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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.25-10-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S ALTERNATIVE INPUTS & ASSUMPTIONS DOCUMENT IN RESPONSE TO ADMINISTRATIVE LAW JUDGE'S RULING MODIFYING 2028 LOSS OF LOAD EXPECTATION STUDY SCHEDULE

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SUMMARY OF RECOMMENDATIONS[1]

The Commission should:

- Require Energy Division to modify the Draft I&A to clearly document how the LOLE modeling results will translate into the final PRM;

- Provide adequate opportunities for Energy Division and parties to discuss the LOLE study methodology prior to Energy Division conducting its study;

- Evaluate methods for setting a PRM that achieves reliability at least cost, including CalCCA's proposed methodology to solve an optimization problem that determines how much accredited capacity needs to be shown in each month to achieve reliability at least cost (defined herein as the "PRM Problem"); and

- Investigate load forecast error assumptions using more recent, US-focused studies, and coordinate with the CEC to develop California-focused assumptions for long-term use.

[1] Acronyms used herein are defined in the body of this document.

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California Community Choice Association[2] (CalCCA) submits this alternative Inputs & Assumptions document pursuant to the *Administrative Law Judge's Ruling Modifying 2028 Loss of Load Expectation Study Schedule*[3] (Ruling), dated March 30, 2026.

I. INTRODUCTION

The loss-of-load expectation (LOLE) modeling used to inform the planning reserve margin (PRM) is a complex exercise with significant implications for the reliability and affordability of the Resource Adequacy (RA) program. CalCCA supports an RA program that plans to an annual 0.1 LOLE reliability standard and appreciates the opportunity to engage in the study process to ensure the RA program meets this standard. Ensuring the results of the study

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

[3] *Administrative Law Judge's Ruling Modifying 2028 Loss of Load Expectation Study Schedule*, Rulemaking (R.) 25-10-003 (Mar. 30, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M603/K465/603465636.PDF.

adhere to the 0.1 LOLE standard without over- or under-estimation is critical to ensuring the RA program results in a system that reflects and balances two objectives: reliability and affordability. To meet these objectives, CalCCA's proposal set forth herein (CalCCA Proposal) incorporates alternative inputs and assumptions (I&A) focused on formalizing the process for setting the PRM in a manner that directly considers reliability and cost.

The CalCCA Proposal builds upon comments filed by CalCCA and The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) prior to the establishment of the 2025 and 2026 PRMs.[4] CalCCA and Cal Advocates encouraged the Commission to consider cost, in addition to reliability, when setting PRMs. Specifically, CalCCA stated that "the primary consideration of the RA program is ensuring a reliable system," but "the focus on reliability should not lose sight of the implications for affordability."[5] Cal Advocates requested the Commission investigate whether a monthly or seasonal PRM framework could introduce ratepayer savings with the objective of determining "the most cost-effective approach to reliability."[6]

The CalCCA Proposal: (1) documents the overall framework for setting PRMs that meet reliability targets in a least cost manner; (2) provides a practical step-by-step process for implementing the framework; and (3) illustrates how the process would work using numerical results from a simplified model that only accounts for variability and uncertainty on the demand side. As a next step, CalCCA aims to implement its proposed approach using a full demand-and-

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[4] *See California Community Choice Association's Reply Comments on Administrative Law Judge's Ruling Modifying Track 2 Schedule*, R.23-10-011 (Aug. 23, 2024) (CalCCA August 2024 Comments), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M538/K612/538612858.PDF; *see also Comments of the Public Advocates Office on Track 2 Proposals*, R.23-10-011 (Aug. 9, 2024) (Cal Advocates August 2024 Comments), https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=537763739.

[5] *See* CalCCA August 2024 Comments, at 4.

[6] *See* Cal Advocates August 2024 Comments, at 4-10.

supply-side probabilistic reliability model. This modeling will largely leverage the assumptions and data established in the Commission's draft I&A, apart from the sources used for estimating load forecast error, as described in Section IV., below.[7]

CalCCA encourages the Commission to provide adequate opportunities for Energy Division and parties to present their proposed study methodologies and results, and receive input at each step, so that parties can evaluate different approaches before recommending the PRM(s) the Commission should adopt for the RA program. CalCCA looks forward to discussing its proposed methodology, and the methodologies of Energy Division and other parties, to compare how each approach results in PRMs that meet reliability and at what cost. As set forth in detail below, CalCCA recommends through its Proposal that the Commission:

- Require Energy Division to modify the Draft I&A to clearly document how the LOLE modeling results will translate into the final PRM;
- Provide adequate opportunities for Energy Division and parties to discuss the LOLE study methodology prior to Energy Division conducting its study;
- Evaluate methods for setting a PRM that achieves reliability at least cost, including CalCCA's proposed methodology to solve an optimization problem that determines how much accredited capacity needs to be shown in each month to achieve reliability at least cost (defined herein as the PRM Problem); and
- Investigate load forecast error assumptions using more recent, US-focused studies, and coordinate with the California Energy Commission (CEC) to develop California-focused assumptions for long-term use.

[7] CalCCA will file the modeling results on August 14, 2026, consistent with the scheduled adopted in the *Administrative Law Judge's Ruling Modifying 2028 Loss of Load Expectation Study Schedule*, R.25-10-003 (Mar. 30, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M603/K465/603465636.PDF.

II. THE COMMISSION SHOULD PROVIDE ENERGY DIVISION AND STAKEHOLDERS ADEQUATE OPPORUNITY TO DISCUSS THE LOLE STUDY METHODOLOGY

Energy Division's Draft I&A,[8] while helpful for understanding the sources of information Energy Division plans to use in its study, should be modified to clearly document how the LOLE modeling results will translate into the final PRM used to set the RA requirements.[9] The process used to establish the 2026 PRM did not clearly document how this translation would occur, leading to confusion and divergent stakeholder suggestions late in the study process.[10] To prevent this situation from occurring again, the Commission should modify the Draft I&As to include a description of the methodology that will be used to translate the results of the LOLE study into final PRMs, and allow parties an opportunity to weigh in on the methodology before the Commission conducts its 2028 LOLE study.

The Commission should also provide adequate opportunities for Energy Division and parties to present their proposed study methodologies and results and receive input at each step. This will allow parties to evaluate different approaches before studies are completed, so that

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[8] *Proposed Inputs & Assumptions, SERVM 2026 Data Updates in Support of Resource Adequacy (RA) and Integrated Resource Planning (IRP)* (Apr. 9, 2026) (Draft I&A), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M604/K617/604617992.PDF.

[9] Section 5.5 of the Draft I&A explains how Energy Division Staff will surface LOLE in study, but does not explain how the results of LOLE surfacing will translate into the PRMs used to set the RA requirements.

[10] *See* D.24-12-003, *Decision on Track 2 Issues*, R.23-10-011 (Dec. 5, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M550/K149/550149956.PDF (deferring adoption of the 2026 PRM to Track 3, recognizing additional vetting and further analysis of the issues raised by parties was needed). The 2026 PRM was ultimately adopted in D.25-06-048, *Decision Adopting Local Capacity Obligations for 2026-2028, Flexible Capacity Obligations for 2026, and Program Refinements,* R.23-10-011 (June 27, 2025), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M571/K237/571237404.PDF. In D.25-06-048, the Commission noted: "there is no consensus among stakeholders as to which PRM proposal should be adopted and parties advocate for a wide range of solutions. Several parties express uncertainty and a lack of confidence in Energy Division's LOLE study results and revisions, and recommend that Energy Division continue developing and vetting the LOLE modeling. These robust stakeholder discussions about Energy Division's LOLE studies further demonstrate the complexity of the LOLE modeling, as well as how these types of studies are highly sensitive to inputs." *See id.* at 32-33.

Energy Division can adjust its approach if necessary based on party input, and before recommending the PRM(s) the Commission should adopt for the RA program. The methodologies of Energy Division and other parties should be evaluated to compare how each approach results in PRMs that meet reliability standards and the costs of doing so.

III. THE COMMISSION'S LOLE MODELING SHOULD IDENTIFY THE PRM THAT ACHIEVES THE RELIABILITY TARGET AT LEAST COST

To inform the Commission's methodology for translating the LOLE study into the PRMs, CalCCA provides a consistent, logical process for setting the PRM, generally leveraging the same set of tools and input data as the Staff proposal. The CalCCA Proposal maintains the current requirement of meeting an annual 0.1 LOLE reliability standard, and adds an objective of minimizing RA procurement costs when allocating LOLE across the year to ensure the reliability standard is met cost-effectively. To do so, the Commission should solve an optimization problem that determines how much accredited capacity needs to be shown in each month to achieve reliability at least cost (referred to herein as the PRM Problem) by: (1) developing risk-reserve curves for each month from pairing many different portfolio's accredited capacity with its LOLE; and (2) use monthly RA prices, monthly 1-in-2 peak demand, and the monthly risk-reserve curves to solve the PRM Problem. These steps are described in detail below.

A. The PRM Can Be Set by Solving for How Much Accredited Capacity Needs to be Shown in Each Month to Achieve Reliability at Least Cost

In setting the PRM, the Commission should consider how much accredited capacity needs to be shown in each month to achieve reliability at least cost. The primary goal of the CalCCA Proposal is to establish a framework that directly connects reliability evaluations from a probabilistic reliability model, such as SERVM, to the current design of the Commission's RA program. The RA program establishes monthly-varying resource accreditation rules, dictating how much of a resource can be counted toward meeting RA requirements. To comply with RA

program rules, load-serving entities (LSE) must, on a month-by-month basis, show contracts with resources whose accredited capacity is sufficient to meet the LSE's forecasted 1-in-2 monthly peak day demand plus a PRM. The RA program commits to choosing PRMs that meet a system-level reliability target of 1 loss-of-load event in ten years, *i.e.*, a LOLE of 0.1 loss of load events per year, or similar metric. Once shown as RA, resources have an obligation to offer their capacity into the CAISO market to ensure reliability to this standard.

1. Motivating Policy Question: How Much Accredited Capacity Needs to be Shown Each Month to Achieve Reliability at Least Cost?

Contracted resources shown by LSEs in the monthly RA filings are committed to support system-level grid reliability through a must-offer-obligation with the CAISO market. The motivating policy question associated with the Commission's LOLE study efforts is therefore: ***How much accredited capacity needs to be shown, in aggregate, each month to ensure that the committed resources result in a LOLE that is at or below 0.1 loss of load events per year?*** The requirement that the system is reliable establishes an "LOLE budget" for which expected loss of load events can be allocated in any variety of ways to the individual months of the year, as long as the total across the year does not exceed 0.1 loss of load events.[11] The allocation of the LOLE budget from month to month can be changed by deciding how much accredited capacity must be shown in each month. Requiring more accredited capacity in a particular month means less LOLE is allocated to that month, and vice versa. In past LOLE study efforts, Energy Division staff sought to allocate the LOLE budget in a way that levelized the PRM across all or a subset

[11] Requiring that a system meet a target 0.1 loss-of-load events per year to be reliable does not say anything about the allocation of events over the year. Being reliable does not imply that all months of the year are equally reliable or that particular months need to be more reliable than others. *See also* MISO 2026-27 PRM study, at 5 and 33 (providing an example of grid planners choosing sub-annual planning reserve margins to allocate a 0.1 LOLE over a year), https://cdn.misoenergy.org/PY%202026-2027%20LOLE%20Study%20Report728909.pdf.

of months. However, as noted by Cal Advocates, "it remains unclear why a levelized PRM is desirable or necessary for the Commission, whether a levelized PRM ensures reliability, and if it is the most cost-effective approach to reliability."[12]

An alternative way to allocate the LOLE budget is to pick the least-cost allocation. Reducing the amount of accredited capacity that must be shown in a month lowers RA costs, with the tradeoff that reducing the available accredited capacity increases the risk of loss of load events. The least-cost allocation of the LOLE budget across the year would simultaneously consider how each month's accredited capacity changes RA costs and changes LOLE to arrive at monthly requirements for accredited capacity that achieve a reliable system at least cost.

2. The Motivating Policy Question Can be Answered Using a Constrained Optimization Model

A constrained optimization problem can be used to mathematically express the decision of how much accredited capacity to show in each month in a way that is least cost yet satisfies the requirement that the system is reliable:

Choose K_m^* [amount of aggregate accredited capacity to show each month] to:

$$minimize \ \sum_m K_m \cdot p_K^m \qquad \text{[Least Cost]}$$

$$such\ that: \sum_m f^m(K_m) \leq 0.1 \qquad \text{[Reliable]}$$

Where:

- m – Month
- K_m – Aggregate accredited capacity in month m
- p_K^m – Price of accredited capacity in month m
- $f^m(K_m)$ – Unknown function of accredited capacity in month m to LOLE in m

[12] *Comments of the Public Advocates Office on Track 2 Proposals*, R.23-10-011 (Aug. 9, 2024) at 4, https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=537763739.

After developing the constrained optimization problem, the next step is to translate the constrained optimization problem in terms of the PRM. In the RA program, the required amount of accredited capacity in each month is indirectly chosen by setting a PRM and requiring that the shown accredited capacity meet or exceed the peak 1-in-2 demand plus the PRM. Rather than choosing the accredited capacity each month, we can reformulate the previous optimization problem in terms of the choice of PRM. First, define the achieved reserve margin, as the amount that the accredited capacity exceeds the 1-in-2 peak demand each month (D_{50}^{m}):

Define: $\alpha_m = \frac{K_m}{D_{50}^{m}} - 1$ [achieved reserve margin in month m]

With this definition, the variable in the constrained optimization is the achieved reserve margin instead of the required amount of aggregate accredited capacity, K_m, (*i.e.*, substitute $K_m = D_{50}^{m}(1 + \alpha_m)$ into the previous equations). Now, the equivalent PRM Problem becomes:

Choose α_m^* [planning reserve margin in each month] to:

$$minimize \ \sum_m D_{50}^{m}(1 + \alpha_m) \cdot p_K^m \quad \text{[Least Cost]}$$

$$such\ that: \sum_m f^m\left(D_{50}^{m}(1 + \alpha_m)\right) \leq 0.1 \quad \text{[Reliable]}$$

Where:

- D_{50}^{m} – Peak 1-in-2 managed demand in month *m*
- α_m – Achieved reserve margin in month *m*

a. Identify the Risk-Reserve Curve For Each Month

To solve the PRM Problem, the Commission should find the relationship between accredited capacity and risk of unmet demand in the form of monthly risk-reserve curves. The challenge to finding an optimal solution to the PRM Problem is that the monthly varying relationship between accredited capacity and reliability, f^m, is unknown. The relationship

between accredited capacity and expected loss of load is called the risk-reserve curve,[13] illustrated in **Figure 1**. This curve is expected to be unique for each month. It depends on the resource accreditation rules and the underlying detailed probabilistic character of demand and supply variability in each month.

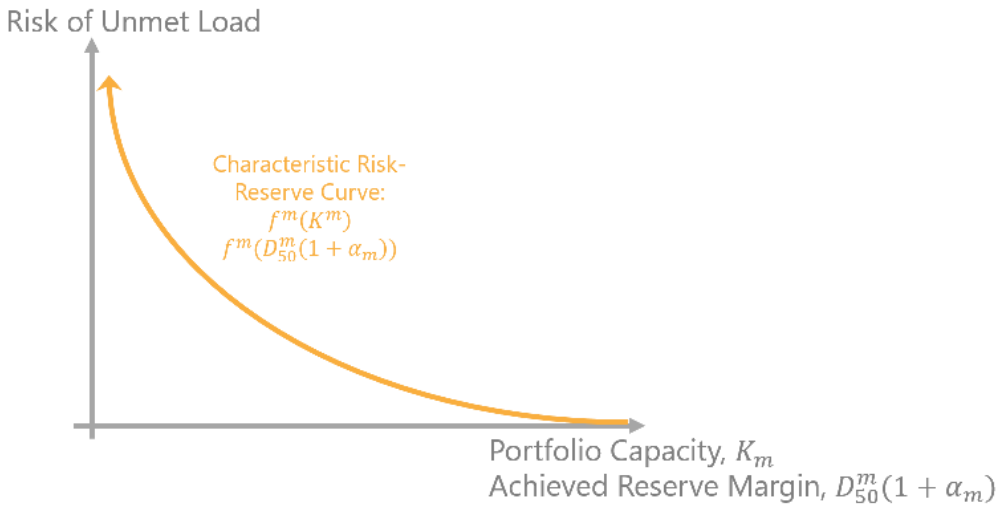

Figure 1. Illustration of a risk-reserve curve showing the relationship between accredited capacity and loss of load expectation.

b. Define Points on the Risk Curve by Pairing Accredited Capacity and Probabilistic Reliability Model Runs

Even though the full risk-reserve curve is unknown, it is possible to sample the curve at any individual point by choosing a particular portfolio of resources, *R*, then finding that portfolio's reserves and risk of unmet load. On the one hand, we can use the slice-of-day (SOD) accreditation rules to find the accredited capacity of the portfolio in each month. On the other hand, we can simulate the portfolio in a probabilistic reliability model, such as SERVM, to find the LOLE in each month for that specific portfolio ($LOLE_m$). The relationship between the choice of a portfolio

[13] *See also* Brattle and Astrape, *Resource Adequacy Requirements: Reliability and Economic Implications* (2013), at 3-5 (providing a more detailed discussion on determining system reliability as a function of planning reserve margin), https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf.

of resources, the achieved reserve margin for that portfolio, and the resulting LOLE for that portfolio is illustrated in **Figure 2**. For any portfolio of resources, the resulting monthly achieved reserve margin and risk of unmet load become coordinates of a point on the risk-reserve curve.

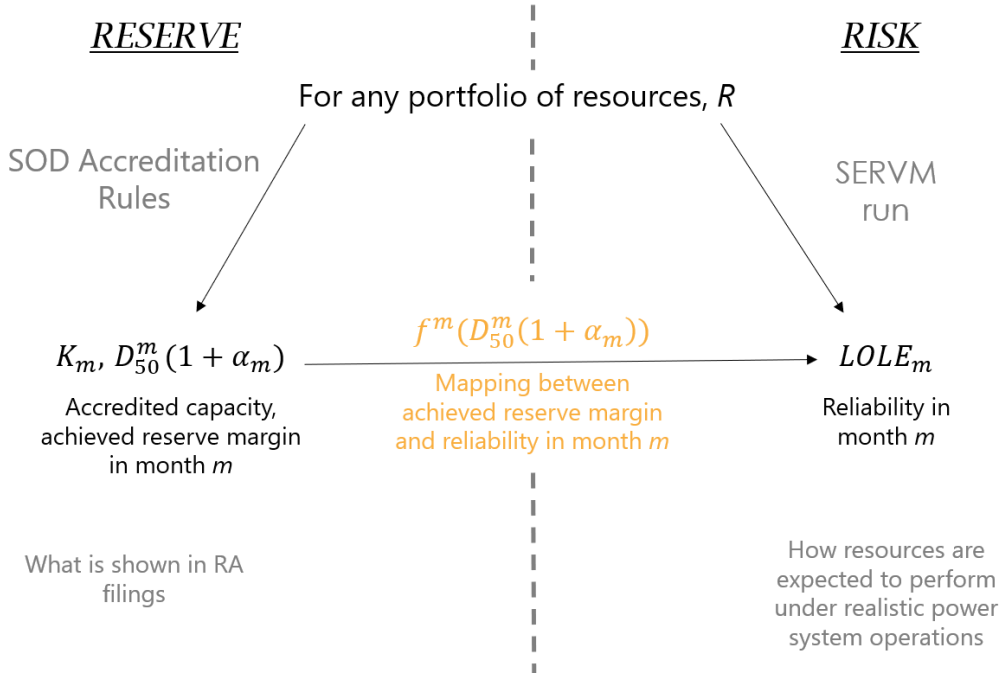

Figure 2. Illustration of how the relationship between reserves and the risk of unmet load can be found for any specific portfolio of resources.

c. Repeat Probabilistic Reliability Simulations with Different Portfolios to Provide an Estimate of the Unknown Risk-Reserve Curve

With repeated simulations of different portfolios, R_i, we can sample a variety of points on the risk-reserve curve. For each specific portfolio, R_i, there will be specific points on the risk-reserve curve, expressed with respect to accredited capacity: $R_i \rightarrow (K_m^i, LOLE_m^i)$, or equivalently expressed with respect to achieved reserve margin: $R_i \rightarrow (D_{50}^m(1+\alpha_m^i), LOLE_m^i)$.

The coordinates of individual points from this true, but unknown, relationship between risk and reserves can be used to estimate the risk-reserve curve for the PRM Problem, illustrated in **Figure 3**. The estimated risk-reserve curve, $\widehat{f_m}$, provides a function that can be defined across the full domain of the PRM Problem and therefore used to find the least-cost monthly PRMs.

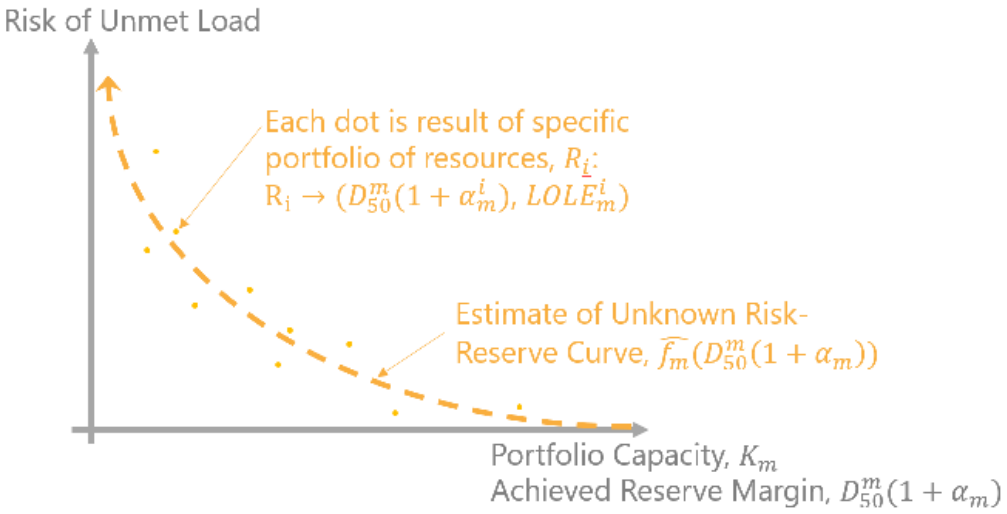

Figure 3. Illustration of how simulations of different portfolios of resources provide points that can be used to estimate the risk-reserve curve

d. Simultaneously Evaluate Each Month's Unique Tradeoffs Between RA Costs and Reliability, While Ensuring that the Overall Annual Reliability Target is Met

With 12 monthly RA showings and 12 monthly relationships between risks and reserves, it is challenging to conceptualize the optimal solution to the PRM Problem. It is easier to illustrate the process with just two periods, for which we assume the price of accredited RA capacity is much higher in period 1 than period 2 (*i.e.*, $p_K^1 \gg p_K^2$). Increasing the achieved reserve margin in period 1 or 2 will lower risk of unmet load in the respective period, however doing so requires procuring more RA capacity, which is considerably more expensive in period 1 than in period 2, as illustrated in **Figure 4**. The optimal solution to the PRM Problem under the assumption that RA prices are much higher in period 1, is to allocate all of the LOLE budget to period 1, such that the LOLE in period 1 is 0.1 and RA costs in period 1 are as low as possible. To stay reliable over the entire year, the LOLE in period 2 must be zero, requiring a high planning reserve margin in period 2. Because the RA price in period 2 is so much lower than period 1, the high PRM in period 2 is still cost-efficient relative to the option of lowering the

reserve margin in period 2 with the commensurate increase in the reserve margin in period 1 to maintain the 0.1 LOLE over the year.

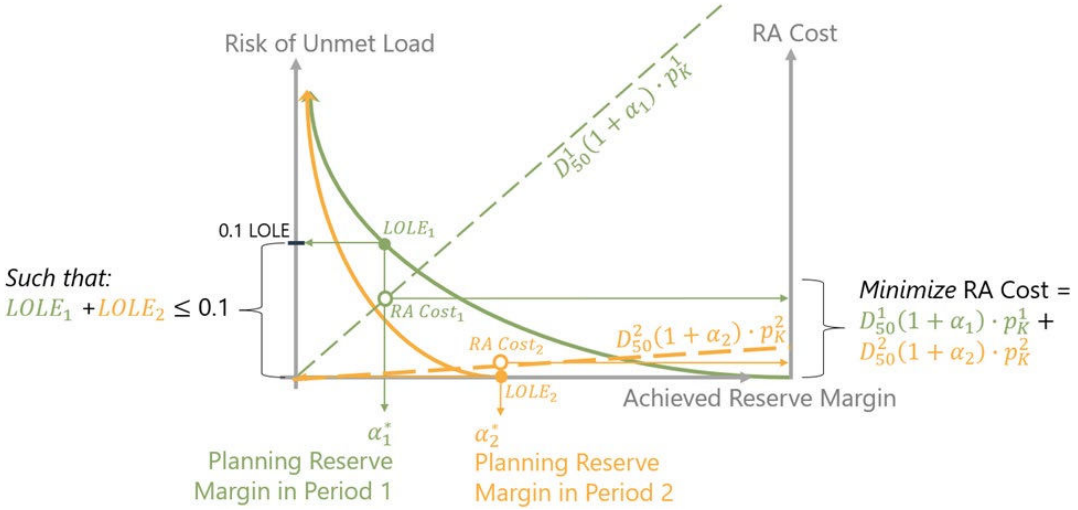

Figure 4. Illustration of the optimal PRM in a case with only two periods where the price of capacity in period 1 is much higher than the price of capacity in period 2.

The above concepts that apply with two periods can be extended to 12 months, but require monthly risk-reserve curves, monthly RA prices, monthly 1-in-2 peak demands, and monthly PRMs.

B. The Commission Can Practically Solve the PRM Problem to Set the RA Program's PRMs

In Section III.A., CalCCA proposes that the Commission set the PRM using a constrained optimization model that solves for how much accredited capacity needs to be shown in each month to achieve reliability at least cost. This section provides a practical application of CalCCA's proposal that can be used to set the PRMs used in the Commission's RA program.

1. Solve the PRM Problem Using Monthly RA Prices, Monthly 1-in-2 Peak Demand, and the Monthly Risk-Reserve Curves

To implement the CalCCA Proposal, the Commission should solve the PRM Problem using monthly values for RA prices, peak demand, and risk-reserve curves. Unfortunately, it is impractical to evaluate every possible point in the risk-reserve relationship. Probabilistic

reliability models, such as SERVM, are computationally expensive to run and there are an extremely high number of different possible combinations of resource portfolios.

Instead of evaluating every possible point, CalCCA proposes the following steps as a practical pathway to develop the risk-reserve curves and solve the PRM Problem in the context of the 2028 PRM setting process. For illustrative purposes, CalCCA used a simplified model that focuses only on demand uncertainty and variability, as described in Appendix A, to demonstrate the steps of the process using numerical values. We expect the values and even relative relationships between months to differ from these simplified model results once these steps are followed using a full probabilistic reliability model and SOD accreditation rules.

a. Begin with a Baseline Portfolio

As a starting point, we must choose an initial portfolio of resources, R. The expected baseline, R_B, as defined by the Energy Division, is a reasonable starting point because it reflects the full set of resources that could be available to commit to serving California loads. In addition, the composition of the portfolio reflects the proportions of thermal generation, variable generation, and energy storage that are expected to be available in 2028.

b. Systematically Adjust Accredited Capacity with Perfect Capacity and/or Negative Operating Units

Solving the PRM Problem requires an estimate of the risk-reserve curve for each month, inclusive of all achieved reserve margins that yield monthly loss of load expectations between 0 and over 0.1 events. To estimate the risk-reserve curve over this range, we must develop and evaluate portfolios whose LOLEs range from near zero LOLE in *any* month to at least 0.1 LOLE in *every* month.

Again, there are too many possible combinations of portfolios that could yield this range of LOLE to evaluate all possible combinations. Instead, we will start with the expected baseline,

R_B , then systematically reduce loss of load expectation by adding perfect capacity in 500 megawatts (MW) increments until LOLE is near zero in all months. Next, moving in the opposite direction, we will systematically increase the loss of load expectation by adding negative operating units (NOU) in 500 MW increments to the expected baseline, R_B, until the LOLE is positive in all months.[14]

For each of these unique portfolios, R_i, we will use the SOD accreditation rules, as reflected in the Energy Division's UCAP-Adjusted PRM Calibration Workbook[15] to calculate the portfolio's monthly accredited capacity, K_m^i. We will simulate the portfolio in a probabilistic reliability model, similar to the Energy Division's SERVM model, to record the loss of load expectation of the portfolio for each month, $LOLE_m^i$. Using the definition of the achieved reserve margin from Section III.A., we will calculate the monthly achieved reserve margin, α_m^i, that corresponds to the monthly accredited capacity of the portfolio R_i.[16]

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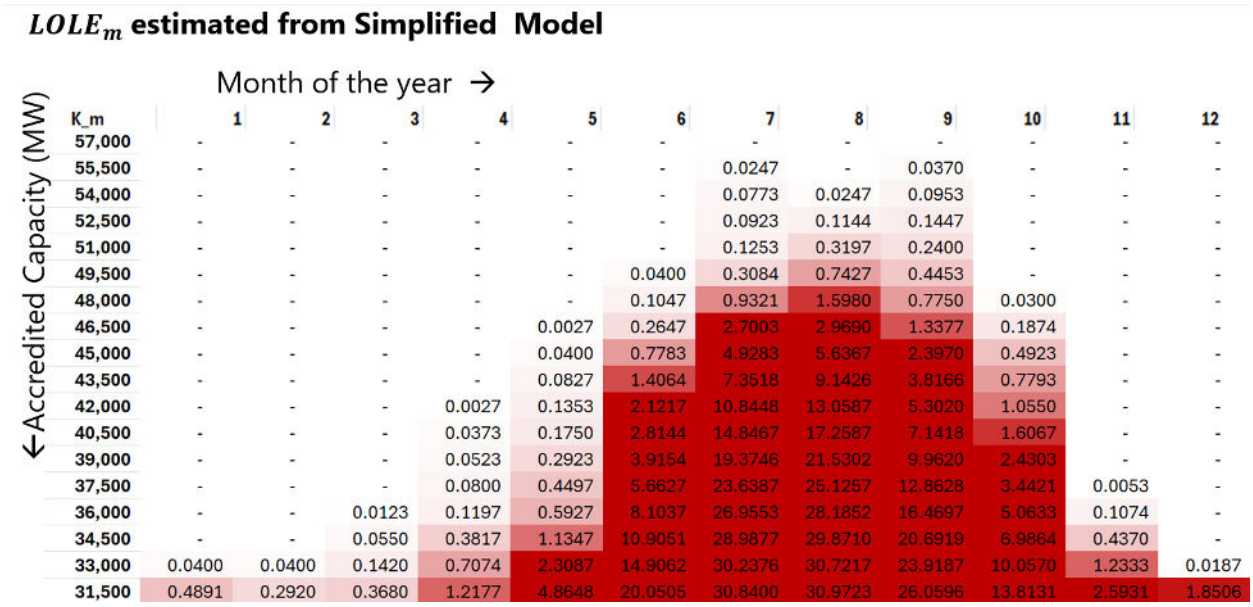
[14] Before doing too many model runs with only NOU, trial runs should verify that the relationship between accredited capacity and LOLE is not sensitive to the decision to only increment NOU. The trials would remove other resources from the expected baseline (*e.g.,* CCGT or 4-hour storage), to see if they result in similar relationship between the remaining accredited capacity and $LOLE_m$. Ideally, SOD accreditation rules result in different portfolios with similar levels of accredited capacity having similar $LOLE_m$. However, this is not guaranteed and can only be verified through trials with alternative resource combinations.

[15] *See* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/ucap_adjusted-prm-calibration-workbook-20260123.xlsm.

[16] This recalculation of the accredited capacity for each portfolio is important because the accredited capacity may change by more or less than the PCAP or NOU increment due to interactions in the SOD accreditation rules with the other baseline resources (particularly with storage and variable resources).



K_m	1	2	3	4	5	6	7	8	9	10	11	12
57,000	-	-	-	-	-	-	-	-	-	-	-	-
55,500	-	-	-	-	-	-	0.0247	-	0.0370	-	-	-
54,000	-	-	-	-	-	-	0.0773	0.0247	0.0953	-	-	-
52,500	-	-	-	-	-	-	0.0923	0.1144	0.1447	-	-	-
51,000	-	-	-	-	-	-	0.1253	0.3197	0.2400	-	-	-
49,500	-	-	-	-	-	0.0400	0.3084	0.7427	0.4453	-	-	-
48,000	-	-	-	-	-	0.1047	0.9321	1.5980	0.7750	0.0300	-	-
46,500	-	-	-	-	0.0027	0.2647	2.7003	2.9690	1.3377	0.1874	-	-
45,000	-	-	-	-	0.0400	0.7783	4.9283	5.6367	2.3970	0.4923	-	-
43,500	-	-	-	-	0.0827	1.4064	7.3518	9.1426	3.8166	0.7793	-	-
42,000	-	-	-	0.0027	0.1353	2.1217	10.8448	13.0587	5.3020	1.0550	-	-
40,500	-	-	-	0.0373	0.1750	2.8144	14.8467	17.2587	7.1418	1.6067	-	-
39,000	-	-	-	0.0523	0.2923	3.9154	19.3746	21.5302	9.9620	2.4303	-	-
37,500	-	-	-	0.0800	0.4497	5.6627	23.6387	25.1257	12.8628	3.4421	0.0053	-
36,000	-	-	0.0123	0.1197	0.5927	8.1037	26.9553	28.1852	16.4697	5.0633	0.1074	-
34,500	-	-	0.0550	0.3817	1.1347	10.9051	28.9877	29.8710	20.6919	6.9864	0.4370	-
33,000	0.0400	0.0400	0.1420	0.7074	2.3087	14.9062	30.2376	30.7217	23.9187	10.0570	1.2333	0.0187
31,500	0.4891	0.2920	0.3680	1.2177	4.8648	20.0505	30.8400	30.9723	26.0596	13.8131	2.5931	1.8506

Figure 5. Example of systematically changing the portfolio to sample points on the risk-reserve curve, recorded as pairings of accredited capacity and loss of load expectation in each month.

c. Estimate the Risk-Reserve Curve for Each Month

Using the monthly paring of achieved reserve margin and loss of load expectation (α_m^i, $LOLE_m^i$), use a curve fitting technique to estimate the risk-reserve curve, $\widehat{f_m}$, for each month. The curve should be most accurate over the range of 0 to 0.1 loss of load expectation for each month, as this is the domain that will be utilized in solving the Planning Reserve Margin problem.

Exponential curves fit to the data from the simplified model, generated in Step 2, are shown for each month in **Figure 6**. In this example the parameters *A* and *b* were found for each month to minimize the square errors in the double exponential equation: $LOLE_m = A * \exp(-\exp(b * \alpha_m))$. The proposed approach should work for any curve that is monotonically decreasing with achieved reserve margin.

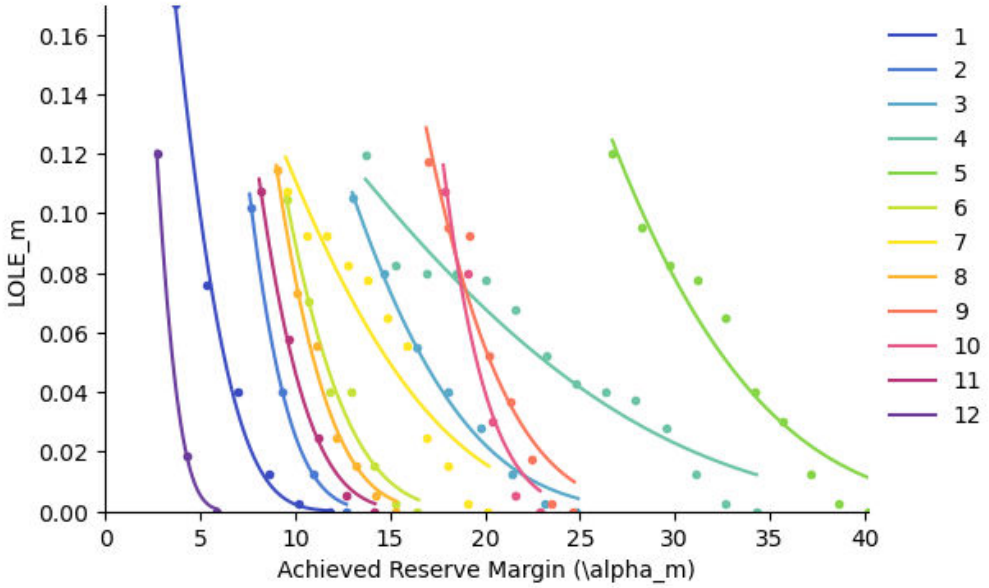


Figure 6. Estimated risk-reserve curve for each month using parameters for an exponential curve and data from the simplified model.

d. Solve the Planning Reserve Margin Problem

Finally, with monthly RA prices, monthly 1-in-2 peak demand, and the monthly estimates of the risk-reserve curve, solve the PRM Problem (*i.e.*, find the least cost PRM in each month such that the sum of monthly LOLE is less than or equal to 0.1 events per year).

Using Excel's GRC Non-linear solver, monthly RA prices from the Energy Division's 2023 RA Market Report, the CEC 2025 IEPR monthly forecast for CAISO 1-in-2 peak managed net load, and the estimated risk-reserve curves from Step 3, we solved the PRM Problem and found the least cost monthly PRMs for the simplified model shown in **Table 1**.

