) less than 45 days, Debt Service Coverage Ratio falls below 1.0, cash reserves is below 5% of annual expenses, default on procurement contract required to meet Resource Adequacy requirements or to the CAISO scheduling coordinator due to non-payment, insolvency or bankruptcy.

<sup>24</sup> CalCCA Opening Comments at 7-9.

<sup>25</sup> SCE Opening Comments at 26.

existing enforcement mechanisms will ensure CCAs report upon identification of a trigger event. Therefore, rather than requiring regular reporting, the Commission should require a CCA to assess its financial metrics once every 60 days, and report to Energy Division within 10 days if it observes a trigger event.

Cal Advocates recommends modifying the Staff Proposal’s trigger “downgrade below investment grade credit rating”<sup>26</sup> to “lacks investment grade credit rating.” The Commission should reject this modification. First, the lack of a credit rating alone is not indicative of poor financial health. The Staff Proposal recognizes the limits of relying on a credit rating and thus relies on other financial health metrics that a credit rating agency would similarly review. Requiring an investment grade credit rating to avoid continual financial monitoring by the Commission would place undue burden on smaller or recently-formed CCAs. As described in CalCCA’s April 15, 2022 Reply Comments,<sup>27</sup> obtaining a credit rating by an independent agency is costly and requires an extreme amount of time and effort that may be too burdensome for smaller or recently-formed LSEs. Additionally, the Cal Advocates proposal would have the practical effect of placing all newly-formed CCAs, irrespective of financial health, directly into financial monitoring since such entities will not have the requisite financial history to obtain any credit ratings. Requiring credit ratings of all CCAs would be unnecessarily burdensome, particularly when Energy Division can already obtain the information necessary to discern a CCA’s financial health through the triggers included in the Staff Proposal.

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<sup>26</sup> Staff Proposal at 9.

<sup>27</sup> *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 (April 15, 2022) at 13.

**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**

SDG&E recommends that the POLR be notified once a CCA triggers any of the financial monitoring conditions.<sup>28</sup> PG&E recommends that if, once a CCA reports a trigger, the Commission expects a CCA failure or expects the CCA's liquidity is inadequate to meet its needs, the Energy Division must inform the POLR of the potential need for POLR services and hold a joint meeting between the POLR, Energy Division, and CCA to prepare "mitigation steps."<sup>29</sup> CalCCA cautions against adopting SDG&E and PG&E's recommendation without modifications to provide additional precautions that would avoid providing the POLR with confidential information.

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 a CCA and 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.

PG&E's proposal presents a different problem. To implement PG&E's approach requires Energy Division to concretely assess a CCA's financial circumstances – a highly subjective

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<sup>28</sup> SDG&E Opening Comments at 12.

<sup>29</sup> PG&E Opening Comments at 12.

determination. It would also require the Energy Division to pre-judge the outcome of financial circumstances. Even if a CCA were strained financially, there are often mitigation measures available to support a favorable outcome.

Finally, the POLR's need for a CCA's financial information remains unclear, 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. For these reasons, CalCCA continues to recommend the Commission require Energy Division to keep confidential: (1) the fact that a CCA triggered financial reporting and (2) the reported information.

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.

**C. The Commission Should Not Require CCAs to Provide Non-Confidential Financial Information to the POLR Upon Request, as this Information is Already Publicly Available for the POLR to Access**

SCE recommends the Commission require CCAs to report non-confidential information to the POLR upon request.<sup>30</sup> The Commission should reject this recommendation. CCAs already post publicly available financial information and policies to their websites and these issues are addressed in their monthly Board packets.<sup>31</sup> The information posted provides data points necessary to calculate days liquidity on hand and debt ratio, risk management policies, and ratemaking policies and changes. This information captures several interacting factors that contribute to the financial health of an LSE. In addition, CalCCA has developed a page on its website to allow for easy access of each member’s financial information and policies in a transparent and standardized format.<sup>32</sup> The Commission should not put unnecessary requirements on CCAs to provide the POLR with public information upon request, as this information is already available for the POLR to easily access whenever it chooses.

**D. The Commission Should Not Require Meetings Similar to the PRG as Part of CCA Financial Monitoring**

SDG&E recommends the Commission modify the financial monitoring reporting requirements to include “meetings with consumer advocates and additional relevant stakeholders, similar to the [PRG] structure established by the IOUs.”<sup>33</sup> The Commission should reject this recommendation, as it extends beyond the Commission’s authority and serves no clear purpose.

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<sup>30</sup> SCE Opening Comments at 27.

<sup>31</sup> For an example of a CCA Board Packet, see: <https://www.peninsulacleanenergy.com/board-of-directors/>.

<sup>32</sup> See: <https://cal-cca.org/key-cca-documents/>.

<sup>33</sup> SDG&E Opening Comments at 12.

D.02-08-071 required the IOUs to establish Commission-authorized PRG to review and assess the IOUs' overall procurement strategy.<sup>34</sup> PRGs review RFO development, bid evaluation and rankings, hedging strategies, and procurement portfolio positions and transactions, among other functions.<sup>35</sup> The PRGs are intended to allow interested, non-market-participant parties with the ability to review and provide recommendations on IOU procurement that is ultimately subject to Commission oversight and approval.

While the Commission has oversight authority over IOU procurement activities and financials, it does not have the same authority with respect to CCAs. Instead, it is the CCA local governing boards that have oversight and approval authority over CCA procurement activities and financial decisions. Therefore, unlike with the IOUs, the Commission cannot require CCAs to modify their practices in response to recommendations made by a PRG-like meeting.

Given that the Commission has no authority to dictate CCA procurement and financial decisions, SDG&E's intended purpose of PRG-like meetings is unclear. SDG&E's comments fail to provide any details on the expected outcomes of these meetings. SDG&E also fails to provide any details on who would participate, how the Commission would ensure the participants have the expertise necessary to participate, and how the Commission would ensure confidential information is not shared with other market participants. In establishing the PRG, the Commission determined it was necessary in order to, "offer assessments and recommendations to each utility and then to the PUC when the contracts and/or reasonableness

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<sup>34</sup> D.02-08-071, *Interim Opinion*, R.01-10-024 (Aug. 22, 2002):  
[https://docs.cpuc.ca.gov/PublishedDocs/WORD\\_PDF/FINAL\\_DECISION/18659.PDF](https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/18659.PDF).

<sup>35</sup> D.07-12-52, *Opinion Adopting Pacific Gas and Electric Company's, Southern California Edison Company's, and San Diego Gas & Electric Company's Long-Term Procurement Plans*, R.06-02-013 (Dec. 20, 2007), at 119:  
[https://docs.cpuc.ca.gov/PublishedDocs/WORD\\_PDF/FINAL\\_DECISION/76979.PDF](https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/76979.PDF).

criteria are submitted for expedited PUC review.”<sup>36</sup> Since the CCA would not have a filing with the Commission that would necessitate such review by parties that would intervene in a proceeding, it is not clear what purpose SDG&E’s proposal would serve.

The PRG process is a time-consuming one, and mirroring this process for financial monitoring CCAs would add a substantial amount of work for Energy Division, CCAs, and participating stakeholders. The Commission should not introduce a new time-consuming task with no authority to impact outcomes or clear purpose. To do so would result in unreasonable spending of customer funds.

The purpose of financial monitoring should be to ensure that the Commission and the POLR are not surprised by immediate customer returns. The Commission should therefore forego the establishment of a PRG-like meeting for financial monitoring of CCAs and instead adopt the process in the Staff Proposal, which would require meetings between Energy Division and the CCA triggering financial reporting on up to a monthly basis.

**E. The Commission Should Not Adopt Any Triggers that are Undefined or that Introduce Subjectivity**

SDG&E recommends adding additional financial reporting triggers, including (1) reasonable expectation bankruptcy will occur, (2) uncertainties about the CCA’s ability to continue as a going concern or any adverse opinion or material weakness in a CCA’s audited financial statement, and (3) the filing of a material lawsuit that could significantly adversely impact past, present or future financial results.<sup>37</sup> The Commission should reject these additional triggers that include undefined, unquantifiable, and subjective metrics such as “*reasonable expectation...*”, “*uncertainties* about a CCAs ability to continue...”, and “filing of a *material* lawsuit that could

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<sup>36</sup> D.02-08-071 at 25.

<sup>37</sup> SDG&E Opening Comments at 11.

*significantly* adversely affect past, current or future financial results.” These triggers would introduce ambiguity as to whether a CCA has hit a trigger and whether the trigger actually reflects financial difficulties. What is reasonable, what is uncertain, and what is significant are subjective – what may be uncertain to one entity may not be uncertain to another. Because the Commission and parties are contemplating enforcement mechanisms for failure to report a triggering event (e.g., Rule 1 violations, financial penalties, etc.), it must be completely clear how to determine whether a triggering event occurred. The Commission should aim to set the financial reporting triggers based upon verifiable metrics that leave no room for interpretation around whether a CCA hit the trigger.

Furthermore, SDG&E’s proposed trigger regarding the filing of a material lawsuit is not necessarily related to financial health, unlike the financial metrics included in the Staff Proposal. The mere filing of a lawsuit against a CCA also does not necessarily indicate the potential of CCA financial distress, as SDG&E states, nor would it foresee a judgment that would be adverse to a CCA’s financial health.

Finally, SDG&E’s proposed additional triggers present challenges for creating a process whereby a CCA that is financially monitored can exit financial monitoring. Unlike the other triggers suggested by the Staff Proposal which could present clear thresholds for CCAs to exit financial monitoring, SDG&E’s proposed additional triggers do not present a clear path for CCAs to exit financial monitoring. It is unclear how a CCA can remedy “uncertainties” related to a CCA’s financial statement or “reasonable expectation” of an insolvency or bankruptcy and absent clear parameters, CCAs could be subject to extended and unnecessary financial monitoring. SDG&E’s proposed material lawsuit trigger also presents a scenario where a single lawsuit could result in a CCA remaining in financial monitoring for years, irrespective of the nature of the lawsuit or the likelihood that the plaintiff(s) is likely to succeed in its claims.

**F. The Commission Should Adopt Staff's Proposed Financial Monitoring Triggers, as Parties Proposed Recommendations to the Triggers are Excessive, or Lead to Unintended Consequences**

Several parties recommend modifying the triggers in the Staff Proposal to make them more stringent, including raising the percent cash reserves, days liquidity on hand (DLOH), and debt service coverage ratio triggers.<sup>38</sup> The Commission should reject these recommendations as they are excessively and unnecessarily stringent, in some cases, tripling the requirements under the Staff Proposal. For example, the Staff Proposal would trigger financial reporting if DLOH dips below 45 days,<sup>39</sup> while SDG&E proposes DLOH of 90 days.<sup>40</sup> Additionally, while a debt service coverage ratio of 1.0-1.25 signifies continuing financial viability and is not an indicator of financial distress, SDG&E proposes to use a debt service coverage ratio of 1.5 without any explanation as to why a higher trigger is warranted.<sup>41</sup> SCE suggests that the 5 percent cash reserves is set too low. The only rationale SCE provides to support its claims is that targeted reserves in CCA implementation plans typically range from 15 percent to 30 percent.<sup>42</sup> A CCA's targeted cash reserves and cash reserves that point to financial distress should not be equivalent. This trigger offers little value as it is duplicative of the DLOH trigger and operationally it may lead CCAs to draw down lines of credit and increase interest costs for no commercial reason other than to comply with the metric.

Other parties recommend adding additional triggers such as current ratio and unrestricted net position.<sup>43</sup> The Commission should decline to adopt these additional triggers, as the triggers proposed by Staff are better indicators of financial distress.

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<sup>38</sup> SCE at 27, SDG&E at 10-11.

<sup>39</sup> Staff Proposal at 9.

<sup>40</sup> SDG&E at 10.

<sup>41</sup> *Id.*

<sup>42</sup> SCE at 27.

<sup>43</sup> Cal Advocates at 18, SDG&E at 10.

- Current ratio is a less reliable measure of financial strength than debt service coverage ratio - The debt service coverage ratio below one, as proposed by Energy Division Staff signifies losses or slim surpluses and should be used to trigger financial reporting.
- Unrestricted net position, as CalCCA understands the argument, duplicates the DLOH metric, since CCAs do not have substantial capital assets.

Any financial monitoring proposal should focus on the ability for the Commission to evaluate useful information that provides the Commission with indicators of potential customer return – not on requiring CCAs to report financial information as often as possible, even when they are in good financial health. There is insufficient information in the record to point to the need to go from no financial monitoring at all to financial monitoring based upon triggers that a CCA may hit even when they are financially stable.

The Commission should therefore adopt the triggers in the Staff Proposal with the clarifications and modifications made by CalCCA in opening comments. If after implementing the financial monitoring program, the Commission finds the triggers are not effective in providing the Commission with advance notice of likely customer returns, then the Commission can consider if it needs to update the triggers at that time.

## **V. CONTRACT ASSIGNMENT**

### **A. The Commission Should Reject Cal Advocates’ ROFR Proposal and SEIA/LSA’s Required Contract Novation Proposal and Alternative Proposal**

Cal Advocates and SEIA/LSA continue to support either a ROFR or mandatory assignment of contracts from the CCA to the POLR in the event of a return of customers without notice. The methodology and effectiveness of these proposals continues to fail to provide meaningful and enforceable remedies. Notably, these parties mistakenly argue:

- CalCCA misstates the law by arguing that CalCCA confused Chapter 11 and Chapter 9 bankruptcy process;
- PU Code 387 gives clear authority to allow the Commission to mandate a ROFR;

- The ROFR would not impact competitiveness in contract negotiations; and
- The assignment of a contract to the POLR should be completely one sided and lie with the generator.

The Commission should reject these arguments for the reasons described in sections V.A.1 and V.A.2.

**1. The Commission Should Reject Cal Advocates’ Claims that Concerns Regarding ROFR Enforcement in Bankruptcy Are Overstated**

Cal Advocates suggests that:

CalCCA misstates the law. CalCCA’s references to the “bankruptcy estate” “reorganizing” and the Supremacy Clause, among others, suggest that CalCCA confuses Chapter 11 bankruptcy, which covers corporate reorganization, with Chapter 9 bankruptcy, which covers CCAs and other municipalities. Federal bankruptcy courts have limited authority in a Chapter 9 case, due to states’ reservation of their powers over municipalities under the Tenth Amendment.<sup>44</sup>

The Cal Advocates’ argument misses the point. The provision of the Bankruptcy Code that makes *ipso facto* clauses, like the proposed automatic reassignment provision, generally unenforceable in bankruptcy is expressly incorporated into chapter 9. 11 U.S.C. § 901. Thus, such a clause would likely be assignable only at the election of the entity seeking bankruptcy protection – whether in chapter 9 or chapter 11. Cal Advocates also ignore that chapter 9 relief is available only to a “political subdivision or public agency or instrumentality of a State.” 11 U.S.C. § 101(40). While there is one example of a California CCA seeking relief under Chapter 9,<sup>45</sup> an IOU like PG&E is not so eligible and may only seek relief under chapter 11. Finally, while Section 904 of the Bankruptcy Code limits the Bankruptcy Court’s ability to interfere with an eligible

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<sup>44</sup> Cal Advocates Opening Comments at 6-7.

<sup>45</sup> *In re Western Community Energy*; Bankr. C.D. Cal., Case No. 21-12821.

municipality’s property, revenues, and powers of governance, by electing federal bankruptcy relief the municipality subjects itself to the requirements of that chapter the Bankruptcy Code.<sup>46</sup>

The case that Cal Advocates cites reiterates these basic principles.<sup>47</sup> While the Bankruptcy Court’s authority to afford interim relief in a chapter 9 proceeding is limited by Section 904,<sup>48</sup> the Bankruptcy Court will ultimately be asked to confirm a plan of adjustment that provides for the municipality’s reorganization on a final basis.<sup>49</sup>

## **2. The Commission Does Not Have Clear Authority Under PU Code 387 to Mandate a ROFR**

Cal Advocates asserts that the Commission has the requisite jurisdiction under Section 387 to mandate a ROFR in favor of the POLR in every wholesale RA energy contract.<sup>50</sup> 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.

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<sup>46</sup> See *County of Orange v. Merrill Lynch & Co. (In re County of Orange)*, 191 B.R. 1005, 1021 (Bankr. C.D. Cal. 1996) (“By authorizing the use of chapter 9 by its municipalities, California must accept chapter 9 in its totality; it cannot cherry pick what it likes while disregarding the rest.”); see also *In re City of Vallejo*, Case No: 08-26813, Dkt. No. 473, p.4:7-12 (Bankr. E.D. Cal. March 13, 2009) (“[w]hen a state authorizes its municipalities to file a chapter 9 petition it declares that the benefits of chapter 9 are more important than state control over its municipalities.”).

<sup>47</sup> See Cal Advocates Opening Comments n. 15 citing *United States v. Bekins*, 304 U.S. 27, 54 (1938) (“The State acts in aid, and not in derogation, of its sovereign powers. It invites the intervention of the bankruptcy power to save its agency which the State itself is powerless to rescue.”).

<sup>48</sup> See, e.g., *In re City of Detroit* 841 F.3d 684 (6th Cir. 2016) (Bankruptcy Court lacks authority to enjoin chapter 9 debtor against shutting off water supply) [Cal Advocates n. 17].

<sup>49</sup> See *In re Valley Health System* (Bankr. C.D. Cal. 2010) 429 B.R. 692 (confirming chapter 9 plan of adjustment including the sale of assets, after analyzing California state law requirements) [Cal Advocates n. 17].

<sup>50</sup> Cal Advocates Opening Comments at 8 (footnotes omitted). (“Public Utilities Code Section 387, subsections (g), (h), (j), and (k) provide authority for the Commission to exercise oversight over CCAs in order for the POLR to ensure continuity of service. This authority includes explicit, broad authority to set POLR-related rules for all LSEs, and to “do all things that are necessary and convenient in the exercise of” “supervis[ing] and regulat[ing] each provider of last resort, as necessary.”)

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)(c)), facilitating applications by LSEs to request transfer of responsibility (subsection (d)), transition of obligations from one POLR to another (subdivision (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 subdivision (h), which allows the Commission to “[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 unsupported 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 below.

### **3. ROFR or Mandatory Contract Novation Will Complicate CCA Contracting and Add Unnecessary Procurement Costs to CCAs**

Cal Advocates contends that a ROFR will not impact the competitiveness of procurement. Cal Advocates overlooks important impacts of the ROFR on the wholesale RA market and CCA competitiveness.

To support its contention, Cal Advocates states:

In addition, SEIA/LSA noted that “at the [March 7, 2022] workshop, CalCCA acknowledged that a required novation/assignment of a procurement contract, in most circumstances, would mitigate risk ‘because now you have the probability of two parties defaulting which is less than the probability of one-party defaulting.’”[footnote omitted] That is, CalCCA already conceded the SCE argument that the Staff Proposal cites. The full proceeding record supports rejection of CalCCA’s assertion that the Cal Advocates ROFR would place LSEs at disadvantage in their contract negotiations. The Commission should not rely on this argument to justify rejecting the Cal Advocates ROFR.<sup>51</sup>

Cal Advocates ignores the fact that 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 for which the Cal Advocates proposed ROFR would have been with an entity in bankruptcy. It is hard to imagine that the large quantity of RA purchased in that lengthy period would not have impacted the contracts of LSE buyers strictly because the POLR and not the primary buyer was not financially solvent. The viability of this proposal does not rest on Cal Advocates’ mistaken understanding of CalCCA “conceding” to anything. The fact remains that the financial status of the POLR can and will have an impact on any contract entered into by an LSE which has a ROFR provision.

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<sup>51</sup> Cal Advocates Opening Comments, at 9:  
<https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M496/K416/496416748.PDF>.

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

Based upon the comments from SCE, Energy Division staff should clarify how the discounting of a re-entry fee for an assigned RA contract will be performed. 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 benchmark price. In SCE's comments, it appears that they have assumed that the credit will be done on the quantity side of this equation. That is, the re-entry fee will be reduced by subtracting from the RA quantity required, the quantity of the RA contract that is assigned to the POLR. If this is the methodology selected, then SCE's comments are logical in that the POLR will only avoid the cost of those MWs if the CCA either continues to pay the resource or has already pre-paid the resource.

CalCCA had interpreted the proposal to discount the price side of the equation. That is, the calculation of the re-entry fee would reduce the RA benchmark to the price of the assigned contract for the quantity of the amount of RA that is assigned to the POLR. For example, if an LSE had a 100 MW RA assignable contract at a price of \$5/kw-month when the benchmark is \$7/kw-month, the re-entry fee would reflect the lower assigned contract price for its quantity and would calculate the remaining RA at the benchmark price. Using this calculation, the payment of the contract by the POLR can occur and the CCA/customers subject to the re-entry fee would effectively pay the benchmark for all RA not met by assigned contracts but the lower price of the assigned contract for the contracts that are assigned, the re-entry fee would be lowered to the price of the assigned contract.

Given the two different interpretations of how this discounting process can occur, Energy Division staff should clarify which variation they are proposing.

**VI. CONCLUSION**

For all the foregoing reasons, CalCCA respectfully requests consideration of the recommendations herein.

Respectfully submitted,



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

May 5, 2023

**APPENDIX A**  
**To**  
**CALIFORNIA COMMUNITY CHOICE ASSOCIATION’S REPLY COMMENTS ON**  
**RULING OF THE ASSIGNED ADMINISTRATIVE LAW JUDGE ENTERING STAFF**  
**PROPOSAL INTO THE RECORD AND NOTICING PUBLIC WORKSHOPS**

Data Sources for Table 1: 2021-2023 Stack Analysis

Row(s)	Source
1	CAISO 1-in-2 Load Forecast. Monthly peak demand forecast for a median (1-in-2) weather year. Values for 2021 and 2022 are from the CEC’s 2021 California Energy Demand (CED) Forecast, Mid Baseline AAEE Scenario 3 AAFS Scenario 3 using the monthly maximum of the CAISO managed net load: ( <a href="https://efiling.energy.ca.gov/GetDocument.aspx?tn=241174">https://efiling.energy.ca.gov/GetDocument.aspx?tn=241174</a> ). Values for 2023 are from the CEC’s 2022 CED, Planning Scenario using the monthly maximum of the CAISO managed net load: ( <a href="https://efiling.energy.ca.gov/GetDocument.aspx?tn=248359&amp;DocumentContentId=82768">https://efiling.energy.ca.gov/GetDocument.aspx?tn=248359&amp;DocumentContentId=82768</a> )
2	Planning Reserve Margin per Commission D.22-06-50. <sup>52</sup>
4-7	California ISO NQC List. The CAISO lists the net qualifying capacity (NQC) for all resources in the CAISO footprint. Values for 2021 are from the CAISO 2021 NQC list ( <a href="http://www.caiso.com/Documents/NetQualifyingCapacityList-2021.xlsx">http://www.caiso.com/Documents/NetQualifyingCapacityList-2021.xlsx</a> last updated 11/12/2021), for 2022 are from the CAISO 2022 NQC list ( <a href="http://www.caiso.com/Documents/Final-Net-Qualifying-Capacity-Report-for-Compliance-Year-2022.xls">http://www.caiso.com/Documents/Final-Net-Qualifying-Capacity-Report-for-Compliance-Year-2022.xls</a> last updated 11/02/2022) and values for 2023 are from the 2023 NQC list ( <a href="http://www.caiso.com/Documents/Final-Net-Qualifying-Capacity-Report-For-Compliance-Year-2023.xls">http://www.caiso.com/Documents/Final-Net-Qualifying-Capacity-Report-For-Compliance-Year-2023.xls</a> last updated 03/01/2023).
8	Event-Based Demand Response. Demand response quantities are from the Commission’s Resource Adequacy Compliance Materials. <sup>53</sup> Demand response totals include avoided losses and are from event-based programs at PG&E, SCE, and SDG&E.
9	Imports. Imports values for 2021 are the actual aggregated import RA from 2021 reported by the CAISO ( <a href="http://www.caiso.com/Documents/HistoricalResourceAdequacyImportAggregateData.xlsx">http://www.caiso.com/Documents/HistoricalResourceAdequacyImportAggregateData.xlsx</a> ). Imports for 2022 and 2023 reflect the CEC’s assumed RA imports available to the CAISO market. <sup>54</sup>
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

<sup>52</sup> 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>.

<sup>53</sup> 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>.

<sup>54</sup> 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>.

	historical ambient temperature derates within the CAISO. <sup>55</sup> Our approach parallels recent Commission discussions regarding the need to include thermal derates in reliability modeling. <sup>56</sup>
11	D.21-12-015 allowed: “excess resources from an IOU’s <i>existing</i> portfolios may be used to meet or supplement these procurement targets up to the upper end of its contingency procurement target.” <sup>57</sup> Line 11 represents the total of the three IOUs’ excess resources from their portfolios as filed in the IOUs’ 2022 Excess Resources Reports. <sup>58</sup> No excess is assumed for 2021.
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.” <sup>59</sup> 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. <sup>60</sup> 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. <sup>61</sup> Excess procurement begins in 2022.
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 IOUs’ 2021 Excess Resources Reports. <sup>62</sup>
16	Expected new-build resources online by 8/1/23. Resources mandated by the Commission pursuant to D.19-11-016 and D.21-06-035 assuming a 40% delay and/or failure rate.

<sup>55</sup> 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>.

<sup>56</sup> *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](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).

<sup>57</sup> D.21-12-015 at 103.

<sup>58</sup> <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials>.

<sup>59</sup> D.21-12-015 at 101-102.

<sup>60</sup> The additional resources procured under this authorization are described in the Commission’s RA materials with additional detailed provided in advice letters filed by the IOUs. 2022 IOU Excess Resources Reports: <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials>.

<sup>61</sup> CalCCA used the amounts in the IOU Excess Resources 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.

<sup>62</sup> <https://www.cpuc.ca.gov/industries-and-topics/electricalenergy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliancematerials>.

<b>DOCKETED</b>	
<b>Docket Number:</b>	22-RENEW-01
<b>Project Title:</b>	Reliability Reserve Incentive Programs
<b>TN #:</b>	250117
<b>Document Title:</b>	California Community Choice Association Comments - ON THE STAFF WORKSHOP ON THE DEMAND SIDE GRID SUPPORT PROGRAM
<b>Description:</b>	N/A
<b>Filer:</b>	System
<b>Organization:</b>	California Community Choice Association
<b>Submitter Role:</b>	Public
<b>Submission Date:</b>	5/11/2023 4:14:13 PM
<b>Docketed Date:</b>	5/11/2023

*Comment Received From: California Community Choice Association  
Submitted On: 5/11/2023  
Docket Number: 22-RENEW-01*

**ON THE STAFF WORKSHOP ON THE DEMAND SIDE GRID  
SUPPORT PROGRAM**

*Additional submitted attachment is included below.*

**STATE OF CALIFORNIA  
STATE ENERGY RESOURCES  
CONSERVATION AND DEVELOPMENT COMMISSION**

*IN THE MATTER OF:*

*Reliability Reserve Incentive Programs*

DOCKET NO. 22-RENEW-01

RE: Demand Side Grid Support Program

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE  
STAFF WORKSHOP ON THE DEMAND SIDE GRID SUPPORT PROGRAM**

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May 11, 2023

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**STATE OF CALIFORNIA  
STATE ENERGY RESOURCES  
CONSERVATION AND DEVELOPMENT COMMISSION**

*IN THE MATTER OF:*

*Reliability Reserve Incentive Programs*

DOCKET NO. 22-RENEW-01

RE: Demand Side Grid Support Program

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION’S COMMENTS ON THE  
STAFF WORKSHOP ON THE DEMAND SIDE GRID SUPPORT PROGRAM**

The California Community Choice Association<sup>1</sup> (CalCCA) submits these Comments pursuant to the *Notice of Staff Workshop on the Demand Side Grid Support Program* (the “Workshop”).

**I. INTRODUCTION**

CalCCA appreciates the opportunity to comment on the proposed Second Edition of the Demand Side Grid Support (DSGS) Program Guidelines (Proposed DSGS Guidelines).<sup>2</sup> As noted in CalCCA’s Comments in response to the January 27, 2023 Workshop on DSGS and the Distributed Electricity Backup Assets Program (DEBA), community choice aggregators (CCAs) have heretofore been unable to receive funding for offering their customers emergency load reduction programs.<sup>3</sup> While CCA customers may get enrolled in the Emergency Load Reduction

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

<sup>2</sup> 22-RENEW-01, Emery, Ashley and Erik Lyon. April 2023. *Demand Side Grid Support Program: Proposed Draft Guidelines Second Edition*, California Energy Commission. Publication Number: CEC-300-2023-003-D.

<sup>3</sup> 22-RENEW-01, *California Community Choice Association’s Comments on the January 27, 2023 Workshop on the Demand Side Grid Support Program and Distributed Electricity Backup Assets Program* (Feb. 17, 2023) (CalCCA January Workshop Comments), at 1-6.

Program (ELRP) through the investor-owned utility (IOU) that provides that customer transmission and distribution services, CCAs themselves are not able to enroll customers in ELRP or administer and receive funding for ELRP. As a result, significant untapped incremental load and potential emergency supply likely exists with CCA customers not otherwise enrolled in ELRP.

Recognizing the potential for additional incremental emergency capacity, the Legislature passed Assembly Bill (AB) 209 (2022) revising the DSGS enabling legislation (AB 205 (2022)) to all California customers to enroll in DSGS, so long as the customer is not already enrolled in a CPUC jurisdictional demand response (DR) program.<sup>4</sup> While the Proposed DSGS Guidelines do allow CCA customers to participate in DSGS, there are limitations that can and should be removed while still safeguarding the ELRP through the prohibition of dual enrollment.

CalCCA provides the following recommendations for modifications to the Proposed DSGS Guidelines to ensure all untapped incremental capacity for emergency reliability events is effectively enrolled in an emergency demand response program:

- Allow all customers of CCAs, not only water agencies or customers participating with backup generators (BUGs), to receive incentives through Option 1 to increase the possibility of CCA participation as DSGS providers;
- In addition to requiring aggregators of customers offering a DSGS program to seek permission from CCAs of an aggregator's intent to enroll customers in a CCA's territory, require aggregators to provide the CCA with information necessary for the CCA to accurately forecast customer load;
- Involve CCAs in discussions between the California Energy Commission (CEC), the IOUs and aggregators on data sharing to prevent dual enrollment between all DR programs offered to customers;
- Provide clarification on the compatibility of Option 3 with virtual power plants (VPPs) operating with consistent load modification;
- Adjust incentive Option 3 to better align with the periods of highest need;
- Clarify how and when actual performance information after an emergency event will be published for stakeholder review; and

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<sup>4</sup> Public Resources Code (PRC) § 25792(a) (creating DSGS) (as amended by AB 209).

- Clarify whether the allowance of \$5 million per year of administrative costs applies in aggregate or to each DSGS provider.

## **II. THE PROPOSED DSGS GUIDELINES SHOULD BE REVISED TO ALLOW ALL CCA CUSTOMERS TO RECEIVE INCENTIVES FOR OPTION 1**

Option 1 of the Proposed DSGS Guidelines should be modified to allow all CCA customers, and not only water agencies or customers participating with BUGs, to be eligible to receive the incentives for participation in Option 1. While CalCCA understands the need to prevent cannibalization of customers from ELRP, the practical reality is that there may be customers in CCA service territories that are not enrolled in ELRP but can contribute capacity or load reduction during emergency events. CCAs have unique connections to their local communities and can create programs through Option 1 of DSGS to unlock untapped capacity and load reduction from customers not otherwise enrolled in ELRP. The examples provided in the CalCCA January Workshop Comments of CCAs operating demand response programs in their service territories demonstrate the innovative and community-focused programs CCAs already provide to their customers.<sup>5</sup>

To the extent a customer is enrolled in ELRP, the eligibility verification protections will immediately flag that customer as unable to participate in the CCA's program, and therefore dual enrollment will be prevented. Option 1 should be modified to allow CCAs to offer DSGS incentives to all its customers, and not just water agencies and customers operating BUGs.

## **III. AGGREGATORS SHOULD BE REQUIRED TO PROVIDE DEFINED CUSTOMER DATA TO ALLOW CCAS TO ACCURATELY FORECAST LOAD AND ENSURE RELIABILITY**

Customer load reductions can be a critical tool to relieve grid strain during extreme weather events. To allow all DR providers and customers to meet the needs of this “all-hands-on-

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<sup>5</sup> CalCCA January Workshop Comments at 5-7.

deck” moment, CalCCA supports a variety of providers engaging with customers to encourage their participation in a DR program that works for each customer. However, there must be guardrails established to ensure that all DR providers engage in a coordinated and streamlined fashion and that load serving entities (LSEs), IOUs and the California Independent System Operator (CAISO) have visibility into the load in their respective service areas for accurate load forecasting.

Hence, CalCCA supports the provisions in the Proposed Guidelines requiring aggregators of customers to obtain written permission from each applicable CCA to participate in the DSGS Program.<sup>6</sup> As recognized by CEC Staff during the Workshop, visibility from the CCA as the LSE is necessary to ensure CCAs have adequate information for accurate load forecasting. Without such information, the risk of “uninformed” or incorrect scheduling can significantly impact reliability during an emergency event.

For example, in reports on both the August 2020 and September 2022 heat waves, the CAISO noted the challenges faced by LSEs in scheduling their load and the impact on reliability. In the 2020 Report, the CAISO noted that “[u]nder-scheduled load by scheduling coordinators limited the ability of the day-ahead market to secure sufficient supply to meet actual demand.”<sup>7</sup> Challenges reported by scheduling coordinators in accurately forecasting demand included poor

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<sup>6</sup> See Revised DSGS Guidelines at 2, Ch. 2, § A.1.c. (requiring that aggregators receive written permission from the CCA prior to the aggregator enrolling customers in the CCA’s territory). CalCCA notes that the section in the Proposed Guidelines entitled “What’s New in These Guidelines?” omits CCAs from its description of who aggregators of customers must get written permission from (only listing the publicly-owned utilities (POUs)), but the actual Guidelines do require aggregators to obtain written permission from both POUs and CCAs. See Proposed Guidelines, at v. (omitting CCAs in error), and at 2, Ch. 2, § A.1.c. (requiring aggregators to receive written permission from each applicable POU and CCA).

<sup>7</sup> *Final Root Cause Analysis – Mid-August 2020 Extreme Heat Wave*, prepared by CAISO, CPUC, and CEC (Jan. 13, 2021) at 61, located at: <http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf>.

data quality and availability.<sup>8</sup> The September 2022 heat wave report discusses similar challenges, finding that “[LSEs] continue to experience challenges in coming to the market with accurate load forecast to construct their bid-in demand.”<sup>9</sup>

Given the challenges in past extreme weather events, it is crucial that aggregators of customers under DSGS share adequate data with CCAs to enable accurate load forecasting. Specifically, CalCCA recommends that the CEC require aggregators to share the following program participation data with the LSE:

- Customer identifiers: customer name, service account ID (SAID), service account address;
- Program information: program name, DSGS participation pathway (i.e., Option 1, 2 or 3), aggregator name; and
- Load information: resource type, expected aggregated load reduction amount for all customers participating in the aggregator’s portfolio.

It is CalCCA’s understanding that the aggregator shares all this information with the CEC at the time of program enrollment so it should not be burdensome to also share this information with the respective CCA. CCAs have grown to serve approximately one-third of load in CA and are the default electricity provider in their areas, tending to serve 85% or more of the customers in their member jurisdictions. More accurate forecasting of demand response participation by customers helps LSEs optimize how much energy to buy and reduces costs for ratepayers. As a result, CCAs have a material and growing interest in the load forecasting impacts of programs serving their customers.

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<sup>8</sup> *Id.* at 62.

<sup>9</sup> *Summer Market Performance Report, Sept. 2022*, prepared by CAISO (Nov.2, 2022), at 50, located at: <http://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf>.

#### **IV. CCAS SHOULD BE INVOLVED IN DISCUSSIONS BETWEEN THE CEC, THE IOUS, AND AGGREGATORS OF CUSTOMERS REGARDING METHODS TO PREVENT DUAL ENROLLMENT**

Any discussions between the CEC, the IOUs and aggregators of customers regarding methods and data to prevent dual enrollment between DSGS and other DR programs should also include the CCAs. Question 1 from the Workshop presentation includes the following question: “[f]or utilities, do the guidelines include appropriate data to enable eligibility verification and dual enrollment checks?”<sup>10</sup> Given that CCA customers could already be enrolled in a CCA DR program, CCAs should be part of the discussion regarding the development of dual enrollment prevention processes (i.e., how and when is program participation data exchanged between IOUs, CCAs and aggregators, which entity completes the dual enrollment check, etc.). While the enrollment and eligibility requirements set forth in the Proposed DSGS Guidelines appear to require enough information to ensure the prevention of dual enrollment, the CCAs would like to join any further discussions of developing the processes to prevent dual enrollment.

#### **V. THE CEC SHOULD CLARIFY WHETHER INCENTIVE OPTION 3 IS COMPATIBLE WITH VIRTUAL POWER PLANTS OPERATING WITH CONSISTENT LOAD MODIFICATION**

The CEC has made it clear that the DSGS program should only fund incremental and emergency load reductions.<sup>11</sup> CalCCA understands this to mean that DSGS funding should not be utilized for: (1) reductions that already receive funding through other DR programs; (2) reductions already being counted for Resource Adequacy (RA); or (3) reductions that occur regularly as a result of load modifying activities or programs. That said, the CEC should clarify

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<sup>10</sup> 22-RENEW-01, *Presentation – April 26, 2023 DSGS Program Staff Workshop* (Apr. 26, 2023), at 36.

<sup>11</sup> *Id.* at 4 (summarizing policy goals and considerations of the DSGS program, including “[m]aximiz[ing] incremental capacity and load reduction from demand-side resources”).

that a VPP capable of producing incremental reductions on top of regularly scheduled load modification is eligible to participate in DSGS. Specifically, CalCCA requests confirmation that:

- If a CCA's VPP can dispatch incremental resources during a DSGS event (above and beyond the load shifting it regularly produces), the incremental load reduction is eligible for DSGS incentives;
- As DSGS is meant to be incremental to existing load modification and RA, the incremental reductions the VPP produces during those event hours should not be included as load reduction in a CCA's year-ahead RA load forecast with the CEC; and
- Any other regularly scheduled reductions in load produced by the CCA's VPP on event days or non-event days should still inform load reduction in a CCA's year-ahead RA load forecast with the CEC.

CalCCA looks forward to further collaboration on this topic as the CEC and parties determine how to establish the baseline to distinguish the incremental load reduction produced for the DSGS program from regularly scheduled load reduction.

#### **VI. THE INCENTIVE VALUES IN OPTION 3 SHOULD BE ADJUSTED TO INCENTIVIZE DSGS PARTICIPATION DURING PERIODS OF PEAK DEMAND**

CalCCA recommends the following adjustments to Incentive Option 3:

- Reducing incentive values by \$2/kW in May; and
- Increasing incentives by \$2/kW in July, August, and September.

These adjustments will more effectively spur incremental load reduction while maximizing the value of the strategic reliability reserve. In addition, the increased incentive values for July, August and September will further incentivize participation under Option 3 during those periods of peak system demand.

#### **VII. THE CEC SHOULD CLARIFY HOW AND WHEN ACTUAL LOAD REDUCTIONS ACHIEVED WILL BE REPORTED FOR STAKEHOLDER REVIEW**

The Proposed DSGS Guidelines require DSGS Providers to provide information to the CEC in conjunction with their claim for administrative costs and incentive payments, allowing

the CEC to determine the actual load reduction during an emergency event.<sup>12</sup> The CEC should also, however, provide stakeholders, including CCAs in whose territories aggregators operate under DSGS, aggregate data regarding actual load reduction after an event has occurred. This aggregate data will provide information useful for load forecasting for future emergency events.

**VIII. THE CEC SHOULD CLARIFY WHETHER THE \$5 MILLION PER YEAR ALLOWANCE FOR ADMINISTRATIVE COSTS APPLIES IN AGGREGATE OR TO EACH DSGS PROVIDER**

The Proposed DSGS Guidelines should be revised to clarify the \$5 million per year allowance for administrative costs. Chapter 6 regarding program payments states that “the CEC shall reimburse DSGS providers for up to \$5 million per year in administrative costs based on the administrative cost structure identified in the initial application.”<sup>13</sup> Clarity should be provided regarding whether the \$5 million per year allowance applies to reimbursements for administrative costs in aggregate, or whether each DSGS provider is allocated \$5 million per year for administrative costs.

**IX. CONCLUSION**

CalCCA looks forward to further collaboration with the CEC on this topic.

Respectfully submitted,



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

May 11, 2023

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<sup>12</sup> See Proposed DSGS Guidelines at 19-22, Ch. 6.

<sup>13</sup> Proposed DSGS Guidelines at 19, Ch. 6, § A.



## Comments on Issue paper and track A straw proposal

Initiative: Extended day-ahead market ISO balancing authority area participation rules

### Comment period

May 10, 2023, 08:00 am - May 17, 2023, 05:00 pm

### Submitting organizations

California Community Choice Association

## California Community Choice Association

Submitted on 05/17/2023, 12:02 am

### Contact

Shawn-Dai Linderman (shawndai@cal-cca.org)

### 1. Please provide a summary of your organization's comments on the Extended Day-Ahead Market (EDAM) ISO Balancing Authority Area (BAA) Participation Rules issue paper and track A1 straw proposal, and May 10, 2023 stakeholder meeting discussion:

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the EDAM ISO BAA Participation Rules Issue Paper and track A1 Straw Proposal (Issue Paper/Straw Proposal). CalCCA's comments can be summarized as follows:

The California Independent System Operator Corporation (ISO) should evaluate its roles as a BAA operator and a market operator with the ISO BAA stakeholders on a timeline that allows any resulting changes to the ISO tariff or business practices to effectuate the necessary separation between the two roles can be implemented for day one of EDAM.

As an initial starting point, the ISO should take a conservative approach to setting the Confidence Factor. When using the historical performance of non-resource sufficiency evaluation (RSE) eligible supply to inform the Confidence Factor, the ISO should consider previous years with similar west-wide seasonality, loads, and temperatures and more recent trends that take into account more recent capacity conditions that affect economic import availability.

The ISO should consider adding the following additional reliability criteria so that the ISO sets the EDAM Reliability Margin during other times of potential system stress: the issuance of a Flex Alert, a Residual Unit Commitment (RUC) infeasibility, or a Resource Adequacy (RA) outlook that predicts less available RA capacity than forecasted load plus reserves.

While making transmission available to the EDAM on a hurdle-free basis may result in a reduction in transmission revenue and wheeling access charge (WAC) revenues relative to historical revenues, transmission revenue recovery and WAC revenues should be a transitional mechanism only, accompanied by a sunset date such that the proposal does not introduce indefinite uplift payments.

In evaluating advisory RSE failures, expected RA offers must be considered before taking actions to cure to avoid over-procuring to cover RSE deficiencies that appear in the advisory timeframe but not in the binding run.

The ISO should include Reliability Demand Response Resource (RDRR) as a load modifier to the RSE load forecast until it has met its use limitations.

The ISO should adopt a metered load allocation approach in track A1 for RSE failure surcharges and develop an allocation methodology in track B that allocates charges to RA resources failing to meet their must-offer obligation first and to metered load second.

## **2. Provide your organization's comments on the proposed EDAM ISO BAA Participation Rules initiative scope and schedule:**

The Issue Paper/Straw Proposal commits to further evaluating potential measures to increase the separation between the ISO's roles as a BAA and market operator in a subsequent forum.<sup>[1]</sup> The ISO should conduct this evaluation with ISO BAA stakeholders on a timeline that allows the ISO to implement any resulting changes to the ISO tariff or business practices to effectuate the necessary separation between the two roles for day one of EDAM.

Given the significant implementation lift for EDAM, the ISO should also provide a detailed implementation schedule as soon as possible, including the sequencing of the rollout of EDAM implementation and the onboarding of EDAM entities. It would be prudent for the ISO to consider implementing EDAM before onboarding the first EDAM participant to ensure a smooth implementation before BAAs begin participation.

<sup>[1]</sup> Issue Paper/Straw Proposal at 4.

## **3. Provide your organization's comments on the track A1 proposal related to section 4 - criteria to set the ISO BAA's net EDAM export transfer constraint:**

CalCCA supports the implementation of a net EDAM export transfer constraint that would limit EDAM export transfers out of the ISO BAA during stressed system conditions. The net EDAM export transfer constraint is defined as  $\text{Net Export} \leq \text{RSE Eligible Supply} + \text{Non-RSE Eligible Supply} \times \text{Confidence Factor} - \text{RSE Obligation} - \text{EDAM Reliability Margin}$ . In this initiative, the ISO and ISO BAA stakeholders will need to determine:

1. How to set the Confidence Factor that will be applied to non-RSE eligible supply (i.e., economic imports) to reflect the amount of non-RSE eligible supply the ISO BAA is confident will deliver; and
2. Under what conditions the ISO will implement the constraint and at what EDAM Reliability Margin quantity.

The ISO proposes to set the Confidence Factor based upon a review of historic performance on non-RSE eligible supply. As an initial starting point, the ISO should take a conservative approach to setting the Confidence Factor. As commenters at the May 11, 2023 workshop explained, the ISO BAA does not receive benefits from non-RSE eligible supply in terms of RSE credit and therefore the ISO BAA should be able to minimize the risks associated with exporting non-RSE eligible supply as an EDAM transfer. When using the historical performance of non-RSE eligible supply to inform the Confidence Factor, the ISO should consider previous years with similar west-wide seasonality, loads, and temperatures, and more recent trends that take into account more recent capacity

conditions that affect economic import availability.

The ISO proposes to set the EDAM Reliability Margin based on three criteria the ISO believes represent the greatest intra-day system reliability risks:

1. Replacement reserves based on forecasted Most Severe Single Contingency (MSSC);
2. Protection for a non-credible contingency based on weather conditions (i.e., fires); and
3. Gas operational flow order/curtailments.

CalCCA understands the proposal to say that the ISO BAA operators will set the EDAM Reliability Margin daily at hourly granularity based upon the one criterion that would result in the largest EDAM Reliability Margin. CalCCA agrees these criteria could signal intra-day reliability risk and supports using the greater of the three to set the EDAM Reliability Margin. However, criteria two and three require more definition around how they will be measured for setting the EDAM Reliability Margin. The ISO should provide examples that show when fire risk or gas operational flow orders/curtailments would result in the ISO BAA setting the EDAM Reliability Margin and to what level. It appears these criteria may require some level of operator discretion.

The ISO might consider adding additional reliability criteria so that the ISO sets the EDAM Reliability Margin during other times of potential system stress. Specifically, at the April 5, 2023 workshop, the ISO contemplated other criteria such as the issuance of a Flex Alert, a RUC infeasibility, or an RA outlook that predicts less available RA capacity than forecasted load plus reserves. While these criteria clearly signal potential stressed system conditions for the next day, the Issue Paper/Straw Proposal does not put forth any of these criteria for use in setting the net EDAM export transfer constraint. It may be because criteria number 1 above (replacement reserves based on forecasted MSSC) already covers these additional triggers. If not, the ISO should consider adding to the EDAM Reliability Margin when any of these criteria are met.

#### **4. Provide your organization's comments on the track A1 proposal related to section 5 - transfer resource settlement and transfer revenue distribution:**

CalCCA has no comments at this time.

#### **5. Provide your organization's comments on the track A1 proposal related to section 6 - process for recovering historical wheeling access charge revenues:**

The ISO proposes a process for determining the recoverable foregone historical WAC revenues, including revenues associated with reduction in WAC revenues at existing transfer locations; unrealized WAC revenues attributed to non-firm use of approved new transmission builds that increase transfer capability between EDAM BAAs; and revenues for wheeling-through transfer volumes for EDAM BAAs that exceed the total imports/export transfers from the EDAM BAA.

CalCCA continues to hold its position in the EDAM stakeholder process. That is, while making transmission available to the EDAM on a hurdle-free basis may result in a reduction in transmission revenue and WAC revenues relative to historical revenues, transmission revenue recovery and WAC revenues should be a transitional mechanism only, accompanied by a sunset date such that the proposal does not introduce indefinite uplift payments. The ISO proposes to forecast foregone WAC revenues based upon historical WAC revenues three years prior to EDAM implementation and then update this forecast only upon changes in EDAM BAA participation. This appears to result in uplift payments in perpetuity. Unlike cost recovery provided through the transmission access charge (TAC), WAC revenues are not guaranteed, and the evolution of EDAM does not warrant uplifts to

cover these foregone revenues in perpetuity.