Table 1. Solution to the Planning Reserve Margin problem using estimated risk-reserve curves from the simplified model, with optimal planning reserve margins highlighted in yellow.

Month	RA Price	D_50^m	alpha_m	D_50^m(1+alpha_m)	RA Cost_m	f_hat^m(alpha_m)
1	$ 5.7	30,849	12.7	34,760	$ 196,741	-
2	$ 5.7	30,181	13.0	34,095	$ 192,977	-
3	$ 5.4	29,646	24.4	36,891	$ 197,738	0.0042
4	$ 5.8	31,656	35.2	42,807	$ 249,995	-
5	$ 7.1	33,538	40.2	47,020	$ 335,254	-
6	$ 10.8	43,814	16.5	51,044	$ 551,272	-
7	$ 17.5	47,455	18.1	56,043	$ 980,753	0.0275
8	$ 21.4	48,150	13.2	54,526	$ 1,168,492	0.0149
9	$ 24.1	45,740	21.5	55,580	$ 1,337,817	0.0393
10	$ 11.4	39,882	22.8	48,986	$ 556,969	0.0075
11	$ 6.5	33,282	13.9	37,893	$ 246,684	0.0033
12	$ 7.0	31,644	4.4	33,040	$ 231,611	0.0034
			Std. Dev		Total RA Cost	Total LOLE
			10.06		$ 6,246,302	0.1000

C. While CalCCA's Proposal Uses Similar Inputs and Modeling Techniques to Energy Division's Draft I&A's, it Differs in its Ability to Identify Least-Cost PRMs Compared to the Existing Approach

The CalCCA Proposal leverages a similar probabilistic reliability model and data sources used by Energy Division Staff. The primary difference is in CalCCA's process for systematically estimating the risk-reserve curves for each month and using those curves in a constrained optimization to find least-cost PRMs that meet the annual reliability requirement. CalCCA describes this difference below.

1. The Energy Division Proposal Does Not Reconcile Conflicting Results from Annual LOLE and Monthly Stress Tests

Staff's proposal starts with the expected baseline portfolio, R_B, and uses the SERVM model to find the total LOLE across the year. In the previous 2024 and 2026 LOLE studies, the baseline portfolio was "overly reliable" because the total LOLE was below the target level of 0.1

loss-of-load events per year.[17] Staff proposes to then modify the baseline portfolio by adding PCAP or reducing import availability until the annual LOLE reaches the target level of reliability of 0.1 loss-of-load events per year. CalCCA calls this modified portfolio the calibrated baseline portfolio, R_C.

If the 2028 PRM process is similar to the previous 2026 PRM study, then it is expected that all of the 0.1 loss-of-load events for the calibrated baseline portfolio will again be concentrated in the month of September. For each month, the SOD accreditation rules are used to find the accredited capacity of the calibrated baseline portfolio, K_m^C. The resulting monthly achieved reserve margin of the calibrated baseline portfolio is then found with the same definition of achieved reserve margin from Section II.A. ($\alpha_m^C = \frac{K_m^C}{D_{50}^m} - 1$).

At this point, it is not clear what Energy Division proposes to do with this result. The monthly achieved reserve margins of the calibrated baseline satisfy the reliability requirement ($\sum_m LOLE_m \leq 0.1$). However, if the 2028 study results are again similar to 2026, all of the loss of load events will be concentrated in September[18] and many of the monthly achieved reserve margins from the calibrated baseline will be extremely high, particularly in the low demand months of the winter and spring.[19] Energy Division proposes to "ensure that LOLE across the entire 12 months totals 0.1, though being exact is difficult. Staff will also concentrate LOLE in the summer months of June through September and ensure that LOLE is 0 or only slightly above

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[17] *See* Draft I&As, at 48 ("In previous LOLE studies, such as the one performed in 2024 for the 2026 study year, staff lowered the simultaneous import constraint to raise LOLE since the original LOLE study was over reliable. In addition, once the overall annual study was calibrated to 0.1 LOLE (with all LOLE in September) staff used blocks of 'Perfect Demand' or Negative Operating Unit (NOU) to raise LOLE in individual months.").

[18] *Ibid.*

[19] *Loss of Load Expectation Study for 2026, Including Slice of Day Tool Analysis* (July 19, 2024), at Table 12, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M536/K273/536273741.PDF.

0 in the other months of the year."[20] In effect, the Energy Division proposes setting the PRM in a way that changes the allocation of the LOLE budget away from the allocation with the calibrated baseline portfolio. No clear justification is provided for why it is better to concentrate LOLE in June through September than to leave concentration in September, as it is with the calibrated baseline portfolio. In order to change the allocation of LOLE across months and to eliminate the extremely high achieved reserve margins of the calibrated baseline portfolio, Energy Division, in previous studies, utilized monthly stress tests to change the monthly PRMs to values that differ from $\alpha^{C}_{m,}$, the monthly achieved reserve margins of the calibrated baseline portfolio.

2. CalCCA's Alternative Provides a Rational Foundation for Developing Reasonable PRMs Through Further Policy Discussions

The lack of a clear pathway from the LOLE study to a PRM frustrates policy discussions, as was apparent in the 2026 PRM process.[21] CalCCA's alternative provides a rational foundation for developing reasonable planning reserve margins through further policy discussions. Key to this process is the development of monthly risk-reserve curves, estimated from on the one hand, repeated runs of probabilistic reliability models like SERVM, and on the other hand, translation of each individual resource portfolio into monthly accredited capacity based on the SOD rules. Once these risk-reserve curves are established, it is relatively simple to evaluate a variety of proposals for choosing planning reserve margins.

For example, one question that was raised during the development of this proposal was whether monthly variation in RA prices are an artefact of sellers simply shaping annual RA costs,

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[20] Draft I&As, at 48.

[21] D.25-06-048, at 32 ("As parties have noted, there is no consensus among stakeholders as to which PRM proposal should be adopted and parties advocate for a wide range of solutions. Several parties express uncertainty and a lack of confidence in Energy Division's LOLE study results and revisions, and recommend that Energy Division continue developing and vetting the LOLE modeling. These robust stakeholder discussions about Energy Division's LOLE studies further demonstrate the complexity of the LOLE modeling, as well as how these types of studies are highly sensitive to inputs.").

such that changes in the RA market simply shift around RA prices within the year, without changing the annual RA cost. In such a case, the objective function in the PRM Problem should not minimize the sum of monthly RA costs, instead it should minimize the highest monthly RA requirement. The effect of this shift in objective function can be quickly developed in Excel, and using the same monthly risk-reserve curves, solved to find monthly PRMs that minimize RA costs based on the highest monthly RA requirement. The reformulation of the PRM problem and resulting PRMs are described in Appendix B, using risk-reserve curves from the simplified model.

Another question that can be quickly evaluated is what the tradeoffs between the complexity of twelve monthly PRMs are versus the simplicity of a single annual PRM that also meets the reliability requirements of the LOLE at or below 0.1 loss of load events per year. To address this question, CalCCA developed an Excel model that considers different weighting between the least cost PRMs (as in **Table 1**) and the least complexity PRMs (where monthly PRMs with a standard deviation of zero, *i.e.*, a single annual PRM, is the least complex), while still requiring that any valid monthly PRMs stay within an annual LOLE of 0.1. The efficient frontier for this tradeoff, demonstrated in **Figure 7**, shows that the desire for lower complexity results in an increase in RA costs. Based on the risk-reserve curves from the simplified model, a single annual PRM increases RA costs by about nine percent over the least cost monthly PRMs, equivalent to more than $570 million per year with the 2028 demand forecast and monthly RA prices from 2023.

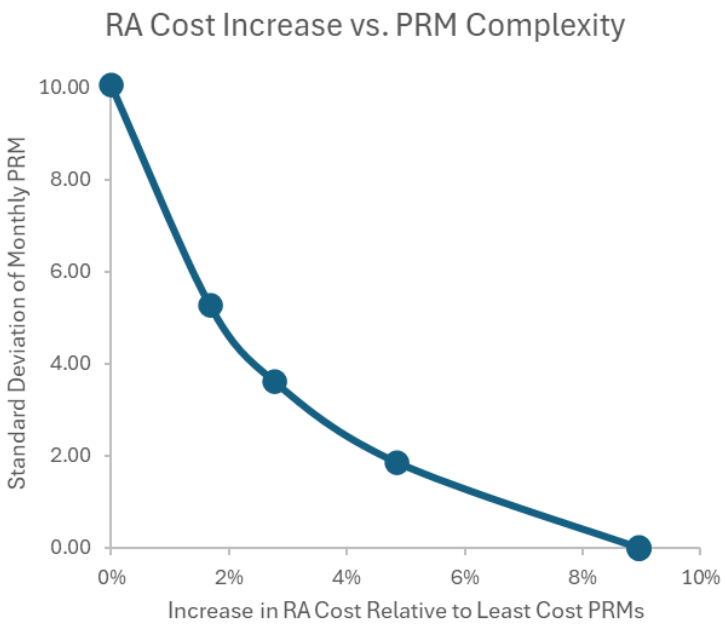

Figure 7. Efficient frontier for the tradeoffs between RA costs and complexity of PRMs, as measured by the standard deviation of monthly PRMs, using risk-reserve curves from the simplified model.

The flexibility to evaluate all of these questions demonstrates that CalCCA's alternative approach provides a firm foundation to anchor policy discussions on the best way to set PRMs for the 2028 RA program.

IV. ALTERNATIVE SOURCES SHOULD BE USED TO INFORM LOAD FORECAST ERROR ASSUMPTIONS THAT ARE TARGETED TO THE CALIFORNIA CONTEXT

The Commission should use alternative sources to inform load forecast error assumptions that are more closely aligned with the California context. Load forecast error due to economic and demographic uncertainties are a key component to setting the PRM to ensure a 0.1 LOLE. LSE RA requirements add up to a system-wide requirement that is based on a 1-in-2 peak demand forecast using data from as recent as two years before the operating year. After the IEPR load forecast is adopted, overall system-wide RA requirements do not change, and actual weather-normalized load can be higher (or lower) than the load forecast. As a result, maintaining

a reliable system requires a portion of the PRM to include resources needed to cover load forecast error due to economic and demographic risks.

In its CalCCA April Comments, CalCCA recommends that Energy Division use past Integrated Energy Policy Report (IEPR) forecasts of peak demand to validate and adjust load forecast error assumptions in SERVM.[22] Energy Division's distribution of load forecast errors in SERVM is based on a paper analyzing the Euro Area Gross Domestic Product (GDP) growth forecasts collected from the European Central Bank Survey of Professional Forecasters (SPF).[23] While the SERVM distribution appears reasonable, there is no documentation demonstrating that the ability to forecast GDP growth in the Euro Area is a good approximation of California's ability to forecast 1-in-2 peak demand for the RA program.[24] The Commission should therefore investigate alternative sources to inform load forecast error that are more relevant to the United States (U.S.) and California contexts.

In the near term, the Commission should leverage existing, U.S.-focused sources that are available to inform load forecast error assumptions. In its analysis going forward, CalCCA plans to incorporate the values from a Midcontinent Independent System Operator study that bases load forecast error parameters on U.S. economic forecasting errors and the relationship between

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[22] *California Community Choice Association's Comments on Draft Inputs & Assumptions*, R.25-10-003 (Apr. 24, 2026) (CalCCA April Comments), at 9, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M605/K320/605320632.PDF.

[23] *See* C. Bowles, R. Friz, V. Genre, G. Kenny, A. Meyler, and T. Rautanen, "An evaluation of the growth and unemployment forecasts in the ECB Survey of Professional Forecasters," Journal of Business Cycle Measurement and Analysis 2, no. 4 (2010), at 1-28: http://dx.doi.org/10.1787/jbcma-v2010-2-en.

[24] The only documentation of the load forecast errors that CalCCA could find states: "The load forecast multipliers used in Energy Division modeling are based on analysis of near-term forecasting that was available from the OECD Journal. Staff evaluated projections of 1 year ahead and 2 year ahead GDP growth, noting the magnitudes of GDP uncertainty and their probabilities. These figures were entered as a basis for the load forecast uncertainty variables in SERVM. *See* Energy Division "Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions– Guidance for Production Cost Modeling and Network Reliability Studies" (Feb. 20, 2018), at 29, https://www.cpuc.ca.gov//media/cpucwebsite/files/uploadedfiles/cpucwebsite/content/utilitiesindustries/energy/energyprograms/electpowerprocurementgeneration/irp/2018/1unified-ia-main-draft-20180220.pdf.

economic growth and load growth. In particular, the study estimates economic forecast errors from comparing Congressional Budget Office projections of GDP growth to actual growth in Bureau of Economic Analysis statistics. The study then scales GDP growth forecast errors by rate at which electric load grows relative to GDP to develop a final load forecast error distribution, shown in **Table 2**.[25]

Table 2. Load forecast error based on U.S. economic forecast errors from MISO PRM study.

Load Forecast Error (%)	Probability
-2.0	0.0090
-1.0	0.2050
0	0.5730
1.0	0.2050
2.0	0.0090

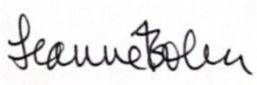
In the long term, the Commission should begin working with the CEC to develop California-focused load forecast error assumptions. As recommended in CalCCA April Comments, the Commission, in coordination with the CEC, should use past 1-in-2 peak demand forecasts from the IEPR planning forecast to validate, and possibly adjust, the load forecast errors in SERVM. Using CEC IEPR data to inform load forecast errors would ensure that the assumptions used in the Commission's modeling reflect the load forecasting experience in California.

[25] *See* MISO Planning Year 2025-2026 Loss of Load Expectation Study Report, at 32, https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdfE

V. CONCLUSION

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

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

June 5, 2026

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S ALTERNATIVE INPUTS & ASSUMPTIONS DOCUMENT IN RESPONSE TO ADMINISTRATIVE LAW JUDGE'S RULING MODIFYING 2028 LOSS OF LOAD EXPECTATION STUDY SCHEDULE

Description of Simplified Model Used to Provide Illustrative Numerical Values

CalCCA developed a simple probabilistic reliability model which only considers variability and uncertainty on the demand side. All treatment of supply is handled through specification of perfect capacity (PCAP), with no variability and uncertainty. The purpose of this simplified model is to rapidly produce illustrative numerical values, rooted in a portion of the actual load data that will be used in the 2028 LOLE study.

For a specified level of PCAP, the simplified model uses the Energy Division's net managed load for the CAISO region for each of the 25 weather years,[26] Energy Division's assumed load forecast error distribution,[27] and an assumption of six percent operating reserves,[28] to calculate the LOLE in each month. In the model, unserved energy occurs whenever the managed net load, scaled by the load forecast error, plus the operating reserve margin, exceeds PCAP. A loss-of-load event occurs if there is unserved energy within a day. A flow chart of the simplified model, reflecting the Energy Division's assumed load forecast error distribution, is shown in **Figure 1**, below.

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[26] Hourly net loads for 25 weather years scaled to the 2028 forecast downloaded from https://files.cpuc.ca.gov/energy/modeling/2026_servm_updates/HourlyLoad_CA_Regions_V2025E_2224_Mon_2028.csv. CalCCA calculated the CAISO net managed load as the sum of the "Net Load" columns for SDG&E, PG&E, and SCE.

[27] Draft I&A, at 46.

[28] The six percent operating reserve requirement is based on Energy Division's assumption that not having sufficient resources to satisfy Regulation Up and Spinning Reserve requirements leads to unserved energy. Regulation Up and Spinning Reserve requirements are each 3% of hourly demand. *See* Draft I&A, at 39-40.

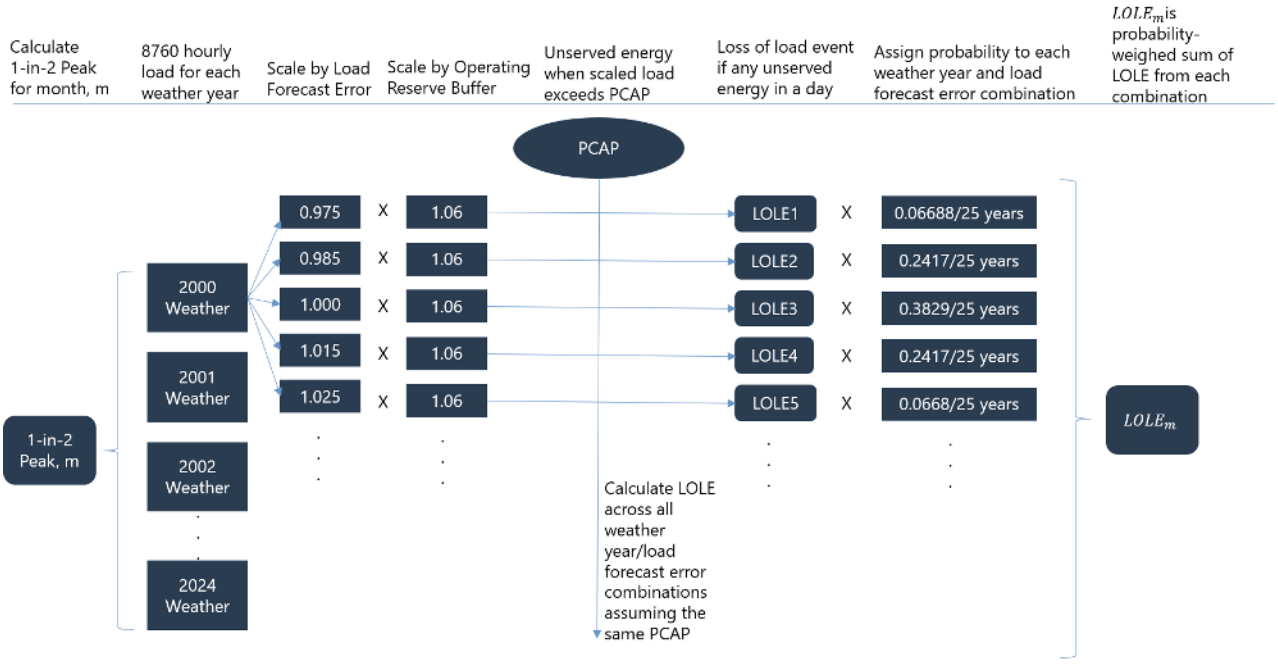

Figure 1. Flow chart for calculation of monthly LOLE for a specified level of PCAP.

CalCCA wrote the simplified model in the Python programming language using the pandas package. With this code, systematically evaluating the monthly LOLE for 60 distinct PCAP values starting at 28,000 MW and ending at 57,500 MW with 500 MW increments takes about 1 minute and 30 seconds on a desktop computer. The output of the code is a table containing the resource portfolio identifier, the month, the monthly accredited capacity of the resource portfolio, the monthly 1-in-2 peak demand, the monthly achieved reserve margin based on the accredited capacity and 1-in-2 peak demand (using the identity $K_m = D_{50}^m\ (1 + \alpha_m)$), and the resulting monthly LOLE from the probabilistic simulation of the resource portfolio. An excerpt of the table is shown in **Table 1**. The full table has 720 rows (60 resource portfolios with 12 months of data for each portfolio). To facilitate collaboration, CalCCA recommends all parties conducting LOLE studies, including the Energy Division, produce a similar table for any probabilistic reliability simulation they conduct of a particular resource portfolio.

Table 1. Excerpt from output of simplified model showing monthly LOLE for different levels of PCAP in the simulated resource portfolio.

R_i	Month	K_m	D_50_m	alpha_m	LOLE_m
Unique identifier for resource portfolio R_i	Month of the year	Monthly accredited capacity of resource portfolio R_i (MW)	Monthly 1-in-2 peak demand for 2028 (MW)	Monthly achieved reserve margin (%) for R_i, based on K_m and D_50_m	Monthly LOLE from probabilistic reliability simulation of portfolio R_i (expected events per year)
6	1	55,000	30,849	78.29	-
6	2	55,000	30,181	82.23	-
6	3	55,000	29,646	85.53	-
6	4	55,000	31,656	73.74	-
6	5	55,000	33,538	63.99	-
6	6	55,000	43,814	25.53	-
6	7	55,000	47,455	15.90	0.055317
6	8	55,000	48,150	14.23	0.005345
6	9	55,000	45,740	20.25	0.052342
6	10	55,000	39,882	37.91	-
6	11	55,000	33,282	65.26	-
6	12	55,000	31,644	73.81	-
7	1	54,500	30,849	76.67	-
7	2	54,500	30,181	80.58	-
7	3	54,500	29,646	83.84	-
7	4	54,500	31,656	72.17	-
7	5	54,500	33,538	62.50	-
7	6	54,500	43,814	24.39	-
7	7	54,500	47,455	14.84	0.064986
7	8	54,500	48,150	13.19	0.015014
7	9	54,500	45,740	19.15	0.092645
7	10	54,500	39,882	36.65	-
7	11	54,500	33,282	63.75	-
7	12	54,500	31,644	72.23	-
8	1	54,000	30,849	75.05	-
8	2	54,000	30,181	78.92	-
8	3	54,000	29,646	82.15	-
8	4	54,000	31,656	70.59	-
8	5	54,000	33,538	61.01	-
8	6	54,000	43,814	23.25	-
8	7	54,000	47,455	13.79	0.077328
8	8	54,000	48,150	12.15	0.024683
8	9	54,000	45,740	18.06	0.095317
8	10	54,000	39,882	35.40	-
8	11	54,000	33,282	62.25	-
8	12	54,000	31,644	70.65	-
9	1	53,500	30,849	73.43	-
9	2	53,500	30,181	77.26	-
9	3	53,500	29,646	80.47	-
9	4	53,500	31,656	69.01	-
9	5	53,500	33,538	59.52	-
9	6	53,500	43,814	22.11	-
9	7	53,500	47,455	12.74	0.082672
9	8	53,500	48,150	11.11	0.055317
9	9	53,500	45,740	16.97	0.117328
9	10	53,500	39,882	34.14	-
9	11	53,500	33,282	60.75	-
9	12	53,500	31,644	69.07	-

For each paring of accredited capacity, K_m, and $LOLE_m$ (*i.e.*, rows of **Table 1**, above, and also summarized in **Figure 5** of the CalCCA Proposal), CalCCA substituted achieved reserve margin for the accredited capacity. For each month, we then fit a double exponential function, described in Section III.B.1.c., across the achieved planning reserve margins that yield monthly LOLE between 0 and slightly above 0.1. The parameters of the curve fit and the valid domain of the achieved reserve margin are shown in **Table 2**. We assume that the LOLE is zero for any achieved reserve margin that exceeds the valid domain. Any achieved reserved margin that is below the valid domain results in a LOLE greater than 0.1 and is therefore infeasible.

Table 2. Estimates of the monthly risk-reserve curves from data derived from the simplified model.

Month	\alpha_min	\alpha_max	A	B
1	3.7	11.9	1.216119E+00	1.835660E-01
2	6	12.7	2.084077E+00	1.457431E-01
3	9.6	24.9	1.411375E+00	7.208796E-02
4	12.1	34.3	8.422441E-01	4.509645E-02
5	22.2	40.2	1.990913E+00	3.954603E-02
6	8.4	16.5	1.919186E+00	1.114348E-01
7	6.4	20.2	6.976690E-01	6.486722E-02
8	6.9	15.3	2.197440E+00	1.214933E-01
9	13.6	24.7	2.026401E+00	6.375892E-02
10	16.5	22.9	1.470141E+01	8.873022E-02
11	6.6	14.2	2.227775E+00	1.352231E-01
12	1.1	5.9	3.155361E+00	4.356417E-01

APPENDIX B
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S ALTERNATIVE INPUTS & ASSUMPTIONS DOCUMENT IN RESPONSE TO ADMINISTRATIVE LAW JUDGE'S RULING MODIFYING 2028 LOSS OF LOAD EXPECTATION STUDY SCHEDULE

If RA costs do not vary by month, but are instead based on LSEs procuring RA capacity to meet their highest month's RA requirement, then the objective function in the PRM Problem needs to be reformulated to find the least-cost PRMs that meet the reliability requirement. Instead of minimizing the sum of monthly RA costs, the reformulated objective function minimizes the cost of RA based on the highest monthly RA requirement.

Choose α_m^* [planning reserve margin in each month] to:

$$minimize \ \max_m \{D_{50}^m(1+\alpha_m)\} \cdot p_K \qquad \text{[Least Cost]}$$

$$such\ that: \sum_m f^m\left(D_{50}^m(1+\alpha_m)\right) \leq 0.1 \qquad \text{[Reliable]}$$

Where:

- p_K – Annual price of accredited capacity ($/kW-yr)

This reformulated PRM Problem relies on the same estimate of the monthly risk-reserve curve in the original formulation. CalCCA developed an Excel model that solves this alternative PRM problem using the GRC Non-linear solver, assuming that the annual price of RA is equal to the sum of the 12 monthly RA prices used in the original formulation. The resulting least-cost PRMs are shown in the table below.

Table 1. Reformulation of the PRM Problem to minimize annual RA costs based on risk-reserve curves from the simplified model.

Month	D_50^m	alpha_m	D_50^m(1+alpha_m)	f_hat^m(alpha_m)
1	30,849	20.4	37,137	-
2	30,181	30.9	39,492	-
3	29,646	31.3	38,921	-
4	31,656	40.2	44,381	-
5	33,538	40.2	47,020	-
6	43,814	25.7	55,063	-
7	47,455	16.0	55,066	0.0412
8	48,150	14.4	55,066	0.0072
9	45,740	20.4	55,066	0.0517
10	39,882	23.2	49,146	-
11	33,282	33.6	44,479	-
12	31,644	29.4	40,934	-
		Std. Dev	**Total RA Cost**	**Total LOLE**
		8.61	$ 7,067,143	0.1000
		Price RA ($/kW-yr)	128.34	

CalCCA provides this example of reformulating the PRM problem only to illustrate the flexibility of the approach for discussing various policy proposals. Once the challenging step of developing monthly risk-reserve curves is complete, it is relatively easy to investigate alternative perspectives on how to define least-cost or the importance of having seasonal or annual PRMs rather than monthly-varying PRMs.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes.	R.25-02-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S TRACK 2 OPENING BRIEF

PUBLIC VERSION

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Counsel to
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

June 16, 2026

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SUMMARY OF RECOMMENDATIONS[1]

- The Commission should require the IOUs to:
    - value any pre-2019 Banked RECs used for bundled customer RPS compliance at the compliance year RPS MPB; and
    - credit that value to the vintage corresponding to any such RECs' generation year;
- In the alternative, the Commission should instruct IOUs that use Pre-2019Bbanked RECs for bundled customer compliance to first proportionately allocate Pre-2019 Banked RECs to the Later Departing Customers who paid for those Pre-2019 Banked RECs via a decrement to the applicable LSE's RPS Procurement Need;
- If the Commission does not adopt CalCCA's valuation or allocation proposals rooted in the indifference requirements, it should adopt Staff's recognition that Pre-2019 Banked RECs provide compliance value and instruct the IOUs to:
    - value any Pre-2019 Banked RECs used for bundled customer RPS compliance at a 90/10 composite of the RPS MPB and a new PCC-3 REC MPB, which the Commission should instruct its Energy Division to produce and publish along with the other MPBs; and
    - credit that value to the vintage corresponding to any such RECs' generation year.

[1] Acronyms used herein are defined in the body of this document.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes.	R.25-02-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S TRACK 2 OPENING BRIEF

Pursuant to Rule 13.12 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure[2] (RPP), the *Assigned Commissioner's Amended Scoping Memo and Ruling*[3] (Amended Scoping Ruling), the *Administrative Law Judge's Ruling Issuing Staff Report*[4] (ALJ Ruling), and the *E-Mail Ruling Cancelling Evidentiary Hearing and Further Modifying the Track Two Proceeding Schedule*[5] (E-Mail Ruling), the California Community Choice Association[6] (CalCCA) submits this Track Two Opening Brief.

I. INTRODUCTION

The question in Track Two is simple and straightforward:

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

[3] *Assigned Commissioner's Amended Scoping Memo and Ruling*, Rulemaking (R.) 25-02-005 (Feb. 3, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M597/K166/597166403.PDF.

[4] *Administrative Law Judge's Ruling Issuing Staff Report,* R.25-02-005 (Mar. 27, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M603/K533/603533506.PDF.

[5] *Email Ruling Cancelling Evidentiary Hearing and Further Modifying the Track Two Proceeding Schedule,* R.25-02-005 (Apr. 24, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M605/K750/605750799.PDF.

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

> When two groups of customers – current bundled investor-owned utility (IOU) customers and "Later Departing" customers – pay the same amount for Pre-2019 Renewable Energy Credits (REC) through their rates at the time the RECs are banked for future use (Pre-2019 Banked RECs),[7] should they receive comparable benefits when the RECs are used?

The answer is equally straightforward:

> The indifference statutes require that both customer groups who paid for the RECs receive the associated benefits.

Consequently, when bundled customers realize the benefit of these banked RECs by using them for Renewables Portfolio Standard (RPS) compliance, Later Departing Customers must receive a proportional benefit, whether in compensation or in-kind. Specifically, section 366.2(g) requires that community choice aggregator (CCA) customers receive the "value of any benefits that remain with bundled service customers."[8] If that value is not conveyed, one group of customers will receive the value of the REC attributes, while another group does not. In addition to violating section 366.2(g), this results in a clear violation of section 451's requirement that rates be "just and reasonable." It also results in violations of section 453(a) and (c)'s requirements that public utilities avoid "any preference or advantage to any corporation or person" and "unreasonable difference as to rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service."

Through its own reasoning, the Energy Division's Staff Report and Proposals on Pre-2019 Banked Renewable Energy Credits[9] (Staff Report) approaches the same conclusion. The

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[7] Specifically, RECs generated by PCIA resources from 2011 through 2018 that the IOUs did not need for RPS compliance in the years in which they were generated, and which were therefore stored in the 'bank' for later use.

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

[9] *Staff Report and Proposals on Pre-2019 Banked Renewable Energy Credits*, R.25-02-005 (Mar. 27, 2026), Attachment A to ALJ Ruling, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M603/K465/603465623.PDF.

Staff Report concludes: "CalCCA makes a compelling argument that departed customers paid for a portion of these RECs…."[10] The Staff's reservations lie in the determination of the value of the banked RECs.

The IOUs' testimony advocating for zero value for the pre-2019 banked RECs floods the zone with arguments that distract from this simple reality that Later Departing customers paid for the RECs and deserve to benefit from those payments based on indifference principles:

- They employ a laundry list of past grievances regarding Power Charge Indifference Adjustment (PCIA) cost shifts to suggest the Commission's hands are tied today, despite recognizing themselves that RECs are bankable and most of their grievances can no longer be addressed;
- They incorrectly suggest departed customers will receive the value of the RECs twice or that CalCCA's proposal will result in an unsanctioned true-up;
- They "cry wolf" about an RPS apocalypse and serious impacts to bundled customer affordability that their own witnesses admit are *de minimis* in the near term and, regardless, are uncertain and avoidable over the long-term;
- They overlook the zero-sum nature of the PCIA to allege unlawful cost increases for bundled customers while ignoring the current cost increases departed customers face under the *status quo*; and
- They ignore the fact the Commission values Post-2018 RECs with the exact same attributes as Pre-2019 RECs at the RPS MPB to suggest the RECs are worth less than the current benchmark.

None of these arguments overcome the statutory requirement, as this Opening Brief explains.

Once the fundamental principle is recognized—all customers should get what they pay for—the Commission need only determine how to measure the benefit that Later Departing Customers should receive. The value of the benefit received by bundled customers, the avoided cost of RPS compliance, provides the best proxy for the Later Departing Customer benefits. But for the use of the banked RECs, the IOUs would have been required to procure additional RPS

[10] *Id*. at 8.

products from the market to meet any short position. To gain equivalent value to the banked Portfolio Content Category (PCC)-1 RECs received from the bank, which fill the most important RPS "bucket," the IOUs would have paid the market price for a PCC-1 REC. The most accurate available measure for a PCC-1 REC is the RPS market-price benchmark (MPB), a price for PCC-1 transactions that the Commission already develops based on market data collected from load-serving entities.

Accepting that indifference requires the provision of REC value to Later Departing Customers, Energy Division Staff adds unnecessary complexity to the question of value. It contends that determining value requires making "numerous assumptions regarding counter-factual scenarios."[11] The same can be said, however, about the indifference principle underlying the entire PCIA: what the bundled portfolio and rates would have been had load not departed raises innumerable questions of counterfactual IOU procurement strategies. Yet in the face of this complexity, the Commission has administered a PCIA methodology for many years that determines the value of PCIA resources, ignoring the many counterfactual procurement strategy questions. Despite Staff's reservations, the Staff Report makes an admirable attempt to find REC values between the IOU and CCA positions. Unfortunately, none of these alternatives align the solution with the fundamental principle at issue, and the resulting value would fall short of what the law requires.

CalCCA urges the Commission to bring its focus to the simplicity of the solution. Customers who paid the same amount for the same resources should receive comparable benefits. The value of the benefits for Later Departing Customers is best measured by the value of the avoided compliance benefit bundled customers received.

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[11] *Id*. at 8.

CalCCA therefore recommends:

- The Commission should require the IOUs to:
    - value any pre-2019 Banked RECs used for bundled customer RPS compliance at the compliance year RPS MPB; and
    - credit that value to the vintage corresponding to any such RECs' generation year;
- In the alternative, the Commission should instruct IOUs that use Pre-2019Bbanked RECs for bundled customer compliance to first proportionately allocate Pre-2019 Banked RECs to the Later Departing Customers who paid for those Pre-2019 Banked RECs via a decrement to the applicable LSE's RPS Procurement Need;
- If the Commission does not adopt CalCCA's valuation or allocation proposals rooted in the indifference requirements, it should adopt Staff's recognition that Pre-2019 Banked RECs provide compliance value and instruct the IOUs to:
    - value any Pre-2019 Banked RECs used for bundled customer RPS compliance at a 90/10 composite of the RPS MPB and a new PCC-3 REC MPB, which the Commission should instruct its Energy Division to produce and publish along with the other MPBs; and
    - credit that value to the vintage corresponding to any such RECs' generation year.

II. LEGAL STANDARD

California law requires customer indifference when customers depart IOU generation service. California Public Utilities Code Sections 365.2, 366.2, and 366.3 require that no customer—either bundled or unbundled—should have additional costs shifted to them as a result of retail choice.[12] California statutes require CCA customers to continue paying the

[12] Cal. Pub. Util. Code §§ 365.2 ("The commission shall ensure that bundled retail customers of an electrical corporation do not experience any cost increases as a result of retail customers of an electrical corporation electing to receive service from other providers. 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."); 366.2(a)(4) ("The 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."); 366.3 ("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

above-market costs of IOU resources originally procured on their behalf, even after they depart.[13] In return, CCA customers are entitled to receive the value of the resources' attributes that remain with bundled customers or an allocated share of the attributes, to compensate the unbundled customers for the payments they continue to make for those resources.[14]

In addition to these indifference statutes, Section 451 requires all rates and charges collected by a public utility to be "just and reasonable."[15] Section 453 also prohibits public utilities from charging discriminatory rates.[16] Specifically, section 453(a) prohibits public utilities from "mak[ing] or grant[ing] any preference or advantage to any corporation or person, or subject[ing] any corporation or person to any prejudice or disadvantage."[17] Section 453(c) further prohibits public utilities from establishing or maintaining any "unreasonable difference as to rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service."[18]

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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.").

13 Cal. Pub. Util. Code § 366.2(f) ("A retail end-use customer purchasing electricity from a community choice aggregator pursuant to this section shall reimburse the electrical corporation that previously served the customer for all of the following: (1) The electrical corporation's unrecovered past undercollections for electricity purchases, including any financing costs, attributable to that customer, that the commission lawfully determines may be recovered in rates, (2) Any additional costs of the electrical corporation recoverable in commission-approved rates, equal to 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.")

14 Cal. Pub. Util. Code § 366.2(g) ("Estimated net unavoidable electricity costs paid by the customers of a community choice aggregator shall be reduced by the value of any benefits that remain with bundled service customers, unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits.").

15 *See* Cal. Pub. Util. Code § 451.

16 *See* Cal. Pub. Util. Code § 453.

17 Cal. Pub. Util. Code § 453(a).

18 Cal. Pub. Util. Code § 453(c).

The Commission's Order Instituting Rulemaking in this proceeding determined that this is a rulemaking,[19] with Track Two categorized as a ratemaking proceeding.[20] Under RPP Rule 6.1, the Commission may institute rulemaking proceedings to "adopt, repeal, or amend rules, regulations, and guidelines for a class of public utilities or of other regulated entities," and to "modify prior Commission decisions which were adopted by rulemaking."[21] In rulemakings, all parties "have equal standing where their proposals are concerned: they must show by a preponderance of evidence that the Commission should adopt their proposal, rather than an alternative."[22] All parties also bear the burden of production "for those parts of their showing that ask the Commission to disregard a competing proposal."[23]

As demonstrated throughout this Opening Brief, CalCCA's proposals to credit Pre-2019 Banked RECs at the RPS MPB, or at an alternative compliance value, or to allocate the RECs to other LSEs, clearly meet these standards. The Commission should therefore adopt one of CalCCA's recommendations and apply it in the IOUs' 2027 Energy Resource Recovery Account (ERRA) Forecast cases.[24]

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[19] *Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes*, R.25-02-005 (Feb. 26, 2025), at 18.

[20] Amended Scoping Ruling at 7.

[21] RPP, Rule 6.1.

[22] D.18-10-019, at 32.

[23] *Id*.