When entering into a transaction, it is important that the parties know the costs and benefits of that transaction. In adopting a WAC process that will potentially create uplift (if the historical WAC revenues are not achieved), parties will undertake transactions whose complete costs will not be known until after they are settled. This can lead to parties making the wrong transactions because they lack information on the total cost impact. In addition, such uplifts will not always be paid by the entity that entered into the transaction and will therefore shift costs among market participants. The ISO, as a market operator, should strive to avoid such market inefficiency.

**6. Provide your organization's comments on the track A2 proposal and track B initial scoping items related to section 7 – avoiding resource sufficiency evaluation (RSE) failures:**

The ISO will run advisory RSEs at 6 am and 9 am before the binding RSE run at 10 am. Because the day-ahead market bidding deadline is also 10 am, the binding run will include all of the bids from RSE eligible resources, but the advisory runs will not. Therefore, the ISO proposes to publish RA offers expected between 6 am and 10 am along with the advisory RSE results to better reflect the supply expected to be included in the binding RSE run. CalCCA agrees with this approach. In evaluating advisory RSE failures, expected RA offers must be considered before taking actions to cure to avoid over-procuring to cover RSE deficiencies that appear in the advisory timeframe but not in the binding run. There is a risk that expected RA offers will not materialize or that the calculation of expected RA offers will change between 6 am and 10 am due to new outages. CalCCA expects this risk would be small, and that expected RA offers will largely reflect actual offers. The ISO should confirm this expectation by evaluating historical RA compliance with day-ahead must-offer obligations and historical RA outages submitted between 6 am and 10 am for the next day to determine the risk associated with assuming all resources with a day-ahead must-offer obligation will provide bids into the day-ahead market. Appropriate actions taken to cure advisory RSE deficiencies may depend on how realistically expected RA offers reflect actual RA offers.

The ISO contemplates accounting for RA RDRR in the RSE if the failure amount of the 9 am advisory run exceeds the quantity of expected RA offers. The ISO should include RDRR in the RSE and the ISO should include it as a load modifier to the RSE load forecast until the RDRR has met its use limitations. This approach would allow the ISO to account for supply that will be available in real-time.

In track B, the ISO will consider developing a mechanism for the ISO to procure cure capacity (similar to the ISO's existing CPM authority). If the ISO develops its own curing mechanism, the ISO should cure advisory RSE deficiencies only (1) when it is reasonably certain a material deficiency will occur considering expected RA offers and prior efforts to cure deficiencies, and (2) after the ISO has weighed the costs of curing against the cost of the RSE failure and has ensured the cost of curing would not exceed the failure charges.

**7. Provide your organization's comments on the track A1 proposal and track B potential solutions related to section 8 - process to allocate RSE failure surcharges and revenues:**

In track A1, the ISO proposes to allocate RSE failure surcharges and revenues to metered demand. In track B, the ISO will consider allocation methodologies that more accurately reflect cost-causation principles. The Issue Paper/Straw Proposal puts two ideas forward: allocating to load-serving entities (LSEs) based on LSE-specific RSE targets net of LSE supply, and allocating first to RA capacity that fails to meet its RA obligations and second to metered demand. The ISO should adopt a metered demand allocation in track A1 as an interim solution, as developing an allocation methodology that

aligns with cost causation will require additional stakeholder discussion and time to develop a feasible solution that accurately reflects the cause of the failure.

As CalCCA previously commented, it would be extremely difficult to tie a resource's schedule to a particular LSE because there is not a one-for-one relationship between the schedule of a resource and the LSE for which it is serving. The only way for the ISO to allocate charges based on metered demand net of supply would be for the ISO to review contracts between LSEs and suppliers to understand the contractual obligation of the resources. The schedule alone does not provide this information. Further, this allocation cannot be done based upon an assessment of RA contracts alone. RA requirements and RSE requirements are not identical, and LSEs face RA penalties that follow cost causation principles specific to RA deficiencies. Any allocation methodology for RSE failure deficiencies should not be duplicative of RA penalties and should instead target the specific RSE requirements the charges would be based upon. RA requirements and RSE requirements are different and serve different purposes. LSEs enter into many different types of contracts with RSE-eligible resources beyond RA-only contracts, including contracts for substitute capacity and contracts for hedges (e.g., firm-energy contracts, call options, etc.). Additionally, resources may provide partial capacity or capacity to multiple different LSEs, making it difficult to determine which portion of the capacity ties to which LSE.

The ISO should adopt a metered load allocation approach in track A1 and develop an allocation methodology in track B that allocates charges to RA resources failing to meet their must-offer obligation first and to metered load second.

**8. Provide your organization's comments on section 9 – resource adequacy imports in EDAM:**

Virtual power plants (VPP) out-of-state are becoming an increasingly available resource to California entities. The ISO should ensure VPPs can qualify for the RSE and clarify the bidding and modeling rules for virtual power plants to provide RSE capacity.

**9. Provide your organization's comments on the proposed WEIM Governing Body role, described in section 10:**

CalCCA supports the WEIM Governing Body role in the Issue Paper/Straw Proposal. The scope of issues within this initiative, namely how the ISO BAA will operate under EDAM, falls squarely within the authority of the ISO Board of Governors.

**10. Provide any additional comments on the EDAM ISO BAA Participation Rules issue paper and track A1 straw proposal, and May 10, 2023 stakeholder meeting discussion:**

CalCCA has no additional comments at this time.

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

Order Instituting Rulemaking to Review,  
Revise, and Consider Alternatives to the  
Power Charge Indifference Adjustment.

R.17-06-026

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

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May 24, 2023

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## SUMMARY OF RECOMMENDATIONS

California Community Choice Association (CalCCA) supports the Proposed *Decision Addressing Greenhouse Gas-Free Resources, Long-Term Renewable Transactions, Energy Index Calculations, and Energy Service Providers' Data Access* (Proposed Decision), with the following limited comments and requested modifications:

- ✓ The Proposed Decision's adoption of a minimum volume-based threshold of 1,000 gigawatt-hours for setting the greenhouse gas-free (GHG-Free) market price benchmark (MPB) rather than a threshold based on the number of contracts entered into strikes a reasonable balance between the positions of the parties;
  - ✓ The Commission should require Pacific Gas and Electric Company and Southern California Edison Company to file their Tier 1 Advice Letter indicating their election between the GHG-Free MPB or GHG-Free allocations for 2024 within 30 (rather than 60) days of the effective date of the final Decision to allow community choice aggregators adequate time to plan for 2024; and
  - ✓ The final Decision should direct parties to the proper proceedings to address:
    - Vintaging changes when an investor-owned utility (IOU) procurement contract is amended, renewed, or extended, which is the subject of a September 9, 2022 Motion filed by CalCCA in this proceeding; and
    - The urgent need for a permanent framework to credit the Portfolio Allocation Balancing Account when IOUs use banked Renewable Energy Certificates for renewables portfolio standard compliance.
-

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

Order Instituting Rulemaking to Review,  
Revise, and Consider Alternatives to the  
Power Charge Indifference Adjustment.

R.17-06-026

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

California Community Choice Association<sup>1</sup> (CalCCA) submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the *Decision Addressing Greenhouse Gas-Free Resources, Long-Term Renewable Transactions, Energy Index Calculations, and Energy Service Providers' Data Access* (Proposed Decision or PD), issued on May 4, 2023.

**I. INTRODUCTION**

CalCCA appreciates the opportunity to submit comments on the Proposed Decision, issued after thoughtful consideration by the Commission, Administrative Law Judge (ALJ), and Energy Division staff on the remaining issues in this proceeding. Stakeholders were able to submit numerous sets of comments, engage with Energy Division through various workshops and meetings, and answer data requests that informed this PD. The Proposed Decision should be

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

adopted, as it complies with the requirements of the Public Utilities Code to ensure that unbundled customers receive either the value, or are allocated a fair and equitable share, of the benefits that unbundled customers paid for prior to their departure from bundled service but that remain with bundled service customers.<sup>2</sup> As a result of the Commission's extensive and thoughtful work reflected in the PD, the PCIA's accuracy will be positively impacted if this Proposed Decision is adopted.

The following are the actions taken in the Proposed Decision. First, the Proposed Decision will modify the calculation of the Power Charge Indifference Adjustment (PCIA) in two ways: (1) by adopting a methodology to compensate unbundled customers for the incremental greenhouse gas-free (GHG) value of large hydroelectric energy resources in the investor-owned utilities' (IOUs') portfolios; and (2) by revising the calculation of the Energy Index Market Price Benchmark (MPB) to improve accuracy and transparency by basing the calculation on historical generation output rather than load.

Second, the Commission also considered, but the Proposed Decision rejects, revising the Renewables Portfolio Standard (RPS) MPB to include long-term fixed price (LTFP) transactions (along with the currently included short-term, index-plus transactions) in the calculation of the RPS MPB.

Third, the Proposed Decision declines to extend access to Electric Service Providers (ESPs) to confidential IOU data for PCIA forecasting purposes.

Fourth, the Proposed Decision denies all motions not previously ruled upon, and closes the proceeding.

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<sup>2</sup> See California Public Utilities Code § 366.2(g) (“[e]stimated net unavoidable electricity costs paid by the customers of a [CCA] shall be reduced by the value of any benefits that remain with bundled service customers, unless the customers of the [CCA] are allocated a fair and equitable share of those benefits”).

CalCCA supports the Proposed Decision, with the following limited comments and requested modifications:

- ✓ The Proposed Decision’s adoption of a minimum volume-based threshold of 1,000 gigawatt-hours (GWh) for setting the GHG-Free MPB rather than a threshold based on the number of contracts entered into strikes a reasonable balance between the positions of the parties;
- ✓ The Proposed Decision should require Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) to file their Tier 1 Advice Letter indicating their election between the GHG-Free MPB or GHG-Free allocations for 2024 within 30 days (rather than 60 days) of the effective date of the Decision to allow community choice aggregators (CCAs) adequate time to plan for 2024; and
- ✓ The Proposed Decision should direct parties to the proper proceedings to address:
  - Vintaging changes when an IOU procurement contract is amended, renewed, or extended, which is the subject of a September 9, 2022 Motion filed by CalCCA in this proceeding; and
  - The urgent need for a permanent framework to credit the Portfolio Allocation Balancing Account (PABA) when IOUs use banked Renewable Energy Certificates (RECs) for RPS compliance.

## **II. THE PROPOSED DECISION SHOULD BE ADOPTED WITH LIMITED MODIFICATIONS**

### **A. The Proposed Decision’s Adoption of a Minimum Volume-Based Threshold of 1,000 GWh for the Commission to Establish a GHG-Free MPB Strikes a Reasonable Balance Between the Positions of the Parties**

Energy Division Staff’s Supplemental Proposal on GHG-Free resources proposed a minimum criterion of ten GHG-Free transactions for the Commission to set a GHG-Free MPB. PG&E and CalCCA both recommended rejecting the minimum transaction criteria.<sup>3</sup> CalCCA, however, opposed PG&E’s recommendation for a minimum-volume criteria of 3,500 GWh

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<sup>3</sup> *California Community Choice Association’s Reply Comments on Administrative Law Judge’s Ruling Requesting Comments on Supplemental Greenhouse Gas-Free Proposal and Issues in Scope*, R.17-06-026 (Mar. 24, 2023) (CalCCA Reply Comments), at 5; *Opening Comments of Pacific Gas and Electric Company (U 39 E) to Administrative Law Judge’s Ruling Requesting Comments on GHG-Free Resources Supplemental Energy Division Staff Proposal and Issues in Scope*, R.17-06-026 (Mar. 17, 2023), at 4-5.

because that high criteria will effectively allow the IOUs to ensure the GHG-Free MPB is always zero given the IOUs own a majority of hydroelectric resources within the California Independent System Operator (CAISO) system.<sup>4</sup> The Alliance for Retail Energy Markets and Direct Access Customer Coalition (AReM/DACC) recommended removing all minimum criteria for setting the GHG-Free MPB, which CalCCA supported.<sup>5</sup>

The Commission agrees with parties in the Proposed Decision that a volume-based threshold is preferable to a threshold based on the number of contracts.<sup>6</sup> Therefore, the PD sets a minimum threshold for establishing a GHG-Free MPB for any given year at 1,000 GWh.<sup>7</sup> While CalCCA prefers no minimum threshold, the Proposed Decision should be adopted as it strikes a reasonable balance between the recommendations of the parties with respect to setting the GHG-Free MPB.

**B. PG&E and SCE Should be Required to file a Tier 1 Advice Letter Electing the GHG-Free MPB or Allocation for 2024 Within 30 (Rather Than 60) Days of the Final Decision to Allow Adequate Time for CCA Planning**

The Proposed Decision requires PG&E and SCE to each file a Tier 1 Advice Letter within 60 days of the effective date of the Decision to indicate whether it elects for 2024 the GHG-Free MPB or to provide an interim allocation of large hydroelectric energy.<sup>8</sup> The Commission intends to vote on this Proposed Decision, at the earliest, at the Commission's June 8, 2023 Business Meeting.<sup>9</sup> Assuming the Final Decision is issued in June, the Tier 1 Advice Letters will be filed in mid-August, providing very limited time for CCAs to complete their planning for 2024.

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<sup>4</sup> CalCCA Reply Comments, at 5-8.

<sup>5</sup> *Comments of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition to Administrative Law Judge Wang's Ruling Requesting Comments on Supplemental GHG-Free Proposal and Issues in Scope*, R.17-06-026 (Mar. 17, 2023), at 5.

<sup>6</sup> Proposed Decision at 34.

<sup>7</sup> *Id.*

<sup>8</sup> *Id.*, Conclusion of Law (COL) 3, at 45-46.

<sup>9</sup> *Id.*, Cover Page.

Accordingly, CalCCA requests that the Commission require PG&E and SCE to file the Tier Advice Letters within 30, rather than 60, days of the final Decision.

**C. The Final Decision Should Direct Parties to the Proper Proceeding(s) to Address Issues Raised in Response to ALJ Wang’s March Ruling**

Ordering Paragraphs (OP) 7 and 8 of the Proposed Decision state that “[a]ll motions not previously ruled upon are hereby denied,” and “Rulemaking 17-06-026 is closed.”<sup>10</sup> These statements appear to dispose of, without addressing, CalCCA’s September 9, 2022 motion (September Motion) requesting to add into the proceeding’s scope the appropriate venue to decide vintaging changes when an IOU procurement contract is amended, renewed, or extended.<sup>11</sup> In addition, also not addressed are comments issued in response to ALJ Wang’s March 23, 2023 ruling (March ALJ Ruling) regarding the urgent need for a permanent framework to credit the PABA when IOUs use banked RECs for RPS compliance.<sup>12</sup> The closing of the proceeding without addressing these issues is surprising given that comments submitted in response to the ruling reflect either unanimous agreement by the IOUs and CalCCA (or a lack of opposition) to the Commission taking up these issues.<sup>13</sup> The Proposed Decision’s silence will unnecessarily cause both Commission resources and party resources to be spent re-raising, potentially re-disputing, and hopefully resolving where they can be addressed. For some parties, those future efforts will be the second, third or even fourth time addressing the same issue. CalCCA does not oppose closing this proceeding without deciding on these issues. However,

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<sup>10</sup> *Id.*, at OP 7 and 8, at 47.

<sup>11</sup> *California Community Choice Association’s Motion to Amend Assigned Commissioner’s Second Amended Scoping Memo and Ruling*, R.17-06-026 (Sep. 9, 2022) (September Motion), at 1.

<sup>12</sup> *Administrative Law Judge’s Ruling Requesting Comments on Supplemental Greenhouse Gas-Free Proposal and Issues in Scope*, R.17-06-026 (Mar. 3, 2023), at 1-2.

<sup>13</sup> DACC/AReM raised further issues for the Commission’s consideration in reply comments, and it is unclear if other parties support or oppose the consideration of those issues.

CalCCA does request that the Commission provide guidance in the final Decision as to where and when it will address these issues in the future.

**1. The Commission Should Provide Guidance in the Final Decision as to When and Where Re-Vintaging of Amended IOU Procurement Contracts Will be Addressed**

The Final Decision should provide guidance as to when and where re-vintaging of amended IOU procurement contracts will be addressed. CCAs requested the issue of re-vintaging be addressed in PG&E's 2019 Energy Resource Recovery Account (ERRA) Compliance case.<sup>14</sup> In response to the CCAs raising the issue, the Commission recognized the need to take a closer look at where vintaging is best addressed:

[T]he Commission's currently open proceeding, Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment, R.17-06-026, is more appropriate for considering how the Commission should address contract vintages for the utilities in the future, and we intend to explore these matters in that proceeding.<sup>15</sup>

The next time CalCCA seeks to address this simple issue will be the fourth time it or its members have raised it, including: (1) the 2019 ERRA Forecast Proceeding, (2) the September Motion, and (3) comments in response to the March ALJ Ruling. Indeed, if these comments are considered here, it will be the fifth time.

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<sup>14</sup> *Opening Comments of Joint Community Choice Aggregators on Proposed Decision Resolving Phase One of Pacific Gas and Electric Company's Energy Resources Recovery Account (ERRA) Compliance Application for the 2019 Record Year*, Application (A.) 20-02-009 (June 30, 2021) ("Joint CCA Opening Comments").

<sup>15</sup> D.21-07-013, *Decision Resolving Phase One of Pacific Gas and Electric Company's ERRA Compliance Application for the 2019 Record Year*, A.20-02-009 (July 15, 2021), at 21 (emphasis added).

**2. The Commission Should Provide Guidance in the Final Decision as to When and Where Issues Concerning the Use of Banked RECs to Meet IOU RPS Compliance Requirements Will be Addressed**

The Final Decision should also provide guidance as to when and where issues concerning the use of banked RECs to meet IOU RPS compliance requirements will be addressed. As explained in detail in CalCCA’s March 17, 2023 comments,<sup>16</sup> the use of banked RECs to meet the IOUs’ RPS compliance requirements escalated in the past few years, requiring the development of interim solutions to account for that use within each IOU’s PABA. While parties have largely agreed on the interim solutions proposed within the PG&E and SCE ERRA forecast cases, the development of a permanent framework to value banked RECs as Retained RPS is both necessary and urgent. Both the existing Voluntary Allocation and Market Offer process and proposed programs, such as SCE’s Green Share program in A.22-05-022, *et al.*, will further increase demand for RECs from the IOUs’ RPS-eligible portfolios, likely leading to an increased use of RECs to meet RPS compliance obligations in the near term. In two separate decisions, the Commission has stated the development of a REC-crediting framework is, or should be, within the scope of this proceeding.<sup>17</sup>

It may be that the Commission plans to address these issues in a subsequent Order Instituting Rulemaking regarding the PCIA, or elsewhere. If that is the case, a paragraph or a few sentences in the Final Decision explaining as much can be valuable, saving both parties and the

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<sup>16</sup> *California Community Choice Association’s Comments on Administrative Law Judge’s Ruling Requesting Comments on Supplemental Greenhouse Gas-Free Proposal and Issues in Scope*, R.17-06-026 (Mar. 17, 2023), at 11-15.

<sup>17</sup> D.20-02-047, at 13-16 (resolving PG&E’s 2020 ERRA Forecast case and stating “A tracking framework within PABA and mechanisms to value banked RECs at the end of the compliance period may help resolve these issues. These issues are however, more appropriately addressed by the Commission in the PCIA proceeding.”); D.22-12-044 at 22; D.22-12-042 at 22; and D.22-12-012 at 61-62 (stating “... the current scope of the PCIA proceeding includes consideration of whether to modify or clarify the calculation of the PCIA for VAMO transactions, so we do not address SoCal CCAs’ request here.”).

Commission substantial time and effort. CalCCA has included a Conclusion of Law to enact this recommendation in Attachment A hereto, although a brief discussion of the Commission’s plans within the section discussing comments on the proposed decision also could be sufficient.

**III. CONCLUSION**

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

Respectfully submitted,



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

May 24, 2023

**ATTACHMENT A  
TO  
COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION  
ON THE PROPOSED DECISION**

**Proposed Changes to Findings of Fact, Conclusions of Law and Ordering Paragraphs**

**CONCLUSIONS OF LAW**

15. The Commission plans to address the issues of the appropriate venue to consider the re-vintaging of amended contracts and the development of a permanent framework for crediting banked RECs in \_\_\_\_\_.

**ORDERING PARAGRAPHS**

3. Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) shall each indicate, in the Energy Resource Recovery Account (ERRA) Forecast Application filing for the first year of a three-year period corresponding to a Renewables Portfolio Standard compliance period, whether such utility shall elect to provide an interim allocation of large hydroelectric energy for that three-year period. For 2024 only, PG&E and SCE shall each (a) file a Tier 1 advice letter within ~~60~~30 days of the effective date of this decision to indicate whether it elects to provide an interim allocation of large hydroelectric energy and (b) update its 2024 ERRA Forecast Application workpapers, as applicable, within 90 days of the effective date of this decision to reflect whether it elects to provide an interim allocation of large hydroelectric energy.

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

Application of Pacific Gas and Electric Company  
(U39E) for Review of the Disadvantaged  
Communities – Green Tariff, Community Solar  
Green Tariff and Green Tariff Shared Renewables  
Programs.

A.22-05-022

And Related Matters.

A.22-05-023

A.22-05-024

**REPLY BRIEF OF THE  
JOINT COMMUNITY CHOICE AGGREGATORS AND  
CITY AND COUNTY OF SAN FRANCISCO**

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May 30, 2023

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## Summary of Recommendations

- The Commission must dismiss claims that modifications to existing programs shall meet the same requirements as the establishment of new community renewable energy programs.
- The Commission must maintain and expand the Disadvantaged Communities Green Tariff (“DAC-GT”) and Community Solar Green Tariff (“CSGT”) programs. Specifically the Joint CCAs propose the following considerations:
  - The DAC-GT and CSGT programs should be maintained irrespective of the approval of a new community renewable energy program as they target a distinct customer group and provide specific benefits to vulnerable customers.
  - The Commission should recognize that the DAC-GT and CSGT programs are well positioned to take advantage of Federal Tax Credits.
- The CSGT program should be modified as proposed by the Joint CCAs, and if the program is not successful after that point, it should be rolled into the DAC-GT program.
- The Joint CCAs recommend the following modifications to the DAC-GT and CSGT programs:
  - The Commission should allocate new and additional capacity to expanding or new CCA program administrators.
  - The Commission should allow Investor-Owned Utility (“IOU”) CSGT projects that are no longer viable due to CCA expansion to move to the DAC-GT program but should not default affected customers into the IOU DAC-GT program.
  - The Commission should support solar plus storage systems under the DAC-GT and CSGT programs as a voluntary option.
  - The Commission should maintain a program administrator’s ability to auto-enroll or self-enroll customers in the DAC-GT and CSGT programs.
  - Program administrators should be allowed to cease program solicitations under the DAC-GT and CSGT programs if and when available capacity falls below 500 kW.
  - The Commission should recognize that all DAC-GT and CSGT program administrators are bound by Commission oversight.
  - The Commission should approve the Joint CCA’s expansion of the DAC-GT program, rather than PG&E’s top off approach for the DAC-GT and CSGT programs, as it is a preferable approach to support new resources and expand customer participation in the program.
- The Commission should recognize that CCAs cannot be required to participate in successor Green Access Programs.
- The Commission should resolve remaining questions and gaps associated with CCSA’s Net Value Billing Tariff proposal prior to considering approval.

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

Application of Pacific Gas and Electric Company (U39E) for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Programs.	A.22-05-022
And Related Matters.	A.22-05-023 A.22-05-024

**REPLY BRIEF OF THE  
JOINT COMMUNITY CHOICE AGGREGATORS AND  
CITY AND COUNTY OF SAN FRANCISCO**

**I. INTRODUCTION**

Pursuant to Rule 13.12 of the Rules of Practice and Procedure of the California Public Utilities Commission (“CPUC” or “Commission”) and in accordance with the *Assigned Commissioner’s Scoping Memo and Ruling*, dated December 2, 2022 (“Scoping Memo”), the *Administrative Law Judges’ Ruling Revising Procedural Schedule*, dated February 23, 2023 (“February Ruling”), and the *Administrative Law Judge’s Ruling Updating Procedural Schedule and Requiring Use of Briefing Outline*, dated April 21, 2023 (“April Ruling”), Clean Power Alliance of Southern California (“CPA”), the City and County of San Francisco, acting by and through its Public Utilities Commission (“CleanPowerSF”), East Bay Community Energy (“EBCE”), Lancaster Choice Energy (“LCE”), Marin Clean Energy (“MCE”), Peninsula Clean Energy Authority (“PCE”), Pico Rivera Innovative Municipal Energy (“PRIME”), San Diego Community Power (“SDCP”), San Jacinto Power (“SJP”), and San José Clean Energy (“SJCE”) (collectively, the “Joint Community Choice Aggregators” or “Joint CCAs”) hereby submit this Reply Brief.

As set forth in Decision (“D.”) 18-06-027 and D.21-12-036, the current proceeding for the Investor-Owned Utilities’ (“IOUs”) Green Access Program (“GAP”) Applications was determined as the forum in which the CPUC would review the GAPs, including the Disadvantaged Communities Green Tariff (“DAC-GT”), Community Solar Green Tariff (“CSGT”) and Green Tariff Shared Renewables (“GTSR”) programs.<sup>1</sup> Additionally, Public Utilities Code Section 769.3(b)(1), as enacted by Assembly Bill (“AB”) 2316 (Ward, 2022), directs the Commission to evaluate the performance of the GAPs. Pursuant to the Scoping Memo, the Commission determined that the evaluation of the programs should be conducted by parties as part of this proceeding.

This Reply Brief responds directly to Opening Briefs submitted by Arcadia Power, Inc. (“Arcadia Power”), California Environmental Justice Alliance, Vote Solar, and the Natural Resources Defense Council (“CEJA et al.”), Coalition of California Utility Employees (“CUE”), Coalition for Community Solar Access (“CCSA”), Cypress Creek Renewables, LLC. (“Cypress Creek”), Pacific Gas and Electric Company (“PG&E”), the Public Advocates Office (“Cal Advocates”), the Solar Energy Industries Association (“SEIA”), Southern California Edison Company (“SCE”), and The Utility Reform Network (“TURN”) filed on May 17, 2023.

## **II. ARGUMENTS**

### **A. Objectives of the DAC-GT and CSGT Programs**

#### **1. The Commission Must Dismiss Claims that Modifications to Existing Programs Shall Meet the Requirements of New Community Renewable Energy Programs.**

The Commission should find that existing GAPs must be evaluated by different statutory requirements than proposed community renewable energy programs. As noted above, one

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<sup>1</sup> See D.18-06-027 at 104, Ordering Paragraph (“OP”) 16; D.21-12-036 at 55-56, OP 11.

purpose of the current proceeding is to address the requirements in AB 2316 which sets out two separate and distinct goals for the Commission. On or before March 31, 2024, the Commission shall (i) evaluate existing GAPS, including the DAC-GT and CSGT programs,<sup>2</sup> and (ii) determine whether it would be beneficial to establish a new community renewable energy program.<sup>3</sup> As noted in detail in the Joint CCAs' Opening Brief, the evaluation of the existing GAPS is subject to the criteria outlined in Section 769.3(b)(1)(A).<sup>4</sup> If the Commission determines that an existing program does not meet all of these goals, the Commission may authorize the termination or modification of the program.<sup>5</sup> Separately, *if* the Commission establishes a new community renewable energy program, that new program must meet all of the requirements of Section 769.3(c).<sup>6</sup>

CCSA's interpretation of AB 2316 erroneously concludes that existing GAPS should be modified to meet "not only the three goals identified as part of the review process for existing programs" (per Section 769.3(b)(1)(A)), but also the six criteria required for newly established community renewable programs (per Section 769.3(c)).<sup>7</sup> As CCSA correctly notes in its Opening Brief, one objective of this proceeding "should be to effectuate the purpose of AB 2316."<sup>8</sup>

However, CCSA's interpretation of AB 2316 is incorrect because (1) CCSA's analysis does not

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<sup>2</sup> Pub. Util. Code § 769.3(b)(1).

<sup>3</sup> Pub. Util. Code § 769.3(b)(2).

<sup>4</sup> *See* Pub. Util. Code § 769.3(b)(1)(A)(i)-(iii) (namely the programs must (i) efficiently serve distinct customer groups, (ii) minimize duplicative offerings, and (iii) promote robust participation by low-income customers.)

<sup>5</sup> Pub. Util. Code § 769.3(b)(1)(C).

<sup>6</sup> Pub. Util. Code § 769.3(c) (newly established community renewable energy programs in accordance with Section 769.3(b)(2) must (i) be complimentary to, and consistent with Title 24 of the California Code of Regulations, (ii) ensure at least 51 percent of the program's capacity serves low-income customers, and (iii) minimize impacts to nonparticipating customers by prohibiting the program's costs from being paid by nonparticipating customers in excess of the avoided costs.)

<sup>7</sup> Opening Brief of the Coalition for Community Solar Access Regarding Green Access Programs ("CCSA Opening Brief") at 3.

<sup>8</sup> CCSA Opening Brief at 2-3.

follow the basic requirements of statutory construction, (2) the plain meaning of the statute clearly and unambiguously indicates that the DAC-GT and CSGT programs are only subject to the evaluation criteria in Section 769.3(b)(1), (3) CCSA misconstrues legal precedent in its request for the Commission to look at the legislative intent of Section 769.3, and (4) CCSA reaches the wrong conclusions even when looking at the entire substance of the aforementioned statute.

First, CCSA fails to follow the basic requirements of statutory construction because it does not first rely upon the plain meaning of AB 2316. CCSA relies on *Moyer v. Workmen's Comp. Appeals Bd.* in stating that a court must consider the particular clause or section in the context of the statutory framework as a whole in order to harmonize various parts of a statutory enactment.<sup>9</sup> However, the court in *Moyer v. Workmen's Comp. Appeals Bd.*, states that, in order to determine the intent of a statute, a court must “turn *first* to the words themselves [for] the answer.”<sup>10</sup> The court further emphasizes that a court is “required to give effect to statutes ‘according to the usual, ordinary import of the language employed in framing the[m].’”<sup>11</sup> In opinions that postdate *Moyer*, the California Supreme Court follows this primary rule of statutory interpretation which first looks to the ordinary meaning of the language in a statute, and if no ambiguity exists in the language, the plain meaning of the statute governs.<sup>12</sup> It is “[o]nly when the language of a statute is susceptible to more than one reasonable construction is it appropriate

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<sup>9</sup> CCSA Opening Brief at 3-4, fn. 3. (citing *Moyer v. Workmen's Comp. Appeals Bd.* (1973) 10 Cal. 3d 222, 230 (“*Moyer v. Workmen's Comp. Appeals Bd.*”))

<sup>10</sup> *Moyer v. Workmen's Comp. Appeals Bd.*, 10 Cal. 3d 222, 230 (citing *People v. Knowles* (1950) 35 Cal. 2d 175, 182) (*emphasis added.*)

<sup>11</sup> *Id.* (citing *In re Alpine* (1928) 203 Cal. 731, 737.)

<sup>12</sup> *Hunt v. Superior Court* (1999) 21 Cal.4th 984, 1000 (“In determining intent, we look first to the words of the statute, giving the language its usual, ordinary meaning. If there is no ambiguity in the language, we presume the Legislature means what is said, and the plain meaning of the statute governs.”) (citing *People v. Snook* (1997) 16 Cal.4th 1210, 1215); *see also Diamond Multimedia Systems, Inc. v. Superior Court* (1999) 19 Cal.4th 1036, 1047.

to turn to extrinsic aids, including the legislative history of the measure, to ascertain its meaning.”<sup>13</sup> CCSA does not first address the plain language meaning of the statute nor establish that ambiguity exists in the statute, but rather directly states that the statute must be considered in its entirety to support its interpretation that modifications to existing programs must meet the Section 769.3(c) criteria.

Second, the plain meaning of the statute clearly and unambiguously indicates that the DAC-GT and CSGT programs are only subject to the evaluation criteria in Section 769.3(b)(1). There is no ambiguity within Section 769.3. There are three statutory paragraphs at issue here; Sections 769.3(b)(1), 769.3(b)(2), and 769.3(c). In Sections 769.3(b)(1) and 769.3(b)(2) the statute clearly identifies the two separate and distinct goals to (i) evaluate existing programs, and (ii) determine whether it would be beneficial to establish a new tariff or program, both of which the Commission must accomplish on or before March 31, 2024. Subsequently, Section 769.3(c) sets out requirements for a new community renewable energy program, if established. It is clear from the plain language of the statute that only newly established programs pursuant to Section 769.3(b)(2) are subject to the requirements in Section 769.3(c).

As evidence of this, the Commission should consider the language used within Section 769.3, specifically the use of the term “establish” as used in its various forms within the statute. The Merriam-Webster dictionary defines “establish” as “to bring something into existence.”<sup>14</sup> Additionally, Black’s Law Dictionary defines “establish” as “[t]o make or form; to bring about or into existence.”<sup>15</sup> Section 769.3(b)(2)(A) asks the Commission to determine whether it would

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<sup>13</sup> *Diamond Multimedia Systems, Inc. v. Superior Court* (1999) 19 Cal.4<sup>th</sup> 1036, 1055 (citing *Granberry v. Islay Investments* (1955) 9 Cal.4<sup>th</sup> 738, 744.)

<sup>14</sup> “Establish.” Merriam-Webster.com Dictionary, Merriam-Webster, <https://www.merriam-webster.com/dictionary/establish>. Accessed 29 May. 2023.

<sup>15</sup> “Establish.” Black’s Law Dictionary (11<sup>th</sup> ed. 2019).

be beneficial *to establish* a new tariff or program.<sup>16</sup> The next Section (Section 769.3(b)(2)(B)), which immediately precedes Section 769.3(c) provides steps that the CCAs and electric service providers must take “[i]f the commission *establishes* a community renewable energy program pursuant to subparagraph (A)” (referring to Section 769.3(b)(2)(A)).<sup>17</sup> Finally, Section 769.3(c) provides that “[t]he community renewable energy program, *if established*, shall do all of the following...”<sup>18</sup> Based on the definition of “establish,” it is clear from the language used that Section 769.3(b)(2) and Section 769.3(c) should apply to new programs brought into existence as part of the Commission’s compliance with the statute, and not currently existing programs. Furthermore, the speculative nature of the word “if”, when used with “established,” indicates that Section 769.3(b)(2)(B) and Section 769.3(c) should only apply to programs that might exist in the future, rather than existing programs.

Additionally, this repeated use of the term “established” connects the establishment of a new tariff or program to the criteria in Section 769.3(c). In other words, it is clear from the language used that the programs referred to in subdivision (c), *if established*, are the same programs referenced in subdivision (b)(2)(A)-(B), *if established*. Conversely, there is nothing in subdivision (b)(1) that links the modification of existing GAPs, or “customer renewable energy subscription programs” as they are referred to in this section, to the *establishment* of a program or the requirements in subdivision (c). Therefore, the statute is unambiguous that the DAC-GT and CSGT programs, as existing programs under subdivision (b)(1), are not subject to the requirements in subdivision (c).

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<sup>16</sup> Pub. Util. Code § 769.3(b)(2)(A).

<sup>17</sup> Pub. Util. Code § 769.3(b)(2)(B). (*emphasis added.*)

<sup>18</sup> Pub. Util. Code § 769.3(c). (*emphasis added.*)

Third, CCSA misconstrues legal precedent in its request for the Commission to look at the legislative intent of Section 769.3. CCSA cites *West Pico Furniture Co.* to argue that in order to determine the scope and purpose of a statute, the Commission must look to the entire substance of the statute.<sup>19</sup> The issue in *West Pico Furniture Co.* was the interpretation of a particular phrase within a specific code section.<sup>20</sup> The court went on to clarify that in “[i]nterpreting particular words, phrases or clauses in a statute, it is a cardinal rule that the entire substance of the statute or that portion related to the subject under review should be examined in order to determine the scope and purpose of the provision containing such words, phrases, or clauses.<sup>21</sup> However, CCSA does not make the argument that there are any words or phrases within Section 769.3 that are ambiguous or in need of clarification. Rather, CCSA claims that because Section 769.3 is silent on the goals of modifications to existing programs, a holistic reading of the statute requires that the programs meet all the criteria in Section 769.3(c).<sup>22</sup> Section 769.3’s “silence” should not be construed as a particular word or phrase in the statute that needs interpreting. As detailed above, there is no ambiguity within the plain language of the statute that would require this sort of statutory interpretation.

Finally, even if the Commission were to determine that Section 769.3 was ambiguous and in need of further interpretation, in considering the legislative history of AB 2316, it is undeniable that the Legislature purposefully and distinctly separated out the requirements of an

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<sup>19</sup> CCSA Opening Brief at 3-4, fn. 3. (citing *West Pico Furniture Co. v. Pacific Finance Loans* (1970) 2 Cal. 3d 594, 608 (“*West Pico Furniture Co.*”))

<sup>20</sup> *West Pico Furniture* at 607 (interpreting the phrase “bone fide load of a principal amount of five thousand dollars or more” within Cal. Fin. Code § 22053 as in effect at that time which stated: “The following sections of this division do not apply to any bone fide loan of a principal amount of five thousand dollars (\$5,000) or more or to a duly licensed personal property broker in connection with any such load, if the provisions of this section are not used for the purpose of evading this division.”)

<sup>21</sup> *West Pico Furniture* at 608 (citing *Wallace v. Payne* (1925) Cal. 539, 544.)

<sup>22</sup> CCSA Opening Brief at 3.

existing GAP versus the establishment of a new community renewable energy program. This is made especially clear when considering the August 26, 2022 Senate Floor Analysis which memorializes the Senate Floor Amendments to AB 2316 made on August 24, 2022. These amendments “narrow[ed] the application of criteria exclusively to the new proposed program...”<sup>23</sup> Prior to this amendment, Section 769.3(b)(1)(A) contained a fourth criteria which would require that the evaluation of the existing programs include whether the program “[s]atisfies the criteria described in subdivision (c)” (referring to the criteria required in Section 769.3(c) for newly established programs.<sup>24</sup> This makes it explicitly clear that while the Legislature had contemplated including the additional Section 769.3(c) criteria in the evaluation of existing programs, those additional criteria were explicitly removed from Section 769.3(b)(1)(A) and the consideration of existing programs. Therefore, the Commission should determine that modifications to the DAC-GT and CSGT programs must only meet the criteria detailed in Section 769.3(b)(1)(A).

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<sup>23</sup> See AB 2316 Senate Floor Analysis, August 26, 2022 at 2, available at: [https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill\\_id=202120220AB2316#](https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=202120220AB2316#).

<sup>24</sup> AB 2316, 2021-2022 Leg., Reg. Sess., § 2(b)(1)(A)(iv) (as amended by Senate August 11, 2022, available at: [https://leginfo.legislature.ca.gov/faces/billVersionsCompareClient.xhtml?bill\\_id=202120220AB2316&version=20210AB231692AMD](https://leginfo.legislature.ca.gov/faces/billVersionsCompareClient.xhtml?bill_id=202120220AB2316&version=20210AB231692AMD)

## **B. Evaluation of Current DAC-GT and CSGT Programs**

### **1. The DAC-GT and CSGT Programs Must be Maintained and Expanded as Appropriate.**

#### **a. The DAC-GT and CSGT Programs Should be Maintained Irrespective of the Approval of a New Community Renewable Energy Program as They Target a Distinct Customer Group and Provide Specific Benefits to Vulnerable Customers.**

The Commission must reject any proposals to sunset the DAC-GT and CSGT programs as supported by some parties in Opening Briefs. Specifically, TURN advocates for sunsetting the DAC-GT and CSGT programs in favor of the Net Value Billing Tariff (“NVBT”) program proposed by CCSA and as modified by TURN.<sup>25</sup> Additionally, Cal Advocates recommends that the Commission freeze DAC-GT and CSGT solicitations in order to provide customers the option to transfer to the successor GAP once it is operational, and then sunset the DAC-GT and CSGT programs.<sup>26</sup> These recommendations to sunset the DAC-GT and CSGT programs presuppose (i) that a successor GAP will be adopted and implemented, and (ii) there cannot be multiple, concurrently-administered community renewable energy programs. The Joint CCAs strongly disagree with these presumptive notions.

First, there is no requirement under AB 2316 that a new community renewable energy program be created as part of this proceeding. Rather, the Commission is tasked with determining whether a new program would benefit ratepayers.<sup>27</sup> Therefore, action should not be taken on the presumption that a new program will be adopted and implemented. Second, AB 2316 does not preclude the existence of multiple community renewable energy programs

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<sup>25</sup> Opening Brief of The Utility Reform Network (“TURN Opening Brief”) at 15, 19.

<sup>26</sup> Opening Brief of the Public Advocates Office on Consolidated Applications for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Program (“Cal Advocates Opening Brief”) at 17.

<sup>27</sup> Pub. Util. Code § 769.3(b)(2).

administered in parallel. If the existing GAPs are found to meet the criteria defined in AB 2316, those programs should be maintained regardless of whether a new program is adopted.

TURN supports the sunset of the DAC-GT and CSGT programs, in part, based on the fact that maintaining the DAC-GT and CSGT programs while simultaneously establishing the NVBT “would result in substantial duplication.”<sup>28</sup> TURN also claims that because the NVBT serves a wider array of customers inclusive of DAC-GT and CSGT customers, the Commission should find that the DAC-GT and CSGT programs are no longer needed if the NVBT is authorized.<sup>29</sup> TURN further purports that, when assessing whether there is potential duplication of similar GAP offerings, the Commission should look to “whether duplication could undermine the likelihood that a customer enrolls in the option that best serves their needs.”<sup>30</sup>

The Joint CCAs strongly disagree that the concurrent administration of the DAC-GT and CSGT programs and the NVBT would result in duplication. Although the DAC-GT and CSGT programs would serve a subset of customers eligible to participate in a proposed NVBT program, that in and by itself does not signify that the programs are duplicative. The DAC-GT program, unlike the NVBT proposal, specifically serves low-income customers exclusively. Additionally, both the DAC-GT and CSGT programs provide a set 20% bill discount in contrast to the NVBT which would provide subscribers with bill discounts based on the value of subscribed generation to the grid.<sup>31</sup> PG&E, in its Rebuttal Testimony, provided analysis indicating that a NVBT program subscriber would see a monthly savings of \$22 while a DAC-GT subscriber receiving the 20% bill discount would receive a monthly savings of \$41.<sup>32</sup> This indicates that low-income

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<sup>28</sup> TURN Opening Brief at 15-16, 19-20.

<sup>29</sup> *Id.*

<sup>30</sup> *Id.* at 5.

<sup>31</sup> TURN Opening Brief at 15-16.

<sup>32</sup> Exhibit PGE-03: PG&E Rebuttal Testimony at 22.

customers would likely receive greater benefits under the set 20% bill discount provided by the DAC-GT and CSGT programs.

Based on these facts, it is evident that the DAC-GT and CSGT programs are not duplicative of the proposed NVBT program, namely because they target different customer types and provide distinct and specific benefits to vulnerable customers. Furthermore, it is plausible, if not probable, that eligible customers may find that the DAC-GT and/or CSGT programs provide a greater benefit, and therefore, best serve their individual needs.

**b. The DAC-GT Program Successfully and Efficiently Brings the Benefits of Renewable Energy to Vulnerable Customers While Providing Bill Relief.**

In its Opening Brief, Cal Advocates recommends that the Commission sunset the DAC-GT programs as they are undersubscribed and therefore, not effective.<sup>33</sup> Cal Advocates' position that the DAC-GT programs are undersubscribed is factually inaccurate based upon testimony provided by CCAs and IOUs.<sup>34</sup> When looking at the status of each program administrator's program, the evidence presented clearly shows that almost all programs that have been administered for more than one year are fully subscribed, or nearly fully subscribed. More specifically, as recognized by Cal Advocates, all of the CCA DAC-GT programs that have been in operation for over a year are at or near full program capacity.<sup>35</sup>

Additionally, the Joint CCAs have demonstrated that the DAC-GT program is successful in procuring new, steel-in-the-ground renewable energy while providing bill discounts to low-income customers. As described in detail in the Joint CCAs' Testimony and Opening Brief, the

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<sup>33</sup> Cal Advocates Opening Brief at 14.

<sup>34</sup> See Opening Brief of the Joint Community Choice Aggregators and City and County of San Francisco ("Joint CCA Opening Brief") at 22-23, Table 3 (providing the percentage of DAC-GT program allocated capacity subscribed for each program administrator.)

<sup>35</sup> Cal Advocates Opening Brief at 14; *see also* Joint CCA Opening Brief at 13, Table 1.

DAC-GT program administrators have enrolled over 24,577 customers,<sup>36</sup> procured over 70 megawatts (“MW”) of new solar resources,<sup>37</sup> and have provided over \$6.8 million in bill savings to low-income customers.<sup>38</sup> These numbers clearly illustrate that program administrators have successfully implemented their DAC-GT programs by bringing new solar resources to disadvantaged communities (“DACs”) while providing low-income customers with meaningful bill discounts. Therefore, the Commission should reject any proposal to sunset the DAC-GT program for being unsuccessful or undersubscribed.

Relatedly, CCSA asserts that the DAC-GT program does not efficiently serve customers as it is not *economically* efficient because that it relies on subsidies.<sup>39</sup> CCSA’s determination that “efficient” should be defined as “*economically* efficient” is arbitrary and should be dismissed. As AB 327 (Perea, 2013) and D.18-06-027 outline, the DAC-GT and CSGT programs were developed to promote access to distributed generation resources among residential customers in DACs. It is not the programs’ goal to be cost-effective or “economically efficient.” Specifically, D.18-06-027 states “the statutory criteria for the successor [net energy metering] tariff, such as the requirement to ensure that the total costs are approximately equivalent to total benefits, should not be applied in the development of alternatives for DACs.”<sup>40</sup> The Commission further explained, when examining the goals of programs benefiting DACs like the DAC-GT and CSGT programs that “[b]ecause this program serves multiple state policy goals, and is intended as an equity program to allow low-income customers and those in DACs to access solar distributed generation and clean energy on the same basis as other residential customers, we find that it is

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<sup>36</sup> Joint CCA Opening Brief at 22, Table 3.

<sup>37</sup> *Id.* at 14, Table 1.

<sup>38</sup> *Id.* at 17.

<sup>39</sup> CCSA Opening Brief at 13.

<sup>40</sup> D.18-06-027 at 10.

appropriate not to apply this constraint [that the total costs are approximately equivalent to total benefits] to DAC programs.”<sup>41</sup> PG&E’s Opening Brief supports these arguments.<sup>42</sup> For these reasons, CCSA’s claim that the DAC-GT program is inefficient due to the use of subsidies is misplaced and should be dismissed by the Commission.

**c. The DAC-GT and CSGT Programs are Well Positioned to Take Advantage of Federal Tax Credits.**

Multiple parties in Opening Briefs, including Arcadia Power,<sup>43</sup> CUE,<sup>44</sup> CEJA et al.,<sup>45</sup> TURN,<sup>46</sup> and Cypress Creek,<sup>47</sup> claim that the NVBT proposal should be adopted because of the opportunity to take advantage of federal tax credits. CCSA claims that in order “[t]o capture federal incentives, California first and foremost must create a program that successfully supports deployment of community renewable facilities.”<sup>48</sup> Specifically, CCSA describes several provisions in the Inflation Reduction Act (“IRA”) related to the investment tax credit (“ITC”) that are “relevant to projects that would be built under a community renewables program.”<sup>49</sup>

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<sup>41</sup> *Id.*

<sup>42</sup> Pacific Gas and Electric Company’s (U 39 E) Opening Brief (“PG&E Opening Brief”) at 21-22. (citing D.18-06-027).

<sup>43</sup> Opening Brief of Arcadia Power, Inc. at 18 (“Lastly, the NVBT priorities the use of state and federal incentives.”)

<sup>44</sup> Opening Brief of the Coalition of California Utility Employees at 9 (“If the Commission timely adopts the NVBT, projects under the NVBT will be in a good position to maximize state and federal incentives.”)

<sup>45</sup> Opening Brief of the California Environmental Justice Alliance, Vote Solar, and the Natural Resources Defense Council (“CEJA et al. Opening Brief”) at 11 (“In particular, CEJA et al. support a program based on the NVBT that requires a 25-year ACC lock-in, 51% low-income customer participation per project, and implementation of the program in a timely manner to ensure that it can leverage federal and state funding opportunities.”)

<sup>46</sup> TURN Opening Brief at 43 (“TURN urges the Commission to expedite implementation to increase opportunities for NVBT projects to compete for federal and state funding that would be used to increase bill savings for subscribers.”)