[24] *See* D.25-12-028, *Decision Approving Southern California Edison Company's 2026 Energy Resource Recovery Account-Related Revenue Requirement Forecast* (Dec. 19, 2025), at 113 (requiring SCE to track any Pre-2019 Banked RECs used in 2026 in order to "allow any updated guidance from the Commission regarding the treatment of Pre-2019 Banked RECs to apply to Pre-2019 Banked RECs used for bundled compliance in 2026" through SCE's 2026 October Update); D.25-12-027, *Decision Approving Pacific Gas and Electric Company's 2026 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2026 Electric Sales Forecast* (Dec. 23, 2025) (requiring the same tracking as the SCE Decision); D.25-12-008, *Decision Approving San Diego Gas & Electric Company's 2026 Electric Procurement Revenue Requirement Forecasts, 2026, 2026 Electric Sales Forecast, and Greenhouse Gas Related Forecasts* (Dec. 5, 2025), at Ordering Paragraph 8 ("In the event that San Diego Gas & Electric Company forecasts that it will need to use pre-2019 banked renewable energy credits in 2026, it shall file an application requesting Commission authorization to do so. Such an application shall include a valuation proposal.").

III. BACKGROUND

A. Legal and Policy Origins of the PCIA

Through the passage of Assembly Bill (AB) 117 in 2002, the California Legislature broadened opportunities for retail electric competition previously allowed only through Direct Access (DA) service via Electric Service Providers (ESPs) by authorizing Community Choice Aggregation.[25] Instead of receiving all services (*i.e.,* generation, transmission, distribution, and other services) from their IOU (as a bundled customer), CCA customers receive generation service from their local CCA, and continue receiving transmission, distribution, and all other services from the IOU (unbundled or departed load customer).[26] Today, 25 CCAs are in operation in California serving more than 15 million customers.[27]

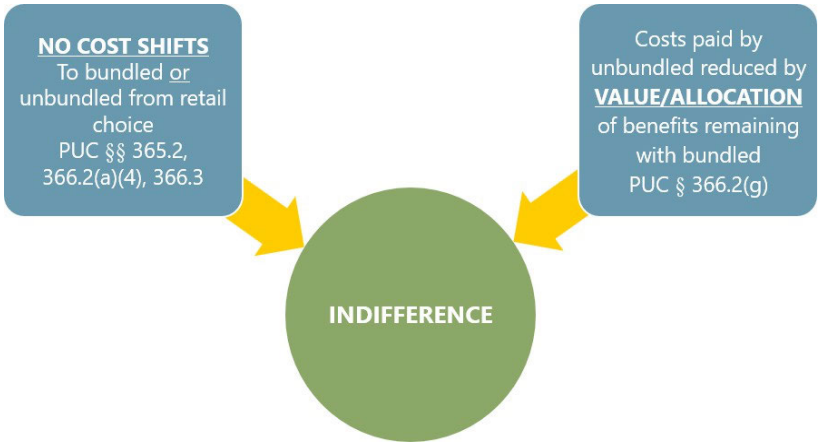
As set forth above, California law requires customer indifference as a result of retail choice. Statutory indifference has three related requirements:

- Bundled customers should not experience cost increases as a result of the implementation of a CCA program (Sections 365.2, 366.2(a)(4), and 366.3);
- Departed load should not experience cost increases as a result of an allocation of costs not incurred on behalf of the departed load (Sections 365.2, 366.2(a)(4) and 366.3); and
- Unavoidable electricity costs paid by CCA customers must be reduced by the value of benefits that remain with bundled customers, unless the CCA customers receive an allocation of a fair and equitable share of those benefits (Section 366.2(g).

These components of indifference are shown in Figure 1 below:

[25] AB 117 (Stats. 2002, ch. 838).
[26] Exh. CCA-1 at 4:21-23. DA/ESP customers are also Unbundled or Departed Load Customers.
[27] *Id*. at 4:23-24.

Figure 1: Statutory Indifference Requirements[28]



In addition, Sections 451 and 453 require the Commission to set just and reasonable rates, and to prohibit the IOUs from setting discriminatory rates.

The PCIA is the tool the Commission adopted consistent with the statutes referenced above "to equalize cost sharing" between these two groups of customers and ensure indifference.[29] Therefore, when customers of IOUs depart from bundled service and receive their electricity from a non-IOU provider, such as a CCA, "those customers remain responsible for costs previously incurred on their behalf by the IOUs — but only those costs."[30] Consistent with these indifference statutes, the PCIA also conveys to departed load customers the value of resource attributes retained by the IOU for bundled customers.[31]

B. How the PCIA Operates

PCIA rates are established to recover the IOU's above-market costs related to PCIA-eligible resources (Indifference Amount).[32] The Indifference Amount is the difference between

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28 *Id*. at 5:8-9.

29 *See* D.18-10-019, at 3; Exh. CCA-1 at 6:3-5.

30 *Scoping Memo and Ruling of Assigned Commissioner*, R.17-06-026 (Sept. 25, 2017), at 2; *see also* D.18-10-019, *Decision Modifying the Power Charge Indifference Adjustment Methodology*, R.17-06-026 (Oct. 11, 2018), at 3. *See* Exh. CCA-1 at 6:5-8.

31 Exh. CCA-1 at 6:8-9

32 *Id*. at 6:10-11.

the cost of the IOU's supply portfolio and the market value of the IOU's supply portfolio as demonstrated in Figure 2.[33]

Figure 2: Indifference Amount Calculation[34]

The PCIA tracks both: (a) the costs of resources; and (b) the value of the benefits provided by the IOUs' PCIA-eligible portfolios and retained by the IOU for bundled customers.[35] Since D.11-12-018, the value of the IOUs' supply portfolio has been derived from administratively determined proxy values that are intended to estimate the market value of the resource portfolio attributes: Energy Value, RPS Value, and Resource Adequacy (RA) Value.[36] These values are calculated by multiplying eligible resource output (quantities) by the relevant MPBs (prices).[37] Since 2019, the PCIA is "trued up." This true-up is meant to erase the difference between what one group originally paid another group (based on best forecasts available) and what that group should have been paid the other group (based on how reality turned out).

As part of the PCIA, each generation resource and customer is assigned a "vintage."[40] A distinct portfolio of generation resources is identified for each vintage year based on when a

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33 *Id*. at 6:11-13.
34 *Id*. at 6:14.
35 *Id*. at 6:16-18.
36 *See, e.g.*, D.11-12-018, at 9-10, Ordering Paragraph (OP) 5, OP 8; D.19-10-001, at 6 ("Market Value is the estimated financial value, measured in dollars, that is attributed to a utility portfolio of energy resources for the purpose of calculating the [PCIA] for a given year."). D.23-06-006 subsequently also required Energy Division to calculate a separate adder for Greenhouse-Gas Free (GHG-Free) energy. *See also* Exh. CCA-1 at 6:18-7:2.
37 Exh. CCA-1 at 7:2-3.
40 *Id*. at 7:4.

commitment to procure each resource was made.[41] Customers are assigned vintage years according to the date the customer departed bundled IOU service.[42] Customers continuing to receive bundled service from the IOU are included in the latest vintage (*e.g.*, bundled customers are currently vintage 2026).[43] An Indifference Amount is calculated for each vintage (summing portfolio costs and values), and all customers are responsible for the cumulative Indifference Amount for years prior to and including their vintage.[44] Thus, when a cost is included in a particular vintage, customers in that vintage and all later vintages are responsible for that cost.[45] Customers in prior vintages are not responsible for that cost.[46] Conversely, when a credit is attributed to a particular vintage, customers in that vintage and all later vintages receive the credit. Customers in prior vintages do not receive the credit.[47]

C. RPS-Eligible Resources Produce Value Through RECs the IOUs Use Immediately or Bank for Later RPS Compliance

RPS Value, as one of the components of IOU portfolio value, estimates the financial value attributable to RECs generated by PCIA-eligible resources and retained by the IOU for bundled customer RPS compliance obligations.[48] This RPS Value is determined by applying the RPS MPB to the quantity of RECs used by the IOU.[49] To the extent an IOU uses RECs to meet the needs of bundled customers, the PCIA design requires that bundled customers "purchase" departed load customers' share of the RECs to convey the value of the RECs to departed load

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41 *Id*. at 7:4-6.
42 *Id*. at 7:6-7.
43 *Id*. at 7:7-9.
44 *Id*. at 7:9-11.
45 *Id*. at 7:11-13.
46 *Id.* at 7:13.
47 *Id*. at 7:14-16.
48 *Id*. at 8:15-17 (citing D.19-10-001, at 6, 26; D.11-12-018, at 8, 10, Conclusion of Law (COL) 3).
49 *Id*. at 8:17-18. RPS Value may also include revenue received when the IOU's RECs are sold to third parties.

and ensure indifference according to California law.[50] That "purchase" is priced at the RPS MPB.[51]

The issue being considered in this Track Two arises from a unique characteristic of RECs, which makes them different from other generation resource attributes (*e.g.*, energy and RA): RECs can be banked and stored by the IOUs for later use.[52] This leads to the question of how and when value should be provided to unbundled customers for these RECs for which they pay but that the IOU stores for later use.[53]

Prior to 2019, bundled customers paid for the cost of IOU generation resources through generation rates, including RPS-eligible resources that generated RECs whether they were used for compliance in the year generated or banked for later use.[54] Departed load customers also paid for a share of these IOU generation resources on a vintaged basis through PCIA rates.[55] Each year, the IOUs would forecast the quantity of RECs from PCIA-eligible resources that would not be sold to third parties, and these RECs were valued in the PCIA for departed load customers using the RPS MPB in the year of generation.[56] The value was credited to the PCIA, providing a partial offset to the costs paid by then departed load customers.[57] In essence, all customers who were bundled customers *at the time the REC was generated* paid for RECs banked for later use.[58]

In 2019, the Commission refined D.11-12-018's requirements, deferring payment by bundled customers for banked RECs until they are used for compliance and, likewise, deferring

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50 *Id*. at 8:18-9:1.
51 *Id*. at 9:1-2.
52 Vol. 1 Tr. 30:9-14 (Joint IOU Panel [Brown, Morien, Pulgar]); Exh. CCA-1 at 9:3-5. *See* Cal. Pub. Util. Code § 399.13(a)(5)(B).
53 Exh. CCA-1 at 9:5-7.
54 *Id*. at 9:8-10.
55 *Id*. at 9:10-12.
56 *Id*. at 9:12-14.
57 *Id*. at 9:14-16.
58 *Id*. at 9:16-17.

compensation to departing load for those RECs until they are used for compliance.[59] These new requirements therefore recognized that customers do not realize the value of the IOUs' REC banks until those RECs are used for bundled customer RPS compliance (or sold):[60]

> Any of the offered [RPS resource] quantity that is not sold will be considered as Actual Unsold RPS and should not be assigned credit in PABA until the value of the RPS product, if any, is known. If previously unsold RPS is sold in a future year, it should be valued at the actual transacted price. If previously unsold RPS is used by the IOU for compliance in a future year, it should be valued at the applicable future year's RPS Adder [MPB]. If Unsold RPS is never used, it should not be assigned credit.[61]

The Commission therefore required the IOUs to treat banked RECs as Retained RPS when those banked RECs are later used for compliance for bundled customers.[62] This is reflected in the IOU accounting as charging bundled customers for the cost of those RECs at the then-current market value (*i.e.*, the RPS MPB) and including an offsetting credit in the PCIA.[63] This credit to the PCIA for the value of RECs compensates departed load customers for the value of their share of the RECs.[64] These refinements did not upset the original accounting for RECs generated before 2019.[65] They merely created a more granular accounting for such RECs, which, until recent years, had not been used for bundled customers' RPS compliance.[66]

D. The Four Relevant Customer Groups at Issue in This Proceeding

Four categories of customers exist in the context of Pre-2019 Banked RECs:

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59 *See generally* D.19-10-001.
60 *Id*., at 35.
61 *Id*., at 30.
62 Exh. CCA-1 at 10:8-9.
63 *Id*. at 10:9-12.
64 *Id*. at 10:12-13.
65 *Id*. at 10:13-14.
66 *Id*. at 10:14-16.

- **Then-Bundled Customers:** customers who were bundled *at the time the RECs were banked* (who are, today, both Current Bundled and Later Departing Customers);

- **Previously Departed Customers:** customers who had already departed *at the time the RECs were banked*;

- **Current Bundled Customers:** customers who are *currently* bundled and on whose behalf the banked RECs are now being used; and

- **Later Departing Customers:** customers who departed *after the RECs were banked* and no longer remain in the group of customers on whose behalf the RECs are now being used.[67]

Figure 3, below, demonstrates two of these categories of customers that existed *at the time the RECs were generated*:[68]

Figure 3: Customer Groups When Pre-2019 Banked RECs Were Generated[69]

Both Then-Bundled Customers and Previously Departed Customers *paid* for their share of the RECs when they were generated. Because Previously Departed Customers had paid the cost of their share of the RECs, but those RECs were retained by the IOU for bundled customers, Previously Departed Customers received a credit against their PCIA obligations for the value of their share of the RECs.[70] That credit was calculated using the value of the RPS MPB at the

67 *Id*. at 10:20-11:4, 13:3-8.
68 *Id*. at 11:3-4.
69 *Id*. at 11:5.
70 *Id*. at 11:7-11.

time.[71] These Previously Departed Customers therefore were fairly compensated for their share of the Pre-2019 Banked RECs and no longer have any claim to further value or allocation for those RECs.[72]

The benefits Then-Bundled Customers received at that time depended on whether the RECs were needed for compliance.[73] If the RECs were counted at that time toward Then-Bundled Customer compliance (*i.e.,* they were not banked), Then-Bundled Customers benefited immediately.[74] However, if the RECs were not needed at that time for bundled customer compliance, the IOUs placed the RECs in the 'bank' for later use.[75] Then-Bundled Customers received no credit at the RPS MPB at that time for the share of the RECs for which they paid.[76] Therefore, the *only customers that received a credit at the RPS MPB for the RECs for which they paid were Previously Departed Customers*.[77] The only 'value' provided to Then-Bundled Customers for banked RECs was the deferred ability to use the RECs at some future point.[78]

Figure 4 below provides a graphic illustration (in orange) of: (1) the immediate benefit to Previously Departed Customers when RECs were generated; and (2) the deferred benefit to Then-Bundled Customers when RECs were banked.[79]

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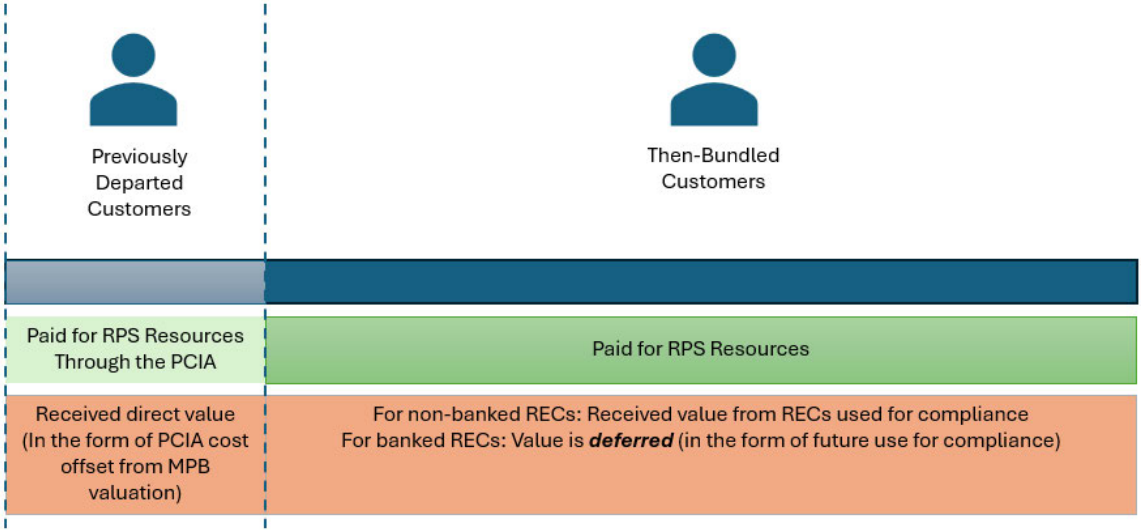
71 *Id*. at 11:11-12.
72 *Id*. at 11:12-14.
73 *Id*. at 11:15-16.
74 *Id*. at 11:16-17.
75 *Id*. at 11:18-19.
76 *Id*. at 11:19-12:1 (citing Exh. CCA-1, Attachment C [PG&E Response to CalCCA DR 3.04 and 3.05]).
77 *Id*. at 12:2-3.
78 *Id*. at 12:3-5.
79 *Id*. at 12:6-8.

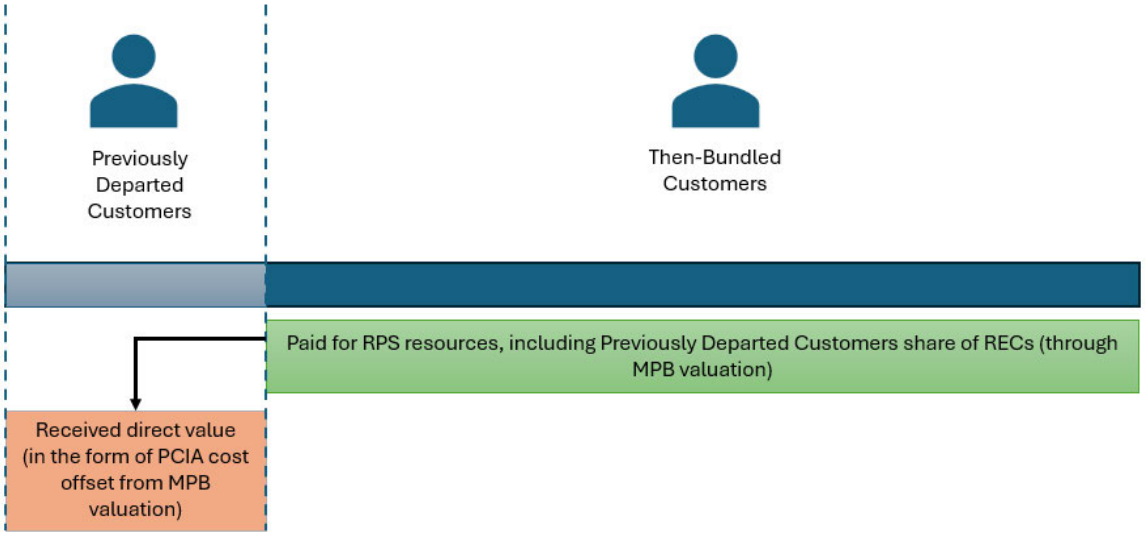
Figure 4: REC Benefit Conveyed to Customer Groups When RECs Were Generated and Banked[80]



In fact, Then-Bundled Customers paid for the value conveyed to Previously Departed Customers for the RECs retained by the IOU by virtue of the PCIA framework, as shown in Figure 5.[81]

[80] *Id*. at 12:9-10.
[81] *Id*. at 12:12-13.

Figure 5: REC Benefits Were Conveyed to Previously Departed Customers[82]



After the Pre-2019 Banked RECs were banked, some of the Then-Bundled Customers departed bundled service to be served by CCAs or ESPs (i.e., Later Departing Customers).[83] This split the category of Then-Bundled Customers in two, creating two further categories of customers: Current Bundled Customers and Later Departing Customers.[84] Current Bundled Customers are those customers that continue to take bundled service after the Later Departing Customers leave bundled service.[85]

Later Departing Customers paid for the Pre-2019 Banked RECs when they were Then-Bundled Customers, but upon their departure from bundled service were not paid for those RECs which remained in the bank, ready for future use.[86] These Later Departing Customers number in

82 *Id*. at 13:1-2.
83 *Id*. at 13:3-4.
84 *Id*. at 13:5-6.
85 *Id*. at 13:6-8.
86 *Id*. at 13:9-11.

the millions, constituting between 29 percent and 66 percent of customers in each IOU's service territory, depending on the IOU and the REC generation year.[87]

Recently, the Joint IOUs began to use Pre-2019 Banked RECs to meet their RPS compliance requirements for Current Bundled Customers, thus avoiding the purchase of additional RECs at current market prices.[88] In doing so, Current Bundled Customers receive the deferred value of the Pre-2019 Banked RECs.[89] However, Later Departing Customers still have not received *any* value for the Pre-2019 Banked RECs for which they also paid when they were Then-Bundled Customers—neither the 'avoided cost' value Current Bundled Customers enjoy nor the ability to use those banked RECs.[90] These Later Departing Customers will not otherwise receive any benefit when the IOUs use the RECs for Current Bundled Customer compliance needs.[91] Absent a credit to the PCIA or an allocation of these Pre-2019 Banked RECs, Later Departing Customers will not receive a share of the value of those RECs despite paying for them, as illustrated in Figure 6 below.[92]

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87 *Id*. at 13:11-14:2 (citing Exh. CCA-1 Attachment C [SCE response to CalCCA 3.14, PG&E response to CalCCA 3.14, and SDG&E response to CalCCA 3.14]. There is arguably a fifth category of customers within the pool of "Current Bundled Customers" who were Later Departing Customers that then returned to bundled service. They are a very small portion of customers.

88 *Id*. at 14:3-5.

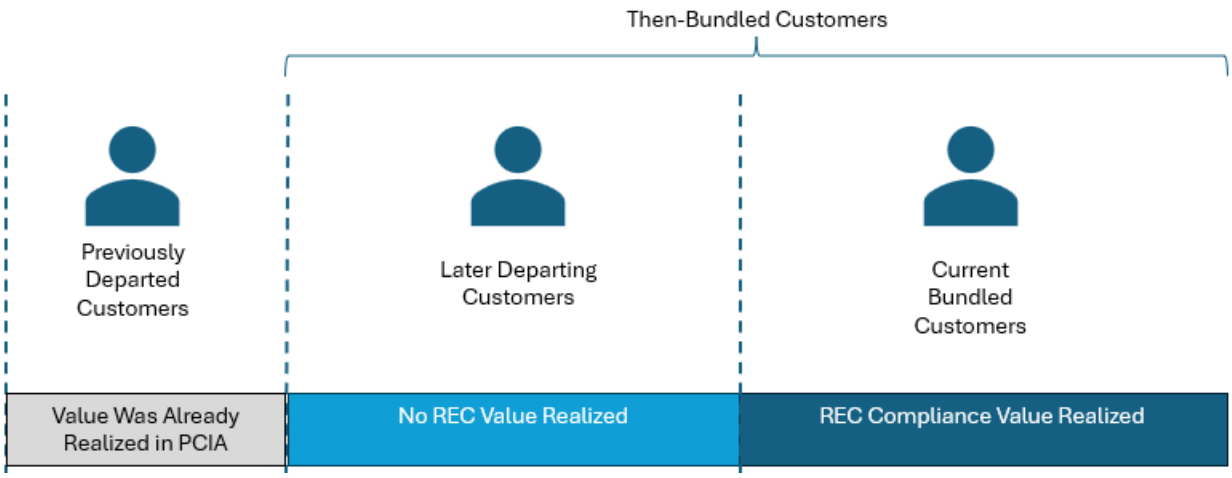
89 *Id*. at 14:5-6.

90 *Id*. at 14:6-9.

91 *Id*. at 14:9-11.

92 *Id*. at 14:11-13.

Figure 6: Customer Groups When Pre-2019 Banked RECs Are Later Used for Compliance[93]



IV. THE COMMISSION MUST ENSURE THAT CUSTOMERS WHO PAID FOR PRE-2019 BANKED RECS RECEIVE THE BENEFIT OF THOSE RECS

A. The Indifference Principle Requires the Commission to Ensure All Customers Who Depart IOU Service Still Receive the Benefit of the IOU-Owned Resources for Which They Pay

In this proceeding the Commission is considering resources paid for by both Later Departing Customers and Currently Bundled Customers before 2019. The Commission's task is to determine how to allocate the benefit of these Pre-2019 Banked RECs when the IOUs choose to take these resources out of the bank and use them for compliance purposes now. The only resolution that ensures indifference in compliance with section 366.2(g) is for *both* Later Departing Customers *and* Currently Bundled Customers to receive the associated benefits for the portions of the REC bank that they originally paid for. In other words, the Commission must ensure that neither customer group is given the unlawful windfall of the entire benefit of resources for which a share was paid for by the other customer group.

[93] *Id*. at 14:14-16.

Later Departing Customers paid for a portion of these RECs through generation rates prior to their departure when they were bundled,[94] but they never benefitted from those RECs. Instead, the RECs were banked for future use, meaning they were not used for compliance on Later Departing Customers' behalf when they were still bundled customers.[95] Furthermore, Later Departing Customers did not receive a reduction in their generation rates for the value of these RECs through a credit or any other mechanism.[96] Exhibit CCA-025 shows PG&E's witness in its 2026 ERRA Forecast case admitting as much:[97]

> Q Okay. So, Ms. Berry, let's now consider the customer who was bundled in 205 and has now departed since then.
>
> That customer would have paid for excess RECs in 2015, but would never have received a credit for that REC at the RPS benchmark; correct?
>
> A That is correct.
>
> Q And that customer -- the same customer -- would never have had that same REC retired on her behalf; is that correct?
>
> A That is correct. And that was also consistent

This clear admission demonstrates the key fact underlying the need for the Commission to act: Later Departing Customers paid for the Pre-2019 Banked RECs when they were generated; they

94 Vol. 1 Tr. 37:12-23; 39:5-41:1 (Joint IOU Panel [Brown, Morien, Pulgar]); Exh. CCA-25.
95 Vol. 1 Tr. 45:22-46:6 (Joint IOU Panel [Brown, Morien, Pulgar]).
96 Vol. 1 Tr. 47:23-48:12 (Joint IOU Panel [Brown, Morien, Pulgar]).
97 Exh. CCA-25.

have never benefitted from that payment; and, if the IOUs use the RECs for compliance without crediting Later Departing Customers for their value, they never will benefit.

At the Track Two hearing and in testimony, the Joint IOUs repeatedly sought to cloud the record on what should have been the simple question of whether both Previously Departed Customers and Then-Bundled Customers received a credit, *i.e.*, a reduction in cost responsibility, for the renewable energy that created the RECs when the RECs were generated, or if only Previously Departed Customers received that benefit.[98] Despite strong assertions otherwise—based almost entirely on semantics surrounding the word "credit"—the answer is that Then-Bundled Customers never saw a reduction in their cost responsibility on account of the value of the renewable energy that created the Banked RECs, but Previously Departed Customers did.[99]

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[98] The IOUs assert that the generation rates paid by Then-Bundled Customers took into account the value of the RECs *indirectly* because their rates included the anticipated revenue from customers that at the time were paying PCIA rates. *See* Vol. 1 Tr. 42:7-10 (Joint IOU Panel [Brown, Morien, Pulgar]) ("[B]undled service customers paid less because departing load customers had to contribute their above-market costs, which did include the above-market RPS adder."); 42:22-24 (Joint IOU Panel [Brown, Morien, Pulgar]) ("Bundled generation rates were set to include the reduction that we expected to receive from departing load customers' PCIA revenue.").

[99] *See* Vol. 1 Tr. 23:4-12; 41:10-45:21; Exh. JIOU-1 at 9, Fig. III-2. A share of the above-market costs in the IOUs' PCIA-eligible portfolio were recovered from Previously Departed Customers through PCIA rates, and the rest of the cost of the portfolio was recovered from bundled customers through their ERRA generation rates. To calculate those PCIA rates, the Commission compared the cost of an IOUs' PCIA-eligible portfolio to the market value of that portfolio, with the difference constituting the above-market costs of the IOUs portfolio. One component of the market value was the value of the forecasted renewable energy to be generated that year, calculated as a forecasted quantity of renewable energy multiplied by the then-applicable RPS MPB. Since the market value reduces the costs recovered via the PCIA, another way of stating the impact would be to say that Previously Departed Customers' PCIA rates included a credit for the value of the forecasted renewable energy. Reducing ERRA generation rates by the amount of PCIA revenue departed customers would provide is just an acknowledgement that Previously Departed Customers helped cover the cost of the IOUs' above-market costs when the RECs were generated. The fact those rates included a credit from the PCIA only shows *Previously Departed Customers* enjoyed a benefit from the RECs; it does not show that any other customers, including Later Departing Customers, enjoyed a benefit. There certainly was no direct recognition of the value of the RECs in Then Bundled Customers ERRA generation rates in the year they were generated. The simple example in Exh. CCA-01, Attachment A, of CalCCA Witness Dickman's direct testimony, better demonstrates how each customer group is treated in the relevant timeframes.

Later Departing Customers—who were Then Bundled Customers at the time the RECs were banked—therefore have not received a "credit" or reduction in their PCIA obligation. Instead, they paid for the RECs at the same generation rate as Currently Bundled Customers. The RECs were simply put on the shelf to be used at a future date, but the Later Departing Customers departed before the RECs were used for compliance. Today the IOUs seek to use the RECs for RPS compliance on behalf of their bundled customers. The question the Commission must address is how to value these RECs to ensure that *all* customers that paid for the RECs receive their share of the benefit.

B. To Achieve Indifference, the Commission Must Determine and Provide Later Departing Customers Their Share of the Appropriate Value of the Pre-2019 Banked RECs

1. The Commission Should Value Pre-2019 Banked RECs at the Compliance Year RPS MPB and Credit that Value to the Generation Year's Customer Vintage

As noted above, one of the methods Section 366.2(g) directs the Commission to ensure indifference is by providing CCA customers the *value* of benefits remaining with bundled service customers:

> Estimated net unavoidable electricity costs paid by the customers of a community choice aggregator shall be reduced by ***the value of any benefits that remain with bundled service customers,*** unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits.[100]

The Commission can accomplish its indifference mandate in this case by using a relatively simple process that PG&E already used multiple times to allocate the value of Pre-2019 Banked RECs.[101] Namely, the Commission should value these Pre-2019 Banked RECs at the RPS MPB

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[100] Cal. Pub. Util. Code § 366.2(g) (emphasis added).

[101] Exh. CCA-01 at 31:8-32:5; Exh. CCA-03 at 19:14-20:14; Vol. 1 Tr. 103:3-105:5 (Joint IOU Panel [Brown, Morien, Pulgar]) (demonstrating PG&E's past valuation of Pre-2019 Banked RECs at the

for the year in which the RECs are used for compliance, and should credit the value for these RECs to the customer vintage corresponding to the RECs' generation year. In other words, if a REC was generated in 2015, the credit is placed in that vintage year; customers who departed in 2016 and thereafter will receive their proportionate share of the credit.

When the IOUs use Pre-2019 Banked RECs to comply with RPS obligations, the value of these banked RECs is best calculated by identifying the avoided cost of alternate RPS-compliance attributes that the IOUs would have needed to purchase absent the availability of the Pre-2019 Banked RECs.[102] These purchases would have occurred in the market,[103] and the RPS MPB in the compliance year is a proxy value that best estimates that avoided cost.[104] Crediting this value to the customer vintage year in which the REC was banked takes advantage of the 'vintaging' feature of the PCIA and allocates appropriate costs and values to the relevant customer groups.[105] Because of the way PCIA vintaging works, this credit will avoid double compensating or double charging any of these groups.[106] The vintaging process will proportionately spread out the benefits of those RECs to the customer vintages who paid for them.[107] Using this methodology is the only just and reasonable outcome, and it is the only outcome that ensures there is no unlawful discrimination against customers or classes of customers.

CalCCA Witness Dickman provides a numerical example reproduced in Table 1, below, to illustrate how the vintage-specific credit works. In the example, the value of the RECs banked

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compliance year RPS MPB and crediting that value to the RECs' generation year vintages, in the same manner as CalCCA's proposal in this proceeding).

102 Exh. CCA-01 at 21:10-13.

103 *Id*.

104 *Id*. at 28:12-17.

105 *Id*. at 29:1-6.

106 *Id*. at 30:13-31:4.

107 *Id*. at 29:1-6; 30:19-31:1.

in 2015 is $6 million in 2026.[108] To accomplish indifference, Later Departing Customers should be given a credit of $3.6 million in exchange for their 60 percent share of the REC bank (60,000 megawatt hours (MWh) * $60/MWh).[109] Crediting the total value of the 2015 banked RECs (*i.e.*, $6 million) to resource vintage 2015 results in this $3.6 million returning through PCIA rates to Later Departing Customers (who departed bundled service between 2015 and 2025).[110]

Table 1: PCIA Rate Impact of Vintage-Specific Credit[111]

PCIA Template (Simplified)																
Vintage	UOG Legacy	2009	# # # # #	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Cost of Portfolio ($000)																
Market Value of Portfolio ($000)																
RPS Value				($6,000)												($6,000)
Indifference Amount	$0	$0	# # # # #	($6,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($6,000)
IOU System Sales by Vintage (GWh)	70,000	70,000		63,000	59,564	56,127	52,691	49,255	45,818	42,382	38,945	35,509	32,073	28,636	25,200	
PCIA Rates	-	-		(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	
Value to Bundled Load															($2,400)	($2,400)
Value to Later Departed Load	$0	$0	# # # # #	($327)	($327)	($327)	($327)	($327)	($327)	($327)	($327)	($327)	($327)	($327)		($3,600)
Total Banked REC Value ($000)	**$0**	**$0**	**# # # # #**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($2,400)**	**($6,000)**

Current Bundled Customers are able to use the banked RECs and end up paying $0 for their share of these RECs.[112] This is fair because they originally paid for these RECs, and therefore no double payment for the RECs will occur.[113] The PCIA vintaging process will drop $2.4 million back into the pockets of Current Bundled Customers (seen in the 2026 vintage column in Table 1) precisely to offset the $2.4 million value of their portion of the REC bank (40 percent of the $6 million flowed through the PCIA).[114] They therefore end up paying $0 for the use of their 40 percent of the banked RECs.[115]

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108 *Id.* at Attachment A-3.

109 *Id*. at Attachment A-3.

110 *Id*. at Attachment A-4.

111 *Id*. at Attachment A-4. Note that this example assumes customers depart at a linear rate although the model would work for any rate of customer departure.

112 *See id*. at Attachment A-3 – A-4.

113 *See id*. at Attachment A-2 – A-4.

114 *Id*. at Attachment A-4.

115 *See id*. at Attachment A-4.

This allocation treats all customers fairly and ensures three things. *First*, Later Departing Customers receive their share of the benefit for the RECs for which they originally paid when the RECs are pulled out of the bank and used for compliance. In the above example, these customers receive the current value of 60 percent of the 2015 banked RECs.[116]

Second, Current Bundled Customers receive a proportionate credit for the portion of the RECs for which they initially paid. In the above example, Current Bundled Customers receive their 40 percent of the 2015 banked RECs for which they paid in 2015 without having to pay for them again.[117] Overall, Current Bundled Customers purchased their share of the banked RECs in 2015 (40,000 MWh), and purchased Later Departing Customers' share of the banked RECs in 2026 (60,000 MWh) because they are using them solely for Current Bundled Customer compliance. Third, Previously Departed Customers receive nothing in 2026—no true up, no 'double payment' for RECs, and no reopening or reconsideration of generation rates paid a decade ago.[118]

2. The Commission Could, in the Alternative, Allocate the Pre-2019 Banked RECs to CCA Customers

In the alternative, the Commission could utilize section 366.2(g)'s "allocation" option to achieve indifference regarding the IOUs' use of Pre-2019 Banked RECs:

116 *Id*. at 29:1-3.

117 *Id*. at 29:3-5. As **Table 1** demonstrates, the PCIA vintaging process deposits a credit that is designed to precisely offset any debit for these RECs.

118 *Id*. at 29:5-6.