<sup>47</sup> Opening Brief of Cypress Creek Renewables, LLC at 24 (“The NVBT can take maximum advantage of state and federal incentives including the Inflation Reduction Act.”)

<sup>48</sup> Exhibit CCSA-007: Surrebuttal Testimony (Smithwood) at 66.

<sup>49</sup> Exhibit CCSA-001: Amended Prepared Direct Testimony (Smithwood) at 95-96 (“Key provisions relevant to projects that would be built under a community renewables program created

The Joint CCAs agree that it is important for renewable energy projects to take advantage of federal tax credits to reduce the cost of programs to ratepayers but find it misleading that parties seem to indicate that such benefits could only be reaped under a *new* community renewable energy program, or the NVBT specifically. The Commission must recognize that projects developed under the DAC-GT and CSGT programs can equally take advantage of existing and new tax credits as (1) it is already common practice for developers to incorporate ITC into renewable energy project power purchase agreement (“PPA”) pricing, and (2) the new enhanced tax credits approved under the IRA will also benefit DAC-GT and CSGT projects.

First, even prior to the passage of the IRA the DAC-GT and CSGT programs benefited from the ITC as it is common practice for project developers to incorporate ITC benefits into PPA pricing. This practice will continue with the extension of the ITC benefits under the IRA. It is misleading for CCSA to claim that these federal incentives cannot be captured until a new program is created to support community renewable facilities when the DAC-GT and CSGT programs are already in place and are already taking advantage of these ITC incentives.

Second, the new and enhanced ITC benefits, specifically the 20% ITC adder for qualified low-income economic benefit projects that serve low-income customers (“Low Income Community Bonus”),<sup>50</sup> can also be incorporated into the DAC-GT and CSGT programs. In fact, in its latest DAC-GT and CSGT solicitation materials, CPA modified its pro forma PPA to add a

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pursuant to this proceeding include: (1) a renewal of the [ITC] to 30% of eligible project costs (for projects that meet prevailing wage requirements); (2) an extension of the ITC through 2032...;(3) the inclusion of interconnection costs as ITC eligible expenditures for projects sized 5 MW or less; (4) a 10% ITC adder for projects using equipment produced domestically; (5) a 10% ITC adder for projects located in energy communities; (6) a 10% ITC adder for projects sized 5 MW or less that are located [in] low income communities or on “Indian Land”; and (7) a 20% ITC adder for projects installed on qualifying residential rental buildings or for qualified low-income economic benefit projects sized 5 MW or less that serve low and moderate income customers (e.g. low-income community solar projects.”) (citing 26 U.S.C. § 48(a),(e).)

<sup>50</sup> 26 U.S.C. § 48(e)(1)(A)(ii).

requirement for the project developer to make commercially reasonable efforts to qualify for and receive the Low-Income Community Bonus, and pass through the benefits of such incentives in the form of a reduced contract price.<sup>51</sup>

In summary, the Commission should not overlook the fact that the DAC-GT and CSGT programs are already in place, and already well positioned to take advantage of existing federal tax credits, as well as new enhanced tax credits developed under the IRA. The establishment of a new community renewable programs is certainly not a requirement for these tax incentives to be realized in California.

**2. The CSGT Program Should be Modified as Proposed by the Joint CCAs, and If the Program Is Not Successful After That Point, it Should be Rolled into the DAC-GT Program.**

In its Opening Brief, PG&E recommends consolidation of the DAC-GT and CSGT programs such that the combined program would use the DAC-GT eligibility rules and operate under the current DAC-GT program processes, effectively creating an expanded DAC-GT program.<sup>52</sup> The Joint CCAs are not opposed to this proposal, however, as noted in the Joint CCAs' Rebuttal Testimony, the Commission should first implement the Joint CCAs' proposed CSGT program modifications.<sup>53</sup> Only if these modifications prove to be unsuccessful, should the Commission then approve the consolidation of the two programs.

To determine whether the DAC-GT and CSGT programs should be combined, the Joint CCAs propose that the Commission first authorize CSGT program modifications as proposed in the Joint CCAs' Opening Brief, including modifications to the CSGT project siting requirements. Once those modifications are in place, program administrators should be allowed two years from

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<sup>51</sup> See CPA Advice Letter 0018-E at 5.

<sup>52</sup> PG&E Opening Brief at 19.

<sup>53</sup> Exhibit JCCA-02: Joint CCA Rebuttal Testimony at 24-25.

the date of the Final Decision in this proceeding to submit PPAs to the Commission for approval for their CSGT programs under the new program rules. If the CSGT program solicitations prove to be unsuccessful, the Commission should authorize consolidation of the DAC-GT and CSGT programs pursuant to the process proposed in the Joint CCAs' Rebuttal Testimony.<sup>54</sup> This alternative proposal would allow the CSGT program the opportunity to become successful and provide community solar benefits before determining to roll the program into the DAC-GT program.

### **C. Proposed Modifications to the Current GAP Option**

#### **1. The Commission Should Allocate New and Additional Capacity to Expanding or New CCA Program Administrators.**

Multiple parties have noted the potential that departing CCA load may affect DAC-GT and CSGT customers.<sup>55</sup> Specifically, PG&E notes that as PG&E has executed contracts for nearly all of its DAC-GT and CSGT program capacity, it will not be able to transfer available program capacity to expanding CCAs in the future.<sup>56</sup> Separately, SCE opposes additional CCAs from becoming DAC-GT and CSGT program administrators, in part because it would create changes in available program capacity for the existing programs in the middle of the program lifecycle which can be disruptive to the procurement process.<sup>57</sup>

The Joint CCAs' proposal, detailed in its Opening Brief, to adopt a formal process to allocate *new and additional* DAC-GT program capacity to a CCA upon expansion would address

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<sup>54</sup> *Id.* at 24-25.

<sup>55</sup> See PG&E Opening Brief at 13; Opening Brief of Southern California Edison Company ("SCE Opening Brief") at 31, 33 (stating that if SCE does contract for a DAC-GT or CSGT facility and the community in which it is located subsequently forms a CCA program, SCE would expect participation in that community renewable facility to be substantially impacted."); Joint CCA Opening Brief at 24 (noting that customers previously enrolled in IOU DAC-GT programs that switch to a CCA should not be penalized when they enroll in CCA electricity service.)

<sup>56</sup> PG&E Opening Brief at 13.

<sup>57</sup> SCE Opening Brief at 39.

both concerns.<sup>58</sup> First, to PG&E's point, the expanding CCA would no longer be reliant on IOU unprocured program capacity. Rather, under the Joint CCAs' proposal, an expanding CCA would request Commission approval, via a Tier 2 advice letter, for *additional* DAC-GT program capacity sufficient to support the transitioning, already enrolled, DAC-GT customers (with a minimum increase of 1 MW in capacity).<sup>59</sup> This would ensure that currently enrolled DAC-GT customers may continue to benefit from the DAC-GT program, while alleviating PG&E's concerns about having to transfer PG&E's unprocured DAC-GT program capacity to the CCAs.

Second, the Joint CCAs' proposal could also be leveraged to address new CCA DAC-GT or CSGT program administrators as noted by SCE. Namely, a CCA that becomes a new DAC-GT and/or CSGT program administrator would also request *new and additional* program capacity from the Commission in its initial DAC-GT and CSGT Implementation Plan, based on the CCA's proportional share of eligible customers in DACs in its service territory pursuant to Resolution E-4999.<sup>60</sup> Allocating new program capacity to new CCA program administrators would prevent changes in another program administrator's program capacity while allowing low-income customers in the service area of new CCA program administrators to not be precluded from the programs.

**2. The Commission Should Allow IOU CSGT Projects That Are No Longer Viable Due to CCA Expansion to Move to the DAC-GT Program But Should Not Default Affected Customers into the IOU DAC-GT Program.**

The Joint CCAs acknowledge that there may be an instance where an expanding CCA impacts an IOU CSGT project such that the project may no longer be viable as pointed out by

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<sup>58</sup> See Joint CCA Opening Brief at 27-29.

<sup>59</sup> Joint CCA Opening Brief at 29.

<sup>60</sup> Resolution E-4999 at 7 (providing that the total MW a CCA could serve should be based on the CCA's proportional share of load of eligible customers within the respective IOU's distribution service territory.)

SCE in its Opening Brief.<sup>61</sup> In this instance, the Joint CCAs support SCE’s proposal that the IOU may move the CSGT contract to the DAC-GT program so that the CSGT project does not become a stranded asset.<sup>62</sup> However, the Joint CCAs disagree with SCE’s proposal that the customers that were previously enrolled under the CSGT project should then be enrolled in the utility’s DAC-GT programs.<sup>63</sup> Per D.05-12-041 and Public Utilities Code Section 366.2(c)(15)(A)(i), customers are defaulted into CCA electricity service upon CCA implementation or expansion.<sup>64</sup> Hence, SCE’s proposal, assuming it applies to customers that would be in the expanding CCAs service territory, contradicts existing law and Commission guidance.

Instead, the following rules should apply if and when a CCA expands into an area where a utility CSGT project is located. If the expanding CCA is a DAC-GT program administrator, the rules and process described in Section II.C.1. above should apply. More specifically, the customers previously enrolled in the utility’s CSGT program should be rolled over into the expanding CCA’s DAC-GT program (rolling customers over into the CCA’s CSGT programs is not feasible as the CCA will not have an eligible project that would fit the requirements of the CSGT program). If the expanding CCA is not a DAC-GT or CSGT program administrator, the customer should have the choice to remain in the utility’s DAC-GT program or move over to CCA electricity generation service. The Joint CCAs believe this is the best approach to ensure

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<sup>61</sup> See SCE Opening Brief at 38 (noting that a CSGT project may no longer be viable if there is insufficient customer enrollments to meet program capacity, project subscription level for CARE/FERA eligible customers falls below 50% of the capacity, etc.).

<sup>62</sup> *Id.*

<sup>63</sup> *Id.* at 38-19.

<sup>64</sup> D.05-12-041 at 65 Conclusions of Law 35 (“New customers should be automatically assigned to the CCA unless the utility receives an opt-out request.”); *see also* Pub. Util. Code § 366.2(c)(15)(A)(i) (“... Any notification shall inform customers of both of the following: (i) That the customer is to be automatically enrolled and that the customers has the right to opt out of the community choice aggregator without penalty.”)

that low-income customers continue to receive program benefits while also maintaining the principle of customer choice upon CCA expansion.

**3. The Commission Should Support Solar Plus Storage Systems Under the DAC-GT and CSGT Programs as a Voluntary Option.**

As noted in its Opening Brief, the Joint CCAs strongly support a determination that solar plus storage resources are eligible for the DAC-GT and CSGT programs. However, the Joint CCAs disagree with Cal Advocates that the inclusion of storage resources in these programs should be mandatory.<sup>65</sup> Instead, it should be a voluntary option because the inclusion of storage as a requirement may create unnecessary barriers to the program. For example, potential sites for the DAC-GT and CSGT programs may not physically have room to include paired storage and therefore, including this requirement would limit the siting eligibility for these programs.<sup>66</sup> Second, the added value of storage resources would depend on each unique circumstance, e.g. if the project would be able to obtain deliverability status and provide Resource Adequacy (“RA”) capacity. Due to these uncertainties regarding the ability and value of adding storage resources to the programs, the Joint CCAs recommend that solar plus storage resources should be added to the program as voluntary options. Each program administrator, moving forward, would indicate in the solicitation materials submitted to the Commission via an advice letter which resources would be eligible for participation. Furthermore, the advice letter requesting approval of the power purchase agreement would describe the resource type and reasons for selection of the particular resource type (i.e. solar only or solar plus storage resource).

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<sup>65</sup> Cal Advocates Opening Brief at 3.

<sup>66</sup> See Exhibit JCCA-02: Joint CCAs Rebuttal Testimony at 10-11.

#### **4. The Commission Should Maintain a Program Administrator’s Ability to Auto-Enroll or Self-Enroll Customers in the DAC-GT and CSGT Programs.**

Cal Advocates requests that the Commission suspend auto-enrollment for the DAC-GT and CSGT programs in order to “mitigate ratepayer bill impacts from rapid automatic participation in a ratepayer-funded program.”<sup>67</sup> Conversely, a large number of parties support the use of auto-enrollment, including SCE,<sup>68</sup> SEIA,<sup>69</sup> and PG&E.<sup>70</sup> The Joint CCAs agree that auto-enrollment of customers should continue to be allowed under the DAC-GT program. As an initial matter, Cal Advocates failed to provide sufficient evidence of how the suspension of auto-enrollment would affect ratepayer bill impacts. Presumably, program administrators would still be able to self-enroll customers in the DAC-GT and CSGT programs even if auto-enrollment were suspended. The determination to use auto-enrollment or self-enrollment does not change the capacity cap for each program and, therefore, does not change the number of customers, or the associated bill impacts, under the programs.

The Joint CCAs continue to urge the Commission to maintain a program administrator’s ability to determine the best enrollment approach for their individual community.<sup>71</sup> As described in detail in the Joint CCAs’ Opening Brief, both auto- and self-enrollment processes have benefits and one option may be better for some program administrators and not for others.<sup>72</sup> Each program administrator should be afforded the flexibility to decide whether to use auto-enrollment, self-enrollment, or a combination of both based on what works best in their service area.

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<sup>67</sup> Cal Advocates Opening Brief at 12.

<sup>68</sup> See SCE Opening Brief at 36.

<sup>69</sup> See Opening Brief of The Solar Energy Industries Association (“[SEIA Opening Brief](#)”) at 25.

<sup>70</sup> See PG&E Opening Brief at 19.

<sup>71</sup> See Joint CCAs Opening Brief at 44.

<sup>72</sup> *Id.*

**5. Program Administrators Should be Allowed to Cease Program Solicitations Under the DAC-GT and CSGT Programs If and When Available Capacity Falls Below 500 kW.**

The Joint CCAs support recommendations for the Commission to adopt a policy whereby a DAC-GT and/or CSGT program administrator may cease program solicitations when available capacity reaches a de minimis level as was proposed by both SEIA and SCE.<sup>73</sup> Specifically, the Joint CCAs support SCE’s proposal that if the remaining capacity for a DAC-GT or CSGT program falls below 500 kilowatts (“kW”), the program administrator may cease solicitations. While the Joint CCAs appreciate SEIA’s approach to encourage ongoing solicitations by not permitting program administrators to cease solicitations until the program administrators have received no development participation in two consecutive rounds of solicitations, the Joint CCAs believe that a program capacity of 500 kW or less, by itself, is enough to justify an end to solicitations. The Joint CCAs believes that SCE’s approach will best ensure that the solicitation costs do not unreasonably exceed the value of seeking to fulfill a minimal amount of remaining program capacity.<sup>74</sup>

**6. All Program Administrators are Already Bound by Commission Oversight**

SCE asserts that all load-serving entities (“LSEs”) that administer the DAC-GT program should be bound by the same rules and statutory oversight as the IOUs, noting that “[w]ithout proper review of contract amendments and administration, the impact on the programs’ funding

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<sup>73</sup> See SEIA Opening Brief at 26 (“the record supports allowing an IOU or CCA to cease conducting new DAC-GT and CSGT solicitations once its remaining program capacity has (1) fallen below 500 kW, **and** (2) there has been no participation by developers in two consecutive solicitations.”); see also SCE Opening Brief at 41 (“SCE proposes that if the MWs remaining for its DAC-GT or CSGT fall below 500 kW, SCE will sunset the program without the need for any further solicitations.”)

<sup>74</sup> SCE Opening Brief at 41.

source would result in the program becoming more dependent upon PPP charges, which would burden rates for all customers.”<sup>75</sup>

It is unclear to the Joint CCAs which additional oversight SCE is seeking as current Commission decisions and Resolutions already provide the requirements that SCE requests. D.18-06-027 provides that all CCA tariffs “must abide by all [DAC-GT] or [CSGT] rules and requirements adopted in this decision.”<sup>76</sup> Additionally, Resolution E-5102 specifically requires CPA to “submit all executed Power Purchase Agreements via a Tier 2 Advice Letter for approval no later than 180 days following notification of selected bidders.”<sup>77</sup> This requirement was also carried over for all Resolutions that approved CCAs as DAC-GT and CSGT program administrators.<sup>78</sup> It is unclear what additional oversight SCE is requesting with respect to CCA DAC-GT and CSGT program administrators and hence, the Commission should dismiss SCE’s request.

**7. While the Joint CCAs Appreciate PG&E’s Top Off Approach for the DAC-GT and CSGT Programs, Expansion of the DAC-GT Program Capacity is a Preferable Approach to Support New Resources and Expand Customer Participation in the Program.**

PG&E is proposing a “top-off” approach for the DAC-GT and CSGT programs which would “use dedicated solar resources to deliver an incremental percentage of renewable energy to customers instead of replacing 100 percent of their energy supply.”<sup>79</sup> Under this proposal, PG&E estimates that with an assumed Renewable Portfolio Standards (“RPS”) portfolio

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<sup>75</sup> SCE Opening Brief at 39.

<sup>76</sup> D.18-06-027 at 104, Ordering Paragraph (“OP”) 17.

<sup>77</sup> Resolution E-5102 at 15, OP 3; *see also* CPA AL 0020-E (submitting an amendment to a DAC-GT power purchase agreement for Commission approval.)

<sup>78</sup> *See* Resolution E-5124 at 34, OP 8, Resolution E-5130 at 14, OP 3, and Resolution E-5246 at 14, OP 4.

<sup>79</sup> Exhibit PGE-02: PG&E Amended Supplemental Testimony at 29; *see also* PG&E Opening Brief at 21.

requirement of 50%, it could double the number of participants receiving bill discounts without adjusting overall program capacity.<sup>80</sup>

While the Joint CCAs support options that increase the number of low-income customers able to participate in the DAC-GT and CSGT programs, the Joint CCAs would like to highlight that the programs were established, in part, to promote the installation of renewable generation in DACs.<sup>81</sup> The Joint CCAs do not believe that PG&E's approach properly encourages new, steel-in-the-ground resources, as required by the programs. Additionally, the Joint CCAs have concerns that this proposed approach would inappropriately shift costs of RPS resources into the DAC-GT and CSGT program portfolio.

Therefore, rather than approving PG&E's top-off proposal, the Joint CCAs recommend expanding the DAC-GT program capacity cap, as described in Section II.D.a.i. of the Joint CCAs' Opening Brief.<sup>82</sup> Expanding the program's capacity cap increases customer participation in the program and provide benefits to a greater number of low-income customers while, at the same time, also encouraging the installation of new renewable energy resources.

#### **D. New GAP Option Proposals**

##### **1. The Commission Should Recognize that CCAs Cannot be Required to Participate in Successor GAPs.**

In Opening Briefs, SCE infers that CCAs may be required to participate in a successor GAP.<sup>83</sup> The CCAs clarify that AB 2316 does not require CCAs to participate in any newly established community renewable energy programs, but rather provides specific steps a CCA must take to notify the Commission regarding whether or not it will participate in a newly

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<sup>80</sup> *Id.*

<sup>81</sup> *See* D.18-06-027.

<sup>82</sup> *See* Joint CCA Opening Brief at 24.

<sup>83</sup> *See* SCE Opening Brief at 8, fn. 19 ("Assuming CCAs must participate in the GAP.")

created program.<sup>84</sup> The statute further notes that a CCA “may begin participating in, or end its participation in, the program at any time by notifying the commission.”<sup>85</sup> This is acknowledged by SCE itself, which cites to Section 769.3(b)(2)(B),<sup>86</sup> as well as CCSA, which provides a process on what would happen if a CCA decides not to participate in its proposed NVBT proposal.<sup>87</sup> Furthermore, neither Section 769.3 nor any other statute provides the CPUC with the general authority to require CCAs to participate in any new GAP. The Joint CCAs request that in its Final Decision, the Commission specifically provide provisions for a CCA to *elect* to participate in any successor GAP or a new community renewable energy program, if eligible under law.

## **2. The Commission Should Resolve the Remaining Questions Associated with CCSA’s NVBT Proposal Prior to Considering Approval**

The Joint CCAs appreciate the NVBT proposal made by CCSA. As a general matter, the Joint CCAs are supportive of programs or proposals that promote the development of clean, distributed energy resources (“DERs”) in California. However, when faced with the multitude of options to foster DERs and when considering California’s affordability challenges, the Commission must proceed cautiously and deliberately when considering approval of new programs or tariffs with far-reaching scope and breadth.

Considering this, the Joint CCAs believe there are still outstanding gaps and/or disagreements between parties with regards to the NVBT which should be analyzed further before the Commission considers approval of the proposal. More specifically, the Joint CCAs request further consideration of the following issues: (1) whether the NVBT resources would be

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<sup>84</sup> Pub. Util. Code § 769.3(b)(2)(B).

<sup>85</sup> *Id.*

<sup>86</sup> *See* SCE Opening Brief at 47, fn. 131.

<sup>87</sup> *See* CCSA Opening Brief at 19.

front-of-the-meter (“FTM”) or behind-the-meter (“BTM”) resources (along with the associated impacts and requirements), and (2) how the NBVT resources would be incorporated into the Integrated Resource Planning (“IRP”) and RA planning processes.

First, CCSA and the IOUs continue to disagree whether resources under the NVBT would be considered BTM or FTM resources. CCSA’s Surrebuttal Testimony provides that “[u]nder CCSA’s NVBT proposal, the Generator Account is a customer account of the relevant LSE and is thus “behind the meter” as is the practice in New York, Maine, and Massachusetts, among others.”<sup>88</sup> However, as noted by PG&E and SCE, CCSA’s proposal seemingly consists of FTM resources as the resources are connected directly to the IOU’s distribution grid, and are not interconnected behind a customer’s meter.<sup>89</sup> The Joint CCAs tend to agree with the utilities and recommend that the issue should be analyzed in more detail before approval can be considered as this determination has wide-ranging impacts on the rules and requirements that should be applicable to the NVBT. Although CCSA refers to the “Generator Account” as a customer account, a “Generator Account,” pursuant to CCSA’s proposal is a customer account, or Facility Owner, associated with the solar or wind generation facility *interconnected to an IOU’s distribution system* through a single meter.<sup>90</sup> It is the Joint CCAs’ understanding that in California, resources that are interconnected to the distribution system are considered FTM resources. Clarification that a “Generator Account” is a customer account does not provide enough detail to support CCSA’s conclusion that the “Generator Account” is behind the meter.

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<sup>88</sup> Exhibit CCSA-007: CCSA Surrebuttal Testimony (Smithwood) at 11.

<sup>89</sup> See SCE Rebuttal Testimony at 6-7 (“...the resources eligible for the [NVBT] are not (in [SCE’s] view) behind-the-meter resources...”); see also PG&E Rebuttal Testimony at 11 (The analyses presented in CCSA’s testimony are fundamentally flawed because the DER in question is not a demand-side resource. It is a [FTM] generator that is injecting all its energy into the grid and not physically offsetting any of its subscriber customer load.”)

<sup>90</sup> Exhibit CCSA-001 CCSA Amended Prepared Direct Testimony (Smithwood) at 41.

CCSA, additionally, relies on the Distributed Energy Resources Action Plan which provides that some distributed energy resources (“DERs”) are FTM resources.<sup>91</sup> The Joint CCAs agree. DERs can be located either behind a customer’s meter or in-front of a customer’s meter (i.e. interconnected directly to the distribution or transmission system). However, simply calling the projects under the NVBT a “DER” does not specify if the resources should be considered BTM or FTM. Instead, the point of interconnection to the utility grid should determine if a project is considered FTM or BTM and rules and requirements should apply accordingly. This distinction is important, as CCSA proposes to base compensation for exported energy on the avoided costs developed in the Commission’s Avoided Cost Calculator (“ACC”).<sup>92</sup> If it is determined that the NVBT resources are FTM resources, the Joint CCAs agree with PG&E and SCE that use of the ACC may not be an appropriate tool to determine avoided costs.<sup>93</sup>

Second, the NVBT does not properly determine how the NVBT resources would be incorporated into the IRP process or an LSE’s year-ahead RA forecast. With regards to the IRP process, it is unclear whether LSEs would need to include the NVBT projects in their IRP forecasting or if a new and separate process would be developed to incorporate NVBT facility owners into the IRP forecasting process. CCSA notes that it “assumes future IRP planning cycles will incorporate community solar plus storage growth in their planning assumptions and community solar plus storage projects will become part of the resource optimization of the IRP,”

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<sup>91</sup> Exhibit CCSA-007: CCSA Surrebuttal Testimony (Smithwood) at 10 (citing Distributed Energy Resources Action Plan at pg. 23).