> Estimated net unavoidable electricity costs paid by the customers of a community choice aggregator shall be reduced by the value of any benefits that remain with bundled service customers, ***unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits***.[119]

To achieve indifference using this pathway, the Commission would require the IOUs to proportionately allocate Pre-2019 Banked RECs to the customers who paid for these RECs via a decrement to the applicable LSE's RPS Procurement Need.[120] This allocation would use the same proportions as CalCCA's valuation proposal described *supra* (*i.e.,* based on the proportions of RECs for which Later Departing Customers and Currently Bundled Customers originally paid).[121]

For the allocation, the IOU would determine how many Pre-2019 Banked RECs it needs to use in a particular year.[122] Then, the IOU would determine the proportional amount of Pre-2019 Banked RECs to allocate to Later Departing Customers.[123] For example and as set forth in Witness Dickman's testimony, if the IOU wants to use 10,000 MWh of 2015 banked RECs in 2026, it would identify an additional 15,000 MWh of 2015 banked RECs to allocate ((reflecting the 40 percent Current Bundled and 60 percent Later Departing Customer split).[124] The IOU would therefore end up using 25,000 MWh of its total 100,000 MWh of 2015 banked RECs for compliance, but would allocate 15,000 MWh of those RECs to the LSEs that serve those customer vintages.[125] These 15,000 MWh of RECs would be allocated to vintages using the PCIA vintaging tool in a similar manner as the valuation proposal discussed *supra*.[126] Then each

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119 Cal. Pub. Util. Code § 366.2(g) (emphasis added).
120 Exh. CCA-03 at 22:6-8.
121 Exh. CCA-01 at 23:12-24:2.
122 *Id*. at 21:23-22:2; 23:14-24:6.
123 *Id*. at 23:12-24:6.
124 *See id*. at 23:14-24:6 (using the same proportion by different absolute values of MWhs).
125 *Id*. at 24:2-5.
126 *Id*. at 21:23-22:2.

vintage would be allocated to the various LSEs serving customers in that vintage proportionate to their vintage load.[127] This allocation would reduce those LSEs' RPS compliance needs.[128]

The allocation of these RECs would benefit the Later Departing Customers who originally paid for the RECs as follows. Later Departing Customers would benefit by a decrease in their LSEs' RPS compliance needs (in the example above by 15,000 MWh total).[129] The IOU compliance need would then be increased by the same amount (in the example above, this would increase the RPS compliance need by 15,000 MWh so that the 25,000 MWh used from the bank would result in a total RPS compliance impact of -10,000 MWh).[130] Ownership of the REC would never be transferred to another LSE.[131] The IOU would simply have to use more of the RECs in its WREGIS retirement account to meet its compliance need.[132] The increase would directly correspond to the decrease in RPS procurement need for the CCA or ESP.[133] The precise amount of RECs used would be determined in the IOUs' annual ERRA Forecast proceedings based on each IOUs' forecasted need to use Pre-2019 Banked RECs.[134] The Commission could implement these changes with simple offsetting adjustments to the Excess Procurement Bank quantities on the relevant LSEs' RPS Compliance Reporting Template.[135]

The Commission has used a similar method of allocation for Resource Adequacy (RA) allocation for the Cost Allocation Mechanism (CAM) in the Commission's RA compliance

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127 *Id*. at 24:2-4.
128 Exh. CCA-03 at 22:6-8.
129 *See id*. at 22:6-8.
130 Exh. CCA-02 at 23:4-6; Exh. CCA-01 at 23:14-24:2 (using the same proportions but different absolute quantity).
131 Exh. CCA-03 at 22:21-23.
132 *See* Exh. CCA-01 at 23:14-24:2.
133 Exh. CCA-03 at 22:6-8.
134 *Id*. at 23:1-4.
135 *Id*. at 23:1-14.

program.[136] RA capacity is similar to RPS compliance in that LSEs must demonstrate to the Commission that they have procured enough RA capacity per compliance period.[137] Under the Commission's CAM framework, "when the IOU procures a resource on behalf of bundled and unbundled customers (as directed by the Commission), each LSE in the IOU service territory is allocated a load ratio share of the RA provided by the resource."[138] However, the IOU *still retains ownership* of the allocated RA portion.[139] The Commission accounts for the fact that the RA is meant to count towards the other LSEs' RA compliance obligation by raising the IOU's RA requirement an equal amount and reducing the other LSEs' RA requirement by their allocated share of the CAM resources.[140]

This proposal also complies with the laws governing California's RPS statutes. Specifically, section 399.15(b)(2) requires the Commission to:

> [E]stablish the quantity of electricity products from eligible renewable energy resources to be procured by the retail seller for each compliance period. These quantities shall be established in the same manner for all retail sellers and result in the same percentages used to establish compliance period quantities for all retail sellers.[141]

Under CalCCA's allocation proposal the Commission will not change the manner in which the relevant quantities are established, or the fact that resulting quantities "result in the same percentages used to establish compliance period quantities."[142] The Commission has already "establish[ed]" the required RPS compliance minimums in D.19-06-023 and the resulting

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136 Exh. CCA-01 at 22:6-8. The Commission also allocates Diablo Canyon Power Plant capacity in a similar manner. D.23-12-036 at OP 9, COL 42; D.24-12-033 at 54-55.
137 Exh. CCA-01 at 22:8-9.
138 *Id*. at 22:9-12.
139 *Id*. at 22:12-13.
140 *Id*. at 22:12-15.
141 Cal. Pub. Util. Code § 399.15(b)(2)(A).
142 *Id*.

percentages, and CalCCA's proposal does not change that fact that these were established and remain unchanged.

CalCCA's proposal would operate, instead, as an adjustment to the Excess Procurement Bank quantities found in the LSEs' RPS Compliance Reporting Templates.[143] Under section 399.13, the Commission has authority to set rules governing LSE use of their REC banks. Section 399.13 empowers the Commission to create rules "permitting retail sellers to accumulate, beginning January 1, 2011, excess procurement in one compliance period to be applied to any subsequent compliance period."[144] The allocation proposal would simply adopt the following rule applicable to all LSEs: to the extent an LSE retains RECs in their banks previously paid by other customer groups, they should allocate those RECs to the other customer groups through offsetting adjustments to their respective Excess Procurement Banks.[145]

3. If the Commission Rejects These Two Proposals, the Commission Could Adopt the Staff Report's Suggestion to Value Pre-2019 Banked RECs at their Compliance Value

The Staff Report concludes that "CalCCA makes a compelling argument that departed customers paid for a portion of these RECs[.]"[146] =With that principle established, section 366.2(g) requires the Commission to achieve indifference by providing the value of the benefits from those payment back to departed customers. Therefore, the commission should value the Pre-2019 Banked RECs at the compliance year RPS MPB and credit that value to the customer vintage of the year in which the RECs were generated. Section 366.2(g) also allows allocation as discussed above.

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143 *See* Exh. CCA-03 at 23:1-4 (citing Final 2023 RPS Compliance Report Templates available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps/rps-compliance-rules-and-process/rps-compliance-and-reporting.)

144 Cal. Pub. Util. Code § 399.13(5)(B).

145 *See id*. ("The rules shall apply equally to all retail sellers.").

146 Staff Report at 8.

However, if the Commission decides *not* to use the methodologies recommended by CalCCA, any alternative valuation methodology still must be grounded in the compliance value of those RECs (*i.e.,* the IOUs' avoided cost).[147] The Staff Report acknowledges that these Pre-2019 Banked RECs *have* compliance value even if their market value is debated.[148] The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) have also concluded that "Pre-2019 Banked RECs should not be valued at zero dollars because they clearly provide some quantifiable compliance value to ratepayers."[149] Per Cal Advocates:

> Pre-2019 Banked RECs can be used to meet LSEs' RPS compliance obligations and therefore provide value to ratepayers when used. Like PCC 3 RECs, Pre-2019 Banked RECs are unbundled from energy and do not contribute to an LSE's Power Content Label. However, like PCC 1 RECs, Pre-2019 Banked RECs can be used indiscriminately to meet LSE RPS obligations. The Commission should consider valuing Pre-2019 Banked RECs based on the attributes they share with PCC 1 and PCC 3 RECs.[150]

Lastly, the Joint IOUs also agree that "[t]he purpose of the REC is to demonstrate RPS compliance."[151] Therefore, if the Commission determines Pre-2019 Banked RECs should not be valued or allocated as discussed *supra*, the RECs should be valued using the following formula that generally aligns with Cal Advocates' recommendation:

Pre-2019 Banked REC Price = (RPS MPB × 90%) + (PCC 3 Market Price × 10%)[152]

Using this methodology, 90 percent of the value would be based on the current-year RPS MPB (*i.e.,* the best available proxy for PCC 1 REC prices) and 10 percent would be based on a

147 Exh. CCA-03 at 24:15-18.
148 *Id*. (citing Staff Report at 8).
149 *Reply Testimony of Cal Advocates on Track Two of the Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes*, R.25-02-005 (Mar. 23, 2026), at 7.
150 *Id.* at 8 (internal citations omitted).
151 Vol. 1 Tr. 28:24-25 (Joint IOU Panel [Brown, Morien, Pulgar]).
152 Exh. CCA-03 at 25:9-13.

current-year PCC 3 market price, reflecting the maximum share of RPS compliance that can be satisfied with PCC 3 RECs under California statute.[153] The IOUs would use this calculation to determine the value of the Pre-2019 Banked RECs they use for compliance, and use the same vintage-specific PCIA credit methodology discussed *supra* in Section IV.B.1.[154] The resulting value reflects the "blended avoided cost of IOU market procurement foregone by using Pre-2019 Banked RECs."[155] The IOUs can use up to 10 percent of PCC 3 RECs for compliance,[156] and those PCC 3 RECs generally trade at a lower price than PCC 1 RECs.[157] This 90/10 weighing thereby acknowledges that IOUs have "some amount of flexibility to rely on PCC 3 RECs, subject to statutory limits, rather than only procuring PCC-1 RECs to meet RPS compliance requirements."[158] This weighting also recognizes that: (1) Pre-2019 Banked RECs can function as PCC-1 RECs for IOU compliance; and (2) (consistent with Staff's and Cal Advocates' observations) Pre-2019 Banked RECs lack certain attributes of standard tradeable PCC-1 RECs.[159]

The Commission currently does not have a PCC-3 market price benchmark. However, this could be determined through the same LSE survey process Energy Division uses to calculate the RPS MPB, drawing on existing transaction data already collected as part of that process.[160] In the near term, if Energy Division determines that sufficient PCC 3 transaction data is not available to produce a reliable market price, the PCC 3 price component could conservatively be

153 *Id*. at 25:14-17.
154 *Id*. at 25:17-19.
155 *Id*. at 25:20-21.
156 *Id*. at 25:14-17.
157 Vol. 1 Tr. 145:18-20, 151:2-6 (Dickman); Exh. JIOU-05.
158 Exh. CCA-03 at 25:25-26:3.
159 *Id*. at 25:21-25.
160 *Id*. at 26:4-6.

set to zero, effectively reducing the formula to 90 percent of the current-year RPS MPB until a more robust data set is available.[161]

While CalCCA recommends valuation of the Pre-2019 Banked RECs at the RPS MPB to ensure indifference among bundled and unbundled customers is achieved, to the extent the Commission seeks alternative methodologies it could either allocate the benefits, or base the benefits on the 90/10 PCC-1 and PCC-3 valuation method discussed herein. In all events, any valuation methodology adopted by the Commission in this proceeding must recognize the compliance value of Pre-2019 Banked RECs to ensure indifference.[162]

V. AMENDED SCOPING RULING ITEMS

A. CalCCA's Proposal to Value Pre-2019 Banked RECs at the Market Price Benchmark is Consistent with Law and Precedent (Amended Scoping Ruling Issue 1)[163]

1. The Indifference Principles in Sections 365.2, 366.2, and 366.3 and Prior Commission Decisions Require Later Departing Customers to Receive Either a Credit for the IOUs' Use of Pre-2019 Banked RECs or an Allocation of a Fair and Equitable Share of the Benefits of Pre-2019 Banked RECs (Issue 1.a)

a. California Law Requires the Commission to Ensure "Indifference"

As noted above, California law requires the Commission to ensure indifference in the context of retail choice. Sections 365.2, 366.2, and 366.3, read in concert, [164] create a "two-way

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[161] *Id*. at 26:6-9.

[162] Vol. 1 Tr. 52:18-53:2 (Joint IOU Panel [Brown, Morien, Pulgar]); Exh. CCA-03 at 26:10-11.

[163] Issues referenced in subtitles of this Section refer to the Issues set forth in the Amended Scoping Ruling.

[164] While CalCCA believes there is no conflict between the statutory instructions in §§ 365.2, 366.2, and 366.3, the IOUs seek an outcome that completely reads out § 366.2(g)'s clear language (requiring departing load to receive the value of benefits that remain with bundled load or an allocation of those benefits). This would violate the Commission's responsibility to, assuming there exists a conflict between two statutory mandates, attempt to harmonize the statutes and best give effect to both. *See San Mateo City School Dist. v. Public Employment Relations Bd.* (1983) 33 Cal.3d 850, 865 (holding the agency "reasonably construe[d]" a statute "in harmony with … existing sections of the Education Code" because "[t]his … is the correct approach when several provisions of state law address a similar subject."); *see*

street" of indifference that is intuitively just, reasonable, and non-discriminatory as required by Sections 451 and 453. On the one hand, an IOU bundled customer should not be disadvantaged by another customer's decision to depart for another LSE.[165] The departed customer must continue to pay for costs incurred on their behalf when they were bundled. On the other hand, departed customers should not be required to pay for "avoidable" costs and costs not incurred on their behalf. In addition, in return for their payments, departed customers must receive either the value or allocation of the benefits remaining with bundled customers.[166] In other words, the indifference statutes were adopted to protect *both* bundled and unbundled customers.

b. CalCCA's Pre-2019 Banked REC Proposal is Consistent With the Statutory Indifference Framework

CalCCA's Pre-2019 Banked REC proposal is consistent with the statutory indifference framework. Pre-2019 Banked RECs "remain" with bundled customers when customers depart. Bundled Customers benefit when the IOUs use the banked RECs for their RPS compliance. The use of these RECs for compliance permits the IOU to avoid purchasing additional RECs on the market. Section 366.3 permits customers to be charged for the costs of *their* RPS compliance. The IOUs are obligated to meet their RPS compliance minimums while conveying to departed load the "value" of "benefits" that "remain[]" with bundled customers.[167] Bundled customers have the obligation to pay the costs necessary to meet the RPS obligations. Bundled customers pay for RPS generation or pay for RECs purchased through PPAs, and—if the RECs they paid

also D.03-06-074, *Order Denying Reh'g of D.02-09-053*, R.01-10-024 (June 24, 2003), at 11 ("Conflicting statutes must be harmonized, if at all possible, giving effect to both statutes in order to implement legislative purpose.")

165 *See* Cal. Pub. Util. Code § 366.3.

166 Cal. Pub. Util. Code § 366.2(g).

167 *See id*.

for are not enough—these customers either pay for the procurement of additional RECs from the market or they must pay to use the RECs originally paid for by now-departed customers.[168]

The IOUs attempt to portray this latter payment as a "cost increase" under the terms of sections 366.3 or 365.2 would permit bundled load to keep and use RECs that were paid for by departed load without providing any benefit to that departed load (in violation of section 366.2(g)). This interpretation is non-sensical and—if true—would render the concept of indifference meaningless and improperly read out language from section 366.2(g). Under this reading of section 366.3, any reduction in the PCIA for the "value of any benefits that remain" (required by 366.2(g)) is mechanically a "cost increase" and therefore unlawful. The PCIA is not, and cannot be, a "finders-keepers" methodology: bundled customers who 'keep' the RECs (by using them for RPS compliance) do not suffer a "cost increase" if they are made to pay departed load for the RECs (paid for by departed load) that they 'find'.

CalCCA's alternate proposal to allocate Pre-2019 Banked RECs when IOUs seek to use them for compliance (as is permitted by 366.2(g)) further demonstrates why this is not an increase in costs. Under such an allocation, Later-Departed Customers receive the RECs they paid for, and would receive the same proportion (as an allocation) that CalCCA proposes to value.

c. Past Decisions Did Not and Could Not Prevent from Accomplishing Statutory Indifference

The IOUs have argued that past ERRA decisions, including D.11-12-018, D.18-10-019, and D.19-10-001 have ratified their proposal to deny departed load any value for these RECs by valuing them at $0.[169] However, to the extent these ERRA decisions did approve the IOUs'

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168 Vol. 1 Tr. 28:4-21 (Joint IOU Panel [Brown, Morien, Pulgar]).

169 Exh. JIOU-01 at 27:22-28:4.

proposal, they were clearly interim solutions until the Commission could properly address this issue in another rulemaking. The Decisions explicitly state that the determination was interim, declining the IOUs' invitations to convert them into unconditional statements of permanent binding policy.[170] In last year's ERRA Forecast Decisions, the Commission explicitly stated that Pre-2019 Banked REC valuation would be considered in a future rulemaking.[171]

The IOUs have also argued that the Commission's past rulemaking decisions (and statements made by parties in working groups during past rulemakings) are binding in this case. That is incorrect. The Commission has noted that this issue was not conclusively resolved by prior decisions.[172] Even if these decisions did "resolve" the issue, the Commission is not bound by its prior decisions, especially if it determines those decisions did not comply with the indifference statutes.[173] Finally, past statements, or even alleged non-statements, from members of past working groups[174] are not relevant to the ultimate question before the Commission: how should the Commission value Pre-2019 Banked RECs in the PCIA to best achieve indifference and its other policy objectives?

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170 D.25-12-028, *Decision Approving Southern California Edison Company's 2026 Energy Resource Recovery Account-Related Revenue Requirement Forecast*, A.25-05-008 (Dec. 18, 2025), at 111-113, COL 14 ("interim"); D.25-12-027, *Decision Approving Pacific Gas and Electric Company's 2026 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2026 Electric Sales Forecast*, A.25-05-011 (Dec. 18, 2025), at FOF 15 ("on an interim basis for the purpose of this decision"); D.24-12-039, *Decision Approving Southern California Edison Company's 2025 Energy Resource Recovery Account-Related Forecast Revenue Requirement*, A.24-05-007 (Dec. 19, 2024) at 68 (approving treatment *"*for this proceeding"); D.24-08-004, *Decision Denying Petition for Modification of Decision 23-06-006*, R.17-06-026 (Aug. 1, 2024), at 5 (denying SCE's Petition for Modification and saying the Commission "may consider the issue in a future rulemaking"); D.23-11-094, *Southern California Edison Company's 2024 Energy Resource Recovery Account Forecast*, A.23-06-001 (Nov. 30, 2023), at 60 ("interim").

171 D.25-12-028, COL 15; D.25-12-027, OP 5-6.

172 *See* D.25-12-028, at 111-112 (discussing disputed language in D.19-10-001 and subsequent decisions).

173 D.21-06-042*, Order Denying Rehearing of Decision 20-08-045,* (A.18-06-015) (June 24, 2021), at 5 (citing *Postal Telegraph-Cale Co. v. Railroad Com. of Cal.* 197 Cal. 426, 436 (1925); section 1708).

174 *See* Exh. JIOU-01 at 13:20-19:13; Exh. JIOU-02 at 15:3-17:4.

2. Valuing Pre-2019 Banked RECs Used for Compliance in a Later Year at the MPB for That Compliance Year is Just and Reasonable, and Does Not Cause Unreasonable or Unjust Downstream Consequences (Issue 1.b)

CalCCA's proposal also meets the just and reasonable standard under section 451 because it fits within the statutory indifference framework. The proposal leaves all relevant groups of customers—Previously Departed Customers, Later Departing Customers, and Current Bundled Customers[175]—as having paid for Pre-2019 Banked RECs *one time* and having received the benefit from those RECs *one time*. The best proxy for the value of a banked REC used for compliance in a particular year is the RPS MPB, which approximates the avoided cost of procuring additional PCC-1 RECs (*i.e.*, the original categorization of the banked RECs), in the market. Any other proposal—especially one that values Pre-2019 Banked RECs at zero dollars—leaves a group of customers who paid for a resource without a reasonable benefit from that resource: a clear unjust and unreasonably discriminatory result.

The record shows the IOUs exaggerate their claims of CalCCA's proposal causing significant impacts to bundled customer affordability, over-tightening of the RPS market, and enormous obstacles to the IOUs optimizing their portfolios and meeting renewable energy goals. Equally specious is the Joint IOUs "Back to the Future" counterfactual argument that the Commission would not have adopted VAMO in 2021 if Pre-2019 Banked RECs were valued at the RPS MPB today.

As set forth below, the near-term rate impacts from CalCCA's proposal on bundled customers are tiny and, in some cases, non-existent. The claimed impacts to the RPS market—which will only occur if certain market factors exist—would be muted in the short-term and

[175] As a reminder, the fourth group discussed *supra*, Then-Bundled Customers, split into two of these groups (Later Departing Customers and Current Bundled Customers).

avoidable over the long-term. And the VAMO decision on which the IOUs rely does not support their reasoning that the Commission relied on a zero valuation of REC banks to determine the utilities were long.

The uncertain *potential* for downstream consequences for one group of LSEs should not outweigh the *certainty* of an existing cost shift from one customer group to another. Setting rates that fail the statutory indifference standard because one group of LSEs *may* have sold themselves short violates section 451.

a. The IOUs' Own Numbers Show CalCCA's Proposal Has *De Minimis* Near-Term Impacts on Bundled Customer Affordability

The best evidence at hand regarding the direct, near-term impacts of CalCCA's proposal is evidence from the IOUs recently filed 2027 ERRA Forecast cases.[176] However, these cases demonstrate that CalCCA's Proposal would have *de minimis* ratepayer impacts. SDG&E currently does not forecast using any Pre-2019 Banked RECs in 2027:[177]

[176] Vol. 1 Tr. 63:10-22 (IOU panel [Brown, Morien, Pulgar]).
[177] Vol. 1 Tr. 68:15-70:11 (Morien).

[
Ms. Morien, do you agree that the impacts on customers' rates in the RPS market would be seen in the IOUs' ERRA forecast cases?

WITNESS MORIEN: Yes, that's -- I agree.

Q And then do you agree that SDG&E does not anticipate using any pre-2019 banked RECs to meet its RPS obligations in 2027?

A That is what our 2027 ERRA forecast testimony says, yes.
]

As a result, there currently are no impacts from CalCCA's proposal in SDG&E's service territory since, as SDG&E's Witness Morien admitted during hearing, zero RECs multiplied by any RPS MPB would be a net impact of zero dollars.[178]

PG&E's service territory currently sees the largest impact to its bundled customers in 2027, but even there the maximum impact is *de minimis* since the IOU only forecasts using [redacted] in 2027, or less than [redacted] of its total stockpile of Pre-2019 Banked RECs.[179] Even at the level of an RPS MPB of $62.45/MWh, that forecasted usage results in a net charge to bundled customers of only [redacted]/kilowatt-hour (kWh) in 2027.[180] For a customer using 500 kWh, that is a monthly bill impact of [redacted] to ensure all customers receive a benefit for the

178 Vol. 1 Tr. 73:1-6 (Morien).

179 Exh. CCA-18 and Exh. CCA-18C.

180 Exh. CCA-18 and Exh. CCA-18C. The reason it is a "net charge" is that only a portion of the Pre-2019 Banked RECs would require compensation to Later Departing Customers under CalCCA's proposal. Some of those RECs were paid for by Then-Bundled Customers who remain bundled today and there is no additional net cost to Current Bundled Customers for these RECs under CalCCA's proposal. Current Bundled Customers are in the IOUs' most recent customer vintage, and CalCCA's proposal will ensure they receive value of the proportion of RECs they already paid for. *See* Exh. CCA-01 at 7:4-16.

RECs for which they paid.[181] If the RPS MPB was instead $12/MWh, the net charge to bundled customers would decrease to [redacted]/kWh in 2027, with a paltry monthly bill impact of [redacted][182]

While SCE was unwilling to answer questions on this issue in response to discovery,[183] or at hearing,[184] simple math makes clear the impacts in its service territory would be a fraction of those in PG&E's service territory.[185] [redacted][187] With an RPS MPB of $12/MWh, that impact would shrink to [redacted]/kWH and [redacted] per month. In other words, there essentially would be no impact.

While the IOUs forecasted use of Pre-2019 Banked RECs will be updated in October, there is good reason to believe these are the *maximum* rate impacts bundled customers would see in these service territories in 2027, all other factors equal. [redacted]

181 Exh. CCA-18 and Exh. CCA-18C.

182 Exh. CCA-18 and Exh. CCA-18C.

183 *See* Exhs. CCA-18 and CCA-18C (confirming most of Witness Dickman's math calculating the ratepayer impacts set forth in Exhs. CCA-04 and Exh. CCA-04C, but refusing to address the simple assumptions and calculations needed to finalize those calculations).

184 [Citation forthcoming] CalCCA was not given access to a confidential transcript before the filing deadline for this Opening Brief, so CalCCA will file an Amended Opening Brief as soon as possible once it has that information.

185 Exh. CCA-19 and Exh. CCA-19C.

186 Exh. CCA-04C at 1:19-2:2.

187 *Id*. at 1:19-2:2.

188 [Citation forthcoming] CalCCA was not given access to a confidential transcript before the filing deadline for this Opening Brief, so CalCCA will file an Amended Opening Brief as soon as possible once it has that information.

[redacted] and since no party has proposed valuing the Pre-2019 Banked RECs below zero dollars, these quantities likely represent the maximum Pre-2019 Banked RECs the IOUs will use in 2027. These *maximum* near-term impacts—calculated with the IOUs own numbers in their own ERRA Forecast cases—are quite *minimal* and far from the massive impacts to bundled customer affordability the IOUs predicted in their testimony.

b. CalCCA's Proposal Will Not Cause the Apocalyptic Harm to the RPS Market the IOUs Claim it Will

The Joint IOUs' also "cry wolf" loudly and repeatedly in this proceeding on the harmful impact of CalCCA's proposal to the RPS market and reduced incentives for the IOUs to sell excess renewable resources. In testimony and *ex parte* meetings, the IOUs claim CalCCA's proposal will:

- "*[F]undamentally* alter the market economics of RPS compliance;"[191]
- Put at risk "the RPS affordability of LSEs *across the state*;"[192]
- Lead to the economics of RPS sales being *"drastically"* changed;[193]

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189 [Citation forthcoming] CalCCA was not given access to a confidential transcript before the filing deadline for this Opening Brief, so CalCCA will file an Amended Opening Brief as soon as possible once it has that information.

190 [Citation forthcoming] CalCCA was not given access to a confidential transcript before the filing deadline for this Opening Brief, so CalCCA will file an Amended Opening Brief as soon as possible once it has that information.

191 Exh. JIOU-02 at 23:10-11 ("CalCCA's … proposal would fundamentally alter the market economics of RPS compliance and would likely have a negative effect on customer affordability.").

192 Exh. JIOU-01 at 38:3-4.

193 *Id*. at 36:5-6 ("the economics of conducting RPS sales could change drastically for the IOUs.")

- Put a *"strain on the market"* that will artificially increase the RPS MPB;[194] and
- Have *"serious downstream consequences."*[195]

The record provides ample evidence to doubt these claims of an impending RPS apocalypse.

The trigger of the IOUs' concerns appears to be that CalCCA's proposal could cause the market supply of RECs to grow tighter *if* certain market factors exist.[196] The IOUs' argument is that valuing Pre-2019 Banked RECs at a non-zero value *may* result in a situation in which purchasing RECs in the RPS market is the least-cost option for the IOUs, and, as a result, the IOUs *may* avoid using their bank of Pre-2019 Banked RECs.[197] In that case, the IOUs *may* seek to purchase PCC-3 RECs in the market or accelerate long-term procurement of PCC-1 RECs.[198]

However, the IOUs entrance into the market would only have the impacts the IOUs suggest *if* the IOUs actually forego using their REC banks *and* certain market factors exist. The factors include the IOUs seeking to procure sufficient amounts of RECs to cause a surge in demand, the RPS MPB being high enough to make using Banked RECs an uneconomic choice, and the RPS market being tight enough to be vulnerable to a surge in demand. Few, if any, of

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194 *Id*. at 42:5-14 (arguing there would be a "strain on the market" similar to the end of a compliance period that would artificially increase the RPS MPB).

195 *San Diego Gas and Electric Company (U 902 E), Southern California Edison Company (U338-E) and Pacific Gas and Electric Company's (U 39-E) Notice of Ex Parte Communication*, R.25-02-005, (Apr. 20, 2026) (IOU Ex Parte), Attachment A, Slide 2.

196 Exh. JIOU-01 at 35:3-5, 22.

197 *Id*. at 35:5-9 ("A non-zero valuation could create a disincentive to use the Pre-2019 Banked RECs for RPS compliance if alternative procurement is a more economic option for the IOUs. A non-zero valuation could lead to a situation whereby IOUs forgo utilizing Pre-2019 Banked RECs because procuring an unbundled REC product, for example, would be less costly than compensating departing load customers again for these Pre-2019 Banked RECs.")

198 *See id*. at 40:3-15 ("if the Commission were to order the IOUs to provide a credit of $20/MWh for every Pre-2019 Banked REC to departing load customers, the IOUs would be incentivized to purchase products that may be lower-priced, such as unbundled Portfolio Content Category (PCC) 3 RECs… Similarly, if the IOUs are required to re-value the Pre-2019 Banked RECs at above zero, IOUs may elect to accelerate long-term procurement …..").

these factors currently exist, and many may only develop over time and after the IOUs have the ability to adapt to the valuation.

In fact, the IOUs' claims they would forego the use of attributes already in their possession runs contrary to prior statements from PG&E that doing so is "non-sensical." For example, PG&E took the opposite position when faced with a similar circumstance related to providing substitution RA for the Diablo Canyon Nuclear Power Plant (DCPP) during extended operations.[199] In the 2026 DCPP Forecast proceeding (Application (A.) 25-03-015),[200] the Alliance for Nuclear Responsibility (A4NR) recommended PG&E purchase the capacity needed for DCPP substitution capacity from the RA bilateral market because it could be purchased at a lower cost rather than using capacity that already existed in the PCIA-eligible portfolio but which would be valued at the RA MPB (and charged to the DCPP extended operations balancing account) when used for DCPP needs.[201]

PG&E responded to A4NR's proposal arguing:

> Consistent with portfolio planning and management practices, PG&E uses capacity from its existing portfolio to meet its RA compliance obligations, including its California Independent System Operation Corporation (CAISO) substitution capacity obligations. In the event that PG&E does not have sufficient capacity from its existing portfolio, PG&E makes attempts to purchase capacity from the RA market to meet the shortfall. ***Requiring PG&E to effectively disregard capacity from its existing portfolio and solely rely on the RA market for DCPP's substitution capacity is nonsensical and would increase the total cost for customers***.[202]

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199 Exh. CCA-01 at 24, n. 49 (citing to PG&E's Rebuttal Testimony in A.25-03-015).

200 *Id*.

201 *Id*.

202 *Id*. (emphasis added).

Despite these arguments in the DCPP case, PG&E argues in this case that it would rather forgo the use of Pre-2019 Banked RECs in its existing portfolio in favor of purchasing more RECs in the market.

In addition, the IOUs anticipate needing only a small portion of their Pre-2019 Banked RECs in the near future, thereby suppressing the likelihood they will seek to purchase market-moving quantities of RECs. The IOUs admit that the direct impact of CalCCA's proposal on the RPS market will depend on the number of Pre-2019 Banked RECs they forecast they will need to use each year and, looking forward, in each RPS compliance period:[203]

> Q Would you agree the impact of CalCCA's proposal depends on the number of pre-2019 banked RECs the utility forecasts it would need to use in each year and each compliance period?
>
> A Erica Brown. I would agree that the direct impact of the proposal depends on the amount used, but that's not the full scope of the impact.

The IOUs also admit that any impacts to bundled customers will occur over time, rather than all at once:[204]

> Q And would you agree that the impacts of CalCCA's proposal are likely to be felt over time unless a utility would need their entire pre-2019 REC bank in

[203] Vol. 1 Tr. 63:10-16 (IOU Panel [Brown, Morien, Pulgar]).
[204] Vol. 1 Tr. 63:23-64-2 (IOU Panel [Brown, Morien, Pulgar]).

one year?

A Erica Brown. I agree that there would be a lingering impact on CalCCA's proposal.

For example, Witness Brown explained at hearing that PG&E has about [redacted] GWh of Pre-2019 Banked RECs in its REC Bank as of January 1,[205] but only forecasts using around [redacted] GWh of Pre-2019 Banked RECs in 2027.[206] [redacted][208]

Finally, much of the IOUs' argument rests on the premise that the RPS MPB will remain high enough to spur their sudden, substantial entrance into the RPS market. While the current RPS MPB is approximately $62.45/MWh, the IOUs' own Exh. JIOU-5 demonstrates a significant softening of PCC-1 REC prices in Q4 of 2025 to Q1 of 2026 to levels of $10.95 MWh for 2026 and $16/MWh for 2027:[209]

[205] [Citation forthcoming] CalCCA was not given access to a confidential transcript before the filing deadline for this Opening Brief, so CalCCA will file an Amended Opening Brief as soon as possible once it has that information.

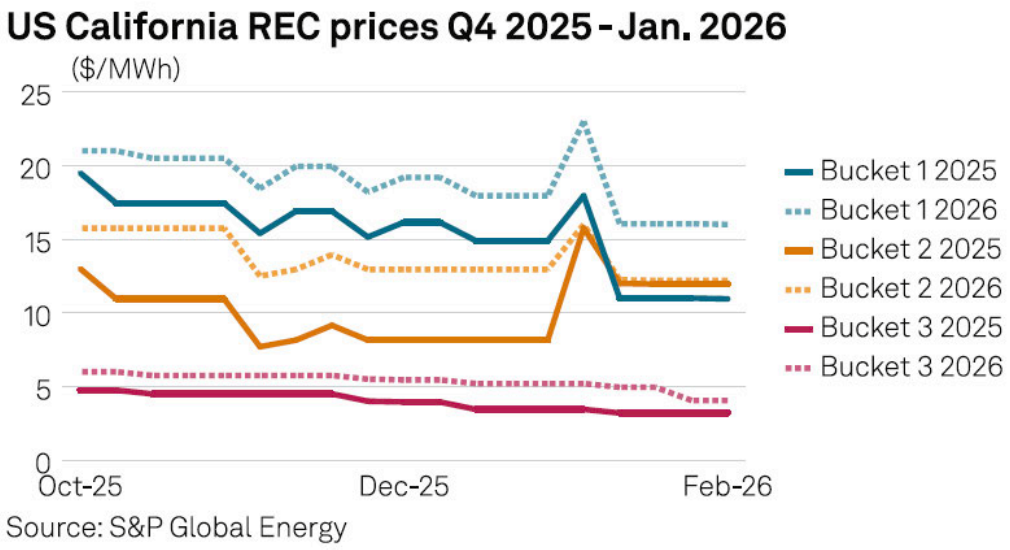
[206] [Citation forthcoming] CalCCA was not given access to a confidential transcript before the filing deadline for this Opening Brief, so CalCCA will file an Amended Opening Brief as soon as possible once it has that information.

[207] [Citation forthcoming] CalCCA was not given access to a confidential transcript before the filing deadline for this Opening Brief, so CalCCA will file an Amended Opening Brief as soon as possible once it has that information.

[208] [Citation forthcoming] CalCCA was not given access to a confidential transcript before the filing deadline for this Opening Brief, so CalCCA will file an Amended Opening Brief as soon as possible once it has that information.

[209] Exh. JIOU-05 at pp. 1/4-2/4.

Figure 7: Excerpt from Exh. JIOU-5



As Witness Dickman explained at hearing, that softening would flow through the RPS MPB,[210] and ultimately reduce both the price risk the IOUs would face by using their REC bank and, therefore, the incentive to avoid that price risk.

Finally, even if the RPS MPB results in an incentive to purchase RECs in the market, the kind of drastic impacts the IOUs predict will require a tight RPS market with little short-term supply. Here again, the recent data in Exh. JIOU-5 is instructive and shows the opposite is true:[211]

- "'[California] has been *quiet as of late*,' a trader said;"
- "'[S]ellers [are] *struggling to move volumes in the absence of active buyers*;'"
- "'Sounds like there might be a bit of *oversupply* they are trying to move, but the *inexistence of bids made the sale impossible*;'"
- "This points to *a market described by oversupply* and imbalance between buyers and sellers;" and

210 Vol. 1 Tr. 160:8-161:13 (Dickman).
211 Exh. JIOU-05 at 3/4 (emphasis added).

- "Taken together, conversations across January 2026 suggest persistent offer pressure and thin bidding activity have *kept the market tone soft*, particularly for PCC3 contracts."

The IOU Panel during the evidentiary hearing agreed:[212]

> Q So all of these statements would suggest that demand for RECs is currently soft and not susceptible to being overwhelmed by the utilities entering into that market to buy RECs, right?
>
> A At this point in time, that is what it suggests.

In other words, even if: (1) the IOUs would actually forego using products at hand; (2) their near-term needs changed enough to spur them to buy substantial amounts of RECs; *and* (3) the RPS MPB was high enough to cause a sudden entrance into came to the market, the low prices and volumes moving such products today mean the market might absorb those volumes with little impact to the affordability of PCC-1 or PCC-3 RECs.

PG&E Witness Brown is right to point out that markets can always change,[213] but she was also right to point out that impacts from CalCCA's proposal will occur over time.[214] Many factors may change between the Commission's Track Two decision and the hypothetical future impacts that concern the IOUs. The muted and long-term nature of the impacts from CalCCA's proposal will give the IOUs time to make adjustments to their portfolios. In fact, the nature of PCIA ratemaking itself could change significantly in Track 3, potentially eliminating these risks altogether. Regardless, it is clear today, with the record before the Commission now, that the

212 Vol. 1 Tr. 68:4-9 (Brown).
213 Vol. 1 Tr. 116:13-20 (Brown).
214 Vol. 1 Tr. 63:23-64-2 (IOU Panel [Brown, Morien, Pulgar]).

ingredients necessary for the IOUs' dark predictions about the impacts of CalCCA's proposal simply do not exist.

c. The Commission's Short-Lived VAMO Effort Does Not Preclude Adoption of CalCCA's Proposal

The Commission's adopted the VAMO process in D.21-05-030. That process resulted in one allocation of RPS attributes to CCAs in 2022 and a subsequent market offer that resulted in significant quantities of RPS attributes being sold. The VAMO was suspended on account of the utilities opting to no longer hold a VAMO process.[215] The IOUs' testimony uses "Back to the Future" reasoning to argue a counter-factual: the Commission never would have adopted VAMO if the Commission knew the IOUs' bank of Pre-2019 RECs would be valued at the benchmark.[216]

Much of the Joint IOUs' argument on downstream impacts rests on the premise that the Commission adopted the VAMO framework because the IOUs possessed significant excess renewable resources, including banked RECs from prior years.[217] The Joint IOUs suggest that recognizing value for Pre-2019 Banked RECs would undermine the conditions that justified VAMO.[218] However, the Commission's decision adopting and implementing VAMO does not support that conclusion.

For example, the Joint IOUs point to D.18-10-019 and D.21-05-030 as evidence that the IOUs' renewable portfolios contain excess resources that can be used to meet compliance

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215 *See, e.g.,* PG&E Advice Letter 7105-E Disposition Letter at 4 (finding a future VAMO process need not be held on very thin reasoning having nothing to do with any certain criteria being met with regard to PG&E having excess RPS attributes to sell; instead relying on the fact that "D.21-05-030 OP 4 expressly gives the IOUs the task to propose the occurrence of future VAMOs, including proposing they do not occur").

216 *See* Exh. JIOU-01 at 4:1-20; 18:7-12; 32:6-9.

217 *See id*.

218 *See id*. at 4:1-20.

requirements in future years.[219] While these decisions acknowledge that the IOUs had renewable resources beyond near-term compliance needs, the Commission did not identify the IOUs' REC banks as contributing to those excess resources.[220] The Joint IOUs argue the RPS resources allocated under VAMO were only excess because an IOU can use those Pre-2019 Banked RECs paid for by Later Departing Customers—without ever having to pay for them—to meet its compliance requirements on behalf of bundled customers.[221]

On the contrary, the fact that the IOUs were accumulating banked RECs is evidence that their annual RPS-eligible generation significantly exceeded bundled customer needs at the time. The Commission decision highlights that CalCCA pointed out then that the annual ERRA forecast proceedings included significant amounts of excess RPS resources that were counted as Unsold RPS under the updated PCIA framework adopted in 2019.[222] Decision 21-05-030 defined "excess resources" simply as those not necessary to meet bundled customers' needs and compliance requirements, and the Commission concluded that voluntary allocation of the IOUs' annual RPS generation could help "reduce excess and/or uneconomic resources in the IOUs' PCIA portfolios."[223]

Decision 21-05-030 also recognized that the amount of excess RPS resources could decline significantly over time. The Commission stated that excess renewable resources could "decline precipitously within the next few years," and as a result the Commission limited the frequency of voluntary allocation solicitations.[224] In other words, the Commission adopted VAMO with the expectation that the IOUs' excess RPS generation in the current period would

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219 *See id*. at 18:7-12.
220 *See* D.18-10-019 and D.21-05-030.
221 *See* Exh. JIOU-01 at 32:6-9.
222 D.21-05-030 at 16-17.
223 *Id*. at 58, Conclusion of Law 2.
224 *Id*. at 33-34.

decline. The Commission specifically rejected PG&E's argument that it should not require IOUs to dispose of resources needed for bundled service customer compliance because the IOUs would be required to procure additional resources for compliance on the market.[225] The Commission acknowledged that replacing resources could increase costs for bundled ratepayers, although market prices at that time were likely to be lower than the cost of legacy RPS contracts.[226] Nothing in the VAMO decision—or the short-lived program itself—should prevent the Commission from acting here.

Lastly, to dispel some of the fog the IOUs seek to create regarding this issue, CalCCA wishes to reiterate that the IOUs can still choose to use these RECs if they are given the right value. There is no reduction of quantity in the market. CalCCA has already demonstrated why the market-clearing price is unlikely to be significantly impacted by valuing these RECs appropriately. In fact, rather than destroy the REC market, this would ensure the IOUs face the appropriate incentives when determining the appropriate mix of resources to procure and use to meet their RPS compliance obligations. The small impacts expected in the near term are the result of correcting this market flaw, not introducing one.

d. Allocating Pre-2019 Banked RECs

Lastly, the Joint IOUs claim CalCCA's alternative proposal to allocate the Pre-2019 Banked RECs to the LSEs of the customers that paid for them would have dire downstream consequences by leaving bundled service short on RPS procurement. For example, they argue that it is a second allocation that, were it adopted, would contradict the reasoning underlying the

225 *See id*. at 19.
226 *See id*.

VAMO decision and constitute a "second VAMO."[227] They also argue that the allocation of these RECs will shorten the IOUs' RPS planning positions.[228]

The Joint IOUs' first downstream impact claim misrepresents the allocation proposal and its impacts. This proposal is not a second VAMO because the allocation is limited to those pre-existing RECs that were generated between 2011 and 2018 and it is not a second allocation of renewable energy that will be produced from the IOUs' current RPS resources.[229] VAMO was adopted in 2021 and only applied to RECs generated after 2022,[230] so it could not apply to any of the Pre-2019 Banked RECs under discussion.

As for the Joint IOUs' second downstream impacts argument, i the IOUs' statements that allocation would "require incremental RPS procurement" and that "IOU customers will face higher costs"[231] serves to demonstrate the fairness of CalCCA's allocation proposal.[232] The IOUs suggest that, but for the Pre-2019 Banked RECs, the IOUs will need to procure additional RPS and, in doing so, will face higher costs. That directly contradicts their position against valuing these RECs in the first place: how can Pre-2019 Banked RECs have zero value while simultaneously helping the IOUs avoid uneconomic procurement?

Putting that contradiction aside, CalCCA has acknowledged the IOUs may need to revisit their procurement strategies in response to the Commission's decision in this proceeding.[233] But that is nothing new. Utilities frequently adjust procurement strategies and individual procurement

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227 Exh. JIOU-02 at 37:15-21.
228 *Id*. at 38:13-14.
229 Exh. CCA-03 at 23:17-24:1.
230 D.21-05-030, *Phase 2 Decision on Power Charge Indifference Adjustment Cap and Portfolio Optimization* (May 24, 2021) at 37 ("[W]e direct the IOUs to confirm Voluntary Allocations and to propose Market Offers in their 2022 RPS Plans for deliveries of energy in 2023.").
231 Exh. JIOU-02 at 38:9-12; 39:1-2.
232 Exh. CCA-03 at 24:7-12.
233 Exh. CCA-01 at 26:3-9.

decisions in response to changes in regulatory policy and market conditions. Given the degree to which the IOUs will need to rely on Pre-2019 Banked RECs in the near future, they will have time to make such adjustments. Ensuring that the customer indifference principle is applied correctly within the PCIA framework—while risking a small IOU short position in the near term—does not create an impermissible market outcome. Instead, it ensures that the costs and benefits of procurement decisions are allocated fairly among customers while giving the IOUs time to avoid significant impacts.

3. Pre-2019 RECs are Similarly Situated to RECs Generated After 2019 in All Relevant Respects for RPS Compliance Purposes (Issue 1.c)

The IOUs are able to use Pre-2019 Banked RECs as direct replacement for PCC-1 RECs they may generate or purchase on the market.[234] Pre-2019 Banked RECs retain their PCC-1 status when they are placed in the bank, meaning they can be used for an unlimited proportion of the IOUs' RPS compliance obligation (unlike PCC-3 RECs, which are capped at 10 percent).[235] As the IOUs admitted, Pre-2019 and Post-2018 Banked RECs are identical as it relates to the RPS.[236]

Nevertheless, the IOUs have tried to confuse this issue. The IOUs claim that the Pre-2019 Banked RECs are categorically different for PCIA purposes because they are not tradeable or transferrable. Banked RECs must be retired in WREGIS within 36 months of generation, and it is true that no banked RECs can be traded or transacted after they are retired in WREGIS (which is true at this point for all Pre-2019 Banked RECs). But today that is also true of any RECs banked in 2019 through 2022, which all parties agree can and should be valued at the compliance year RPS MPB. As both time and the three-year clock continue to run on other banked RECs, it

234 Exh. CCA-03 at 25:21-22.
235 *Id*. at 25:14-22; Vol. 1 Tr. 145:21-146:2 (Dickman).
236 Vol. 1 Tr. 54:13-17; 55:4-56:22; 57:6-58:14 (Joint IOU Panel [Brown, Morien, Pulgar]).

will soon be true of banked RECs from additional years after 2019.[237] Pre-2019 Banked RECs are therefore identical to these other banked RECs for RPS purposes. The fact that these particular banked RECs (both Pre-2019 and Post-2018) are identically situated—including that they will not be traded on the market—does not impact the IOUs' ability to use them to avoid the cost of procuring additional PCC-1 RECs for the current RPS compliance period.

The IOUs have also argued that Pre-2019 Banked RECs do not come along with energy attributes in the year they are used for compliance, and that therefore they are different from PCC-1s transacted in the compliance year. That is another red herring; it is true, but not relevant to the value of the RECs for RPS compliance purposes. The Pre-2019 Banked RECs were associated with energy in the year they were generated and banked, but the value of that energy *was already calculated and accounted for in the PCIA* back when they were generated.[238] The RPS MPB is and was called the "RPS Adder" because it is an *adder*; it is and was meant to calculate the *additional* value of the REC above and beyond the energy value (what the IOUs have called the "Green Premium").[239] The transactions used to calculate the RPS MPB for the relevant compliance years only account for this additional value.[240] To the extent contracts meld the value of other attributes and RECs, the Commission's RPS MPB calculation currently excludes those transactions in part because the process of teasing apart these values is too difficult.[241]

Lastly, the Joint IOUs have argued that PCC-1 RECs transacted in the compliance year can impact the amount of clean energy an LSE can claim on their Power Content Label (PCL) or

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237 *See* Vol. 1 Tr. 54:19-24 (Joint IOU Panel [Brown, Morien, Pulgar]) (agreeing that any banked REC cannot be sold "if it's past three years and has been retired in the WREGIS system").

238 Exh. JIOU-01, Appendix A, A-6–A-7 (Step 2).

239 D.19-10-001 at 7; Exh. JIOU-01, Appendix A, A-6–A-7 (Step 2).

240 *See* Vol. 1 Tr. 146:11-16 (Dickman); D.19-10-001 at COL 2 (adopting proposal to calculate RPS Adder using only PCC-1 "index-plus" transactions").

241 *See* D.23-06-006 at 11-12 ("We are concerned that implementing the LTFP Proposal could reduce the accuracy of the RPS MPB."

for its greenhouse-gas accounting, whereas pulling a Pre-2019 Banked REC out of storage will not affect the PCL in the same manner.[242] The Joint IOUs are correct that this is the case, however they admit that this is, again, also true for IOUs seeking to use *any* banked REC, which are—by definition—generated and banked in a prior calendar year.[243] The Joint IOUs point to no Commission precedent indicating that the marginal value of counting toward a PCL has a particular value or can be estimated.

The Joint IOUs threw out these arguments merely to distract from the relevant point that the value of all these resources is best considered to be the avoided cost it can offer to the IOU.[244] CalCCA's, the IOUs', and the Commission's best estimate of that avoided cost is the RPS MPB.[245] If the IOUs claim the Commission should change how it calculates the RPS MPB applicable to *all* these RECs, they are free to do so in Track 3 of this proceeding.[246] That does not diminish the truth that Pre-2019 Banked RECs are the same as other Banked RECs and represent a direct avoided cost of purchasing a PCC-1 REC in the market today.

Cal Advocates argues that the Commission should seek to estimate the compliance value these RECs provide to ratepayers when used, and that it is different from the avoided cost that Pre-2019 Banked RECs offer to the IOUs. Specifically, Cal Advocates states:

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242 Exh. JIOU-01 at 52:17-54:5; Exh. JIOU-02 at 28:11-15; Exh. JIOU-03 at 12:1-5.

243 Vol. 1 Tr. 57:19-23 (Joint IOU Panel [Brown, Morien, Pulgar]). *See also* Exh. CCA-02 at 20:18-21.

244 *See* D.18-10-019 at 73; *see also* Exh. CCA-01 at 17:22-18:14.

245 *See* D.18-10-019 at 73; *see also* Exh. CCA-01 at 17:22-18:14.

246 R.25-02-005, *Administrative Law Judge's Ruling Authorizing Parties to File Comments on Issues to Address in Track 3* (Feb. 20, 2026) at 1 ("The scopes of Track 1 and Track 2 focused on discrete issues and were relatively narrow compared to the broad set of issues discussed in the [OIR] that opened this proceeding. The OIR identified multiple issues related both to [PCIA] issues as well as [ERRA] issues. Track 3 of this proceeding intends to address the broader set of remaining issues.").

> Like PCC 3 RECs, Pre-2019 Banked RECs are unbundled from energy and do not contribute to an LSE's Power Content Label. However, like PCC 1 RECs, Pre-2019 Banked RECs can be used indiscriminately to meet LSE RPS obligations. The Commission should consider valuing Pre-2019 Banked RECs based on the attributes they share with PCC 1 and PCC 3 RECs.[247]

The appropriate measure is the avoided cost these RECs can offer. Indeed, when an LSE buys a PCC-1 REC for compliance purposes or an IOU chooses to use a banked ERC for these purchases, the PCL or resale value hasve no relevance. However, in response to this argument, CalCCA notes that its alternate 90/10 PCC-1 RPS MPB/PCC-3 MPB proposal discussed *supra* results in a price that combines these two attributes' values using weights based on the quantities IOUs can use them for compliance.

4. Nothing in Law or Precedent Dictates That Customers Forfeited the Value of RECs They Paid for When Departing IOU Service (Issue 1.d)

Nothing in statute or prior Commission decisions provides that customers forfeit the value of banked RECs they paid for when departing IOU service. Section 366.2(g), which requires the Commission to ensure departing load customers receive the benefits of the resources they pay for, is not qualified to limit these benefits when they depart. There is no basis in statute to conclude that departing load customers forfeit the value of RECs that are generated from resources they pay for after they depart. The value of those RECs is used to reduce the 'above market costs' that they pay for in the PCIA. There is no reason this should be different for banked RECs.

Neither has the Commission ever determined that customers have forfeited the value of RECs the IOUs have held for later compliance use when they departed. The Joint IOUs

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[247] *Reply Testimony of Cal Advocates on Track Two of the Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes*, R.25-02-005 (Mar. 23, 2026), at 8 (internal citations omitted).

specifically argue that D.06-07-030 provides support for their claim that CalCCA's proposal inappropriately assumes individual customer ownership of attributes for PCIA purposes.[248] D.06-07-030 considers how to allocate a repayment of a "[Customer Responsibility Surcharge] under-collection loan."[249] In that Decision, the Commission ultimately decided not to calculate individual customer bill credits.[250] The Commission's reasoning in D.06-07-030 does not militate against adopting CalCCA's proposal for two reasons. First, CalCCA does not propose to track individual customers or provide individual bill credits.[251] As noted above, CalCCA's proposal utilizes the same *existing* PCIA vintaging framework as other PCIA costs and benefits.[252] Second, since D.06-07-030 was decided in 2006, the California Legislature added section 366.2(g) to clarify that IOU generation procurement costs paid by the customers of a CCA shall be reduced by the value of any benefits that remain with bundled service customers.[253] This binding statutory language did not exist at the time, and compliance with it requires adopting CalCCA's valuation proposal.

Beyond the question of forfeiture by statute or prior Commission decisions, the Joint IOUs attempt to argue that CalCCA's proposal runs afoul of the PCIA methodology by assuming that *individual customers* retain the rights to be paid for the individual RECs they paid to generate.[254] CalCCA's proposal, like the PCIA overall, addresses *groups of customers* and does not provide for separate treatment of individual customers.

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248 Exh. JIOU-01 at 45:21-46:5.
249 *Id*. at 46:1-10.
250 Exh. CCA-02 at 18:9-14.
251 *Id*. at 18:15-18.
252 *Id*. at 18:18-22.
253 *Id*. at 19:1-4.
254 Exh. JIOU-01 at 3:2-8; *see also id.* at 26:3-15, 27:3-4, 46:7-47:23.

Departing customers retain the right to receive a credit for the value of resources they pay for contemplates *groups* of customers. The PCIA treats customers differently (based on when they departe bundled service) by grouping them into vintages,[255] and CalCCA's proposals requires no more granularity or individual consideration than that. The value of the Pre-2019 Banked RECs, once established by the RPS MPB, is divided amongst vintages of customers (including the most recent vintage, which includes all Currently Bundled Customers[256]).

In fact, PG&E admitted that, when it previously used the same methodology as CalCCA's proposal, it did not need to track individual customers or determine that individual customers had an individual ownership claim to Pre-2019 Banked RECs.[257] The IOUs' argument demonstrates their misunderstanding of CalCCA's proposal, the IOUs' own past practices, prior Commission decisions, and governing law.

B. The Commission Should Direct IOUs To Value Pre-2019 Banked RECs Used For Compliance at the Compliance Year RPS MPB, and Credit That Value to the Customer Vintage for the Generation Year (Issue 2)

1. It is Reasonable to Credit or Allocate RECs to Those Customers Who Invested in RECs the MPB of the Year Those RECs are Used for Compliance (Issue 2.a)

As CalCCA demonstrated above, it is reasonable to require IOUs to either credit or allocate banked RECs to those customer groups who initially paid to generate those RECs. If the IOUs use the RECs for Current Bundled customer compliance, then Later Departing Customers should receive a benefit equal to the value of those RECs as an offset to the PCIA rates they pay. Alternatively, the IOUs should allocate these RECs to the LSEs currently serving those customers. Those results comport with controlling statute and with principles of fairness.

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255 Exh. CCA-02 at 4:6-7.
256 Exh. CCA-01 at 7:7-9.
257 Vol. 1 Tr. 105:6-10; 106:23-107:19 (Joint IOU Panel [Brown, Morien, Pulgar]).

a. The Commission Should Adopt CalCCA's Primary Valuation or Allocation Proposals

If the IOUs were not able to use the Pre-2019 Banked RECs towards their RPS compliance minimum, they would need to go out and procure RECs on the market. For RPS compliance purposes, the Pre-2019 Banked RECs are equivalent to PCC-1 RECs (which can be used for the entire RPS obligation, unlike PCC-3 RECs which can only be used for 10 percent of the compliance minimum). The Commission's Energy Division already calculates the market cost of these PCC-1 RECs, and already uses it to estimate the benefit IOUs receive from RECs that are not transacted on the market.[258] This RPS MPB is therefore the closest thing the Commission, the IOUs, or the CCAs have to the value of the RECs used for compliance in a particular year. The Commission should use the *compliance year* RPS MPB because that reflects the benefit (as an avoided cost not incurred) that bundled load actually enjoys.

In the alternative, the Commission should require the IOUs to allocate the Pre-2019 Banked RECs these IOUs are holding that were paid for by Later Departing Customers. As CalCCA has demonstrated, this kind of allocation is contemplated as an alternative method of accomplishing indifference in section 366.2(g). The allocation would work as described *supra*, with offsetting adjustments to the IOUs' and LSEs' respective Excess Procurement Bank quantities on the relevant LSEs' RPS Compliance Reporting Template.[259]

CalCCA maintains that these two methods of addressing Pre-2019 Banked RECs used for compliance are the only ones that actually achieve the indifference required by statute Commission Staff issued a Staff Report in this Track Two concluding that "CalCCA makes a compelling

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[258] *E.g.*, the RPS resources that unbundled customers' PCIA resources generate in the compliance year that the IOUs choose to retain for their RPS compliance purposes. (D.18-10-019 at COL 2, Attachment B; D.19-10-001 at COL 2.)

[259] Exh. CCA-03 at 23:1-14.

argument that departed customers paid for a portion of these RECs[.]"[260] Commission Staff acknowledge that Pre-2019 Banked RECs have compliance value even if they lack direct market value.[261] Nevertheless, Staff argued that four alternative, compromise values should be considered, despite the fact that none of these reflect the compliance value of those RECs.

b. While Staff's Proposals Are Creative Attempts at Estimating Compromise Values, CalCCA's 90/10 Proposal More Closely Tracks Compliance Value and Is More Reasonable

Despite recognizing that these Pre-2019 Banked RECs provide the IOUs with compliance value, Staff's proposal does not attempt to estimate this value and instead offers four compromises.[262] The first three adopt CalCCA's proposed method of crediting the value of the RECs used to the customer vintage of the RECs' generation year, but propose different methods of calculating that value.[263] Each of these four proposed compromises suffer from at least one key flaw, as described below.

i. Option 1 — Load-Share Weighted RPS MPB

Under this option, Pre-2019 Banked RECs would be valued as a percentage of the current-year RPS MPB, determined by the current percentage of unbundled load share in the relevant IOU service territory.[264] As an initial matter, the percentage of load share has no relevance in assessing market value. While Staff claims this option is intended to reduce the impact of providing value for Pre-2019 Banked RECs when bundled customer pools are smaller, this proposal counterintuitively results in the price used to value banked RECs varying by IOU service territory, even for RECs with identical characteristics:[265]

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260 Staff Report at 8.
261 *Id*.
262 Exh. CCA-03 at 6:10-12 (citing Staff Report at 9).
263 *Id*. at 6:12-15.
264 *Id*. at 6:17-19.
265 *Id*. at 10:8-12.

Table 2 – Load-Share Weighted RPS MPB by IOU Service Territory[266]

IOU	Unbundled Load Weight	RPS MPB ($/MWh)	Staff Option 1 Price ($/MWh)
PG&E	67%	$ 62.45	$ 42.02
SCE	36%	$ 62.45	$ 22.55
SDG&E	82%	$ 62.45	$ 50.92

As Table 2 shows, in 2026 identical RECs held by the different IOUs would vary by up to 125 percent (SDG&E price compared to SCE price), but the market price for RECs in California is state-wide and there is "no basis in market fundamentals for this disparity."[267] In sum, CalCCA and the Joint IOUs agree[268] that this option adds unnecessary inequality across geographies and fails at achieving the only goal staff proposed for it.

ii. Option 2 — DOE REC Value

This option would use the Department of Energy DOE statewide renewable energy premium from 2011 through 2018 as a proxy for the value of Pre-2019 Banked RECs. These values generally ranged from approximately $15 to $17 per MWh.[269] While this option may have been intended as a proxy for the price at the time the REC was generated, it is not. These DOE REC values were only one component (along with IOU resource data) of the weighted average RPS MPB calculation the Commission used under the PCIA framework adopted in D.11-12-018[270] For example, PG&E's territory ranged from $24 to $66 (up to over three times as much as the component DOE REC price). There is no justifiable reason for the Commission to base the

266 *Id*. at 11:3-4.
267 *Id. at 11:9-12.*
268 Exh. JIOU-04 at 6:19-32.
269 Exh. CCA-03 at 6:20-7:3.
270 *Id*. at 12:5-8.

value of these Pre-2019 Banked RECs on only this one component.[271] The Joint IOUs agree with CalCCA's assessment of this proposal as well.[272]

On a more fundamental level, this proposal makes the logical error of looking at prices from a decade ago to value Pre-2019 Banked RECs used for compliance today and in the future. To the extent Staff were purporting to provide the Commission with an estimate of the compliance value these banked RECs provide to bundled customers, the current prices at which substitutes can be purchased or sold is the relevant comparison.[273] Staff's proposal also does not account for any inflation that may have impacted those prices between when they were originally calculated and when the RECs are eventually used for compliance.

CalCCA does note that this Option does not suffer the flaw of Option 1 introducing an unjustified geographical variation across IOU service territories, and fixes a price that provides both IOUs and CCAs with administrative certainty regarding the prices of any Pre-2019 Banked RECs used for compliance.

iii. Option 3 — 50/50 Split

This option would value Pre-2019 Banked RECs at 50 percent of the current-year RPS MPB.[274] While this does result in a value that is half way between the best available avoided cost estimate (the current year RPS MPB) and the IOUs' $0 proposal, that seeming fairness is misleading. The problem statement Staff set out to solve—and what statutes require the Commission to pursue—is achieving indifference. Indifference "should be rooted in accuracy (i.e., compliance value) rather than based on compromises."[275]

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271 *Id*. at 12:8-10.
272 Exh. JIOU-04 at 6:26-27.
273 Exh. CCA-03 at 13:2-5.
274 *Id*. at 7:4-5.
275 *Id*. at 14:2-5.

iv. Option 4 — Adjusted Weighting Mechanism

Staff describes this option as a hybrid mechanism. Under this approach, the Pre-2019 Banked RECs will be divided into two separate buckets: a bundled load share and a departed load share.[276] The bundled load share of RECs are valued at $0, consistent with the Joint IOU proposal, while the departed load share are valued using any of the pricing options presented by CalCCA or Staff (*i.e.,* current RPS MPB, Load-Share Weighted RPS MPB, DOE REC Value, or 50/50 Split).[277] Staff suggests the IOUs will have the flexibility to choose which RECs to apply toward compliance, effectively allowing them to count bundled load's share of RECs toward compliance first and avoid any charge in bundled customer generation rates. When the departed load share of RECs is used for compliance, that value will flow through the PCIA and be shared with bundled and unbundled customers, similar to the other options.[278]

Staff claims that this proposal "ensures bundled load is only buying out the share of banked RECs attributable to departed load — and nothing more."[279] But CalCCA and the Joint IOUs agree that this proposal assigns too much value to Current Bundled Customers.[280] First, it gives them their share of the Pre-2019 Banked RECs at $0.[281] But then, instead of paying Later Departing Customers for the entirety of the RECs they purchased, Option 4 would give a portion of this value to Current Bundled Customers for $0.[282]

CalCCA's proposal is the only proposal that actually accomplishes this split fairly, by using the PCIA vintaging process to split the RECs used for compliance into these same two

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276 *Id*. at 14:7-8.
277 *Id*. at 14:8-10.
278 *Id*. at 7:6-16.
279 Staff Report at 11.
280 Exh. CCA-03 at 15:1-9; Exh. JIOU-03 at 22:11-21 (discussing how it would be inappropriate to use the traditional PABA accounting for this option).
281 Exh. CCA-03 at 14:20-15:1.
282 *Id*. at 15:1-9.

buckets, giving Currently Bundled Customers their bucket for $0, and giving Later Departing Customers their bucket for the avoided cost (the compliance year RPS MPB).[283] Staff's Option 4, on the contrary, appropriately values the first bucket, but then flows the second bucket through the PCIA to deposit the value of a portion of this bucket into the most recent vintage—Current Bundled Customers. Using the example for 2015 Banked RECs used in 2026 in Table 1, *supra*, this would result in Current Bundled Customers using: (1) 40 percent of the RECs at no cost and receiving their benefit ($2.4 million); and (2) receiving 40 percent of the $3.6 million value that should go to Later Departing Customers.[284] This is an unfair double benefit that is not supported by any evidence or logic and therefore it cannot result in just and reasonable rates.

To address this unfair double benefit, the Joint IOUs propose establishing separate balancing accounts to facilitate a PCIA sur-credit or annual bill credit similar to those used to account for the previous PCIA rate cap.[285] While CalCCA does not oppose this treatment if Option 4 is adopted, the Commission should reject the Joint IOU's recommendation to indefinitely keep the replaced valuation ($0 for each Pre-2019 Banked REC) until the new accounting is fully developed and implemented.[286] Reestablishing these accounting procedures that are "similar to those that have been used before," does not require a delay in the effective date of assigning value of the Pre-2019 Banked RECs.[287]

Additionally, Option 4 permits the IOUs to sequence their use of banked RECs. This would permit the IOUs to use RECs that benefit their bundled customers first, while indefinitely delaying the use of RECs paid for by unbundled customers and for which *any* benefits (even

283 *See id*. at 15:10-16:8.
284 *Id.* at 16:10-14.
285 *Id*. at 17:2-4 (citing Exh. JIOU-03 at 23:5-15).
286 *See* Exh. JIOU-03 at 24:7-9.
287 Exh. CCA-04 at 17:7-9.

those diluted benefits described above) would flow to unbundled customers.[288] CalCCA's proposal, on the other hand, would draw down the IOUs' REC banks in a fair, proportional manner.[289] To the extent an IOU wants to use a handful of banked RECs, they need to grab the handful in a neutral manner without cherry-picking their customers as the beneficiaries.

The Joint IOUs, predictably, appreciate what they call the "flexibility" that Staff Option 4 gives them to preference resources that benefit their own bundled customers.[290] But to the extent there is any advantage in "flexibility", the actual *customers* the IOUs are taking advantage of is unbundled customers: the IOUs want to be "abl[e] to choose which bucket to use."[291] This is a framework "designed to give the IOUs operational discretion and the ability to delay or prevent crediting Later Departing Customers."[292] To be clear, under CalCCA's proposal, the IOUs would still be able to choose *how many* banked RECs they seek to use for compliance purposes each year (under the oversight of the Commission and in compliance with their RPS Procurement Plans), they would just not be able to choose to indefinitely strand departed loads' RECs.[293]

In addition to the new PABA accounting discussed above, the Joint IOUs recommend three other adjustments and clarifications to Option 4: (1) setting the proportions of the two buckets based on Later Departing Customers and Current Bundled Customers, excluding Previously Departed Customers, (2) fixing the bundled and unbundled bucket allocations instead of updating them based on changes to the Later Departing Customer/Current Bundled Customer proportion as it changes over time, and (3) exempting any Pre-2019 Banked RECs used in or

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288 Exh. CCA-03 at 16:15-17:1.
289 *Id*. at 17:1-6.
290 Exh. JIOU-03 at 27:6-7.
291 *See id*. at 27:10-13.
292 Exh. CCA-04 at 15:10-11.
293 *Id*. at 15:14-19.

before 2025.[294] The Joint IOUs also argue that any RECs valued using this process should be valued using a PCC-3 benchmark rather than the RPS MPB or Staff's other options.[295]

Taking all of these suggestions together, it is clear the Joint IOUs' priority is not to achieve indifference or identify the compliance value of these RECs, but to maximize the IOUs' ability to strand departed load's share of these RECs and minimize the benefit they receive.

CalCCA does not oppose the Joint IOUs' first adjustment regarding Option 4 (if Option 4 is adopted, which CalCCA does not support[296]), and notes that this concern is fully addressed by CalCCA's proposal to value the Pre-2019 Banked RECs at the compliance year RPS MPB and crediting that value to the customer vintage of the RECs' generation year.

However, CalCCA rejects the Joint IOUs' second adjustment regarding Option 4. This proposal is the Joint IOUs seeking to prevent customers who choose to depart bundled service from receiving the benefit of these resources, in violation of section 366.2(g) and indifference. There is no exception in section 366.2(g) for customers who determine that they prefer to unbundle after 2026. If the IOUs wish to seek such language in the statute, they are free to propose that in the legislature.

CalCCA also rejects the Joint IOUs' adjustment that the Commission determine in this proceeding that Pre-2019 Banked RECs used in or before 2025 should be excluded from Option 4. To the extent there are ongoing proceedings in which the value of these RECs is in dispute,[297]

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294 Exh. JIOU-03 at 18:18-24:9.

295 *Id*. at 24:11-19; 25:23-27:3.

296 *See* Exh. CCA-03 at 15:16-16:9.

297 *See* A.25-05-008, *California Community Choice Association's Application for Rehearing of Decision Approving Southern California Edison Company's 2026 Energy Resource Recovery Account-Related Revenue Requirement Forecast* (Jan. 12, 2026) at 27-41; A.25-05-011, *California Community Choice Association's Application for Rehearing of Decision Approving Pacific Gas and Electric Company's 2026 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2026 Electric Sales Forecast* (Jan. 12, 2026) at 24-39.

the Commission and any reviewing courts can and should determine that value in those proceedings.

Lastly, the Joint IOUs' proposal to value Pre-2019 Banked RECs at a forthcoming PCC-3 MPB is illogical and is not a serious attempt to estimate the compliance value of these RECs. The Joint IOUs describe PCC-3 RECs as the "least-cost replacement product" and claim that they are actually more valuable than Pre-2019 Banked RECs.[298] But this is about RPS compliance, and the Joint IOUs' argument ignores "the fundamental compliance attribute of [Pre-2019 Banked RECs]"—they "retain their originally PCC classification" and can be used as PCC-1 RECs for RPS compliance purposes.[299] For compliance purposes, they "displace or defer" PCC-1 RECs,[300] which trade at a premium to PCC-3 RECs.[301] The Joint IOUs also ignore the fact that PCC-3 RECs, by statute, can only be used to address 10 percent of an LSE's annual RPS compliance obligation.[302]

In addition, while CalAdvocates supports Option 4, this Option creates a flaw identical to that which CalAdvocates objected to related to Option 1. Specifically, CalAdvocates agreed with CalCCA that Option 1 "results in different valuations by service territory," and was therefore "flawed" and "counterintuitive."[303] This position is inconsistent. The same logic that undermines Option 1 applies with equal force to Option 4.

If geographic uniformity is a sound reason to reject Option 1, and Cal Advocates argues that it is, then that same principle compels rejection of Option 4. This is apparent in **Figure 8**, reproduced from CalCCA's Direct Testimony on the Staff Report:

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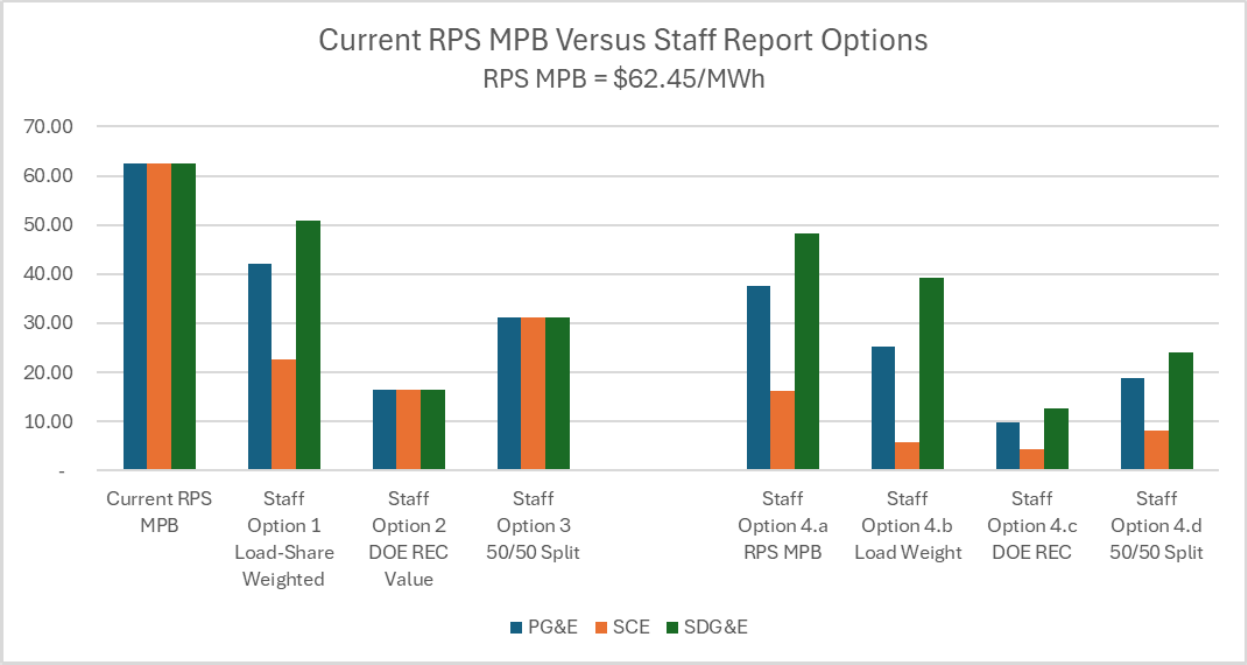
298 Exh. JIOU-03 at 11:15-12:21.
299 Exh. CCA-04 at 18:12-17.
300 *Id*. at 18:19-19:2.
301 Vol. 1 Tr. 145:18-20, 151:2-6 (Dickman); Exh. JIOU-5.
302 Exh. CCA-04 at 19:3-5.
303 Exh. CalAd-02 at 3:4-9.

Figure 8 – Current RPS MPB Versus Staff Report Options[304]



A consistent application of Cal Advocates' own logic leads to the conclusion that Option 4 should not be adopted either.

In sum, Option 4 has multiple structural deficiencies, and the Joint IOUs' recommended changes to Option 4 should mostly be rejected along with Option 4. CalCCA does agree with the Joint IOUs that a special accounting would be necessary to ensure that the correct proportions are used, but notes that even after that accounting is implemented the Joint IOUs would still retain the ability to unfairly strand the value owed to Later Departing Customers.

As CalCCA has argued, if the Commission rejects valuing Pre-2019 Banked RECs at the current-year RPS MPB or allocating the RECs, CalCCA has provided an alternate methodology that is meant to reflect Staff's determination that these Pre-2019 Banked RECs provide a compliance value. Specifically, the Commission could adopt a "compliance-tier-weighted

304 Exh. CCA-03 at 9:1.

formula that addresses the PCC-3 cap directly: 90 percent of the current-year RPS MPB plus 10 percent of the PCC-3 Market price."[305] This reflects the "avoided procurement cost" were the Joint IOU "required to replace Pre-2019 Banked RECs through market procurement," and weighed to give the IOUs the maximum share of compliance that they can satisfy using PCC-3 RECs.[306]

2. Crediting Later Departing Customers with the MPB for the RECs They Purchased Does Not do Violence to the Policy Balance the Commission Struck Prior to 2019 (Issue 2.b)

a. The IOUs' "Prior Cost Shift" Arguments Focus on the Wrong Group of Customers

The IOUs dedicate substantial portions of their testimony to airing past grievances about the PCIA methodology that existed before D.18-10-019.[307] According to the IOUs, Previously Departed Customers paid too little in their PCIA rates, and Then-Bundled Customers were left to pick up the bill. [308] They argue CalCCA ignores these past injustices to "cherry pick" a solution for Later Departing Customers.[309]

But the IOUs' arguments all focus on the wrong group of customers. The prior indifference methodology addressed the allocation of above-market costs between Previously Departed Customers and Then-Bundled Customers, which in 2015, for example, were departed and bundled customers:[310]

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305 Exh. CCA-04 at 19:8-10.
306 *Id*. at 19:10-13.
307 *See, e.g.,* Exh. JIOU-01 at 19:14-23:2, App. C; Exh. JIOU-02 at 7:19-11:9; Exh. JIOU-03 at 2:12-16.
308 Exh. JIOU-02 at 7:19-11:9.
309 Exh. JIOU-01 at 19:14-23:2; IOU Ex Parte, Attachment A, Slide 4.
310 Vol. 1 Tr. 33:14-19 (IOU Panel [Brown, Pulgar, Morien]).

Q Okay. Do you agree that in, say, 2015, there were two sets of customers, those that were departed and those that were bundled?

A Erin Pulgar. For PCIA ratemaking purposes, yes. We had bundled service customers, and we had departing load customers.