<sup>92</sup> Exhibit CCSA-001: CCSA Amended Prepared Direct Testimony (Smithwood) at 43-44.

<sup>93</sup> See PG&E Rebuttal Testimony at 11 (“The ACC, used to establish avoided costs in CCSA’s analyses, was designed to approximate the energy system benefits of many, (likely thousands), of individual, non-targeted customer demand-side interventions across a wide geographic range. It is not designed to calculate the specific benefits of FTM generation,”); see also SCE Rebuttal Testimony at 14 (The DER ACC-based export compensation rate is in appropriate for CCSA’s proposal because it is not a tool used to set pricing for power.”)

but does not detail how this incorporation will take place.<sup>94</sup> Regarding an LSE’s year-ahead RA forecast, CCSA acknowledges that “[t]he initial incorporation of community solar plus storage resources supported by the NVBT could very well cause lag in the full realization of [RA] value” but notes that this would only be “over a short period of time.”<sup>95</sup> However, this lag, and the implications for LSE’s RA forecasts, need additional consideration.

These remaining gaps or disagreements in the NVBT proposal create additional uncertainty in the markets for LSEs at a time when grid reliability and accurate planning and forecasting is of utmost importance. Until these fundamental questions are answered, the Joint CCAs believe that the proposal is not ready for adoption and implementation.

### III. CONCLUSION

The Joint CCAs thank the Commission for its consideration of the matters set forth in this Reply Brief.

May 30, 2023

Respectfully Submitted,

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<sup>94</sup> Exhibit CCSA-001: CCSA Amended Prepared Direct Testimony (Smithwood) at 105.

<sup>95</sup> Exhibit CCSA-007: CCSA Surrebuttal Testimony (Smithwood) at 24.

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

Application of CALIFORNIA  
COMMUNITY CHOICE ASSOCIATION  
for Rehearing of Resolution E-5258.

Application 23-05-\_\_\_\_

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S  
APPLICATION FOR REHEARING OF RESOLUTION E-5258**

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May 30, 2023

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## SPECIFICATION OF ERROR

- × Resolution E-5258 (Resolution) exceeds the Commission’s limited jurisdiction over community choice aggregator (CCA) implementation plans and fails to act as required by Public Utilities Code Section 366.2(c)(8) by (1) failing to provide a firm “earliest possible date” for the launch of East Bay Community Energy’s (EBCE’s) expansion to the City of Stockton and Central Coast Community Energy’s (CCCE’s)<sup>1</sup> expansion to the City of Atascadero, and (2) basing the “earliest possible date” only on the impact on a utility’s “annual procurement plan” as required by Section 366.2(c)(8).
- × The Resolution exceeds the Commission’s limited jurisdiction to address cost shifts and fails to act in the manner required by law by adopting a “new and distinct” cost shift policy that does not comply with Section 366.2(a)(4) and Section 366.3.
- × The Commission fails to act as required by Section 380(e) by applying Resource Adequacy (RA) enforcement in a discriminatory manner.
- × The Resolution does not contain findings that support the order; it is devoid of any findings that (1) RA noncompliance caused increased reliability costs and shifted those costs to the investor-owned utilities’ bundled customers or (2) permitting the CCAs to expand service on January 1, 2024 will cause increased reliability costs and shift those costs to the investor-owned utilities’ bundled customers; consequently the Resolution constitutes an abuse of discretion.
- × The Commission fails to support its findings with substantial evidence demonstrating that the CCAs’ RA noncompliance caused increased reliability costs and shifted those costs to the investor-owned utilities’ bundled customers and, consequently the Resolution constitutes an abuse of discretion.
- × The Commission denies affected parties due process by not providing notice and an opportunity to be heard, and thereby fails to proceed in accordance with law, by adopting material, new policy affecting important issues – RA penalties and cost-shifting – in the context of an enforcement action against particular parties.
- × The Commission prematurely enforces a pending regulation currently being considered in the RA rulemaking, thereby denying the CCAs’ due process to participate in the enactment of such regulation;
- × The Commission fails to act in a manner consistent with its own enforcement procedures, thereby failing to proceed in the manner required by law and denying parties’ due process.
- × The Commission’s retroactive application of a new regulation to the CCAs’ pending implementation plans is unlawful and contravenes due process.

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<sup>1</sup> EBCE and CCCE are referred to collectively as the CCAs.

- × The Resolution imposes a double penalty for RA noncompliance on the CCAs through the suspension of the CCAs' expansion plans after the CCAs already paid the penalties assessed for RA noncompliance.
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Application of CALIFORNIA  
COMMUNITY CHOICE ASSOCIATION  
for Rehearing of Resolution E-5258.

Application 23-05-\_\_\_

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S  
APPLICATION FOR REHEARING OF RESOLUTION E-5258**

Pursuant to Rule 16.1 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure (Rules), Section 8.1 of General Order 96-B, and Public Utilities Code Section 1731,<sup>2</sup> California Community Choice Association<sup>3</sup> (CalCCA) submits this Application for Rehearing of Resolution E-5258<sup>4</sup> (Resolution) issued April 28, 2023, which addressed the implementation date for service area expansions proposed by Central Coast Community Energy (CCCE) and East Bay Community Energy (EBCE) (jointly “CCAs”). Section 1731 requires that any application for rehearing of Resolution E-5258 be filed within 30 days of its date of issuance. This application for rehearing is timely filed.

**I. INTRODUCTION AND SPECIFICATION OF ERROR**

In issuing the Resolution, the Commission exceeded its jurisdiction and statutory authority, failed to proceed in the manner required by law, failed to issue findings in support of

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<sup>2</sup> All subsequent code sections cited herein are references to the California Public Utilities Code unless otherwise specified.

<sup>3</sup> California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Energy For Palmdale’s Independent Choice, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

<sup>4</sup> Resolution E-5258, *Effective Dates for the Expansions of Community Choice Aggregators: Central Coast Community Energy and East Bay Community Energy* (Apr. 27, 2023): <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M507/K472/507472501.PDF>.

its order, issued key findings without substantial evidence in light of the whole record, discriminated in its application of penalties, violated Constitutional due process, and abused its discretion.<sup>5</sup> The extensive legal error permeating the Resolution compels its rehearing.

First, the Resolution fails to proceed in the manner required by law and exceeds the Commission’s very limited jurisdiction over community choice aggregator (CCA) implementation plans by failing to confine its actions to the Legislature’s directive in Section 366.2(c)(8). The statute requires the Commission to set the “earliest possible date” for CCAs to expand their service upon certification of their implementation plans, allowing CCAs certainty in planning their expansion launch.<sup>6</sup> Rather than providing the CCAs with certain implementation dates, the Commission adopted January 1, 2025, as the “earliest possible date” but left the date subject to future modification. The Commission’s action violates the requirements of the statute and leaves the CCAs unable to adequately coordinate with the local governments and the customers which approved and desire the proposed expansions and sets troubling precedent for future CCA expansions.

Second, the Resolution exceeds the Commission’s statutory authority to address potential cost shifts. It adopts a “new and distinct”<sup>7</sup> cost shift policy not previously considered in any formal proceeding and outside the scope of the legislative directives in Section 366.2 and 366.3.

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<sup>5</sup> While the term “abuse of discretion” (Section 1757(a)(5)) is not defined in the Public Utilities Code, Code of Civil Procedure (CCP) Section 1094.5 (administrative mandamus) defines the term to embrace error described in other portions of Section 1757 including Section 1757(a)(2) (failure to proceed as required by law), Section 1757(a)(3) (inadequate findings), as well as Section 1757(a)(4) (absence of substantial evidence to support the findings). Courts have reversed Commission decisions for an “abuse of discretion” in instances where the error might have also been described by reference to another subdivision of Section 1757. *See Calaveras Tel. Co. v. Pub. Util. Comm’n*, 5 Cal. App. 5<sup>th</sup> 972 (2019); *City of Huntington Beach v. Pub. Util. Comm’n* (2013) 214 Cal. App. 4<sup>th</sup> 566 (2013); *The Utility Reform Network v. California Pub. Util. Comm’n*, 166 Cal. App. 4<sup>th</sup> 522 (2008).

<sup>6</sup> § 366.2(c)(8).

<sup>7</sup> Resolution at 10.

The Commission employs its new cost shift policy in an unprecedented fashion to slow CCA expansion to two new communities.

Third, the Resolution fails to proceed as required by Section 380(e) by applying Resource Adequacy (RA) enforcement in a discriminatory manner. The remedy penalty the Resolution imposes on the CCAs cannot be applied to other load-serving entities (LSEs).

Fourth, the Resolution fails both to provide the findings necessary to support the order and to support its central findings with substantial evidence that the CCAs' RA noncompliance shifted costs to investor-owned utility (IOU) bundled customers. The Resolution is premised on an assumption that the CCAs' RA non-compliance actually and directly caused an increase in reliability costs and that those costs were shifted to IOU bundled customers; it does not, however, make such findings or identify substantial evidence supporting that assumption and therefore constitutes an abuse of discretion.

Fifth, the Commission denies interested parties' due process rights to adequate notice and an opportunity to be heard, and thereby fails to proceed in accordance with law, by:

- adopting material new policy affecting important issues – cost shifting and RA penalties – without any process to gain input from interested parties. It adopts these new policies not in a generic proceeding, where all interested parties would have adequate notice that the issues are being considered, but in a narrow enforcement action against two parties;
- enforcing an RA policy currently being considered in the RA rulemaking, thereby prematurely enforcing a pending regulation and denying the CCAs' due process to participate in the enactment of such a regulation;
- failing to utilize any of the enforcement mechanisms prescribed by Resolution M-4846<sup>8</sup> and thus implementing a new procedure without notice;
- retroactively applying a new regulation to the CCAs which was adopted after the CCA Implementation Plans were filed; and

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<sup>8</sup> *Resolution Adopting Commission Enforcement Policy* (Nov. 5, 2020) (Resolution M-4846): <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M350/K405/350405017.PDF>.

- imposing an additional, double penalty for RA noncompliance on the CCAs through the suspension of the CCAs' expansion plans after the CCAs already paid the penalties assessed for noncompliance.

For these and other reasons stated herein, CalCCA requests rehearing of the Resolution.

## II. BACKGROUND

The Resolution effectively suspends indefinitely CCCE's and EBCE's implementation plans to expand their current service to the Cities of Stockton and Atascadero, respectively. To justify this action, the Commission relies on a potential condition that it purports to redress through a newly minted remedy for RA noncompliance currently under consideration in the Commission's RA Rulemaking (R.) 21-10-002.

### A. Commission Involvement in CCA Expansion

As recognized by the Resolution, Commission authority over CCA Implementation Plans derives exclusively from Sections 366.2 and 366.3.<sup>9</sup> Section 366.2 mandates a very limited role for Commission involvement in CCA implementation and expansion to:

- (1) receive from the CCA the implementation plan detailed in Section 366.2(c)(4) to allow the Commission to develop the cost recovery mechanism required by subdivisions (d), (e), and (f);<sup>10</sup>
- (2) notify any electrical corporation serving the customers proposed for aggregation that an implementation plan initiating community choice aggregation has been filed, within 10 days of filing;<sup>11</sup>
- (3) certify within 90 days after the CCA files the implementation plan that the Commission has received the plan, including any additional information necessary to determine a cost-recovery mechanism;<sup>12</sup>
- (4) after certification of receipt of the plan, provide its findings regarding any cost recovery that must be paid by customers of the CCA to prevent shifting of costs as provided for in Section 366.2, subdivisions (d) (Department of Water Resources' (DWRs') electricity purchase costs and contract obligations), (e) (bond related costs

<sup>9</sup> Resolution at 1 (“[t]his Resolution is issued pursuant to Public Utilities Code Sections 366.2 and 366.3”).

<sup>10</sup> § 366.2(c)(5).

<sup>11</sup> § 366.2(c)(6).

<sup>12</sup> § 366.2(c)(7).

between the Commission and DWR and any additional DWR costs), (f) (the electrical corporation’s unrecovered past under-collections and contract costs attributable to the customer departing for CCA service, which are now recovered in the Power Charge Indifference Adjustment (PCIA)), and (h) (specifying that the Commission establish the mechanisms necessary to ensure the charges payable to DWR and the electrical corporations are promptly remitted);<sup>13</sup>

- (5) designate the “earliest possible date” for implementation of a CCA program, taking into consideration the impact on any annual procurement plan of the electrical corporation that has been approved by the Commission;<sup>14</sup>
- (6) provide for registration by CCAs with the Commission, “which may require additional information to ensure compliance with basic customer protection rules and other procedural matters”;<sup>15</sup> and
- (7) authorize community choice aggregation only after it imposes the cost-recovery mechanism pursuant to subdivisions (d), (e), (f), and (h).<sup>16</sup>

Section 366.3 also limits the Commission’s authority to ensuring that “bundled retail customers . . . shall not experience any cost increase as a result of the implementation of a community choice aggregator program,” and that departing load shall not “experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load.”<sup>17</sup>

## **B. CCCE and EBCE Implementation Plan and Expansion Processes**

EBCE submitted an amended implementation plan on September 22, 2022 to expand service to the City of Stockton as of January 1, 2024.<sup>18</sup> CCCE submitted an amended

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<sup>13</sup> § 366.2(c)(7), and (d)-(f).

<sup>14</sup> § 366.2(c)(8).

<sup>15</sup> § 366.2(c)(17).

<sup>16</sup> § 366.2(i).

<sup>17</sup> § 366.3.

<sup>18</sup> *EBCE Addendum No. 2 to the Community Choice Aggregation Implementation Plan and Statement of Intent to Address EBCE Expansion to the City of Stockton* (Dec. 8, 2022):

[https://res.cloudinary.com/diactiwk7/image/upload/v1670611946/EBCE\\_Addendum\\_2\\_CCA\\_Implementation\\_Plan\\_120822\\_e2sqja.pdf](https://res.cloudinary.com/diactiwk7/image/upload/v1670611946/EBCE_Addendum_2_CCA_Implementation_Plan_120822_e2sqja.pdf).

implementation plan on December 8, 2022 to expand service to the City of Atascadero as of January 1, 2024.<sup>19</sup>

In letters dated March 8, 2023, the Commission certified that CCCE's and EBCE's implementation plans are complete and compliant with the requirements of Section 366.2(c). The letters denied, however, the effective dates requested by CCCE and EBCE without setting an alternative date. The letters gave no information on why Energy Division was denying the requested effective dates, stating only that "Energy Division will provide further guidance on the matter." In response, on March 10, 2023, CCCE and EBCE requested pursuant to Section 366.2(c)(8) that the Commission confirm April 1, 2024, and January 1, 2024, respectively as the earliest possible implementation dates for their expansions.

### **C. Commission Resolution E-5258**

On March 27, 2023, Energy Division issued Draft Resolution E-5258<sup>20</sup> (Draft Resolution), suspending implementation of CCCE's and EBCE's service expansions indefinitely. While the Resolution purported to set January 1, 2025 as the earliest possible effective date for the expansions of service for both CCAs, it left the date "subject to modification by further Commission Order."<sup>21</sup>

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<sup>19</sup> *Addendum No. 4 to the Community Choice Aggregation Implementation Plan and Statement of Intent Addressing Central Coast Community Energy's Expansion to Include the City of Atascadero* (Sept. 22, 2022): <https://3cenergy.org/wp-content/uploads/2022/12/Addendum-No.-4-to-the-CCCE-Community-Choice-Aggregation-Implementation-Plan-.pdf>.

<sup>20</sup> Draft Resolution E-5258, Rev. 1, *Effective Dates for the Expansions of Community Choice Aggregators: Central Coast Community Energy and East Bay Community Energy* (Mar. 27, 2023): <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M507/K306/507306274.PDF>.

<sup>21</sup> Draft Resolution at 2.

CalCCA submitted comments on the Draft Resolution on April 17, 2023, identifying legal error in the Draft Resolution.<sup>22</sup> CalCCA concluded that the Draft Resolution was “beyond repair” and requested its withdrawal.

On April 27, 2023, the Commission adopted the Resolution, and the final Resolution was issued on April 28, 2023. The final Resolution failed to address the concerns raised in CalCCA’s April 17, 2023 comments. The conditional nature of the January 1, 2025 implementation date leaves (1) the implementation plans suspended indefinitely, (2) the Cities of Stockton and Atascadero with no date certain as to when their City Council approved CCA service will begin, and (3) the CCAs unable to plan the launch of the service sought by Stockton and Atascadero with certainty.

#### **D. Pending RA Proceeding**

In parallel with this expansion implementation planning, the Commission was considering, but has not yet adopted, changes to the remedies for RA noncompliance in Rulemaking (R.) 21-10-002. The Commission’s RA program, governed by Section 380, places requirements on all LSEs – CCAs, Electric Service Providers (ESPs), and IOUs. The RA program has a clear compliance and penalty framework<sup>23</sup> developed over the years since its initial adoption. The Resolution describes those penalties, including administrative penalties and penalties for deficiencies.<sup>24</sup> An LSE that fails to meet its requirements must pay a pre-

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<sup>22</sup> CalCCA notes that comments on Resolutions are not published on the Commission’s website for reference.

<sup>23</sup> See D.21-06-029, *Decision Adopting Local Capacity Obligations for 2022-2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program*, R.19-11-009 (June 24, 2021) (current RA penalty framework): <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF>.

<sup>24</sup> Resolution at 7.

determined penalty, which increases by multiples as penalties accumulate.<sup>25</sup> The current RA framework does not provide the Commission authority, however, to delay expansions approved by local governments as a penalty for a CCA's failure to meet its RA requirements.

To address this perceived gap, the Energy Division Staff proposed on January 20, 2023, a potential new remedy in R.21-10-002. Staff explains:

To address the potential reliability issues that arise with continued expansion of LSEs that are failing to meet their current summer RA obligations, ED staff propose that a [CCA] or [ESP] must be in good standing in meeting its RA requirements in order to take on new customers. Specifically, ED staff proposes that any CCA or ESP with a deficiency of greater than 2.5% of its system RA requirement on a month ahead RA filing during the previous two calendar years should not be able to expand and take on new any new customer load for the following year. For example, any LSE with RA requirement deficiencies in 2021 or 2022, would not be eligible to expand to serve new load in 2023 for service in 2024.<sup>26</sup>

If this proposal sounds familiar, it is; it is precisely what Energy Division effectuates in the Resolution. The Commission has not, however, issued a decision adopting this new remedy nor does it explain how it falls within the Commission's limited authority under Section 366.2. In fact, the Commission's recent proposed decision in the RA proceeding, issued May 25, 2023, states clearly that: "Energy Division's proposal is not a modification of D.05-12-041 but a new requirement for CCAs planning to implement an expansion in their service territory or CCAs increasing their number of customers."<sup>27</sup> By skipping over the necessary procedural hoops in

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<sup>25</sup> The frequent references herein to the Commission's current RA Program are for context only and should not be regarded as an expression of CalCCA's position on the soundness of that program either legally or from a policy perspective.

<sup>26</sup> R.21-10-002, *Administrative Law Judge's Ruling on Energy Division's Phase 3 Proposals* (Jan. 20, 2023), Appendix A, Energy Division Proposals for Proceeding R.21-10-002, at 34.

<sup>27</sup> R.21-10-002, *Proposed Decision Adopting Local Capacity Obligations for 2024-2026, Flexible Capacity Obligations for 2024, and Program Refinements* (May 25, 2023), at 38.

the RA proceeding and *sua sponte* applying the mechanism, the Resolution skirts an on-going rulemaking process.

### **III. RESOLUTION E-5258 CONSTITUTES ENFORCEMENT AND RATEMAKING BY THE COMMISSION AND MUST BE REVIEWED UNDER THE STANDARDS SET FORTH IN SECTION 1757**

Section 1701.1(a) requires the Commission to “determine whether each proceeding is a quasi-legislative, an adjudication, a ratesetting, or a catastrophic wildfire proceeding...” The Resolution arose not from a formal, categorized proceeding with a public process but as a recommended action by Energy Division Staff without public process. The Commission’s failure to proceed as required by Section 1701.1(a) leaves the standard of public review subject to interpretation.

The Public Utilities Code provides two alternative standards for judicial review of Commission decisions. Section 1757 establishes the judicial review standard for “a complaint or enforcement proceeding, or in a ratemaking or licensing decision of specific application that is addressed to particular parties....” Alternatively, Section 1757.1 establishes the review standard for “any other proceeding.” While the Resolution stems from a deeply flawed process without categorization, the Resolution squarely falls within the definition of both “enforcement” and “ratemaking” proceedings, bringing it within the Section 1757 standard of review.

#### **A. The Resolution is an Enforcement Action Against Particular Parties**

The Resolution represents an enforcement or adjudication action against particular parties – CCCE and EBCE. Rule 1.3 defines "adjudicatory proceedings" as:

- (1) enforcement investigations into possible violations of any provision of statutory law or order or rule of the Commission; and
- (2) complaints against regulated entities, including those complaints that challenge the accuracy of a bill, but excluding those complaints that challenge the reasonableness of rates or charges, past, present, or future.<sup>28</sup>

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<sup>28</sup> Commission Rules of Practice and Procedure (Commission Rules), Rule 1.3.

The Resolution is an “enforcement investigation” related both to the Commission’s enforcement rights under Section 380 and its cost shift authority under Sections 366.2(a)(4) and 366.3.

The Commission’s indefinite suspension of the implementation plans is unambiguously rooted in noncompliance by CCCE and EBCE with the Commission’s RA program requirements, promulgated under Section 380, for 2021 and 2022.<sup>29</sup> The Commission took this action based on its finding that “payment of a Resource Adequacy violation does not fully redress harms caused by a failure to meet Resource Adequacy program requirements...”<sup>30</sup> Even though the RA program already has distinct financial penalties prescribed for RA noncompliance (which were already paid by CCCE and EBCE as recognized in the Resolution<sup>31</sup>), the Commission here expressly and unexpectedly presents an additional RA enforcement action through its Resolution. Indeed, given the harm created by the planning uncertainty for the CCAs and the Cities of Stockton and Atascadero the Resolution created, the Commission’s action can only be viewed as a penalty.<sup>32</sup>

Energy Division Staff’s proposal in the generic RA proceeding, R.21-10-002, reinforces the conclusion that the Resolution is an enforcement action effecting an additional penalty against particular parties for RA non-compliance. Suspension of an implementation plan in response to RA non-compliance is not a current remedy under the existing RA enforcement mechanism. As noted above, however, Energy Division Staff have proposed precisely this mechanism in R.21-10-002.<sup>33</sup> In other words, Energy Division Staff, which also initiated the

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<sup>29</sup> See Resolution at 7-10.

<sup>30</sup> *Id.* at 7.

<sup>31</sup> *Id.*, and Finding 10 at 15.

<sup>32</sup> “Penalty” is defined as a “disadvantage, loss, or hardship due to some action.” [Merriam-Webster Dictionary](#).

<sup>33</sup> See *supra*, n. 26.

Resolution, undeniably view implementation plan suspension as an appropriate enforcement tool to address RA non-compliance.

Likely because the Commission has not yet adopted implementation plan suspension as a formal RA enforcement mechanism, the Resolution cloaks its aim in its authority to prevent cost shifting from CCA customers to IOU bundled customers pursuant to Sections 366.2(a)(4) and 366.3. It suggests further action to consider whether the CCAs' actions violated these provisions.<sup>34</sup>

The Resolution comports with the definition of an adjudicatory or enforcement action, whether the action is aimed at enforcement under Section 380, Section 366.2(a)(4), or Section 366.3. The appropriate standard of review is therefore Section 1757.

**B. The Resolution Involves Matters the Commission Has Characterized as Ratemaking**

The Resolution also represents a ratemaking action, for which the appropriate standard of review is also Section 1757. The action rests on a new cost shift theory, which the Commission concludes arises under Section 366.2(a)(4) or Section 366.3. The purpose of identifying cost shifts is to avoid them by developing new charges for customers leaving the IOU to be served by a CCA or ESP (departing load).<sup>35</sup>

Rule 1.3 defines “ratesetting proceedings” as:

proceedings in which the Commission sets or investigates rates for a specifically named utility (or utilities), or establishes a mechanism that in turn sets the rates for a specifically named utility (or utilities)....<sup>36</sup>

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<sup>34</sup> Resolution at 2, 10, Finding 15 at 16, O¶ 2 at 16.