CalCCA's proposal has nothing to do with the way the Commission addressed indifference between bundled service customers and departed customers as they existed at the time the RECs were generated. The two groups of customers CalCCA seeks to address with its proposal—Later Departing Customers and Current Bundled Customers—were *both bundled customers* when the RECs were generated. Those customers paid the same ERRA generation rates for the Pre-2019 Banked RECs.[311] Whether they paid too much or too little for those RECs, they both paid too much or too little in equal measure. Whether they suffered or benefitted from any cost shift that existed from the prior methodology, they both suffered or benefitted from that cost shift in equal measure.

CalCCA seeks to address the issue of indifference between those two groups of customer *today*, long after a portion of the Then-Bundled Customers departed for CCA service and became Later Departing Customers and long after the RECs were banked for later use.[312] As the IOUs' witnesses admitted during hearings, RECs are unique from other attributes like energy and capacity in that they can be banked for later compliance use.[313] Despite the long list of IOU grievances about prior methodologies to value energy and capacity during the pre-2019 era, no

311 Vol 1. Tr. 37:12-23; 39:5-41:1 (Joint IOU Panel [Brown, Morien, Pulgar]); Exh. CCA-25.
312 Exh. CCA-02 at 15:1-17.
313 Vol. 1 Tr. 30:9-15 (IOU Panel [Brown, Pulgar, Morien]).

"banked energy" or "banked capacity" exists that raises the same questions about fairness *today* that Banked RECs raise.[314] Indeed, with only one exception, the IOUs have only recently begun using Banked RECs for compliance.[315] And because both Current Bundled Customers and Later Departing Customers paid for the same Pre-2019 Banked RECs, both should benefit. That result has nothing to do with the Previously Departed Customers around which so many of the IOUs' arguments are centered regarding who paid too much and who paid too little in the past.[316]

The fact of the matter is that CalCCA does not challenge the previous approach, does not ask the Commission to revisit the pre-2019 PCIA methodology, and does not attempt to quantify a cost shift between Previously Departed Customers and Then-Bundled Customers. Those questions all focus on the wrong group of customers.

b. No Pre-2019 Banked RECs are Being Revalued or Trued Up

The reason the IOUs focus on the wrong group of customers is to foster indignation about "cherry picking" and to cloud an otherwise simple issue.[317] This strategy reveals itself most clearly when the IOUs repeatedly assert that Pre-2019 Banked RECs have already been valued for departed customers, that CalCCA's proposal seeks to true up that value, and that, in doing so, the proposal will provide Later Departing Customers a partial refund for prior settled rates.

These assertions purposefully confuse the difference between "valuing" a REC and "benefitting" from a REC. While the Pre-2019 Banked RECs were "valued" for the purposes of

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314 Vol. 1 Tr. 29:17-30:8 (IOU Panel [Brown, Pulgar, Morien]).

315 Exh. CCA-02C at 15:8-14, n.21 (citing to PG&E, SCE and SDG&E responses to CalCCA Data Request 3.01).

316 As described by the Joint IOUs, it would likely not even be possible at this point to definitively resolve whether there was a previous cost shift due to the fundamentally different PCIA methodologies pre-2019 and post-2018. Exh. JIOU-01 at 28:16-30:19.

317 Exh. JIOU-01 at 19:14-23:2.

calculating Pre-2019 Banked RECs for Previously Departed Customers' PCIA rates, only those customers received any benefits from that valuation. As Witness Dickman explains:

> Take, for example, a REC generated and banked in 2015 and used for Current Bundled Customer compliance in 2026. The IOUs are correct that a "value" was assigned to these RECs in 2015; that value, however, represented the payment to Previously Departed Customers through the PCIA because the RECs generated in 2015 would remain with the IOU. While the Then-Bundled Customers paid for all of the RECs generated in 2015,[318] they received no benefit from those RECs at that time because they were banked – i.e., placed on the shelf – to be used for the benefit of bundled customers at a later time at the IOUs' choosing. The benefit to bundled customers arises only when the IOUs use the banked RECs as compliance instruments in 2026 (in this example) for Current Bundled Customers, avoiding the cost of procuring additional RECs to satisfy their compliance obligation at that time.[319]

Figures 4 and 6, *supra*show these payments and benefits. Figure 4 shows how when the RECs were generated and banked, only Previously Departed Customer received a benefit. Figure 6 shows that when the Pre-2019 Banked RECs are used for Current Bundled Customer RPS compliance, Later Departing Customers do not receive a benefit for their share of the Pre-2019 Banked RECs for which they paid when they were Then-Bundled Customers.

The IOUs repeatedly and continuously seek to mislead the Commission on these simple mechanics in testimony and in *ex parte* meetings:

- When they assert "CalCCA proposes that RECs should be valued twice,"[320] that "Pre-2019 RECs were already valued in years 2012-2018,"[321] and that "Pre-2019 RECs were *already valued* under the pre-2019 PCIA methodology"[322] they (purposefully) fail to

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318 "Payment" by bundled customers prior to 2019 had two dimensions. Bundled customers paid the cost of renewable resources for their share of banked RECs; they also paid the RPS MPB – a market price proxy – for the share of the banked RECs that were attributable to Previously Departed Customers.

319 Exh. CCA-01 at 5:13-6:5.

320 Exh. JIOU-01 at 15:4-6.

321 IOU Ex Parte, Attachment A, Slide 2.

322 *Id.* (emphasis in original).

acknowledge that only Previously Departed Customers benefitted from that valuation in the past. Later Departing Customers never benefitted.

- When the IOUs argue that "departing load customers already received the market value for those attributes in the year of generation,"[323] they (purposefully) fail to explain that only Previously Departed Customers received that value. Later Departing Customers did not receive that value.

- When the IOUs argue that "any ratemaking value associated with renewable attributes from pre-2019 resources was addressed in the relevant generation year ratemaking processes,"[324] they (purposefully) fail to explain that value was only addressed for Previously Departed Customers. It was never addressed for Later Departing Customer.

- When the IOUs argue "[t]he total portfolio indifference calculation prior to 2019 credited the total portfolio cost with the value of energy, the value of RPS, and the value of RA using MPBs set by the Commission,"[325] they (purposefully) fail to explain that only Previously Departed Customers received those credits. Later Departing Customers never received those credits.

- When the IOUs argue that "[t]hese RECs were already valued and accounted for under that methodology,"[326] they (purposefully) fail to acknowledge that only Previously Departed Customers benefitted from that value. Later Departing Customers never benefited from that value.

- When the IOUs assert CalCCA seeks "re-valuation of Pre-2019 Banked RECs in the year of compliance use…" they (purposefully) ignore that the RECs would not be revalued for either Previously Departed Customers or Later Departing Customers.[327]

The utility arguments are equally slippery when they discuss true-ups and rate refunds. When the IOUs argue CalCCA's proposal would constitute "a true-up of previously settled rates"[328] they (purposefully) ignore the fact that Later Departing Customers never received the benefit of the RECs so nothing is being trued up. When the IOUs argue that today's bundled service customers compensating "Later Departing Customers for Pre-2019 Banked RECs is a partial generation rate refund nearly a decade after-the-fact,"[329] they (purposefully) ignore the

323 Exh. JIOU-02 at 2:23-3:1
324 *Id*. at 8:23-24
325 *Id*. at 33:19-22.
326 Exh. JIOU-03 at 2:20-21.
327 Exh. JIOU-01 at 19:22-20:1.
328 *Id*. at 30:1-19.
329 *Id*. at 18:4-12.

fact that providing Previously Departed Customers a credit to their PCIA rates does not require the reconsideration of decades-old ratemaking. It finally provides value for the rates those customers paid.

Correcting for a clear cost shift today does not do violence to the policy balance the Commission struck prior to 2019. The IOUs' past grievances focus on the wrong group of customers, and the Commission should not accept the fog created by the IOUs on revaluations, true-ups and rate refunds.

3. The Commission Does Not Need to Make a Large Change to Implement the Right Policy, Merely Apply Existing PCIA Rules With a Few Small Clarifications (Issue 2.c)

The Commission can require the Joint IOUs to adequately account for the appropriate value of Pre-2019 Banked RECs without inventing any significant new tools. CalCCA's proposal (to value Pre-2019 Banked RECs at the compliance year RPS MPB and credit that value to the customer vintage for the year in which the REC was generated and banked) utilizes existing PCIA features. To accomplish CalCCA's proposal, the IOUs would simply need to know the following information: (1) the quantity of Pre-2019 Banked RECs they use for compliance in a particular year, (2) the generation year of those Pre-2019 Banked RECs, (3) the vintage of the customers in the IOU's territory, and (4) the RPS MPB of the year in which the Pre-2019 Banked RECs are used for compliance. The IOUs either already know this information (number 3), will learn it through the course of the compliance year (number 1), will make a decision that determines it (number 2), or will receive it via email from Energy Division (number 4). As noted above, PG&E already demonstrated how this can easily be done for Pre-2019 Banked RECs because this is the method PG&E used for multiple years to allocate the value of Pre-2019 Banked RECs in its ERRA Forecast proceedings.

For CalCCA's alternate allocation proposal, the only piece of additional information the IOUs need to know is which LSEs have which proportion of the different customer vintages. That is information the IOUs also already know.

For CalCCA's proposal in response to the Staff Report (the 90 percent RPS MPB and 10 percent PCC-3 MPB) the Commission's Energy Division would need to produce a new PCC-3 MPB. But Energy Division could use the same LSE survey process to calculate this new MPB drawing on the transaction data already collected as part of that process.[330] To the extent Energy Division is not ready to produce a PCC-3 this year, it could set the PCC-3 price to $0 for this year's calculation purposes, providing the IOUs the lowest conceivable value for any Pre-2019 Banked RECs used for compliance this year.[331]

None of these treatments for Pre-2019 Banked RECs, would require any significant change to other proceedings or precedents. However, for the allocation proposal, the Commission would need to publish a new RPS Compliance Reporting Template that includes a location for LSEs to adjust the Excess Procurement Banked quantities.[332]

VI. CONCLUSION

CalCCA respectfully requests that the Commission adopt the recommendations set forth herein. Specifically, CalCCA requests that:

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330 Exh. CCA-03 at 26:4-6.

331 *Id*. at 26:6-9.

332 *Id*. at 23:1-4. The Joint IOUs have argued that CalCCA's proposal does not account for customers who departed before a REC was banked, migrated back from departed service to bundled service and then re-departed before that REC was used for compliance. As a preliminary matter, the amount of those customers is extremely small and should not prevent the Commission from adopting a proposal that addresses a much larger wrong. Only SDG&E was able to quantify this group and they identified a total of 91 customers. Exh. CCA-02 at 28:8-10. These customers would benefit twice from the same REC procurement—first when receiving credit for the REC in the generation year through the PCIA and a second time (because of their re-vintage to the later departure year) when receiving a payment to their new vintage. Exh. CCA-02 at 28:14-29:3. This marginal impact should not stand in the way of tens of millions of customers receiving their fair compensation or allocation. Exh. CCA-02 at 29:3-5.

(1) The Commission require the IOUs to:

   a. Value any Pre-2019 Banked RECs used for bundled customer RPS compliance at the compliance year RPS MPB; and

   b. credit that value to the vintage corresponding to any such RECs' generation year;

(2) In the alternative, instruct the IOUs that use Pre-2019 Banked RECs for bundled customer compliance to first proportionately allocate Pre-2019 Banked RECs to the Later Departing Customers who paid for those Pre-2019 Banked RECs via a decrement to the applicable LSE's RPS Procurement Need;

(3) If the Commission does not adopt CalCCA's valuation or allocation proposals rooted in the indifference requirements, it should adopt Staff's recognition that Pre-2019 Banked RECs provide compliance value by instructing the IOUs to:

   a. value any Pre-2019 Banked REC used for bundled customer RPS compliance at a 90/10 composite of the RPS MPB and a new PCC-3 REC MPB, which the Commission should instruct its Energy Division to produce and publish along with the other MPBs; and

   b. credit that value to the vintage corresponding to any such RECs' generation year.

Respectfully submitted,

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June 16, 2026

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2027 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	Application No. 26-05-007 (Filed May 15, 2026)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S PROTEST TO PACIFIC GAS AND ELECTRIC COMPANY'S APPLICATION

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June 17, 2026

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SUMMARY OF RECOMMENDATIONS

- The Commission[1] should set the default discovery timelines for all parties to: (1) five business days prior to the Fall Update; (2) three business days after rebuttal testimony; and (3) two business days after the Fall Update is filed, with exceptions from those timelines allowed in the event that PG&E requires more time due to the number or breadth of data requests;
- The Commission should require PG&E to serve public and confidential workpapers concurrently with all supplements and updates to testimony;
- The Commission should require from PG&E a clear presentation of modifications between its Prepared Testimony and any supplemental testimony;
- The Commission should require PG&E to serve public and confidential workpapers contemporaneously with all testimony supplements and updates over the course of the proceeding;
- The Commission should categorize this Application as ratesetting;
- The Commission should not grant the relief requested in PG&E's Application at this time and should set PG&E's Application for hearing; and
- The Commission should adopt CalCCA's proposed procedural schedule.

[1] Acronyms and defined terms used in the Summary of Recommendations are defined in the body of this Protest.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2027 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	Application No. 26-05-007 (Filed May 16, 2026)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S PROTEST TO PACIFIC GAS AND ELECTRIC COMPANY'S APPLICATION

Pursuant to Rule 2.6 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission or CPUC), the California Community Choice Association[2] (CalCCA) hereby protests the *!"##$%&'(%*!) +!, ' &%%&!- ' . !' */ !0 $1&(2%&!3) 4 #' *5!6, - 7 0 8!+) 2!"/) #(%*!) +! 0 $1&(2%&!9 1: 1*; 1!9 1<; %&14 1*(. !' */ !9 ' (1. !"..) &%(1/ != %>!% !?@?A!0 *12B5!9 1.) ; 2&1!9 1&) : 125! "&%) ; *(! 60 9 9 "8! ' */ ! - 1*12' (%*! C) *DE5#' . . ' F$1! 3 >' 2B1. ! G) 21&. (! ' */ ! - 211*>) ; . 1! - ' . ! G) 21&. (!9 1: 1*; 1!9 1(; 2*!' */ !9 1&) *&%%(%*!6HI J0 8!* (Application).[3]

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[2] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, Energy for Palmdale's Independent Choice, Lancaster 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.

[3] Application (A.) 26-05-007, ! "" #$%&'$( )*(+*, &%$+$%* - &.*&) /*0#1%'2$%*3 (4 "&) 5*+(2*! / ("'$( )*(+* 0#1%'2$%*6171)81*6198$21 4 1)'.*&) /*6&'1.*! . . (%$&'1/*: $';*$'.*<=<>*0)12?5*61.(82%1*61%(7125*! %%(8)'* @066! A*&) /* - 1)12&'$( )*B( )CD5"&. .&E#1*3 ; &2?1.*F(21%&.'*&) /* - 211) ; (8.1* - &.*F(21%&.'*6171)81* 61'82)*&) /*61%( )%$#$&'$( )*@GHI 0A*(May 15, 2026) (Application).

PG&E's annual ERRA Forecast proceeding is immensely consequential for community choice aggregators (CCA) serving customers in PG&E's service area because the Commission sets Power Charge Indifference Adjustment (PCIA) rates in this proceeding. Both bundled and unbundled customers pay PCIA rates. However, unlike bundled customers, whose PCIA rates are naturally buffered by bundled generation rates, unbundled customers are uniquely vulnerable to volatility in the PCIA. PCIA rate setting, therefore, has a disproportionate impact on affordability for CCA customers.

In its Application, PG&E forecasts PCIA rates decreasing for unbundled customers.[4] But there is a strong possibility this forecast will change later in the year. ERRA Forecast proceedings involve several updates to forecast rates, including a "Fall Update" in October, a preliminary Annual Electric True-Up (AET) advice letter submission in November, and a final AET advice letter submission in December. PCIA rates can, and routinely do, change significantly at each stage. This year, CalCCA anticipates several factors creating ***;#='2/*** pressure on PCIA rates, making it highly likely PG&E's forecast PCIA rate decreases evaporate, and potentially reverse, in October.

While many factors drive swings in PCIA rates, particularly impactful among those factors are "market price benchmarks" (MPB)—the Commission's administrative proxies for the components of market value in PG&E's resource portfolio. The calculation of the PCIA revenue requirement nets the cost of PG&E's PCIA-eligible resources against their value, and therefore, lower MPBs mean higher PCIA rates, all else equal (and vice versa).

MPBs impact the PCIA revenue requirement in two discrete ways. First, they impact the calculation of the forecast Indifference Amount—the forward-looking component of the PCIA

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4 J/. at 5.

revenue requirement tied to a projection of portfolio costs and value for the upcoming year (2027, in this case). Second, they impact the calculation of the Portfolio Allocation Balancing Account (PABA) true-up—the rolling true-up component of the PCIA revenue requirement tied to actual portfolio costs and values for the current year (2026, in this case).

PG&E's Application uses the 2026 Forecast Resource Adequacy (RA) MPB ($11.53/kW-month) and Renewable Portfolio Standard (RPS) MPB ($62.45/MWh), released by Energy Division in October 2025, to calculate RA and RPS value for the purposes of both the Indifference Amount and the PABA true-up.[5] To calculate the energy (Brown Power) value, PG&E uses March 26, 2026, forward electric prices for 2027 as a placeholder.[6] Each of those benchmarks will change—and are anticipated to decrease—when Energy Division releases 2026 Actual and 2027 Forecast MPBs in October of this year. In that likely scenario, the value of PG&E's PCIA-eligible portfolio will decrease, exerting upward pressure on PCIA rates. Other factors, including in particular an anticipated update to PG&E's Utility-Owned Generation (UOG) revenue requirement resulting from the resolution of its 2027 Phase 1 General Rate Case (GRC),[7] will also contribute to upward pressure on PCIA rates.

As this Protest discusses below, certain PG&E proposals may exacerbate these impacts. For example, despite implementing Southern California Edison Company's (SCE) "interim methodology" for calculating the capacity value of storage resources in its PCIA portfolio, PG&E resists applying that methodology to non-storage resources. As another example, PG&E proposes to use banked Renewable Energy Credits (REC) towards its "Minimum Retained RPS"

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5 PG&E Prepared Testimony at 8-23.

6 *Id.* at 8-23; Table 4-1 at 4-2.

7 *Id.* at 8-8 to 8-9.

requirement and value those RECs at zero dollars, rather than using significant available quantities of Unsold RPS towards that requirement. Each of these proposals will likely magnify increases in PCIA rates.

CalCCA will assess PG&E's proposals and requests and examine their impacts on PCIA rates. To the extent PG&E's proposals are inaccurate, unreasonable, or inconsistent with past Commission guidance, decisions, or rules, CalCCA intends to address those proposals through testimony and briefing as appropriate. The Commission should not grant any of the relief PG&E requests without setting this matter for hearing. Further, the Commission should adopt CalCCA's modest changes to PG&E's proposed schedule to ensure this important and expedited case runs as smoothly as possible.

I.! CALCCA'S INTEREST

A.! CalCCA Represents the Interests of Twelve CCAs That Serve PG&E's Delivery Service Customers

CalCCA represents the interests of 24 CCAs in California, including 11 CCAs that serve PG&E's delivery service customers. Each of those CCAs is governed by a Board of Directors comprised of elected officials who represent the individual cities and counties the CCA serves, or an elected City Council.[8] CleanPowerSF is the CCA for the City and County of San Francisco, which the San Francisco Public Utilities Commission operates. San José Clean Energy is the City of San José's CCA program, which San José Energy Department administers. While CalCCA's advocacy frequently benefits both bundled and unbundled customers, the CCAs are the sole advocates for their customers and their local energy programs before this Commission.

[8] Redwood Coast Energy Authority's Board of Directors also includes tribes.

B.! CCAs Are Subject to Several Non-Bypassable Charges, Including the PCIA

CCA customers receive generation services from their local CCA and receive transmission, distribution, billing, and other services from the investor-owned utility (IOU). As such, CCA customers must pay the same electric distribution, transmission and non-bypassable rates as the IOU's bundled customers. However, CCA customers pay CCA-specific generation rates, which vary and are partially influenced by local mandates to increase electric vehicle use, procure and maintain clean electricity portfolios that in many cases exceed state requirements for renewable generation, and achieve other local goals. CCA and other unbundled customers are also subject to several non-bypassable charges (NBC), including the PCIA. As discussed below, the 2027 levels of the PCIA will be established in this proceeding.

C.! CalCCA Has a Real, Direct, Tangible, Material, and Pecuniary Interest in the Outcome of this Proceeding

In its Application, PG&E requests the Commission:

1) Adopt the 2027 ERRA-related revenue requirements listed in its Application (and as updated in the Fall Update);
2) Adopt PG&E's forecast 2027 electric sales (as updated in the Fall Update);
3) Adopt PG&E's GHG-related revenue forecasts for 2027 (as updated in the Fall Update);
4) Approve PG&E's recorded 2025 administrative and outreach expenses of $867,000;
5) Approve PG&E's rate proposals associated with its proposed total electric procurement-related revenue requirements to be effective in rates on January 1, 2027; and

6) Grant such additional relief as the Commission deems proper.[9]

Importantly, PG&E requests the Commission establish the 2027 levels of the PCIA, which, as described above, both bundled and unbundled customers pay.

CalCCA seeks to participate in this proceeding in order to protect the interests of the CCAs it represents and the interests of those CCAs' customers, in large part because the PCIA represents a significant component of the overall rates those customers pay. Ensuring the accuracy of the PCIA and other charges CCA customers pay, planning for changes to the PCIA, and protecting customers from the rate shock that can result from those changes are core directives for all CCAs and essential for any load-serving entity (LSE). CalCCA and its members therefore have a real, direct, present, tangible, and pecuniary interest in this proceeding. As this Protest discusses below, PG&E's Application impacts CalCCA's interests in several ways.

II.! GROUNDS FOR PROTEST

The impact of PG&E's Application on both departed and bundled customers requires scrutiny under the applicable legal standards. PG&E, as the applicant, bears the burden of proof in ERRA Forecast proceedings.[10] That burden of proof includes a burden of production, which in ERRA Forecast proceedings is a preponderance of the evidence.[11] That means the Commission

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[9] Application at 34-36.

[10] R.11-02-019K*L1%$.$()*@LMA*N&)/&'$)?*,$"1#$)1*O&+1'5*J4"#141)'&'$()*,#&)K*L$.&##(:$)?*3(.'.K*!##(%&'$)?*6$.P*(+*J)1++$%$1)'*3().'28%'$()*N&)&?141)'*'(*O;&21;(#/12.K*&)/*6198$2$)?*Q)?($)?*J4"2(7141)'*$)*O&+1'5*0)?$)112$)? at 42 (Dec. 28, 2012) (D.12-12-030).

[11] O11K*1M?MK*A.17-06-005,*L1%$.$()*!/("'$)?*,&%$+$%*-&.*&)/*0#1%'2$%*3(4"&)5R.*<=ST*0)12?5*61.(82%1*61%(7125*!%%(8)'*F(21%&.'*&)/*-1)12&'$()*B()CD5"&..&E#1*3;&2?1.*&)/*-211);(8.1*-&.*F(21%&.'*6171)81*&)/*61%()%$#$&'$() at 9-10 (Jan. 16, 2018)*(D.18-01-009); R.11-02-019,*Q2/12*N(/$+5$)?*L1%$.$()*LM*S<CS<C=H=*&)/*L1)5$)?*61;1&2$)?K*&.*N(/$+$1/*at 29 (July 27, 2015) (D.15-07-044) (observing that the Commission has discretion to apply either the preponderance of evidence or clear and convincing standard in a ratesetting proceeding, but noting that the preponderance of evidence is the "default standard to be used unless a more stringent burden is specified by statute or the Courts.").

should not grant the relief PG&E requests unless a preponderance of the record evidence demonstrates PG&E has affirmatively satisfied its burden of proof with respect to that request.

CalCCA protests the Application on the grounds that PG&E's Application and supporting testimony do not demonstrate that PG&E has met its burden of proof with respect to the entirety of the relief it requests. Based on its preliminary review of PG&E's Application, CalCCA has identified certain issues that should prevent immediate adoption of the relief PG&E requests in its Application. These issues directly impact CalCCA's interests and are described in more detail below.

A.! PG&E's Methodology for Calculating Non-Storage Retained RA Quantities and Bundled Open System RA Position Is Not Consistent With SCE's Interim SOD Methodology.

PG&E explains the Commission's RA compliance program transitioned to a Slice-of-Day (SOD) framework in 2025. Under the new SOD framework, LSEs, including PG&E, must show sufficient capacity to meet 24 separate hourly requirements across each month of the year.[12]

The new SOD framework has implications for PCIA ratemaking, because setting PCIA rates require the Commission to determine the value—including RA value—of PG&E's PCIA-eligible resource portfolio. In its 2026 ERRA Forecast proceeding, PG&E proposed several methodologies to reflect the SOD framework in one component of PCIA ratesetting: the calculation of Retained RA value associated with storage resources. The Commission rejected PG&E's proposals in Decision (D.) 25-12-027 and directed PG&E to apply SCE's SOD methodology to calculate the RA value of storage resources "on an interim basis while awaiting a

[12] PG&E Prepared Testimony at 4-11.

more comprehensive decision on implementation of the SoD methodology."[13] PG&E filed Advice Letter 7280-E implementing SCE's SOD methodology for the calculation of Retained RA value from storage resources on January 22, 2026.

In this proceeding, PG&E asserts that it applies SCE's SOD methodology to forecast retained RA volumes for its PCIA-eligible storage resources in 2027, consistent with D.25-12-027.[14] CalCCA will evaluate PG&E's Retained RA calculations to verify that PG&E's forecast indeed accurately reflects SCE's SOD methodology for storage resources.

Based on CalCCA's preliminary review of PG&E's Application, however, it appears PG&E has not fully implemented SCE's interim SOD methodology for PCIA ratemaking purposes. Specifically, PG&E's (1) calculation of its bundled open system RA position (which impacts its Sold and Unsold RA quantities), and (2) its calculation of retained RA quantities from non-storage resources each appear to be inconsistent with SCE's interim SOD methodology. These deviations each have implications for PCIA rates because PG&E's calculation of the RA value (Retained, Sold, and Unsold) of its PCIA-eligible portfolio directly impacts its calculation of the forecast PCIA revenue requirement (the Indifference Amount). CalCCA will examine PG&E's implementation of the SOD framework for PCIA ratemaking purposes in this case, and will review the application of PG&E's methodology to the calculation of its bundled open system RA position and non-storage Retained RA quantities (relative to the impact of SCE's interim SOD methodology on the same calculations) to ensure PG&E's approach is accurate, reasonable, and

[13] A.25-05-011, L1%$.$()*!""2(7$)?*,&%$+$%*-&.*&)/*0#1%'2$%*3(4"&)5R.*<=<U*0)12?5*61.(82%1*61%(7125*!%%(8)'*61#&'1/*F(21%&.'*6171)81*6198$2141)'*&)/*<=<U*0#1%'2$%*O&#1.*F(21%&.' at 37-38 (Dec. 18, 2025) (D.25-12-027).

[14] PG&E Prepared Testimony at 5-11.

consistent with Commission decisions. Based on discovery, CalCCA may address PG&E's approach in testimony as needed.

B.! PG&E Proposes to Cover Its Forecasted Short RPS Position in 2027 Using Pre-2019 Banked RECs, and Not Using Unsold RPS.

The Commission established a minimum retained RPS volume requirement in D.20-02-047.[15] Under this requirement, the annual RPS target quantities provided in D.11-12-020[16] (for calculating the RPS period requirement) serve as minimum quantities for the purposes of calculating PG&E's retained RPS volumes in the PCIA.

As in several previous years, PG&E forecasts a short RPS position in 2027.[17] It expects to use "banked" Renewable Energy Credits (REC)—surplus RECs not used towards bundled customer compliance in prior years—to cover that shortfall.[18] While PG&E proposes to value any RECs banked in years prior to 2019 at zero dollars,[19] it acknowledges that Track Two of the PCIA rulemaking focused on the valuation of pre-2019 banked RECs is currently underway, and a decision in that rulemaking is expected to impact the valuation of any banked RECs PG&E uses in the Fall Update.

Notably, PG&E does not propose to use its Unsold RPS quantities from 2023 (3,073,161 MWh) or 2024 (412,848 MWh) to cover its forecast shortfall in 2027.[20] Nothing in prior Commission decisions requires PG&E to use banked RECs to cover its forecast REC shortfall

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15 A.19-06-001, L1%$.$()*!/("'$)?*,&%$+$%*-&.*&)/*0#1%'2$%*3(4"&)5R.*<=<=*0)12?5*61.(82%1*61%(7125*!%%(8)'*F(21%&.'*&)/*-1)12&'$()*B()CD5"&..&E#1*3;&2?1.*F(21%&.'*&)/*-211);(8.1*-&.*F(21%&.'*6171)81*61'82)*&)/*61%()%$#&'$() (Feb. 27, 2020) (D.20-02-047).

16 R.11-05-005, L1%$.$()*01''$)?*,2(%82141)'*V8&)'$'5*6198$2141)'.*+(2*61'&$#*01##12.*+(2*';1*61)1:&E#1.*,(2'+(#$(*0'&)/&2/*,2(?2&4*(Dec. 5, 2011) (D.11-12-020).

17 PG&E Prepared Testimony at 8-17.

18 J/.

19 J/. at 8-16.

20 * 011*$/., Table 8-2 at 8-15.

before it uses Unsold RPS volumes. Further, Track Two of the PCIA OIR does not address the use of Unsold RPS volumes towards the IOUs' Minimum Retained RPS requirement.

PG&E's approach to meeting its Minimum Retained RPS requirement impacts its calculation of the Retained RPS value of its PCIA-eligible portfolio, and therefore, impacts the PCIA and CalCCA's interests. CalCCA will review PG&E's use and accounting of banked RECs in this case, and more broadly, its minimum retained RPS entries and its calculation of the RPS value of its PCIA-eligible portfolio to ensure it is accurate, reasonable, and consistent with Commission decisions. Based on discovery, CalCCA may address PG&E's approach in testimony as needed.

C.! Other Issues Impacting CalCCA's Interests

In addition to the issues described above, CalCCA has identified several other issues in PG&E's Application that impact CalCCA's interests and require further examination. Those issues include:

- Whether PG&E has correctly and accurately calculated PCIA rates, including whether PG&E's Indifference Calculation inputs and sources are appropriate and comply with D.18-10-019[21] and D.19-10-001;[22]
- Whether PG&E's funding set-asides for the Disadvantaged Community-Green Tariff (DAC-GT) program and the Community Solar-Green Tariff (CS-GT) programs are consistent with the budgets requested by the particular CCAs;
- Whether PG&E is appropriately allocating greenhouse gas (GHG) credits; and
- Whether PG&E is correctly reflecting its Utility-Owned Generation (UOG) revenue requirement in the PCIA.

[21] R.17-06-026, L1%$.$()*N(/$+5$)?*';1*,(:12*3;&2?1*J)/$++121)%1*!/W8.'41)'*N1';(/(#(?5 (Oct. 19, 2018) (D.18-10-019).

[22] R.17-06-026, L1%$.$()*61+$)$)?*';1*N1';(/*'(*L171#("*&)/*X281*G"*N&2P1'*,2$%1*D1)%;4&2P. (Oct. 17, 2019) (D.19-10-001).

CalCCA is still examining the Application, conducting discovery,[23] and communicating with PG&E to better understand and analyze the utility's requests. CalCCA reserves the right to address and protest additional issues within the scope of this proceeding as they arise through continued review, analysis, discovery and investigation of all aspects of the Application and supporting testimony.

III.! CATEGORIZATION OF PROCEEDING, NEED FOR HEARINGS, SCOPE OF ISSUES, AND PROPOSED PROCEDURAL SCHEDULE

A.! CalCCA Agrees This Proceeding Should Be Categorized As "Ratesetting"

PG&E proposes to categorize this proceeding as a ratesetting proceeding within the meaning of Rule 1.3(g) of the Commission's Rules of Practice and Procedure.[24] CalCCA agrees with the categorization of this proceeding as ratesetting.

B.! CalCCA Believes Hearings May Be Necessary

PG&E states the need for hearings in this proceeding, and the issues to be considered in hearings will depend on the degree to which other parties contest PG&E's requests.[25] As this Protest makes plain, CalCCA contests several of PG&E's requests, and may contest additional requests as it continues to review PG&E's Application. While CalCCA will pursue settlement and record stipulations to the extent feasible, PG&E appropriately assumes hearings may be necessary. The Commission should reserve a date for an evidentiary hearing to address unresolved issues of fact.

C.! Issues to be Considered

CalCCA does not object to PG&E's proposed scoping issues.

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[23] As of the date this Protest was filed, CalCCA has submitted over 50 data requests to PG&E in order to evaluate the proposals in the Application.

[24] Application at 30.

[25] J/.

D.! Proposed Procedural Schedule

CalCCA generally supports PG&E's proposed procedural schedule and acknowledges that its proposal is similar to the schedule adopted in recent ERRA Forecast cases. However, that schedule tends to compress case activities following PG&E's rebuttal testimony filing, including the issuance of discovery related to PG&E's rebuttal testimony, preparation for hearing, and briefing. In order to allow parties more time to carry out these important litigation steps, CalCCA proposes to advance by one week PG&E's proposed deadlines for intervenor testimony, rebuttal testimony, and the post-rebuttal meet and confer. CalCCA also proposes to advance the date for an evidentiary hearing by three days.

CalCCA's proposed procedural schedule is below. CalCCA has conferred with PG&E, the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), the Small Business Utility Association (SBUA) and the Direct Access Customer Coalition (DACC) regarding its proposed procedural schedule, and can represent that PG&E does not object to its proposal and that DACC supports its proposal (Cal Advocates and SBUA did not respond with a position on CalCCA's proposal).

Event	**PG&E Proposal**	**CalCCA Counterproposal**
Intervenor Testimony	September 3, 2026	August 27, 2026
Rebuttal Testimony	September 23, 2026	September 16, 2026
Meet and Confer	September 29, 2026	September 22, 2026
Evidentiary Hearings	October 8, 2026	October 5, 2026
Fall Update	October 16, 2026	October 16, 2026
Concurrent Opening Briefs	October 21, 2026	October 21, 2026
Reply Briefs	October 30, 2026	October 30, 2026
Comments on Fall Update	November 16, 2026	November 16, 2026
Comments on Proposed Decision	+ 4 business days after Proposed Decision	+ 4 business days after Proposed Decision
Reply Comments on Proposed Decision	+ 3 business days after Comments on Proposed Decision	+ 3 business days after Comments on Proposed Decision

E.! Other Procedural Requests in Light of the Compressed Nature of This Proceeding.

PG&E and CalCCA have worked cooperatively and constructively in recent ERRA Forecast proceedings, which has allowed both parties to litigate this expedited case without unnecessary motion practice. CalCCA expects both parties will do so again this year. Nevertheless, to promote clear expectations, CalCCA requests that the Commission:

- Set the default discovery timelines for all parties to (a) five business days prior to the Fall Update, (b) three business days after rebuttal testimony and (c) two business days after the Fall Update is filed, with exceptions from those timelines allowed in the event that PG&E requires more time due to the number or breadth of data requests;

- Require PG&E to serve public and confidential workpapers concurrently with all supplements and updates to testimony;

- Require from PG&E a clear presentation of modifications between its Prepared Testimony and any supplemental testimony; and

- Require PG&E to serve public and confidential workpapers contemporaneously with all testimony supplements and updates over the course of the proceeding.

IV.! COMMUNICATIONS AND SERVICE

CalCCA consents to "email only" service and request that the following individuals be added to the service list for A.26-05-007 on behalf of CalCCA:

Party Representative
Nikhil Vijaykar
Keyes & Fox LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Telephone: (408) 621-3256 ***!***
E-mail: nvijaykar@keyesfox.com

Information-Only Please include the individuals listed below on the information-only service list for this proceeding:

Brian Dickman
NEWGEN STRATEGIES & SOLUTIONS LLC
225 Union Boulevard, Suite 450
Lakewood, CO 80228
Telephone: (303) 828-4035
E-mail: bdickman@newgenstrategies.net

Tim Lindl
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E-mail: tlindl@keyesfox.com

Leanne Bober
Director of Regulatory Affairs and Deputy General Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
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Sacramento, CA 95814
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Email: kevin@cal-cca.org

V.! CONCLUSION

For the foregoing reasons, CalCCA requests that the Commission set this matter for hearing to fully examine the issues discussed above.

Dated: June 17, 2026

Respectfully submitted,

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_____!