<sup>35</sup> See generally, Section 366.2(a)(4), (d), (e), and (f).

<sup>36</sup> Commission Rules, Rule 1.3.

The Resolution establishes a mechanism – a new and distinct cost shift policy – that could form the basis of a new non-bypassable charge or penalty, and therefore can be classified as ratesetting.

The generic rulemaking on cost shifts, the Power Charge Indifference Adjustment (PCIA) proceeding (R.17-06-026), supports this conclusion. This rulemaking is the primary proceeding in which the Commission adopts non-bypassable charges for departing load<sup>37</sup> and has been appropriately categorized by the Commission as “ratesetting.”<sup>38</sup> The Resolution is premised on a finding of a cost shift from the CCAs to IOU bundled customers and, therefore, can also be considered a ratemaking action for which the standard of Review is under Section 1757.

### **C. Review of the Commission’s Action in the Resolution Under Section 1757 Warrants Rehearing**

As set forth in detail below, review of the Commission’s action in Resolution E-5258 under the standards set forth in Section 1757 warrants rehearing. Section 1757 requires a Court, and thus the Commission on rehearing, to determine whether “on the basis of the entire record” any of the following occurred:

- (1) The Commission acted without, or in excess of, its powers or jurisdiction;
- (2) The Commission has not proceeded in the manner required by law;
- (3) The decision of the Commission is not supported by the findings;
- (4) The findings in the decision of the Commission are not supported by substantial evidence in light of the whole record;
- (5) The order or decision of the Commission was procured by fraud or was an abuse of discretion; and
- (6) The order or decision of the Commission violates any right of the petitioner under the Constitution of the United States or the California Constitution.

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<sup>37</sup> See R.17-06-026, *Scoping Memo and Ruling of Assigned Commissioner* (Sept. 25, 2017) at 13; see also [Power Charge Indifference Adjustment \(ca.gov\)](http://ca.gov).

<sup>38</sup> *Id.* at 25.

In this case, the only possible record is the CCAs' submitted Implementation Plans, and the Commission's letter in response. While parties were able to file Comments on the Draft Resolution, no fact finding, evidentiary hearing, or other materials exist to support the Commission's decision. None of the speculative findings in the Resolution were premised on proffered factual assertions subject to cross-examination.<sup>39</sup> Therefore, given that "no new or additional evidence shall be introduced" upon review, the Resolution must be reviewed in that context.

#### **IV. THE RESOLUTION EXCEEDS THE COMMISSION'S LIMITED JURISDICTION OVER CCA IMPLEMENTATION PLANS AND FAILS TO ACT IN THE MANNER REQUIRED BY LAW**

The Commission in issuing the Resolution has exceeded its statutory authority granted by the Legislature over CCA Implementation Plans and thereby failed to act in the manner required by law. The Commission is a state agency created by the California Constitution, which grants it broad authority to regulate utilities.<sup>40</sup> In addition, the Legislature has plenary power to confer additional authority and jurisdiction upon the Commission.<sup>41</sup> When the Legislature has provided express legislative directions or restrictions on the Commission's power, the Commission is not permitted to act outside of the authority explicitly granted.<sup>42</sup>

The CCAs and the Cities of Stockton and Atascadero are not utilities, but rather public agencies, and thus the Commission is limited to actions expressly authorized by the Legislature.<sup>43</sup> The Legislature, through Assembly Bill (AB) 117 and as set forth in Section

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<sup>39</sup> See *Independent Energy Producers Assoc./Utility Reform Network v. Pub. Util. Comm'n*, 223 Cal. App. 4<sup>th</sup> 945 (2014).

<sup>40</sup> *San Diego Gas & Electric Co. v. Superior Court*, 13 Cal. 4<sup>th</sup> 893, 914 (1996).

<sup>41</sup> *Id.*

<sup>42</sup> *Pacific Tel. and Telegraph Co. v. Pub. Util. Comm'n*, 62 Cal. 2d 634, 653 (1965) ("[w]hatever may be the scope of regulatory power . . . , it does not authorize disregard by the commission of express directions to it, or restrictions upon its power found in other provisions of the act or elsewhere in general law," and finding that if the commission wants to expand its power, "[s]uch arguments should be addressed to the Legislature, from whence the Commission's authority derives, rather than to this court").

<sup>43</sup> *Monterey Peninsula Water Mgmt. Dist. v. Pub. Util. Comm'n*, 62 Cal. 4<sup>th</sup> 693, 698 (2016); *County of Inyo v. Pub. Util. Comm'm*, 26 Cal. 3d 154, 166-167 (1980).

366.2, did give the Commission a very narrow scope of oversight in the implementation and operation of a CCA. When, as here, the Commission restricts the activity of a public agency in a manner not expressly authorized by the Legislature, the Commission’s error is not simply procedural; it is an act in excess of its subject matter jurisdiction.<sup>44</sup>

**A. The Commission’s Role in Overseeing CCA Implementation Planning is Narrowly Defined by Statute**

The Commission has concluded that AB 117 does not confer authority for “general regulatory oversight of CCAs.”<sup>45</sup> The Commission has further clarified: “we do not believe that AB 117 intended to give this Commission broad jurisdiction over CCAs.”<sup>46</sup> In focusing specifically on the regulatory process for considering CCA implementation, it found that: “AB 117 does not provide us with authority to approve or reject a CCA’s implementation plan or to decertify a CCA.”<sup>47</sup> Importantly, it also concluded that its jurisdiction was limited by the express terms of the statute: “We assume that if the Legislature intended for us to regulate the CCA’s implementation plan in other ways, the Legislature would have included explicit language in the statute with regard to its intent.”<sup>48</sup>

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<sup>44</sup> In the case of government bodies, express language is required. *Monterey*, 62 Cal.4<sup>th</sup> at 698; *see also* Section 1757(a)(1). The Commission may not acquire subject matter jurisdiction by consent, waiver, or estoppel. *Sullivan v. Delta Airlines*, 15 Cal. 4th 288, 307, fn.9 (1997); *Summers v. Superior Court*, 53 Cal. 2d 296, 298 (1959). Nor may the Commission rely on broadly worded text in statutes applicable to public utilities described in Section 3 of Article XII of the California Constitution, such as Section 701.

<sup>45</sup> D.05-12-041, *Decision Resolving Phase 2 Issues on Implementation of Community Choice Aggregation Program and Related Matters*, R.03-10-003 (Dec. 15, 2005), Conclusion of Law (COL) 2, at 60; *see also id.*, COL 1, at 60 and Finding of Fact (FOF) 2, at 56.

<sup>46</sup> *Id.* at 16; *see also* D.12-09-021, *Order Denying Rehearing of Resolution E-4250*, Application of Pacific Gas and Electric Company for Rehearing of Resolution E-4250, A.10-05-015 (Sept. 13, 2012) (the Commission acknowledges its “limited jurisdiction over CCAs” in contrast to its “general jurisdiction” over IOUs).

<sup>47</sup> D.05-12-041, at 4; *see also id.*, at 14 (“we find nothing in the statute that directs the Commission to approve or disapprove an implementation plan or modifications to it. Nor does the statute provide explicit authority to “decertify” a CCA or its implementation plan”).

<sup>48</sup> *Id.* at 15.

The Resolution exceeds the narrow grant of jurisdiction of AB 117 by recasting the phrase “earliest possible date.” Instead of interpreting the phrase as a directive to approve a plan as soon as possible after the clear statutory requirements are met, the Resolution treats its authority to set the “earliest possible date” as a vehicle (not heretofore employed) to enforce RA compliance by burdening local government with an indefinite and uncertain date on which that government may offer CCA benefits to its citizens. By adopting that construction of Section 366.2, the Commission exceeds its jurisdiction and fails to act in the manner required by law.

The statutory limitations on the Commission’s role exist for a reason, as they are necessary to support the planning and coordination between the expanding CCA and the local governments included in the expansion. The process for offering CCA service in a new jurisdiction is complex and requires local government bodies develop and adhere to a strict timeline based on the Commission’s designated “earliest possible date” set pursuant to Section 366.2(c)(8). The Resolution frustrates implementation planning by failing to set a clear “earliest possible date” for launch.

In the case of an expansion, the local governments that have formed an existing CCA work with the new local jurisdiction long before launching service. The process requires the local government joining the existing CCA to pass an ordinance authorizing its action<sup>49</sup> and then requires extensive, ongoing coordination between the CCA and the local government.<sup>50</sup> The Legislature has directed that new customers be provided clear notice of the change in service; amongst the information to be included in that notice perhaps the most critical is notice of the timing of the transition.<sup>51</sup> In addition, CCAs must work with the IOU in whose territory the CCA

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<sup>49</sup> § 366.2(c)(12).

<sup>50</sup> *See* § 366.2(c).

<sup>51</sup> § 366.2(c)(15).

will provide the new service to both notify the IOU of the planned commencement of service, and to plan for the transfer of applicable accounts within a quick 30-day period after CCA notification of its service commencement.<sup>52</sup> Also necessary for launch or expansion of service is the procurement of electricity to serve customers. The timing of customer notice and procurement are, by necessity, based entirely on the “earliest possible date” set by the Commission and must be established well in advance of a CCAs launch or expansion of service.

The statute anticipated this extensive process in Section 366.2(c)(8). The statutory requirement that the Commission “shall designate” the earliest possible launch date gives the CCA the date certain it needs to notify customers, plan its launch or expansion, procure electricity, and provide all relevant notices to the IOU. As a result, the Commission’s clear establishment of the “earliest possible date” within the confines of the statute is not only required, but necessary to provide certainty for an effective implementation or expansion. In setting an earliest possible effective date, the statute permits the Commission to “tak[e] into consideration the impact on any annual procurement plan of the electrical corporation that has been approved by the commission.”<sup>53</sup>

In this case, the Commission (1) set no firm date, and (2) rejected the date set forth in the CCAs’ implementation plan based on the CCAs’ RA compliance history. The Resolution therefore fails to set the earliest possible date in the manner required by law.

**B. The Resolution Exceeds the Commission’s Jurisdiction and Fails to Proceed in a Manner Required by Law by Basing the “Earliest Possible Date” on a CCA’s Resource Adequacy Compliance History**

The Commission’s performance of its duty under Section 366.2(c)(8) to “establish the earliest possible date” for a CCA to launch or expand, while ministerial, is a critical element of

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<sup>52</sup> § 366.2(c)(18)-(19).

<sup>53</sup> § 366.2(c)(8).

the framework for implementation or expansion of CCA service adopted in AB 117. In establishing this date, the Commission may consider “the impact on any annual procurement plan of the electrical corporation.”<sup>54</sup> By, instead, basing the “earliest possible date” for the expansion on the CCAs’ RA compliance history, the Resolution violates Section 366.2(c)(8).

Nowhere does the Resolution state that its tentative January 1, 2025, date for expansion is based on an annual procurement plan – the IOU’s bundled procurement plan<sup>55</sup> – of any IOU. It instead explains the date is needed “to allow the Commission to take further actions to ensure expansion of these CCAs will not cause impermissible cost shifting onto IOU customers.”<sup>56</sup> It concludes, without providing any evidence, that “[g]iven the history and pattern of Resource Adequacy deficiencies by CCCE and EBCE, we find they contributed to cost shifting onto IOU bundled customers.”<sup>57</sup> It further explains that the Commission “has concerns regarding their ongoing ability to meet Resource Adequacy requirements.”<sup>58</sup>

The Resolution therefore turns on RA compliance, not on an IOU annual procurement plan. By basing its action on factors other than the impact of an IOU’s annual procurement plan, it contravenes Section 366.2(c)(8)’s limited, express authorization.<sup>59</sup> The Commission therefore steps beyond its limited statutory authority and fails to act in the manner required by law.

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<sup>54</sup> *Id.*

<sup>55</sup> *See* § 454.5 (IOU procurement plan requirements).

<sup>56</sup> Resolution at 10, and Finding 15 at 16.

<sup>57</sup> *Id.* at 9, and Finding 11 at 15.

<sup>58</sup> *Id.* at 9-10.

<sup>59</sup> In addition, long-standing principles of statutory interpretation require that a statute that provides explicit guidance implies a limitation on any other exercise of authority. This doctrine, “*expressio unius est exclusio alterius*” (expression of the one is the exclusion of the other), remains a foundational statutory interpretation principle today. In utilizing the doctrine to interpret Section 366.2(c), the Commission stated:

A general rule of statutory interpretation suggests that where a statute provides specific guidance – in this case on the Commission’s role and authority – its silence in a related section or on related issues implies a limit on that role and authority. Here, the statute does require the CCA to

**C. The Resolution Exceeds the Commission’s Jurisdiction and Fails to Proceed in the Manner Required by Law by Leaving the “Earliest Possible Date” Subject to Future Modification**

Section 366.2(c)(8) provides that “[t]he commission shall designate the earliest possible effective date for implementation of a community choice aggregation program.”<sup>60</sup> The Resolution does not do so. Instead, it sets a date subject to modification without limitation, stating:

The earliest effective date for Central Coast Community Energy and East Bay Community Energy’s proposed expansions is January 1, 2025, unless the date is modified by further order of the Commission.<sup>61</sup>

The Resolution leaves the Cities of Stockton and Atascadero with no idea when CCA service will be available – an outcome inconsistent with the Legislature’s directive that the Commission promptly set “[t]he earliest possible effective date for implementation of a [CCA] program . . . .”

The Resolution also states that the date is conditioned on “further actions to ensure the expansions will not cause impermissible cost shifting.”<sup>62</sup> However, no further process or schedule is described that would provide a date certain as required by the statute, or that would give the local governments a secure milestone upon which to ground their planning. Section 366(c)(8) requires the Commission to designate the “earliest possible date.” By failing to set a firm date (and not one subject to modification), the Commission has exceeded its jurisdiction and failed to proceed as required by law.

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file the plan here and gives the Commission authority to request information about the plan and to register the CCA. We assume that if the Legislature intended for us to regulate the CCA’s implementation plan in other ways, the Legislature would have included explicit language in the statute with regard to its intent.

D.05-12-041, at 15 (citations omitted).

<sup>60</sup> § 366.2(c)(8) (emphasis added).

<sup>61</sup> Resolution, Ordering Paragraph (OP) 2, at 16 (emphasis added).

<sup>62</sup> *Id.*, Finding 15, at 16.

**V. THE RESOLUTION EXCEEDS THE COMMISSION’S STATUTORY AUTHORITY TO ADDRESS POTENTIAL COST SHIFTS BETWEEN CCA AND IOU BUNDLED CUSTOMERS IN THE CONTEXT OF CCA IMPLEMENTATION**

The Commission attempts to justify its foray outside the existing implementation and RA enforcement frameworks and its failure to provide a certain “earliest possible date” for the expansions by reaching for Sections 366.2(a)(4) and 366.3.<sup>63</sup> Again, these sections provide limited authority for the Commission to prohibit cost shifting between CCA customers and IOU bundled customers as a result of the implementation of a CCA program. Contrary to the Commission’s suggestion otherwise, the Resolution’s “new and distinct type of cost shift” does not fall within the Commission’s express authority. Further, the Commission failed to take the steps required by Section 366.2(c)(7) regarding cost shifts in issuing its certifications that would be required to address any alleged cost shifts.

**A. The Commission’s Implementation Plan Certification Did Not Address Cost Shifting or Require Further Information to Determine Cost Recovery as Required by Section 366.2(c)(7)**

Section 366.2(c)(7) provides clear requirements for addressing potential cost shifts resulting from implementation of a new CCA or expansion. The statute requires the Commission to certify receipt of an implementation plan within 90 days of submission. At the time it certifies the plan, it must also certify that it has received “any additional information necessary to determine a cost-recovery mechanism.” It must then use the information “to provide the community choice aggregator with its findings regarding any cost recovery that must be paid by customers of the community choice aggregator to prevent a shifting of costs.” Notably, the statute specifies that the cost recovery should be “as provided for in subdivisions (d), (e), and (f).” The letters certifying the CCAs’ expansions did not address potential cost shifts, however,

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<sup>63</sup> *Id.* at 2.

and nor did Energy Division Staff request further information from the CCAs to determine whether a cost shift occurred.

**B. The Resolution’s “New and Distinct” Cost Shift Policy Exceeds the Express Statutory Authority Provided to the Commission Pursuant to Subdivisions (d), (e), and (f) of Section 366.2**

In addition to addressing the certification process, Section 366.2(c)(7) defines the scope of cost shifts the Commission is authorized to address in CCA implementation in subdivisions (d), (e), and (f). These costs currently are addressed in the Commission’s PCIA proceeding, R.17-06-026. The Resolution, by its own admission, goes beyond these categories and adopts a “new and distinct” cost shift policy.<sup>64</sup>

Section 366.2 permits recovery of several categories of costs as defined in subdivisions (d), (e), and (f). Subdivisions (d) and (e) require recovery from CCA customers of the DWR costs stemming from the 2000-2001 energy crisis. Subdivision (f) requires recovery of the IOU’s “past undercollections” for energy purchases and:

...the share of the electrical corporation’s estimated net unavoidable electricity purchase contract costs attributable to the customer, as determined by the commission, for the period commencing with the customer’s purchases of electricity from the community choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation.

The statute provides no other express categories of cost recovery in the CCA implementation process.

The types of cost shift addressed by the Resolution go beyond the scope of this express authority. Indeed, unable to rest on the express text of Section 366.2(c)(8), the Commission finds it “necessary to address a new and distinct type of cost shifting that is resulting from LSEs who fail to procure their required capacity under the Resource Adequacy program.”<sup>65</sup> The Resolution

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<sup>64</sup> *Id.* at 10.

<sup>65</sup> *Id.* (emphasis added).

identifies certain “reliability” costs, including “incremental excess procurement resource procurement” by the IOUs and the costs of the Emergency Load Reduction Program (ELRP).<sup>66</sup> These costs do not fall within the scope of subdivisions (d), (e), or (f) and, critically, the Resolution does not claim that otherwise.

In addition, unlike the categories of costs permitted to be recovered under Section 366.2, the Commission has already authorized recovery of these costs from CCA customers to the extent they are “attributable to” CCA customers.<sup>67</sup> CCA customers are already paying and will continue to pay these costs as an element of their distribution charge under the existing Cost Allocation Mechanism.<sup>68</sup>

The Resolution, for these reasons, goes beyond the statutory authority granted to the Commission under Section 366.2(d), (e), and (f).

### **C. Section 366.2(a)(4) Alone Does Not Provide Authority for the Commission’s Action**

The Commission claims authority for the Resolution under Section 366.2(a)(4), which provides that “[t]he implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation.” Subdivision (a)(4) relies on later subdivisions (d), (e), and (f), as discussed above, to provide the explicit mechanisms to prevent such cost

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<sup>66</sup> *Id.* at 9.

<sup>67</sup> See D.21-12-015, *Phase 2 Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023*, R.20-11-003 (Dec. 2, 2021) at O¶ 11 at 163-64; see also D.21-03-056, *Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022*, R.20-11-003 (Mar. 25, 2021) at COL 14 at 82.

<sup>68</sup> *Id.*

shifting. Therefore, Section 366.2(a)(4) cannot be viewed in a vacuum as a broad grant of authority to the Commission to generally prevent cost shifting.

Fundamental rules of statutory construction require harmonization of sections within a statute. In construing the statutory authority provided to the Commission, “significance should be given to every word, phrase, sentence and part of an act in pursuance of the legislative purpose.”<sup>69</sup> In addition, “the various parts of a statutory enactment must be harmonized by considering the particular clause or section in the context of the statutory framework as a whole.”<sup>70</sup>

Harmonizing the subsections of Section 366.2, the legislative intent is clear: subdivisions (d), (e), and (f) are the methodologies provided by the Legislature to prevent the cost shifting identified in subsection (a)(4) that may result from the implementation of the CCA program. In other words, subdivision (a)(4) was not enacted in a vacuum and does not alone provide the Commission authority to prevent cost shifting outside of Section 366.2’s parameters.

**D. Section 366.3 Does Not Provide Authority for the Commission’s Action**

The Resolution also points to Section 366.3 to justify its suspension of the CCAs’ implementation plans.<sup>71</sup> Section 366.3 provides:

Bundled retail customers of an electrical corporation shall not experience any cost increase as a result of the implementation of a community choice aggregator program. The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load.

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<sup>69</sup> *Select Base Materials v. Bd. of Equalization*, 51 Cal. 2d 640, 645 (1959).

<sup>70</sup> *Moyer v. Workmen’s Comp. Appeals Bd.*, 10 Cal. 3d 222, 230-31 (1973) (citing *Select Base Material*, 51 Cal. 2d at 645).

<sup>71</sup> Resolution at 2, 3, 10, 14, Finding 13 at 15.

The cost shift theory adopted in the Resolution is inconsistent with the express language of this provision. In fact, even if the Commission had demonstrated a cost shift as a result of RA non-compliance, which it has not, such a cost shift cannot be grounded in Section 366.3.

The statute addresses cost increases “as a result of the implementation of a community choice aggregator program.” In this case, the alleged cost shift, to the extent it occurred at all, is not “as a result of implementation of a [CCA] program” but, according to the theory espoused in the Resolution, is as a result of the CCAs’ noncompliance with RA requirements. Indeed, the RA noncompliance giving rise to the Commission’s actions was for 2021 and 2022 – years before the implementation of the proposed expansions. Any such noncompliance could not have been as a result of the Cities of Stockton and Atascadero planned expansions.

If, instead, the Commission means to rest its action on the possibility that the CCAs will be non-compliant for the Cities of Stockton and Atascadero in future years, such a conclusion is speculative and, most importantly, has not been proven by substantial evidence.

**VI. THE RESOLUTION FAILS TO PROCEED IN THE MANNER REQUIRED BY LAW BY APPLYING RA ENFORCEMENT IN A DISCRIMINATORY MANNER PROHIBITED BY SECTION 380(E)**

Section 380(e) requires the Commission to apply its RA program rules even-handedly. Each LSE must be subject to the same RA program requirements. Similarly, “[t]he commission shall implement and enforce the resource adequacy requirements established in accordance with this section in a nondiscriminatory manner.”<sup>72</sup> The Resolution, however, results in the Commission’s discriminatory enforcement of its RA program requirements. Therefore, the Commission has not proceeded in the manner required by law.

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<sup>72</sup> § 380(e).

As explained in Section II, the Resolution is effectively an enforcement action for two CCAs' RA program deficiencies. The "cure" for the RA program failures in the Resolution is to intentionally delay a CCA's ability to expand. However, that cure by its very nature is discriminatory as it cannot neatly be applied to IOUs or ESPs.

IOU service territories do not expand, and they are required under their grant of a franchise to serve any new customer who requests service. The Commission thus could not prevent an IOU who has failed to meet its RA requirements from serving new customers. Similarly, the mechanism also cannot be applied to IOUs as central procurement entities (CPEs) for their RA procurement deficiencies – a critical point since PG&E as the CPE came up short for compliance year 2023.<sup>73</sup>

The mechanism is also ill-suited as a penalty for ESPs. The Commission in 2020 recommended against the expansion of the Direct Access program at that time.<sup>74</sup> Consequently, the scope of existing ESP customers cannot legally be expanded.

The enforcement action applied by the Resolution cannot, for these reasons, be applied evenly to all LSEs. For this reason, the Resolution violates Section 366.2(c)(8)'s requirement that the Commission apply RA enforcement "in a nondiscriminatory manner."

**VII. THE RESOLUTION IS AN ABUSE OF DISCRETION, DOES NOT CONTAIN THE REQUISITE FINDINGS TO SUPPORT ITS ORDER, AND IS NOT BASED ON SUBSTANTIAL EVIDENCE TO SUPPORT THE FINDING THAT THE CCAS' RA NONCOMPLIANCE SHIFTED COSTS TO BUNDLED CUSTOMERS**

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<sup>73</sup> Advice Letter 6706-E, Pacific Gas and Electric Company ("PG&E") Central Procurement Entity ("CPE") Annual Compliance Report 2022 Annual Compliance Report (Sept. 19, 2022) at Attachment A – PG&E CPE Aggregate Procurement Summary (2022 PG&E CPE Compliance Report): [https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC\\_6706-E.pdf](https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6706-E.pdf).

<sup>74</sup> See generally D.21-06-033, *Decision Recommending Against Further Direct Access Expansion*, R.19-03-009 (June 24, 2021), *reh'g denied*, D.22-12-058, *Order Denying Rehearing of Decision 21-06-033* (Dec. 19, 2022).