Nikhil Vijaykar
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San Francisco, CA 94104
Telephone: (408) 621-3256 !
E-mail: nvijaykar@keyesfox.com
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California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Marin Clean Energy ("MCE")

Utility type:
☑ ELC ☐ GAS ☐ WATER
☐ PLC ☐ HEAT

Contact Person: Rachel Dec
Phone #: (415) 419-4948
E-mail: rdec@mcecleanenergy.org
E-mail Disposition Notice to: rdec@mcecleanenergy.org

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 93-E-A

Tier Designation: 2

Subject of AL: Supplement to MCE Advice Letter No. 93-E 2027 Budget Request and Marketing, Education, and Outreach Plan for the Disadvantaged Communities Green Tariff Program

Keywords (choose from CPUC listing):

AL Type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: N/A

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? ☐ Yes ☑ No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? ☐ Yes ☑ No

Requested effective date: 7/18/26

No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are to be sent via email and are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission
Energy Division Tariff Unit Email:
EDTariffUnit@cpuc.ca.gov

Contact Name: Rachel Dec
Title: Policy Analyst
Utility/Entity Name: Marin Clean Energy

Telephone (xxx) xxx-xxxx: (415) 419-4948
Facsimile (xxx) xxx-xxxx: N/A
Email: rdec@mcecleanenergy.org

Contact Name: MCE Regulatory
Title: Regulatory Account
Utility/Entity Name: Marin Clean Energy

Telephone (xxx) xxx-xxxx: N/A
Facsimile (xxx) xxx-xxxx: N/A
Email: regulatory@mcecleanenergy.org

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

ENERGY Advice Letter Keywords

Affiliate	Direct Access	Preliminary Statement
Agreements	Disconnect Service	Procurement
Agriculture	ECAC / Energy Cost Adjustment	Qualifying Facility
Avoided Cost	EOR / Enhanced Oil Recovery	Rebates
Balancing Account	Energy Charge	Refunds
Baseline	Energy Efficiency	Reliability
Bilingual	Establish Service	Re-MAT/Bio-MAT
Billings	Expand Service Area	Revenue Allocation
Bioenergy	Forms	Rule 21
Brokerage Fees	Franchise Fee / User Tax	Rules
CARE	G.O. 131-D	Section 851
CPUC Reimbursement Fee	GRC / General Rate Case	Self Generation
Capacity	Hazardous Waste	Service Area Map
Cogeneration	Increase Rates	Service Outage
Compliance	Interruptible Service	Solar
Conditions of Service	Interutility Transportation	Standby Service
Connection	LIEE / Low-Income Energy Efficiency	Storage
Conservation	LIRA / Low-Income Ratepayer Assistance	Street Lights
Consolidate Tariffs	Late Payment Charge	Surcharges
Contracts	Line Extensions	Tariffs
Core	Memorandum Account	Taxes
Credit	Metered Energy Efficiency	Text Changes
Curtailable Service	Metering	Transformer
Customer Charge	Mobile Home Parks	Transition Cost
Customer Owned Generation	Name Change	Transmission Lines
Decrease Rates	Non-Core	Transportation Electrification
Demand Charge	Non-firm Service Contracts	Transportation Rates
Demand Side Fund	Nuclear	Undergrounding
Demand Side Management	Oil Pipelines	Voltage Discount
Demand Side Response	PBR / Performance Based Ratemaking	Wind Power
Deposits	Portfolio	Withdrawal of Service
Depreciation	Power Lines	

Clear Form

June 18, 2026

California Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

MCE Supplemental Advice Letter 93-E-A

RE: Supplemental: 2026 Budget Request and Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff Program

PURPOSE

MCE hereby submits this supplement to Advice Letter 93-E addressing corrections to the 2026 Budget Request and Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff Program that was submitted on April 1, 2026.

This supplemental advice letter is made in accordance with General Order (GO) 96-B and General Rule 7.5.1, which authorizes utilities to make revisions or corrections to advice letters through the submittal of a supplement. This supplement replaces Advice Letter 93-E in part.

BACKGROUND

Pursuant to Ordering Paragraphs ("OP") 2 and 4 of Resolution E-4999,[1] OP 3 of Resolution E-5125,[2] OPs 2 and 3 of D.24-05-065,[3] and OP 4 of Resolution E-5367[4], Marin Clean Energy ("MCE") submitted MCE AL-93, the program budget request and marketing, education and outreach ("ME&O") plan for the Disadvantaged Communities Green Tariff ("DAC-GT) program for the program year ("PY") 2025, on April 1, 2026.

[1] OP 2 and 4 of Resolution E-4999 specifically directed Pacific Gas and Electric Company, Southern California Edison and San Diego Gas & Electric Company to submit annual program budget estimates and ME&O plans to the Commission by February 1 of each year. MCE's implementation Advice Letter, MCE AL 42-E/E-A/E-B was approved in Resolution E-5124, which brought MCE under the same program rules and reporting structure applicable to the IOUs.
[2] OP 3 of Resolution E-5125 directed that DAC-GT and CS-GT Annual Budget Advice Letters are to be submitted as Tier 2 ALs to allow for additional review and oversight.
[3] OP 2 of D.24-05-065 discontinues the CS-GT program and directs program administrators to transfer remaining capacity, customers, and programs into the DAC-GT program. OP 3 of D.24-05-065 makes several modifications to the DAC-GT program, which are reflected in this budget submission.
[4] OP 4 of Resolution E-5367 authorizes DAC-GT CCA Program Administrators to recover costs associated with developing a Confidential Benchmark Value Reference Price (CBVRP) for DAC-GT solicitations.

On page 1 of AL 93-E, the "Background" section does not address the change in the source of funding for the DAC-GT program. MCE submits this supplemental AL to correct this omission by including an additional paragraph clarifying that the DAC-GT program was being funded by Greenhouse Gas (GHG) Auction Revenue and Public Purpose Program (PPP) funds but going forward will be solely funded through PPP funds. The paragraph specifies that AB 1207, signed into law on September 19, 2025, changes the recoverability of DAC-GT program costs to be from PPP funds beginning on July 1, 2026.[5]

MCE is submitting a revised Advice Letter to correct the error. The original Appendices remain the same.

PROPOSED MODIFICATIONS TO ADVICE LETTER 93-E

MCE proposes the following addition to Advice Letter 93-E, reflected in Appendix A1:

"Commission D.18-06-027 established the DAC-GT program in 2018, with funding through both Greenhouse Gas (GHG) Auction Revenue and Public Purpose Program (PPP) funds. On September 19, 2025, AB 1207 was signed into law which introduced changes to Public Utilities Code Section 748.5 including rendering inoperative as of July 1, 2026, the Commission's authority to allocate up to 15 percent of GHG Auction Revenue to clean energy and energy efficiency projects. Per AB 1207 (Irwin), Stats. 2025, Ch. 117, 100% of DAC-GT and/or CSGT program costs will be recovered from PPP funds starting July 1, 2026."

TIER DESIGNATION

This supplemental AL is submitted with a Tier 2 designation, the same Tier designation pursuant to OP 3 of Resolution E-5125.

EFFECTIVE DATE

MCE requests that this supplemental AL become effective concurrent with the original AL 93-E, on May 1, 2026.

NOTICE

A copy of this AL is being served on the official Commission service lists for Rulemaking R.14-07-002 and Application A.22-05-022.

For changes to this service list, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

[5] AB 1207 (Irwin), Chapter 117, Statutes of 2025, amending Health and Safety Code §§ 38501, 38562, 38590.1, 38591.1, 38591.2, 38592.5, 38592.6, 38594; adding and repealing § 38562.1; and amending Public Utilities Code § 748.5 and adding § 748.5.5.

PROTESTS

MCE requests that the Commission, pursuant to General Order 96-B, General Rule 7.5.1, maintain the original protest and comment period designated in advice letter 79-E. Protests must be submitted to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

In addition, protests and all other correspondence regarding this advice letter shall be sent electronically to the attention of:

Rachel Dec
Policy Analyst
Marin Clean Energy
1125 Tamalpais Ave
San Rafael, CA 94901
Email: rdec@mceccleanenergy.org

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

CORRESPONDENCE

For questions, please contact Rachel Dec at (415) 419-4948 or by electronic mail at rdec@mceccleanenergy.org.

/s/ Rachel Dec

Rachel Dec
Policy Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 419-4948
Email: rdec@mceccleanenergy.org

cc: Service List for R.14-07-002 and A.22-05-022

APPENDIX A1

April 1, 2026

California Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

Marin Clean Energy Advice Letter 93-E

RE: 2027 Budget Request and Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff Program

Pursuant to Ordering Paragraphs ("OP") 2 and 4 of Resolution E-4999,[6] OP 3 of Resolution E-5125,[7] OPs 2 and 3 of Decision ("D.").24-05-065,[8] and OP 4 of Resolution E-5367[9] Marin Clean Energy ("MCE") hereby submits this Tier 2 Advice Letter ("AL") to submit the program budget request and marketing, education and outreach ("ME&O") plan for the Disadvantaged Communities Green Tariff ("DAC-GT) program for the program year ("PY") 2027.

TIER DESIGNATION

This AL has a Tier 2 designation pursuant to OP 3 of Resolution E-5125.

EFFECTIVE DATE

[6] OP 2 and 4 of Resolution E-4999 specifically directed Pacific Gas and Electric Company, Southern California Edison and San Diego Gas & Electric Company to submit annual program budget estimates and ME&O plans to the Commission by February 1 of each year. MCE's implementation Advice Letter, MCE AL 42-E/E-A/E-B was approved in Resolution E-5124, which brought MCE under the same program rules and reporting structure applicable to the IOUs.
[7] OP 3 of Resolution E-5125 directed that DAC-GT and CS-GT Annual Budget Advice Letters are to be submitted as Tier 2 ALs to allow for additional review and oversight.
[8] OP 2 of D.24-05-065 discontinues the CS-GT program and directs program administrators to transfer remaining capacity, customers, and programs into the DAC-GT program. OP 3 of D.24-05-065 makes several modifications to the DAC-GT program, which are reflected in this budget submission.
[9] OP 4 of Resolution E-5367 authorizes DAC-GT CCA Program Administrators to recover costs associated with developing a Confidential Benchmark Value Reference Price (CBVRP) for DAC-GT solicitations.

Pursuant to G.O. 96-B, MCE requests that this Tier 2 AL become effective on May 1, 2026, which is 30 calendar days from the date of this filing.

BACKGROUND

On June 21, 2018, the California Public Utilities Commission ("Commission" or "CPUC") approved D.18-06-027, adopting two new community solar programs to promote the use of renewable generation among residential customers in disadvantaged communities ("DACs"),[10] as directed by the California Legislature in Assembly Bill ("AB") 327 (Perea), Stats. 2013, ch. 611. The DAC-GT and the CS-GT programs offer 100% solar energy to eligible customers and provide a 20% discount on the electric portion of the utility bill.

D.18-06-027 allows Community Choice Aggregators ("CCAs") to develop their own DAC-GT and CS-GT programs, and states that CCAs that elect to offer DAC-GT and CS-GT must abide by all rules and requirements adopted in that decision.[11] Pursuant to OP 17 of D.18-06-027, MCE filed its Implementation AL (MCE AL 42-E) on May 7, 2020. The Commission approved AL 42-E in Resolution E-5124, issued April 15, 2021.

Resolution E-4999 from May 2019 approved the investor-owned utilities' ("IOUs") implementation ALs for the DAC-GT and CS-GT programs and established the budgeting procedures and timelines for the programs. The Resolution sets the deadline for submitting annual DAC-GT and CS-GT program budget requests and ME&O plans for the upcoming PY by February 1st of each year.[12] Furthermore, the Resolution specifies that Program Administrators must reconcile prior year budget forecasts and expenditures in their annual budget requests.[13]

On May 30, 2024, the CPUC approved D.24-05-065, discontinuing the CS-GT program and approving a number of modifications to the DAC-GT program. The DAC-GT program modifications pertaining to CCA program administrators include: modifying project siting requirements, increasing program capacity, allowing the voluntary inclusion of storage in projects, ordering the cost containment cap to be updated, changing the budget advice letter deadline to April 1st, and removing the Green-E certification requirement.

On September 27, 2024, MCE submitted its updated tariff documents for the DAC-GT program. On November 15, 2024, the CPUC approved MCE's revised DAC-GT tariff with an effective date of October 27, 2024.

Resolution E-5367, issued on July 30, 2025, approved with modifications Pacific Gas and Electric Company ("PG&E") and Southern California Edison Company's ("SCE") DAC-GT cost

[10] DACs are defined under Resolution E-5212 as communities that are identified in version 3.0 or any subsequent version of CalEnviroScreen as among the top 25 percent of census tracts statewide, plus the census tracts in the highest five percent of CalEnviroScreen's Pollution Burden that do not have an overall CalEnviroScreen score because of unreliable socioeconomic or health data. Resolution E-5212 also expands program eligibility to include California Indian Country.
[11] D.18-06-027, p. 104, OP 17.
[12] Resolution E-4999, OP 2.
[13] Resolution E-4999, OP 4.

containment cap proposal for changes to the methodology for setting the cost containment cap. The Resolution also outlined the process for CCAs to develop their own Confidential Benchmark Value Reference Price ("CBVRP") and to receive cost recovery for a Reviewing Representative ("RR") to develop a CCA-specific CBVRP using the relevant IOU's CBVRP and prepare a report on the reasonableness of the CBVRP calculation for CPUC review through future executed Tier 2 DAC-GT Power Purchase Agreement ("PPA") ALs.[14]

MCE has included cost recovery for its RR's activity through 2025 in the ABAL. MCE selected its Reviewing Representative through a competitive solicitation process, requesting proposals from multiple qualified firms and awarding the contract to the lowest-cost bidder. Its scope of work included executing the required non-disclosure agreement with PG&E; reviewing MCE's executed PPAs; assessing whether MCE's internal data was sufficient to support an independent CBVRP calculation; and finally independently calculating MCE's CBVRP based on available data utilizing the methodology adopted in Resolution E-5367. Finally, MCE's RR provided a Reviewing Determination Letter setting forth MCE's final CBVRP. This competitive procurement process ensured that ratepayer funds were used prudently – MCE obtained qualified, independent third-party review at the lowest offered market price.

Per D.18-06-027, the budget requirements outlined in Resolution E-4999 apply to participating CCAs as well. The submission and approval of this budget AL is the prerequisite to having the DAC-GT budget included in the IOUs' Energy Resource Recovery Account ("ERRA") Forecast in May each year. The ERRA Forecast in turn enables cost recovery of the programs. Therefore, MCE is submitting this advice letter to ensure timely cost recovery for its programs.

Commission D.18-06-027 established the DAC-GT program in 2018, with funding through both Greenhouse Gas (GHG) Auction Revenue and Public Purpose Program (PPP) funds. On September 19, 2025, AB 1207 was signed into law which introduced changes to Public Utilities Code Section 748.5 including rendering inoperative as of July 1, 2026, the Commission's authority to allocate up to 15 percent of GHG Auction Revenue to clean energy and energy efficiency projects. Per AB 1207 (Irwin), Stats. 2025, Ch. 117, 100% of DAC-GT and/or CSGT program costs will be recovered from PPP funds starting July 1, 2026.

PURPOSE

MCE hereby submits the budget request for PY 2027 for the DAC-GT program. Per Resolution E-4999, the budget request includes both the budget reconciliation for the previous PY (i.e., PY 2025) and the budget forecast for the upcoming PY (i.e., PY 2027). In summary, MCE requests a total budget of $5,472 for the DAC-GT program for PY 2027, including PY 2025 DAC-GT reconciliation costs. Because AL 86-E over-forecasted power generation and bill discount costs in the prior year, reconciliation costs are reduced, resulting in a lower budget request for PY 2027.[15] Additional details can be found in Appendix A.

Once the Commission approves MCE's budget request, PG&E will be responsible for including

[14] Resolution E-5367, p. 20 and OP 4.
[15] MCE Advice Letter 86-E.

the total budget request for MCE's DAC-GT program in the 2027 ERRA Forecast filing.[16] Once PG&E receives approval of its ERRA Forecast from the Commission, PG&E will set aside the requested MCE budget in a sub-account of its DAC-GT balancing account. PG&E will then transfer program funds to MCE as determined in Resolution E-5124.[17]

In addition to the budget request, MCE submits its updated ME&O plan for PY 2027 as Appendix B.

CONCLUSION

MCE respectfully requests the Commission approve the budget proposed herein and direct PG&E to transfer funds sufficient to meet MCE's approved annual budgets per the funding mechanisms set forth in Resolution E-5124. MCE also requests approval of its ME&O plan for 2026.

NOTICE

A copy of this AL is being served on the official Commission service lists for Rulemaking R.14-07-002 and Application A.22-05-022.

For changes to this service list, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

PROTESTS

Anyone wishing to protest this advice letter filing may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice filing. Protests must be submitted to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

In addition, protests and all other correspondence regarding this advice letter shall be sent electronically to the attention of:

Rachel Dec
Policy Analyst
Marin Clean Energy
1125 Tamalpais Ave
San Rafael, CA 94901

[16] D.22-01-023, p. 28, OP 3. Modifies the due date for PG&E to file this annual Application to May 15, 2023.
[17] Resolution E-5124, p. 10.

Email: rdec@mcecleanenergy.org

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

CORRESPONDENCE

For questions, please contact Rachel Dec at (415) 419-4948 or by electronic mail at rdec@mcecleanenergy.org.

/s/ Rachel Dec

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Appendices

Appendix A: PY 2027 Budget Request
Appendix B: PY 2027 ME&O Plan

cc: Service List for R.14-07-002 and A.22-05-022

Budget Forecast for the Disadvantaged Communities Green Tariff Program for Program Year 2027

Proposed by Marin Clean Energy

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1. BACKGROUND

MCE is a program administrator ("PA") of the Disadvantaged Communities ("DAC") Green Tariff ("DAC-GT") program. Per Resolution E-4999, annual program budgets must be presented and include the following budget line items:[1]

1. Generation cost delta, if any;[2]
2. 20 percent bill discount for participating customers;
3. Program administration costs: [3]
    a. Program management;
    b. Information technology ("IT");
    c. Billing operations;
    d. Regulatory compliance;
    e. Procurement;
4. Marketing, education and outreach ("ME&O") costs:
    a. Labor costs; and
    b. Outreach and material costs.

In this program budget, MCE includes both the budget reconciliation for the previous program year (PY) (i.e., PY 2025) and the budget forecast for the upcoming PY (i.e., PY 2027).

In addition to budget reconciliation and forecast, annual program budget submissions must also include details on program capacity and customer enrollment numbers. More specifically, MCE reports on:

1. Existing solar generation capacity at previous PY's close (i.e., December 31, 2025);
2. Forecasted solar generation capacity under contract for procurement in the upcoming PY;
3. Customers served at previous PY's close (i.e., December 31, 2025); and
4. Forecasted customer enrollment for the upcoming PY.

Finally, MCE will submit the following workpapers to the California Public Utilities Commission's (CPUC or Commission) Energy Division staff directly:

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[1] A detailed description of each budget line item can be found in MCE's Implementation Plan, submitted in Appendix A to MCE Advice Letter 42-E filed on May 7, 2020.

[2] Resolution E-4999 establishes that *above market* generation costs should include net renewable resource costs in excess of the otherwise applicable class average generation rate that will be used to calculate the customers' bills. In conversations with the CPUC's Energy Division after the release of the Resolution, it was clarified that this budget line item is intended to cover both a potential higher, as well as lower, cost of the DAC-GT/ CS-GT resources than the otherwise applicable class average generation rate. Hence, the term is updated to state the "*Delta of generation costs* between the DAC-GT/ CS-GT resources and the otherwise applicable class average generation rate."

[3] Resolution E-5124 established that PG&E can charge "CCA Integration Costs" to the programs; i.e. costs that incur to PG&E to enable CCAs to administer the programs (e.g., billing support functions). To date, CCAs have been including CCA integration costs on their budget ALs. On March 2, 2023, PG&E submitted Advice Letter 6872-E requesting that the CPUC approve a tariff modification to allow PG&E to record these CCA integration costs directly to PG&E's subaccount, instead of the CCAs seeking cost recovery. Therefore, MCE does not include the CCA integration cost in its 2027 budget forecast. However, MCE still includes the CCA integration cost in the calculation of its administration cost cap, per Resolution E-5124.

1. Calculation of the generation cost delta; and
2. Calculation of the 20% bill discount to participating customers.

2. BUDGET FORECAST FOR PY 2027

For PY 2027, MCE forecasts a total budget of $2,852,801 for the DAC-GT program. A detailed budget forecast for each program by budget line item can be found in the table below.

Table 1: MCE Budget Forecast for PY 2027

Category	**DAC-GT**
Generation Cost Delta	$ 622,164
20% Bill Discount	$ 1,934,379
Program Administration	
Program Management	$ 113,400
Information Technology	$ 23,265
Billing Operations	$ 69,991
Regulatory Compliance	$ 24,871
Procurement	$ 15,492
Subtotal Program Administration	**$ 247,020**
Marketing, Education & Outreach	
Labor Costs	$ 11,618
Outreach and Material Costs	$ 37,620
Subtotal ME&O	**$ 49,238**
Total	**$ 2,852,801**

MCE provides a brief description of each of the budget line items below.

Generation Cost Delta
Through PY 2025, MCE used interim solar generation resources to support the DAC-GT program while procuring a dedicated solar facility for the program. On June 20, 2022, the Commission granted MCE's request to approve its dedicated DAC-GT power purchase agreement (PPA).[4] On November 11, 2024, the Commission approved MCE's first request to amend its dedicated DAC-GT PPA. On June 19, 2024, the Commission approved MCE's second request to amend its dedicated DAC-GT PPA. The new dedicated solar generation facility achieved commercial operation on January 27, 2026 and will serve 4.64 MW of capacity (which was the amount of capacity available to MCE's DAC-GT program prior to the approval of expansion via D.24-05-065) from this resource in PY 2026.

[4] See Disposition of MCE AL 63-E, MCE Disadvantaged Communities Green Tariff Program 2022 Power Purchase Agreement Approval.

MCE's DAC-GT program was previously allocated 4.646 MW of capacity, but Decision 24-05-065 approved a 50% expansion of MCE's DAC-GT program capacity, adding 2.323 MW. Decision 24-05-065 also rolled any unused CS-GT capacity into MCE's DAC-GT program, adding 1.28 MW of capacity.[5] MCE's DAC-GT program now has a total capacity of 8.249 MW. MCE is currently serving new customers using an interim resource as it works to procure a resource to serve the expanded program capacity. MCE anticipates using the existing DAC-GT interim resource for this purpose in PY 2027 as well while it procures a new dedicated resource to serve the expanded capacity.[6]

As such, the DAC-GT generation cost delta budget forecast for PY 2027 is based on the PPA price of the current interim solar generation resource and the PPA price of the dedicated solar facility online in 2026, compared to the costs of serving customers under MCE's residential base tariff, MCE's "Light Green" tariff. For PY 2027, the DAC-GT generation cost delta for customers enrolled under the original DAC-GT capacity is based on the PPA price of the new dedicated solar generation resource, Conflitti Solar. The DAC-GT generation cost delta for customers enrolled under the expanded DAC-GT capacity continues to be based on the PPA price of the current interim solar generation resource.

20 Percent Bill Discount

As set forth in Resolution E-5124, MCE calculates the 20% bill discount on both the generation and transmission and distribution ("T&D") portion of the electric bill for participating customers. The bill discount is then fully included on the generation portion of customer bills, i.e., the discount reduces the electric generation costs of a customer's bill only.[7] MCE then recovers these program costs via this budget AL filing.

In PY 2027, MCE expects to have approximately 5,805 customers enrolled in the DAC-GT program. D.24-05-065 expanded MCE's DAC-GT program capacity by 3.609 MW. MCE has enrolled customers using an interim resource as it works to procure a new resource to serve the remaining program capacity. The PY 2027 forecast for the 20 percent bill discount is based on the actual average monthly bill discount provided to participating customers in 2025, with a 25% increase to account for forecasted increases in electricity rates.

Program Administration Costs

Program administration includes program development, management, budgeting, and reporting. IT costs include the costs to develop program tools and updating existing systems to accommodate program enrollment and billing. Billing operations cover costs for ongoing billing operations and customer support, including the costs of MCE's third-party billing provider. While D.24-05-065 directs PG&E to provide a cost estimate for implementing an automated billing solution, but to date, such a solution has not been implemented. As such, for the time being, MCE assumes that billing costs will remain as they are now. Regulatory Compliance covers costs for regulatory

[5] D. 24-05-065, p. 138.

[6] MCE's solicitation "2026 Green Access Request for Offers" is active and closes on April 3, 2026. While the solicitation is open, it is available at https://mcecleanenergy.org/solicitations/.

[7] Resolution E-5124, p. 12.

compliance and related program filings with the Commission. Procurement covers the costs to develop and manage the solicitations for solar resources under the program, ongoing contract management, as well as annual renewable energy credit ("REC") retirement and compliance functions.

Marketing, Education and Outreach (ME&O)
ME&O budgets are split in two categories – (1) MCE labor costs; and (2) MCE direct costs for outreach and material. More information can be found in Appendix B: Marketing, Education, and Outreach (ME & O) Plan for Program Year 2027.

3. BUDGET CAPS

Resolution E-4999 establishes a cap of 10% of the total budget for program administration costs and a cap of 4% of the total budget for ME&O costs, to apply beginning with each administrator's third program year.[8] Subsequently, in recognition that these programs may exceed the established caps because of their relatively small size, the time it takes to launch, and other factors, the Commission permitted PAs whose budgets exceed the established caps to submit a rationale supporting the exceedance in their Annual Budget Advice Letters ("ABAL").[9] The ABAL was elevated from Tier 1 to Tier 2 to allow for additional review of this and other ABAL components.[10]

The 2027 budget forecast summarized above in Table 1 results in DAC-GT program administration budgets of 9% and ME&O budgets of 2%. As such, MCE does not require an adjustment to the program administration budget cap for DAC-GT for PY 2027.

4. BUDGET RECONCILIATION FOR PY 2025

MCE submitted a budget forecast for PY 2025 as a part of its 2025 Budget Request and ME&O Plan in AL 79-E on July 8, 2024. The table below shows the forecasted and actual costs for PY 2025 per budget line item, as well as the true-up amount that will be carried forward to future program years.

MCE AL 79-E overestimated the 2025 Bill Discount Forecast by $1,763,163 and 2025 Generation Cost Delta by $1,040,907 due to a spreadsheet error. Specifically, MCE's budget applied a multiplier of 178% to account for program expansion and growth in participating customers, when the correct figure should have been 78%. This error had cascading impacts, leading to a substantial budget overestimation. Given this error, MCE's budget reconciliation for PY 2025 is -$2,847,329, which is reflected in MCE's PY 2027 Budget Request of $5,472.

[8] Resolution E-4999, p. 27.
[9] Resolution E-5125, p. 7.
[10] *Id.*

Table 2: MCE Budget Reconciliation for PY 2025

Category	DAC-GT		
	Forecast	Actual	**True-up (Actual - Forecast)**
Generation Cost Delta	$ 1,956,970	$ 916,063	**$ (1,040,907)**
20% Bill Discount	$ 3,310,666	$ 1,547,503	**$ (1,763,163)**
Program Administration			
Program Management	$ 22,820	$ 11,288	**$ (11,532)**
Information Technology	$ 11,617	$ 10,559	**$ (1,058)**
Billing Operations	$ 98,868	$ 90,494	**$ (8,374)**
Regulatory Compliance	$ 18,966	$ 10,251	**$ (8,715)**
Procurement	$ 15,690	$ 4,526	**$ (11,164)**
CCA Integration Costs	$ -	$ -	**$ -**
Subtotal Program Administration	**$ 167,961**	**$ 127,118**	**$ (40,844)**
Marketing, Education & Outreach			
Labor Costs	$ 6,537	$ 2,853	**$ (3,685)**
Outreach and Material Costs	$ 15,000	$ 16,269	**$ 1,269**
Subtotal ME&O	**$ 21,537**	**$ 19,122**	**$ (2,416)**
Total	**$ 5,457,134**	**$ 2,609,805**	**$ (2,847,329)**

-2847329

5. 2027 BUDGET REQUEST

Based on the budget forecast for PY 2027 presented in Section 2 and the budget reconciliation for PY 2025 presented in section 4, MCE is requesting a total budget of $5,472 for the DAC-GT programs in this budget AL.

Table 3: MCE Budget Request for PY 2027

DAC-GT	Total
Budget Carry-over from PY 2025	$ (2,847,329)
Budget Forecast for PY 2027	$ 2,852,801
TOTAL	**$ 5,472**

6. PROGRAM CAPACITY AND ENROLLMENT NUMBERS

MCE reports existing program capacity and customer enrollment numbers as of December 31, 2025, in Table 4 below. In PY 2025, enrolled customers were served with an interim solar resource, as discussed above.

Table 4: Program Capacity and Enrollment Count for DAC-GT for PY 2025

Category	DAC-GT
Program capacity (MW)	8.249
Participating customers (#)	5,805

In Table 5, MCE reports forecasted capacity and customer enrollment for PY 2027. As noted above, the dedicated project to serve existing DAC-GT achieved commercial operation on January 27, 2026. MCE plans to solicit a new project to serve the expanded DAC-GT capacity granted in D.24-05-065, but does not anticipate this project will come online during PY 2027.

Table 5: Forecasted Program Capacity and Enrollment Count for DAC-GT for PY 2027

Category	DAC-GT
Estimated additional capacity to be procured (MW)	3.609
Percentage of total capacity served by interim resource	44%
Percentage of total capacity served by Conflitti	56%
Estimated existing customers served by Conflitti	3,265
Estimated existing customers served by interim resource	2,540
Total forecasted customer enrollment	5,805

Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff Programs for Program Year 2027

Proposed by Marin Clean Energy

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1. PURPOSE AND GOALS

MCE implements a targeted customer marketing, education, and outreach ("ME&O") campaign under the Disadvantaged Communities Green Tariff ("DAC-GT") program to ensure potential customers in disadvantaged communities ("DACs") are aware of the benefits from the program.

Eligible customers for DAC-GT are identified and automatically enrolled in the program by MCE. Hence, no customer recruitment for program participation is required.

MCE's ME&O strategy for the DAC-GT program has three main goals:

1. Notify DAC-GT customers that their account has been automatically enrolled in the program;

2. Provide information (i.e., FAQs) about the program; and

3. Notify DAC-GT customers if they no longer meet eligibility criteria for the program (i.e., moved, installed solar, or no longer enrolled in California Alternative Rates for Energy (CARE) or Family Electric Rate Assistance Program (FERA)[1] and the steps they can take to become eligible for re-enrollment (if applicable).

2. GUIDING PRINCIPLES

MCE is committed to developing diverse and culturally appropriate communication strategies to ensure that stakeholders can participate in decisions and actions that impact their communities. As such, MCE aims to: achieve diverse and meaningful engagement that reflects the demographics of DAC communities to ensure equitable outreach across race, income and age barriers.

3. TARGET AUDIENCE

For the DAC-GT program, in 2021 MCE automatically enrolled eligible customers that live in one of the top 10% of DAC census tracts statewide that are in MCE's service area, as defined by CalEnviroScreen 3.0. Priority was given to customers who made an effort to pay, as defined by at least 4 full or partial payments in the preceding 8 months. With the expanded capacity of the DAC-GT program approved in 2024, MCE enrolled additional customers as identified by CalEnviroScreen 4.0 in the following order:

- Customers who live in one of the top 25% of DAC census tracts and are enrolled in the Arrearage Management Program (Category 1)

[1] CARE and FERA are California programs offering monthly bill discounts to income-qualified households. Income qualification varies based on household size and program year. Currently, a one-or-two-person household qualifies if total gross annual household income is below $52,875.

- Customers who live in one of the top 25% of DAC census tracts and are in arrears (Category 2)
- All other customers who live in one of the top 25% of DAC census tracts (Category 3)

If there is insufficient program capacity to enroll all eligible customers, program participants will be selected for program enrollment using the categories listed above. MCE will monitor program attrition on a monthly basis and enroll additional customers from the waitlist as appropriate.

Figure 1 shows the list of eligible census tracts for DAC-GT auto-enrollment.

Figure 1. Qualifying Neighborhoods in MCE Service Area for DAC-GT Auto-Enrollment

75% CalEnviroScreen 4.0 Score			
Census Tract	**California County**	**ZIP**	**Nearby City (to help approximate location only)**
6013314103	Contra Costa	94565	Bay Point
6013314104	Contra Costa	94565	Bay Point
6013336201	Contra Costa	94520	Concord
6013365002	Contra Costa	94801	North Richmond
6013309000	Contra Costa	94565	Pittsburg
6013310000	Contra Costa	94565	Pittsburg
6013311000	Contra Costa	94565	Pittsburg
6013312000	Contra Costa	94565	Pittsburg
6013313101	Contra Costa	94565	Pittsburg
6013314102	Contra Costa	94565	Pittsburg
6013373000	Contra Costa	94801	Richmond
6013375000	Contra Costa	94801	Richmond
6013376000	Contra Costa	94801	Richmond
6013377000	Contra Costa	94801	Richmond
6013379000	Contra Costa	94804	Richmond
6013381000	Contra Costa	94804	Richmond
6013382000	Contra Costa	94804	Richmond
6013392200	Contra Costa	94806	Richmond
6013358000	Contra Costa	94572	Rodeo
6013366001	Contra Costa	94806	San Pablo
6013366002	Contra Costa	94806	San Pablo
6013368001	Contra Costa	94806	San Pablo
6013368002	Contra Costa	94806	San Pablo
6013369001	Contra Costa	94806	San Pablo

6013314200	Contra Costa	94565	Unincorporated Contra Costa County area
6013315000	Contra Costa	94520	Unincorporated Contra Costa County area
6013327000	Contra Costa	94520	Unincorporated Contra Costa County area
6095252502	Solano	94533	Fairfield
6095250801	Solano	94592	Unincorporated Solano County area
6095252402	Solano	94534	Unincorporated Solano County area
6095253500	Solano	94571	Unincorporated Solano County area
6095250701	Solano	94590	Vallejo
6095250900	Solano	94590	Vallejo
6095251000	Solano	94590	Vallejo
6095251200	Solano	94590	Vallejo
6095251500	Solano	94590	Vallejo
6095251600	Solano	94590	Vallejo
6095251802	Solano	94589	Vallejo
6095251901	Solano	94589	Vallejo
6095251902	Solano	94589	Vallejo

4. ME&O TACTICS AND STRATEGIES

MCE will continue to use the marketing content originally developed to promote DAC-GT, including direct mailers, emails, and webpage. MCE will include a direct mailer and email to send to customers for fiscal year 2027 alerting them if they are unenrolled, and the steps they can take to become eligible for reenrollment. MCE will also provide a one-time mailer to all enrolled customers reminding them of program benefits and sharing other MCE programs for which they're eligible to maximize customer benefits. All program materials will be translated into English and Spanish.

5. METRICS TRACKING

As MCE uses multiple tactics for ME&O, a variety of metrics will be used to evaluate the effectiveness of each effort. Our primary measure of effectiveness is the number of customers reached, which can be measured by:

- Number of customers enrolled based on auto-enrollment criteria;
- Number of customers found to be ineligible for the program based on eligibility criteria;
- Number of customers opting to cancel program participation; and
- Number of customers to be enrolled from the waitlist based on the capacity provided through the total sum of all aforementioned attributes.

FILED
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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.25-10-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2027-2029, FLEXIBLE CAPACITY OBLIGATIONS FOR 2027, AND PROGRAM REFINEMENTS

Leanne Bober,
Director of Regulatory Affairs and
Deputy General Counsel
Lauren Carr,
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June 22, 2026

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Cases

Statutes

California Public Utilities Commission Decisions

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California Public Utilities Commission Rules of Practice and Procedure

SUMMARY OF RECOMMENDATIONS[1]

The Commission should modify the Proposed Decision to:

- Remove the $0 bidding and revenue allocation requirements for imbalance reserves and reliability capacity;
- Adopt LOT, a commonsense affordability measure to align the granularity of RA products with the granularity of RA requirements;
- Adopt a durable RA allocation process for data center loads to reflect their uncertain and discrete nature and ensure RA allocations are fair and accurate;
- Clarify storage QC foldback adjustments to reflect hourly variability consistent with resources' operational capabilities and the SOD framework;
- Clarify PG&E's load migration proposal to reduce ambiguity and provide clear processes and timelines; and
- Clarify the LDES and EO resource showings in the SOD templates and leave room for future improvements.

[1] Acronyms used herein are defined in the body of this document.

The California Community Choice Association[2] (CalCCA) submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[3] on the proposed *Decision Adopting Local Capacity Obligations for 2027-2029, Flexible Capacity Obligations for 2027, and Program Refinements*[4] (Proposed Decision), dated June 1, 2026.

I. INTRODUCTION

The evolving Resource Adequacy (RA) program and electricity landscape necessitates consideration of RA Track 1 proposals in the context of Western market evolution, the Slice-of-Day (SOD) program, and uncertain forecasted load growth. While there are limited elements of the Proposed Decision that CalCCA supports,[5] many other elements of the Proposed Decision fail to adequately progress the RA program in the following ways.

First, in extending the bidding requirements and revenue prohibition to new California Independent System Operator (CAISO) market products, the Commission departs from the objectives of California Public Utilities Code section 380,[6] acts outside of its authority over community choice aggregators (CCA), and raises federal preemption concerns. In addition, it could create reliability issues and result in the need for load-serving entities (LSE) to renegotiate a significant number of contracts, which would likely increase RA costs. ***Second***, the Commission rejects CalCCA's hourly load obligation trading (LOT) proposal, continuing the discrepancy between the granularity of requirements and the products that can be used to meet these requirements, at the expense of ratepayers. ***Third***, by

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

[3] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021).

[4] Proposed *Decision Adopting Local Capacity Obligations for 2027-2029, Flexible Capacity Obligations for 2027, and Program Refinement*, Rulemaking (R.) 25-10-003 (June 1, 2026).

[5] CalCCA supports the Commission's: (1) adoption of co-located Energy Only (EO) counting for the charging sufficiency requirement; (2) adoption of Energy Division's Unforced Capacity (UCAP) proposal, subject to additional development prior to implementation; (3) rejection of Pacific Gas and Electric Company's (PG&E's) proposal to eliminate the Local Capacity Requirement-Reduction Compensation Mechanism; (4) adoption of CalCCA's Central Procurement Entity data transparency and data request use proposals; and (5) adoption of Energy Division's large load meet and confer process.