The Resolution summarily finds that the CCAs have shifted the costs of incremental excess procurement and ELRP resources to bundled customers.<sup>75</sup> Specifically, the Commission finds:

8. Due to Resource Adequacy program procurement deficiencies in 2022, incremental excess resources, paid for by all Load Serving Entity customers, functioned in part as backfill to make up for specific Load Serving Entity deficiencies, rather than being available to provide the full system reliability benefit that was intended, which caused a cost shift.

9. Community Choice Aggregator Resource Adequacy procurement failures in 2022 during stressed electricity system conditions required greater reliance on expensive and extraordinary measures, and thereby contributed to cost shifting onto bundled Investor-Owned Utility customers.

10. While Central Coast Community Energy and East Bay Community Energy paid fines for their Resource Adequacy program violations, the fines do not reflect the cost to other ratepayers when an entity fails to procure as required to maintain reliability, nor do the fines reimburse ratepayers for cost shifting that may be caused by an entity failing to meet its Resource Adequacy requirements.

11. Based on the history and pattern of Central Coast Community Energy and East Bay Community Energy's Resource Adequacy deficiencies, and how Resource Adequacy deficiencies can lead to cost shifting, Central Coast Community Energy and East Bay Community Energy have contributed to cost shifting onto Investor-Owned Utility bundled customers.

14. Because the Commission cannot conclude that Central Coast Community Energy and East Bay Community Energy's planned expansions will not cause further cost shifting, it would be unreasonable to confirm the proposed effective dates in 2024.

The Resolution does not present findings necessary to support the Commission's action. Further, it presents no evidence to support any of these findings, skipping critical analytical steps and lacking the substantial evidence needed to sufficiently demonstrate the impact. The Resolution thus constitutes an abuse of discretion.

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<sup>75</sup> Resolution, Findings 8, 9, 11, and 14 at 15-16.

Decisions of the Commission must be based on “substantial evidence in light of the whole record,”<sup>76</sup> meaning “such relevant evidence as a reasonable mind would accept as adequate to support a conclusion; it is evidence which is reasonable in nature, credible, and of solid value.”<sup>77</sup> Key among the steps to reach the conclusions in the Resolution are analysis demonstrating: (1) the CCAs’ RA noncompliance – not market conditions, weather, or other factors – caused increased costs to the system, (2) the CCA’s noncompliance caused a shift of increased costs of the incremental excess procurement and ELRP to the IOU’s bundled customers, and (3) the CCAs’ past noncompliance will result in their future RA noncompliance for the expanded load and, consequently, future cost shifts. The Resolution leaps over factual review and analysis directly to findings, without record development or substantial evidence.

The Resolution does not and cannot demonstrate that the CCAs caused excess incremental resource and ELRP costs, only that deficiencies could possibly have been caused by the CCAs.<sup>78</sup> In fact, the Resolution states that “some of the expensive measures paid for by all customers” that were utilized during the September 2022 heat wave to avoid blackouts “might have been avoided” if each deficient CCA had met its RA obligations.<sup>79</sup> A statement that a situation might have been avoided, however, does not rise to the level of certainty necessary to prove that a CCA caused harm, nor provide the substantial evidence necessary to prove such harm. Indeed, there is no evidence presented anywhere in the Resolution to support the conclusion that a cost shift actually has occurred.

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<sup>76</sup> § 1757(a)(4); *The Utility Reform Network v. Pub. Util. Comm’n*, 223 Cal. App. 4<sup>th</sup> 945, 959 (2014) (citations omitted) (applying “familiar principles to review for substantial evidence, including all relevant evidence in the record”).

<sup>77</sup> *Los Angeles County Dept. of Children & Family Services v. Superior Court*, 222 Cal. App. 4<sup>th</sup> 149 (2013) (describing the “substantial evidence” standard under California law).

<sup>78</sup> Resolution at 9.

<sup>79</sup> *Id.*

The Commission directed the IOUs to procure the resources to remedy the inadequacy of existing resources “to maintain reliability of the grid during extreme weather events.”<sup>80</sup> D.21-12-015 makes clear that the net costs associated with the IOU supply side procurement “shall be passed through to all benefitting customers consistent with the existing Cost Allocation Mechanism.”<sup>81</sup> Similarly, ELRP costs are recovered through distribution rates from all customers.<sup>82</sup> There is no evidence in the Resolution or Decision 21-12-015 that RA deficiencies drove or even influenced this procurement or the associated costs. In addition, the Commission has not demonstrated that if higher costs were caused by the CCAs, those costs were shifted to the IOUs’ bundled customers. Again, all customers, including CCA customers, pay their share of excess incremental procurement and ELRP.

The Commission also did not demonstrate that the CCAs’ RA noncompliance for 2021-2022 demonstrates their future noncompliance. The Resolution implicitly acknowledges the lack of evidentiary support. The Commission states that it “cannot conclude at this time that the implementation of CCCE and EBCE’s planned expansions will not cause further cost shifting in 2024.”<sup>83</sup> Stated another way, the Commission cannot determine that the CCAs will comply and thereby not shift costs to bundled customers.

The Resolution further undermines its findings. It states: “[i]t is reasonable to set an earliest effective date of January 1, 2025 for Central Coast Community Energy and East Bay Community Energy’s planned expansions in order to allow the Commission to take further actions as warranted to ensure the expansions will to ensure the expansions will not cause

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<sup>80</sup> D.21-12-015, O¶ 2 at 160.

<sup>81</sup> *Id.*, O¶ 11 at 163.

<sup>82</sup> See PG&E Advice Letter 6805-E (Dec. 29, 2022), Tables 1 and 2, at 4-5. Demand Response Expense Balancing Account (DREBA) balance is quantified and identified as being included in distribution revenue requirements. *Id.*

<sup>83</sup> Resolution at 2, 10, Finding 14 at 16.

impermissible cost shifting.”<sup>84</sup> The Commission cannot determine whether its allegations are supported by facts – and its actions “warranted” – without hearing further evidence.

The Commission provided neither the specific findings necessary to support its actions nor substantial evidence to support any such findings. The Resolution thus constitutes an abuse of discretion.

### **VIII. THE RESOLUTION DENIES DUE PROCESS TO AFFECTED PARTIES AND FAILS TO PROCEED IN THE MANNER REQUIRED BY LAW**

The Draft Resolution, to most parties, came out of the blue effecting a significant policy change on March 27, 2023. Not only did the Draft Resolution propose a significant change in RA enforcement policy, but it also proposed a “new and distinct” cost shifting policy. While the action focused solely on the CCAs, the Commission’s findings and conclusions will impact all CCAs, and potentially other parties. The Commission took these significant actions without a public process, or developing a record, to develop the new policy. Despite the Commission’s broad view of its own powers, it is squarely subject to the due process requirements set forth in both the United States<sup>85</sup> and California Constitutions.<sup>86</sup>

The California Supreme Court has ruled on the due process requirements in Commission actions: “due process as to the [California Public Utilities Commission’s] . . . action is provided by the requirement of adequate notice to a party affected and an opportunity to be heard before a valid order can be made.”<sup>87</sup> The Commission itself has recognized that “an elementary and fundamental

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<sup>84</sup> *Id.*, Finding 15, at 16 (emphasis added).

<sup>85</sup> U.S. Constitution, Amendment 14.

<sup>86</sup> Cal. Constitution, Art. 1, § 7.

<sup>87</sup> *People v. Western Air Lines*, 42 Cal.2d 621, 632 (1954).

requirement of due process is notice reasonably calculated to apprise interested parties of the content and pendency of the action and afford them an opportunity to present their objections.”<sup>88</sup>

Courts have also concluded that due process requires that a party have fair notice of a penalty available for particular conduct.<sup>89</sup> “Elementary notions of fairness enshrined in our constitutional jurisprudence dictate that a person receive fair notice not only of the conduct that will subject him [or her] to punishment but also of the severity of the penalty that a State may impose.”<sup>90</sup> The lack of notice of the policies and penalties resulting from the Resolution denied due process to the CCAs and parties subject to the Resolution’s precedent.

**A. The Commission Adopted Broad, Significant New Policy in a Resolution Addressing the Conduct of Two Parties**

The Resolution was an enforcement action with conclusions and orders directed at only two parties. Embedded in the Resolution, however, are material new rules related to RA enforcement and the prohibition of cost shifts.<sup>91</sup> In light of these factors, the Commission’s process was inadequate, failing to provide actual notice of the potential impact of the Resolution on interested parties.

The Commission’s first formal notice of the Draft Resolution to any party, including the CCAs, was its issuance on March 27, 2023. At the time, the Draft Resolution was served on the CCAs along with numerous parties from various Commission service lists, including R.17-06-

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<sup>88</sup> D.21-11-035, *Order Denying Rehearing of Resolution E-5150*, Application of California Solar & Storage Association, Solar Energy Industries Association and Vote Solar for Rehearing of Resolution E-5150, A.21-07-013 (Nov. 18, 2021), at 3 (emphasis added).

<sup>89</sup> See, e.g., *De Anza Santa Cruz Mobile Estates Homeowners Assn. v. De Anza Santa Cruz Mobile Estates*, 94 Cal.App.4<sup>th</sup> 890, 912 (2001).

<sup>90</sup> *BMW of North America, Inc. v. Gore* (1996) 517 U.S. 559, 574.

<sup>91</sup> See *supra*, Sections IV. and V.

026 and R.21-10-002. No proceeding or process preceded the resolution, and the Commission’s process left only 20 days for comments on the draft, with five days for reply comments.<sup>92</sup>

The Commission’s process fails to provide affected parties adequate notice and time to be heard. Due process requires, “at a minimum . . . notice and opportunity for hearing appropriate to the nature of the case.”<sup>93</sup> In addition, “[a]n elementary and fundamental requirement of due process in any proceeding which is to be accorded finality is notice reasonably calculated, under all the circumstances, to apprise interested parties of the pendency of the action and afford them an opportunity to present their objections.”<sup>94</sup>

Serving an enforcement resolution directed at the CCAs was not sufficient to give other parties notice of the potential impacts of the new rules on those parties’ interests; some parties may not have given the Draft Resolution a second thought, believing it was an action to enforce existing rules on specific parties rather than to make new rules. In addition, the Commission’s process failed to provide “a reasonable time” to engage in a public process, limiting their participation to comments on the Draft Resolution. Given the impactful nature of the new rules created through the Resolution, notice and opportunity “appropriate to the nature of the case” requires a far more robust process than what the Resolution process provided.

For example, the Commission has previously defined cost-shifting and adopted regulations in formal proceedings with notice to all parties and an opportunity to be heard. The PCIA, which is the most significant measure to avoid cost-shifting, was adopted after nearly two years of rulemaking.<sup>95</sup> Each time the Commission modifies the PCIA methodology, it provides notice and an opportunity to be heard, with extensive opportunity to address the content of the action,

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<sup>92</sup> Commission Rules, Rule 14.5.

<sup>93</sup> *Mullane v. Central Hanover Bank & Trust Co.*, 339 U.S. 652, 656-57 (1950).

<sup>94</sup> *Id.* at 657 (citations omitted).

<sup>95</sup> *See generally*, D.18-10-019.

affording all parties opportunities to present their objections.<sup>96</sup> Establishing the Resolution’s “new and distinct” cost shift should have been no different. Had the Commission intended to develop this impactful new rule, it should have conducted the assessment in R.17-06-026, starting with an Administrative Law Judge’s ruling establishing a process for considering a new charge.

In addition, the establishment of a new RA enforcement mechanism should occur in the existing RA rulemaking, which as discussed above is actually considering through its formal processes the exact RA enforcement mechanism that the Commission imposed in the Resolution.<sup>97</sup>

Addressing these issues in the appropriate proceedings would have given parties both the opportunity and reasonable time to develop facts and recommendations to inform this important policy shift. By initiating a process with a Draft Resolution, applicable to only two parties, the Commission denied parties their due process rights afforded under ratemaking proceedings.

### **B. The Resolution Unlawfully Enforces a Regulation Pending in a Current Proceeding**

There is no Commission decision that authorizes suspending a CCA implementation plan as a penalty for RA noncompliance or determination of cost shifts, an absence that is unsurprising since no statute authorizes such a step. Instead, and as previously discussed, this new rule is pending as an Energy Division Staff proposal in the RA rulemaking, R.21-10-002.<sup>98</sup>

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<sup>96</sup> See, e.g., D.21-05-030, *Phase 2 Decision on Power Charge Indifference Adjustment Cap and Portfolio Optimization*, R.17-06-026 (May 24, 2021) (issuing a Decision on portfolio optimization after a working group process, reports, comments, and rulings); see also D.20-08-004, *Decision Adopting a Framework and Evaluation Criteria for the Power Charge Indifference Adjustment Prepayment Agreements*, R.17-06-026 (Aug. 12, 2020); D.20-03-019, *Decision Considering Working Group Proposals on Departing Load Forecast and Presentation of Power Charge Indifference Adjustment Rate on Bills and Tariffs*, R.17-06-026 (Apr. 6, 2020); D.19-10-001, *Decision Refining the Method to Develop and True up Market Price Benchmarks*, R.17-06-026 (Oct. 17, 2019).

<sup>97</sup> See *supra*, n.26.

<sup>98</sup> *Id.*

The Commission regularly denies party requests for relief regarding issues being addressed in a pending proceeding, citing the need for due process in the existing proceeding.<sup>99</sup> California courts have also refused to compel party compliance with requirements being contemplated for adoption in the future.<sup>100</sup> By enforcing a policy pending in an existing rulemaking, the Commission has denied the due process rights of the CCAs to adequately address the pending policy in the existing formal rulemaking, including any rights to judicial review of the decisions made therein.

**C. The Commission Failed to Follow Its Own Rules and Procedures for Enforcement Thereby Denying Parties Due Process**

The Commission's Rules and its own detailed enforcement policy, Resolution M-4846 (Enforcement Policy), underscore the problem with the lack of process underlying the Draft Resolution. First, Commission Rule 14.2(d)(1)-(5) prescribes the method of service of a draft resolution. In each of the directives, the Rule presumes a prior action, whether an "advice letter," "request for disclosure of documents," "requests for motor carrier operating authority," or comments "solicited by Commission staff...for purposes of preparing the draft resolution." None of these prior actions preceded the Draft Resolution.

Resolution M-4846 establishes enforcement guidelines and authorizes Commission staff to pursue particular forms of enforcement mechanisms beyond the applicable citation and

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<sup>99</sup> See, e.g., D.03-02-035, *Order Modifying Decision 02-07-032, for Purposes of Clarification, and Denying Rehearing, as Modified*, Application of Pacific Gas and Electric Company for Verification, Consolidation, and Approval of Costs and Revenues in the Transition Revenue Account, A.98-07-003 (Feb. 13, 2003) ("[b]ecause these issues are currently being considered in this pending proceeding, we need not and do not address these rehearing issues in today's order").

<sup>100</sup> See *Gabric v. City of Rancho Palos Verdes*, 73 Cal. App. 3d 183, 202 (1977) (reversing a City decision that a homeowner must comply with a new rule enacted after a permit to build a house was submitted when "the record is clear that the City denied the permit in an effort to prevent Gabric building under the existing ordinance and to compel compliance with an ordinance not yet then in effect but which the City contemplated enacting in the future").

penalty programs.<sup>101</sup> Because suspension of the CCAs' expansions is not currently a part of the RA citation and penalty program, the Resolution can only be viewed as an alternative form of enforcement. The Commission's issuance of Resolution E-5258, however, conforms to none of the alternatives for enforcement described in Resolution M-4648 and thus violates its own Enforcement Policy.

One of the mechanisms that may be initiated by Staff in an Administrative Enforcement Order serves as "an alternative to a citation and could be issued if a case does not necessitate an [Order Instituting Investigation] OII."<sup>102</sup> Importantly, the Enforcement Policy addresses "due process requirements for the implementation of the Policy" including specific requirements for an Administrative Enforcement Order.<sup>103</sup> Resolution E-5258 could be viewed as an attempted exercise of Staff's authority to propose an Administrative Enforcement Order. Of the alternatives, an Administrative Enforcement Order comes closest to the process used to suspend the CCAs' implementation plans. The process for an Administrative Enforcement Order involves a Resolution initiated by staff and a Commission vote on the Resolution<sup>104</sup> – the same process leading up to the issuance of Resolution E-5258.

While Resolution E-5258 resembles an Administrative Enforcement Action, if this is what Staff intended, it failed to follow the due process requirements of this mechanism. Staff are required to deliver a proposed Administrative Enforcement Order to the regulated entity with proof of service. It must also include nine specific categories of information.<sup>105</sup> Key among the

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<sup>101</sup> As is the case with respect to the RA Program, CalCCA expresses no view with respect to the statutory support for Resolution M-4846.

<sup>102</sup> *Id.* at 3, 11.

<sup>103</sup> *See id.*, Attachment, *California Public Utilities Commission Enforcement Policy* (Enforcement Policy) at 12-13.

<sup>104</sup> *Ibid.*

<sup>105</sup> *Id.*, Attachment, at 12.

requirements is “[i]nformation about how to request a hearing on the proposed Administrative Enforcement Order.”<sup>106</sup> In this case, Staff did not provide verified delivery of any document designated as an “Administrative Enforcement Order” and most certainly did not give the CCAs notice of their right to request a hearing. This right is critical, particularly in light of the lack of evidentiary support for the Resolution’s findings, as discussed in more detail below.<sup>107</sup>

Another potential authorized enforcement mechanism that Staff might have used, which is one lying on a considerably firmer statutory base, is the OII. The Commission explained the purpose of an OII in Resolution M-4846:

The Policy does give staff the option of issuing a proposed Administrative Consent Order or Administrative Enforcement Order instead of issuing a citation or seeking an OII in situations not currently covered by an existing citation program or warranting an OII.

The Resolution was undertaken precisely because the situation the Commission’s staff identified is “not currently covered by an existing citation program.” Under the circumstances, Staff could have sought an OII where, again, the CCAs and other interested parties would have had an opportunity to respond to the staff’s allegations. However, Staff did not seek an OII.

While the Enforcement Policy also allows the Commission to “suspend ... the certification of a regulated entity,”<sup>108</sup> any such suspension must be “consistent with existing Commission decisions and orders” and “permitted by the Public Utilities Act.”<sup>109</sup> As noted above, there is no Commission decision that authorizes suspending a CCA certification; again, this fact is evidenced by the Staff’s proposal in R.21-10-002 to adopt this mechanism.<sup>110</sup> Neither

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<sup>106</sup> *Ibid.*  
<sup>107</sup> *See supra*, Section VII.  
<sup>108</sup> Resolution M-4846 at 12.  
<sup>109</sup> *Ibid.*  
<sup>110</sup> *See supra*, Section II.D.

is the Commission authorized by statute to take such an action; indeed, the Commission has acknowledged its limited role in implementation plans.<sup>111</sup> Moreover, application of this mechanism does not square with the facts; Energy Division Staff actually issued letters certifying the expansions on March 8, 2023 – 19 days prior to the issuance of the Resolution. This leaves little possibility that Staff intended to exercise this enforcement alternative.

The suspension of the CCAs’ implementation plans can only be viewed as a means of enforcing RA requirements that is not embraced in an existing citation program nor, more importantly, been authorized by the Legislature. The process used to deny service to the Cities of Stockton and Atascadero conforms to none of the authorized mechanisms. Accordingly, the issuance of Resolution E-5258 violates the Commission’s own Enforcement Policy, thereby failing to proceed in the manner required by law.<sup>112</sup>

**D. The Commission’s Retroactive Application of a New Regulation to the CCAs’ Already Submitted Implementation Plans is Unlawful and Contravenes Due Process**

Even if the Commission’s new cost-shift and RA enforcement policies are deemed lawful – which they are not – the Commission proceeds in a manner not in accordance with law and contravenes due process by retroactively applying these new regulations to the CCAs’ Implementation Plans. When the Implementation Plans were submitted, the CCAs had no notice that the Commission planned to issue a new policy/regulation and retroactively apply it. Courts have found that such retroactive application is unlawful,<sup>113</sup> and the Commission should not be permitted to deny the CCAs’ due process rights in this manner.

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<sup>111</sup> See *supra*, Section IV.A.

<sup>112</sup> *Calaveras Tel. Co. v. Pub. Util. Comm’*, 5 Cal. App. 5<sup>th</sup> 972 (2019); *Southern California Edison v. California Pub. Util. Comm’*, 140 Cal. App. 4<sup>th</sup> 1085 (2019).

<sup>113</sup> *McKeon v. Hastings College* 185 Cal. App. 3d 877, 887 (1986) (“[t]he general rule that statutes will not be given retroactive operation has been followed from the earliest days of California's statehood

**E. The Resolution Imposes a Double Penalty on the CCAs Contrary to Due Process**

As set forth above, the CCAs have already been subject to, and paid, significant penalties under the RA program for their deficiencies. The imposition of previously unknown penalties on top of the RA penalties not only deprives parties with notice of potential penalties associated with failure to the regulatory process, but imposes a double penalty that is contrary to principles of due process and fundamental fairness.<sup>114</sup>

**IX. CONCLUSION**

For the foregoing reasons, the Commission should grant rehearing to correct each of the legal errors specified in this Application for Rehearing of Resolution E-5258.

Respectfully submitted,



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

May 30, 2023

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to the present.... It being the rule that administrative regulations are subject to the same treatment as statutes, a comparable disinclination to apply regulations retroactively has also evolved.”)<sup>114</sup> See *Troensegaard v. Silvercrest Indus.*, 175 Cal. App. 3d 218, 227 (1985) (citing *In re N. Dist. of Cal. “Dalkon Shield” IUD Prods. Liab. Litig.*, 526 F. Supp. 887, 899 (1981) (vacated on other grounds, *In re N. Dist. Of Cal. “Dalkon Shield” IUD Prods. Liab. Litig.*, 693 F.2d 847 (9<sup>th</sup> Cir. 1982)) (double penalties “violate that sense of ‘fundamental fairness’ which lies at the heart of constitutional due process).

# **JUNE FILINGS**



## Comments on workshop

Initiative: Capacity procurement mechanism enhancements

### Comment period

May 12, 2023, 03:00 pm - Jun 01, 2023, 05:00 pm

### Submitting organizations

California Community Choice Association

## California Community Choice Association

Submitted on 06/01/2023, 03:33 pm

### Contact

Shawn-Dai Linderman (shawndai@cal-cca.org)

### **1. Please provide a summary of your organization's comments on the Capacity Procurement Mechanism (CPM) enhancements track 2 stakeholder workshop.**

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (ISO) Capacity Procurement Mechanism (CPM) Enhancements Track 2 Workshop (the Workshop). This track of the initiative will evaluate the CPM Soft Offer Cap (SOC), per the ISO's tariff requirement to do so every four years. CalCCA supports using the fixed cost outputs from the California Energy Commission's (CEC) cost of generation model using a 550 megawatts (MW) combined cycle reference resource and with the 2023 updates to include updated labor rates and inflation.

### **2. Please provide a summary of your organization's comments on fixed cost outputs from the California Energy Commission's cost of generation model.**

It is reasonable for the ISO to continue to use a 550 MW combined cycle resource as the reference resource for this year's SOC update as most of the recent CPM designations still come from gas units.<sup>[1]</sup> This may change in the future as storage and other new technologies come online, but at present, it does not appear necessary to change the reference resource.

CalCCA supports using the fixed cost outputs from the CEC's cost of generation model with the 2023 updates. These updates include updated labor rates and inflation since the 2019 update. During the workshop, the CEC indicated that labor rates and inflation are the major drivers of changes in fixed O&M costs. The CEC also indicated that it did not expect other costs to change significantly between the 2019 update and the present because the reference resource used is a relatively new resource that came online in 2021 and is a mature technology. For these reasons, the CAISO should adopt the \$7.34/kW-month SOC from the CEC's 2023 update.

[1] ISO Presentation at Slide 16:  
<http://www.caiso.com/InitiativeDocuments/Presentation-Capacity-Procurement-Mechanism-Enhancements-May112023.pdf>.

**3. Please provide a summary of your organization's comments on the CPM track 2 proposed scope and schedule.**

CalCCA supports the ISO's proposed scope and schedule in which this track 2 will consider updating the CPM SOC based upon the CEC's cost of generation model and the ISO's tariff-defined formula and a future track will consider ideas for improving the SOC and/or related aspects of the ISO's CPM processes.