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

rejecting CalCCA's large load RA allocation proposal without a path forward to continue to explore how RA allocations should occur under an uncertain large load future, the Commission risks inaccurate and/or unfair RA allocations with potential impacts on reliability and affordability. ***Fourth***, in adopting Energy Division's storage qualifying capacity (QC) adjustments for foldback without modifications to recognize hourly availability, the Commission fails to reflect operational capabilities and the SOD framework.

With these errors, the Commission fails to progress the RA program in the context of Western market evolution, the SOD framework, and uncertain forecasted load growth. To remedy these errors, and provide other necessary clarifications, the Commission should modify the Proposed Decision to:

- Remove the $0 bidding and revenue allocation requirements for imbalance reserves (IR) and reliability capacity (RC);
- Adopt LOT, a commonsense affordability measure to align the granularity of RA products with the granularity of RA requirements;
- Adopt a durable RA allocation process for data center loads to reflect their uncertain and discrete nature and ensure RA allocations are fair and accurate;
- Clarify storage QC foldback adjustments to reflect hourly variability consistent with resources' operational capabilities and the SOD framework;
- Clarify PG&E's load migration proposal to reduce ambiguity and provide clear processes and timelines; and
- Clarify the LDES and EO resource showings in the SOD templates and leave room for future improvements.

II. THE ZERO-DOLLAR BIDDING AND REVENUE ALLOCATION REQUIREMENTS FOR CAISO MARKET PRODUCTS SHOULD BE REMOVED

The Commission should modify the Proposed Decision to remove the $0 bidding and revenue allocation requirements for IR and RC. CalCCA shares the Commission's goal of avoiding "significant costs to ratepayers." However, in maintaining "status-quo" requirements despite changes to the CAISO tariff, the Proposed Decision would likely result in the very ratepayer-cost increases that the Commission aims to avoid.

A. The Proposed Decision Errs in Assuming the Most Economic Outcome for IR and RC Treatment

The Proposed Decision errs by extending the requirement for existing and future RA contracts to: (1) reflect the policy determinations from Decision (D.) 05-10-042[7] to ensure zero-dollar bidding for

[7] D.05-10-042, *Opinion on Resource Adequacy Requirements*, R.04-04-003 (Oct. 27, 2005).

RC and IR products; and (2) to specify that the resource owner is not eligible for capacity-related revenue payments for these products.[8] The Proposed Decision purports to maintain the "status quo" requirements because:

> [t]he Commission is not persuaded by parties that seek to abruptly remove the zero-dollar bid requirement and the revenue allocation prohibition for RA resources without any supporting data. Rather, the Commission is persuaded by [the Public Advocates Office [(Cal Advocates)] that the [Extended Day-Ahead Market (EDAM)] products' impact on RA pricing is uncertain and that if market-clearing prices are high, this could potentially result in significant costs to ratepayers depending on the volume of bids."[9]

The Commission's rationale is not grounded in a reliability concern, but rather in an assumption about optimal economic outcomes that will not hold in all cases. By requiring that all IR and RC revenues be credited to the LSE, the Proposed Decision undermines contractual flexibility that could otherwise enable more efficient outcomes—such as lower RA prices in exchange for allowing generators to retain those revenues. These requirements will likely not lower overall costs, because the revenues from EDAM products will be accounted for in RA prices, similar to how energy revenues are theoretically accounted for in RA prices. The assumption that channeling IR and RC revenues to the LSE will *always* produce the most cost-effective result is incorrect and constrains LSEs from pursuing alternative, potentially lower cost contracting arrangements.

The Proposed Decision claims that pricing experience from the CAISO test environment and initial CAISO implementation of the RC and IR structures, "appears to demonstrate that day-ahead clearing prices are high for RC and, to a lesser extent, IR products."[10] This assessment is not correct, however, as more recently available production data from the CAISO website demonstrates that there are a large number of hours in May when the prices for Residual Unit Commitment (RUC), Imbalance Reserve Up (IRU), and Imbalance Reserve Down (IRD) cleared at or very near $0.[11] Indeed, the CAISO has noted the difference in pricing between the simulation and operation stating:

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8 Proposed Decision, at 101-102.
9 *Id.*, at 101.
10 *Ibid.*
11 *See* CAISO Daily Extended Day-Ahead Market EDAM Reports (May 2026).

> . . . [b]efore launch, test runs between CAISO and PacifiCorp showed persistently high imbalance reserve procurement costs. Those outcomes were driven by simulations with limited data, rather than actual bid behavior. In live operations, those high costs have not materialized. Actual bid data and stakeholder-vetted transitional parameters helped support a stable launch. Overall, imbalance reserve prices have been moderate. Prices are usually low, with predictable increases in the morning and evening ramps, occasionally reaching ~$15/MWh. [IRU] prices have also shown clear regional differences, reflecting the economics of the broader footprint. For instance, CAISO and PacifiCorp East have remained relatively stable, typically below $10/MWh, while PacifiCorp West has seen occasional price spikes up to $55/MWh. This price separation reflects EDAM's ability to shift reserves from lower-cost to higher-cost regions. Across all areas, IRU prices consistently cleared above [IRD] prices.[12]

The Proposed Decision therefore bases its decision-making solely upon data from a test environment in which the results were non-binding on any participant. In the production environment, the data thus far shows no evidence of the high prices postulated by parties as a result of which the Proposed Decision concludes that resources providing RA must bid $0 and flow through the revenues to the LSE.

The Proposed Decision also appears to propose a mandate that both existing and new RA contracts include a requirement that resources bid $0 for RC/IR and that revenues get passed through to the LSE buyer. The Proposed Decision states:

> . . . [t]he Commission concludes that the more prudent approach is to maintain the status quo requirements…and monitor the bidding behavior of the EDAM market and its impact on RC and IR pricing following the initial implementation, and any potential impacts on future RA pricing. … Accordingly, the Commission maintains and affirms the current rules established in D.05-10-042.

Imposing this new requirement would likely require renegotiation of substantial numbers of contracts. Significant disagreement exists among market entities regarding whether these new products, especially the IR product, are RUC products subject to the same treatment under existing contractual language. CCAs are reporting that sellers have already begun stating that under the new EDAM rules, the seller is entitled to the revenues associated with IR. CalCCA has surveyed its members and found that, of the 11 survey respondents, a staggering 249 contracts with September net qualifying capacity

[12] CAISO *Western Energy Markets Observations* (June 1, 2026), at 2.

(NQC) of over 18,600 MW is potentially at risk for contract renegotiation based upon the Proposed Decision's requirements. Further, by adopting these requirements for immediate effect, the Proposed Decision raises questions about the ability of parties to continue using these resources. If new terms are required to be inserted in existing contracts, generators could be in a position to demand high premiums in exchange for agreeing to these new terms. These resources have already been procured and are providing reliability, to be claimed as RA as early as the next showing after the Proposed Decision is adopted. For example, if the Proposed Decision is adopted on July 2, 2026, the next showing would be for September 2026. Renegotiation of contracts in this timeframe is infeasible and, even if it were feasible, could dramatically increase ratepayers costs to pay for reliability which already exists based upon existing contracts.

B. The Proposed Decision Raises Federal Preemption and CCA Autonomy Concerns

The Proposed Decision raises significant federal preemption and CCA autonomy concerns. The Commission acknowledges that the CAISO removed from its Tariff both the requirement that RA resources submit zero-dollar bids into RUC products and the prohibition on resources receiving associated revenues. The Commission further acknowledges that those Tariff revisions were approved by the Federal Energy Regulatory Commission (FERC).[13] Nevertheless, the Proposed Decision would effectively and unlawfully require the re-creation of those FERC jurisdictional provisions in state-mandated contracts. While states retain authority over resource procurement and RA, they may not intrude upon FERC's exclusive jurisdiction over wholesale market participation, bidding behavior, and compensation.[14]

Although the Proposed Decision characterizes these requirements as procurement rules, their practical effect is to dictate how market participants bid into and receive compensation from FERC-jurisdictional market products. The Supreme Court has instructed that preemption analysis turns on the *target* of the state action.[15] Here, the Proposed Decision is not directed at ensuring reliability or

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[13] Proposed Decision, at 84.

[14] *See Hughes v. Talen Energy Marketing, LLC*, 578 U.S. 150, 163-66 (2016) (In *Hughes v. Talen Energy Marketing, LLC*, the Supreme Court invalidated a Maryland program that guaranteed a generator a state-mandated rate for capacity sold into the PJM wholesale capacity market, holding that although states retain authority over generation and resource procurement, they may not condition compensation on participation in or alter the economic outcomes of FERC-jurisdictional wholesale markets.).

[15] See *Oneok, Inc. v. Learjet, Inc.*, 575 U.S. 373, 385-87 (2015*) (*In *Oneok, Inc. v. Learjet, Inc.,* the Supreme Court held that state antitrust claims based on allegations that natural gas traders manipulated price

compliance with RA obligations, but instead at prescribing the economic outcomes of participation in the CAISO's wholesale markets. By requiring zero-dollar bids and prohibiting resource owners from retaining RC and IR revenues, the Commission risks regulating conduct that falls squarely within FERC's exclusive authority.

Furthermore, by focusing on contract economics rather than reliability outcomes, the Proposed Decision exceeds the Commission's jurisdiction over non-investor-owned utility (Non-IOU) LSEs, including CCAs. The Commission may require CCAs to meet certain policy mandates—such as RA and the Renewables Portfolio Standard (RPS)—but it lacks jurisdiction to dictate the specific terms and conditions of their procurement agreements beyond what is necessary to ensure compliance with *reliability* and *clean energy* goals. Public Utilities Code section 380 authorizes the Commission to institute a RA program to accomplish numerous purposes, but dictating the financial terms of LSE contracts is not within the scope of that authority. Because the allocation of IR and RC revenues is fundamentally a question of contractual *economics*—and not reliability—the Commission's attempt to impose a blanket revenue allocation requirement intrudes into procurement decision-making where it lacks legal authority.

C. The Proposed Zero-Dollar Bid Requirement is Likely to Have Adverse Impacts to RA Storage Resources and Reliability

The Proposed Decision will likely have adverse impacts on reliability because bidding $0 in the IR market could prevent storage devices from preserving their state of charge for the hours when they are most needed for reliability. Storage resources are primarily shown to meet net peak needs (i.e., the hours after sunset when solar generation declines but load remains high). Californians have paid significant capacity costs associated with very large amounts of battery storage (13,000 megawatts (MW) as of December 2024[16]) needed to meet SOD reliability needs. Without the ability of storage providers to bid opportunity costs in the IR market, it is not clear that the resources will be used to satisfy California's reliability needs and may instead be dispatched to meet other BAA needs. Worse yet, bidding $0 could make that capacity, and the reliability it provides, available to neighboring BAAs at a low price, despite Californians paying for it to meet their own reliability needs. Additionally, the Proposed Decision's misalignment with current CAISO tariffs and relatively stricter requirements could

indices by submitting false transaction data were not preempted by federal law because the state laws were directed at retail market conduct rather than wholesale rate regulation, emphasizing that preemption analysis turns on the "target at which the state law aims.").

[16] California ISO, *2024 Special Report on Battery Storage* (May 29, 2025), at 4.

disincentivize generators from participating in the Commission's RA program, raising concerns of reliability on top of affordability.

For these reasons, the Proposed Decision's proposed requirement that all IR and RC revenues flow to the LSE and that resources be required to bid $0 should be removed. Instead, LSEs should retain flexibility to negotiate revenue-sharing provisions in a manner that allows sophisticated LSE market participants to negotiate contracts in their customers' best interests. The Commission should strive to align its RA requirements with the CAISO RA requirements, ensuring a California LSEs can effectively participate in the wider EDAM. This outcome supports cost-effective procurement and reflects the diversity of market structures in California.

III. THE PROPOSED DECISION SHOULD BE MODIFIED TO ADOPT LOT, A COMMONSENSE AFFORDABILITY MEASURE TO ALIGN THE GRANULARITY OF RA PRODUCTS AND RA REQUIREMENTS

The Commission errs in rejecting LOT, a commonsense affordability measure to align the granularity of RA products and RA requirements, at the expense of ratepayers. The Commission bases its rejection on several factors: (1) its finding that "there is no demonstrated need for a [LOT] mechanism under the SOD framework;"[17] (2) concerns with the ability to satisfy RA requirements through "financial arrangements," rather than through the contracting of physical capacity;[18] and (3) multiple "outstanding" issues.[19] The Commission errs for the reasons described herein. The Commission should modify the Proposed Decision to adopt LOT to protect ratepayers from the costs of unnecessary RA purchases caused by transactional friction in the SOD program.

***First*,** the Commission finds that the Energy Division Report[20] answers the appropriate questions to inform the need for LOT. Specifically, these questions include:

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17 Proposed Deision, at 121.

18 *Id.,* at 122.

19 *Id.,* at 123-124.

20 *Report on Transactability within the Slice of Day Resource Adequacy Framework*, R.25-10-003 (Feb. 2026).

> . . . whether LSEs were able to comply with their RA requirements under the SOD framework (need), whether hourly load obligation trading could reduce overall capacity procurement by improving alignment between LSEs' contracted resources and LSEs' hourly load obligations (benefits), and whether implementing an hourly load obligation trading would introduce complexity into the RA program and compliance process (feasibility).[21]

Energy Division Report's evaluation is flawed in two primary ways: (1) the Report evaluates whether LOT is *necessary* for compliance rather than whether it *reduces the cost* of compliance; and (2) it materially understates the *amount of excess procurement* that can be *avoided* through LOT. In addition to these fundamental flaws with the questions evaluated in the Energy Division Report, the Proposed Decision errs in its conclusions.

In response to the question of whether LSEs were able to comply with their RA requirements under the SOD framework, the answer is no. The Energy Division Report shows that for the 2025 year-ahead showing, the total system need was *exceeded* in every hour, while some individual LSEs had *deficiencies* in every hour.[22] The fact LSEs were able to cure their deficiencies in the month-ahead filings does not absolve the SOD framework of transactability issues. Some likely procured more RA than necessary to meet their hourly requirements due to the inability to optimize their portfolios. Others will face penalties for the year-ahead deficiencies.

In response to the question of whether LOT could reduce overall capacity procurement by improving alignment between LSEs' contracted resources and LSEs' hourly load obligations, the answer is yes. CalCCA's analysis demonstrates that LSEs could have avoided 2,175 MW of excess procurement in 2025, with an estimated avoided cost of almost $37 million for the single month of September.[23] In total, LOT could have resulted in up to $180 million in avoided RA costs in 2025,[24] 80 percent of which could have been realized within the existing bi-lateral market framework without a central

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21 *Id.,* at 120.

22 Energy Division Report, at 12-15.

23 *California Community Choice Association's Opening Comments on Transactability Issues Filed and Served*, R.25-10-003 (Mar. 16, 2026) (CalCCA Transactability Opening Comments), at 9-10.

24 *California Community Choice Association's Track 1 Proposals on Transactability Issues*, R.25-10-003 (Mar. 3, 2026), at 9-10 and Appendix A.

intermediary,[25] contrary to the Proposed Decision's findings.[26]The Proposed Decision's failure to adopt LOT thus results in a missed opportunity for ratepayer savings.

In response to the question of whether implementing LOT would introduce complexity into the RA program and compliance process, the answer is no. CalCCA provided multiple paths forward for implementing LOT for the Commission's consideration, including additional personnel, automation, and interim guardrails such that the benefits of LOT could be realized without placing untenable complexity and administrative burden on the Commission. Validating these transactions requires nothing more than confirming the trade appears in a single line in two different excel spreadsheets. While the Proposed Decision expresses concern with CalCCA's proposed 25 percent limit,[27] CalCCA has signaled a willingness to consider alternative guardrails but neither Energy Division nor other parties have proposed an alternative. Taken together, the answers to these questions demonstrate that the Commission errs in its finding that "there is no demonstrated need for an hourly load obligation trading mechanism under the SOD framework."[28]

The Commission also expresses concern with LOT as a "mechanism that allows LSEs to satisfy RA requirements through financial arrangements, rather than through the contracting of physical capacity."[29] This concern is misguided, as physical capacity will still be needed to satisfy RA obligations in aggregate. It remains the responsibility of the original LSE, subject to penalties, that there will be sufficient RA to serve its load, whether procuring a resource or procuring a new LOT product. LOTs must be backed by physical capacity under contract by the LSE taking on the load obligation for the LOT to be valid. Without sufficient physical capacity backing the LOT, the short LSE would need to undertake alternative transactions to achieve compliance. Therefore, total system RA requirements would continue to be met fully with physical capacity, whether or not LOTs occur.

The Commission states that there are multiple "outstanding" issues associated with LOT: (1) PCIA rate calculation methodology impacts; (2) "competitive inequities" between IOU and non-IOU LSEs; (3) "necessary coordination" with CAISO regarding capacity procurement mechanism (CPM)

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25 *California Community Choice Association's Reply Comments on Transactability Issues Filed and Served*, R.25-10-003 (Mar. 30, 2026) (CalCCA Reply Comments), at 8 ("Contrary to statements in the Report, the benefits of LOT are substantial, ***even without an intermediary*** facilitating transactions on behalf of the LSEs. CalCCA's analysis demonstrates that 80 percent of the benefits of LOT can be achieved without an intermediary.").

26 Proposed Decision, at 122.

27 *Id.,* at 123.

28 *Id.,* at 121.

29 *Id.,* at 122.

cost allocation; (4) Reliable and Clean Power Procurement Program (RCPPP) interactions; and (5) a demonstration of net benefits to aggregate load.[30] CalCCA has addressed each of these issues in the record of this proceeding.[31] In characterizing these issues as "outstanding" without any analysis of or response to CalCCA's responses to address them, the Commission misrepresents the substantial development that has occurred over several RA proceedings to result in a thorough and well-supported solution to the RA program's affordability challenges. As a result, the Proposed Decision should be modified to adopt the LOT proposal.

IV. THE PROPOSED DECISION SHOULD BE MODIFIED TO ADOPT A DURABLE RA ALLOCATION PROCESS FOR DATA CENTER LOADS

The Commission should revise the Proposed Decision to adopt CalCCA's data center load RA allocation proposal, or at minimum, establish a clearly defined procedural pathway for developing an RA allocation mechanism for data center loads in Track 2 of this proceeding. Public Utilities Code section 380(h)(5) requires the Commission to "[e]nsur[e] that the cost of generating capacity and demand response is allocated equitably." Requiring LSEs to procure RA capacity for Data Centers that are mistakenly assigned to their loads fails that standard. Data centers represent large load additions that can be comparable in size to generation resources and have significant implications for system reliability, procurement needs, and local grid planning. A single data center delay, ramp change, or service-provider change can materially affect an LSE's RA compliance position. If not properly accounted for, this volatility introduces severe risks of reliability issues, stranded assets, or increased costs on existing customers. As such, the Commission must carefully consider and develop standards for incorporating data centers into RA obligations.

CalCCA proposed an alternative RA allocation methodology that would include data center loads in an LSE's RA allocation only after certain milestones are met to improve the certainty of the

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30 *Id.,* at 123-124.

31 CalCCA addressed these issues in the following filings into R.25-10-003: (1) PCIA rate calculation methodology impacts – *California Community Choice Association's Sur-Reply to the Reply Comments of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company on Transactability Issues*, R.25-10-003 (Apr. 17, 2026) (CalCCA Sur Reply), at 12; (2) "competitive inequities" between IOU and non-IOU LSEs – CalCCA Sur Reply at 8; (3) "necessary coordination" with CAISO regarding CPM cost allocation – CalCCA Transactability Opening Comments, at 30-32; (4) Reliable and Clean Power Procurement Program interactions – CalCCA Sur Reply, at 11; and (5) a demonstration of net benefits to aggregate load – CalCCA Transactability Opening Comments, at 16.

forecast of data center load coming online in the RA year.[32] The Proposed Decision rejects CalCCA's proposal, finding that there is "insufficient record at this time to demonstrate that data center load forecasting in the prompt year is so volatile as to necessitate CalCCA's proposed solution."[33] Instead, the Proposed Decision adopts Energy Division's proposal to leverage the existing meet-and-confer process to inform data center RA allocations.[34] While CalCCA supports an improved meet-and-confer process as a way to share information across all relevant parties, including CCAs, the IOUs, and the California Energy Commission (CEC), it is incomplete on its own as a long-term solution to allocating uncertain and discrete data center loads.

For CCAs currently experiencing large load growth, data center demand exhibits a wide band of forecast uncertainty. For example, in the territory of San José Clean Energy (SJCE), three different sources demonstrate a widely different picture of load growth. The CEC 2025 Integrated Energy Policy Report (IEPR) Demand Forecast shows SJCE's load increasing by approximately 40 percent between 2026 and 2028.[35] The Commissions 2026 Integrated Resource Planning (IRP) assumptions show approximately *100 percent* load growth for SJCE over the same two-year time period.[36] SJCE's internal modeling, based upon project-specific confidence levels applied to each data center project in the City of San José's pipeline,[37] projects approximately 10 percent load growth by 2028. These data points reflect significant uncertainty with potentially considerable implications on LSE RA portfolios, customer costs, and system reliability if not forecasted and planned for properly. While helpful, the proposed meet-and-confer process is an information-sharing process, not an allocation framework. It does not and should not be the sole process for determining: (1) which LSE should receive the RA obligation; (2) when the data center load should be included in an RA obligation; (3) whether the forecasted load is sufficiently certain; (4) whether the customer will actually take service from the assumed LSE; or (5) whether the load will ramp on the assumed timeline. The unique nature of data center loads instead necessitates *a*

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[32] *California Community Choice Association's Track 1 Proposals*, R.25-10-003 (Jan. 23, 2026) (CalCCA Track 1 Proposals), at 3-7 (CalCCA proposes that data center load be incorporated into RA requirements when meaningful milestones are met (*e.g.,* interconnection date, site control, permits and construction status). These milestones are directly relevant to whether, when, and by whom data center load will be served.).

[33] Proposed Decision, at 129.

[34] Proposed Decision, at 132-134.

[35] CEC 2025 IEPR Planning LSE Table: https://efiling.energy.ca.gov/GetDocument.aspx?tn=268727.

[36] IRP LSE Forecasts: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/2026-lse-ghg-emission-benchmarks.xlsx.

[37] *See Draft 2026 Renewables Portfolio Standard Procurement Plan of City of San José, Administrator of San José Clean Energy* (Public Version), R.24-01-017 (June 12, 2026), at 22-25.

formal RA allocation process as well as provisions for enforcing information sharing and a process for resolving discrepancies between CCA and IOU information.

The Commission states that it is "closely monitoring" the demand forecasting process of data center load in the annual IEPR demand forecast process at the CEC.[38] While the IEPR *is* a vitally important process in establishing the state's Demand Forecast, the Proposed Decision acknowledges that the CEC's methodology for addressing data center demand is currently under a multi-year refinement effort and is not immediately available to inform RA allocation.[39] Indeed, the CEC acknowledged in the 2025 IEPR Report that data center development is a rapidly evolving area.[40] Among the items making it difficult to forecast electricity demand from data centers are:

1. Limited historical data reference to give confidence to future load from data centers;
2. The dynamic nature of IOU energization queues with projects advancing, withdrawing, or being replaced;
3. Development timelines dependent on permitting, construction, supply chain, and transmission availability;
4. Future data center technologies that may change energy needs in total and in profile; and
5. The potential for data centers to bring their own generation to the grid.[41]

The CEC is considering changes to address these difficulties.

The effort to refine the IEPR forecast process to address data centers is a prudent and necessary effort given the rapidly evolving status of data center load growth. The Commission should not treat IEPR participation, or the meet-and-confer process, as a substitute for resolving these RA allocation issues. Doing so would miss both reliability and affordability opportunities that the CalCCA proposal squarely addresses.

The Proposed Decision should therefore be revised to adopt CalCCA's far more robust RA allocation proposal. If the Commission fails to adopt CalCCA's proposal, the Commission should in the alternative commit to working with the CEC and stakeholders to develop a data center RA allocation process in Track 2. The Commission and other parties also suggest alternative processes to address data center issues, such as multi-agency workshops and/or other proceedings.[42] CalCCA does not oppose

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38 Proposed Decision, at 29.
39 *Ibid.*
40 CEC Supporting Documentation for the 2025 IEPR Forecast (Apr. 15, 2026), at 22.
41 *Ibid.*
42 Proposed Decision, at 128-129.

such processes and acknowledges the benefits they may provide given the wide range of impacts data center loads may have on the industry as a whole. However, the RA allocation issue is a time-sensitive and growing issue that cannot be delayed, as the amount of data center load in the forecast is quickly rising in significant volumes, as demonstrated in SJCE's load forecasts. The Commission should therefore revise the Proposed Decision to adopt CalCCA's data center load RA allocation proposal now, or at minimum, establish a clearly defined procedural pathway in Track 2 of the RA proceeding for developing an RA allocation mechanism for data center loads.

V. STORAGE QC FOLDBACK ADJUSTMENTS SHOULD BE CLARIFIED TO REFLECT HOURLY VARIABILITY CONSISTENT WITH RESOURCES' OPERATIONAL CAPABILITIES AND THE SOD FRAMEWORK

The Commission should modify the Proposed Decision to account for storage foldback consistent with the resources' operational capabilities to align with the hourly nature of the SOD program. The Proposed Decision adopts Energy Division's proposed clarifications and adjustments to the storage QC methodology to address storage "foldback."[43] In response to Energy Division's proposed clarification, CalCCA suggested the Commission clarify proposed calculation to allow resources to count for full capacity in some hours and be derated in other hours to reflect operational capabilities of resources with foldback.[44] The Proposed Decision acknowledges CalCCA's requested clarification but does not rule on it.[45] In doing so, the Proposed Decision would result in a single value that may be too high in some hours and too low in others to reflect the impacts of foldback. This is inconsistent with both the operational capabilities of storage resources experiencing foldback and the SOD framework, which establishes hourly requirements and hourly counting values aimed to better reflect actual operating conditions.

To remedy this, the Commission should modify the Proposed Decision to reflect hourly variability in the storage QC consistent with resources' operational capabilities and the SOD framework, as proposed in the CalCCA's Track 1 Opening Comments.[46] Under the SOD framework, an LSE can claim the full amount of capacity for a single hour but may not need the full capacity in other hours. CalCCA's proposed alternative calculation would result in a higher RA counting in the hour of highest need, and more accurately reflect the impacts of foldback on RA capacity.

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43 Proposed Decision, Ordering Paragraph 6.

44 *California Community Choice Association's Comments on Track 1 Proposals*, R.25-10-003 (Mar. 6, 2026) (CalCCA Track 1 Opening Comments), at 14-16.

45 Proposed Decision, at 23.

46 CalCCA Track 1 Opening Comments, at 14-16.

VI. THE PROPOSED DECISION SHOULD BE MODIFIED TO CLARIFY PG&E'S LOAD MIGRATION PROPOSAL

While CalCCA does not oppose the Proposed Decision's adoption of PG&E's proposal to clarify the load migration definition, the Proposed Decision should be modified to ensure clear timelines and responsibilities and allow for mutually agreeable solutions between the IOU and CCA. The Proposed Decision modifies the definition of load migration to exclude events in which an LSE voluntarily changes the effective date confirmed in its approved implementation plan and does not submit a new implementation plan to the Commission.[47] However, the Proposed Decision fails to address the following clarifications to the proposal requested by CalCCA:

- A CCA providing notice of the delay (either through an Implementation Plan addendum, Advice Letter, or other mechanism) prior to April (or August as described below) should be sufficient to result in a change to the CCA's load forecast;
- If the voluntary change/delay applies to a date when the initial service was in October through December and is being delayed, then the CCA can communicate the change by the August load forecast update rather than the April update; and
- The Commission should allow for a mutually acceptable solution between the IOU and the CCA that deviates from the timeline and process above if one can be reached.[48]

The Proposed Decision should be modified to adopt these clarifications, which are necessary to ensure that ambiguity and uncertainty are reduced in the timelines and processes included in the Proposed Decision. If the Commission adopts these clarifications, CalCCA finds the proposal reasonable and does not oppose it.

VII. THE COMMISSION SHOULD CLARIFY THE SHOWING OF LDES IN THE SOD TEMPLATES AND LEAVE ROOM FOR FUTURE IMPROVEMENTS TO THE LDES AND EO COUNTING METHDOLOGIES

The Proposed Decision adopts two new counting rules that will enhance storage resources' ability to contribute to the RA program. ***First***, the Proposed Decision adopts the QC methodology for LDES utilizing a resource-specific forward charging period (FCP) based on the duration of the resource.[49] CalCCA appreciates the Commission clarifying how LDES resources will count in the RA program. This provides necessary near-term certainty to LSEs who must understand the value of LDES in their portfolios and ensures the counting of LDES can be reflected in the existing templates without becoming overly complex. The Commission should leave room for re-evaluating elements of the LDES

47 Proposed Decision, at 126-127.
48 CalCCA Opening Comments, at 21-22.
49 Proposed Decision, at 45-46.

counting methodology after the Commission and stakeholders have reviewed their functionality in the RA program. This re-evaluation should include a review of the multipliers to determine if they are overly conservative and a review of the methodology's applicability to different durations of LDES.

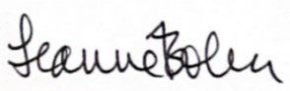
The Commission should also clarify the Proposed Decision regarding whether the Storage Minimum State-of-Charge test will continue to apply to LDES resources, and if so, how. If the Storage Minimum State-of-Charge test is applied to LDES resources without modification, the proposed changes to LDES excess capacity counting will fail to achieve their intended impact. This conflict is particularly acute given that the existing validation test is limited to a two-day window, whereas the new LDES proposal permits up to an eight-day FCP.

Second, the Proposed Decision modifies the way EO resources can count towards charging sufficiency, by allowing EO resources paired with a deliverable resource to count towards the charging sufficiency requirement of off-site storage. CalCCA applauds the Commission for recognizing the reliability contribution of these resources. The Commission also references a forthcoming study by the CAISO that will provide information on whether the Commission can reasonably assume storage can charge from EO capacity, including: "(1) the extent to which transmission congestion constrains output from generation resources; and (2) the extent to which transmission congestion constrains storage resources' ability to charge."[50] Consideration of how EO resources can contribute to *RA requirements* in addition to charging sufficiency requirements, especially when already paired with deliverable resources as proposed by CalCCA,[51] should be considered in conjunction with the CAISO study.

VIII. CONCLUSION

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

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and
Deputy General Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

June 22, 2026

[50] Proposed Decision, at 32.
[51] CalCCA Track 1 Proposals, at 7-11.

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2027-2029, FLEXIBLE CAPACITY OBLIGATIONS FOR 2027, AND PROGRAM REFINEMENTS

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

Proposed text deletions show as **~~bold and strikethrough~~**
Proposed text additions show as **bold and underlined**

FINDINGS OF FACT

~~21. Based on CAISO's Business Practice Manual and CAISO's current tariff, the Commission determines that RCU and RCD products are components of the RUC process.~~

~~22. Based on CAISO's Business Practice Manual and CAISO's current tariff, the Commission finds that IR products and RC products are used interchangeably, and that the RC process is a component of the RUC process.~~

~~23. Based on CAISO's Business Practice Manual and CAISO's current tariff, the Commission finds that IR products are capacity products for purposes of the Commission's RA program.~~

24. A prudent approach is to **remove** **~~maintain~~** the status quo bidding and revenue requirements for capacity products adopted in D.05-10-042 and monitor the bidding behavior of the EDAM market and its impact on RC and IR pricing following the initial implementation, and any potential impacts on future RA pricing.

~~25. The Commission credits the underlying analysis and findings in Energy Division's Transactability Report.~~

~~26. The Commission is persuaded by the Transactability Report's conclusion that the record does not demonstrate transactability concerns under the SOD framework.~~

~~27. The Commission is persuaded by the Transactability Report's finding that implementation of an hourly load obligation trading mechanism would add significant complexity to the SOD program and a substantial burden on Commission staff and resources.~~

~~28. There are multiple outstanding issues with CalCCA's proposed hourly load obligation trading mechanism that would require development before reconsideration.~~

29. PG&E's proposal to clarify "changes to approved implementation plans" **with CalCCA's additional clarifications are reasonable** ~~**is a reasonable clarification**~~ to reduce uncertainty and to be consistent with the Commission's intent in D.19-06-026.

New: The record demonstrates a need for the ability to transact RA products in the same unit of time as the hourly slice-of-day requirements.

New: Energy Division's proposed meet-and-confer process is insufficient for an RA allocation process for data center loads.

New: A formal RA allocation process based on relevant milestones is necessary to ensure RA obligations associated with data center loads maintain the reliability and affordability of the RA program.

CONCLUSIONS OF LAW

4. Energy Division's proposed clarifications and adjustments to the storage QC methodology, in addition to ~~**CAISO's**~~ **CalCCA's** suggested modifications to the definition and clarification, are reasonable and should be adopted.

18. The Commission ~~**maintains and affirms**~~ **removes** the policy rules established in D.05-10-042 for offering RA capacity products into the CAISO market. ~~**As IR products are deemed capacity products for purposes of the RA program, D.05-10-042 applies to IR products.**~~

19. There is ~~**no**~~ **a** demonstrated need for an hourly load obligation trading mechanism under the SOD framework ~~**at this time**~~.

~~**20. Reconsideration of any hourly obligation trading proposal will require a demonstrated need that transactability issues exist under the current RA framework.**~~

21. PG&E's proposal to clarify "changes to approved implementation plans" **with CalCCA's additional clarifications** should be adopted.

New: CalCCA's proposal for an hourly load obligation trading mechanism is reasonable and should be adopted.

New: CalCCA's proposal for RA allocations of data center loads is reasonable and should be adopted.

ORDERING PARAGRAPHS

6. The following clarifications and modifications to the storage qualifying capacity (QC) methodology are adopted as follows:

(a) The storage QC calculation is **the MW that can be provided continuously over four consecutive hours** ~~**MAX_CONT_ENERGY_LIMIT less MIN_CONT_ENERGY_LIMIT, divided by four and**~~ constrained by the point of interconnection; and

(b) **The storage resource can be shown up to its net QC in each hour constrained by the MWh that are available** ~~**The storage QC value is clarified as the output level at which a resource can discharge for four or more continuous hours**~~ without being affected by nonlinearity (or foldback). ~~**Once Energy Division has access to a value of continuous energy unaffected by foldback, that value will be incorporated into the calculation in subpart (a) above.**~~

~~**15. Load-serving entities' (LSE) future Resource Adequacy (RA) contracts must reflect the policy determinations from Decision 05-10-042 to ensure zero-dollar bidding for capacity products, and to specify that the resource owner is not eligible for capacity-related revenue payments. LSEs shall use the California Independent System Operator Day-Ahead Market Enhancements Transitional Measures, or other equally effective means, to effectuate this requirement.**~~

New: CalCCA's Hourly Load Obligation Trading proposal is adopted, and Energy Division is authorized to implement compliance validation in the existing templates with CalCCA's proposed guardrails until RA compliance automation can be further explored.

New: CalCCA's data center RA allocation proposal is adopted, and Energy Division shall include data center loads in LSE RA allocations upon the completion of the progress milestones in the proposal.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes.	R.25-02-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S TRACK TWO REPLY BRIEF

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Counsel to
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

June 25, 2026

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SUMMARY OF RECOMMENDATIONS[1]

In response to the Joint IOUs' Track 2 Opening Brief, the Commission should:

- Reject the Joint IOUs' argument that the Commission's past interim decisions tie its hands. Track 2 was established to resolve the unsettled issue of how Pre-2019 Banked RECs should be valued in the PCIA, and all parties bear the burden of demonstrating that their proposal best satisfies the indifference standard. The Commission makes its Track 2 decision on a blank slate.
- Reject the Joint IOUs' attacks on CalCCA's proposals. Contrary to the IOUs' assertions:
    - The RPS compliance benefits from Pre-2019 Banked RECs were never valued in the pre-2019 ERRA rates that Later Departing Customers paid when they were still bundled customers;
    - Prior cost shifts are a red herring since both Later Departing Customers and Current Bundled Customers were bundled customers when pre-2019 rates were set;
    - Later Departing Customers will never benefit from RECs for which they paid under a $0 valuation, meaning a $0 valuation increases costs for Later Departing Customers;
    - The current PCIA methodology does not foreclose CalCCA's proposals; and
    - CalCCA's allocation proposal is feasible and lawful.
- Reject the Joint IOUs' proposed modifications to Staff Proposal 4 because those modifications would leave bundled customers with all the benefits that were paid for by both bundled and Later Departing Customers;
- Reject the Joint IOUs' thin timeliness arguments. The Joint IOUs base those arguments on legal doctrines that do not apply to a prospective rulemaking and, regardless, the "claim" did not accrue until the IOUs began using Pre-2019 Banked RECs for Current Bundled Customer RPS compliance. CalCCA has consistently challenged the resulting $0 valuation since that time;
- Adopt the proposed method of valuing Pre-2019 Banked RECs used for bundled customer RPS compliance that CalCCA recommended in its Opening Brief (*i.e.*, using the RPS MPB and crediting that value to the vintage corresponding to the year any such REC was generated);
- In the alternative, adopt the allocation method CalCCA recommended in its testimony and Opening Brief; and
- If the Commission does not adopt either of these valuation or allocation proposals rooted in the indifference requirements, it should adopt CalCCA's 90/10 composite (of the RPS MPB and a new PCC-3 REC MPB) price proposal that CalCCA recommended in its Opening Brief.

[1] Acronyms used herein are defined in the body of this document.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes.	R.25-02-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S TRACK TWO REPLY BRIEF

Pursuant to Rule 13.12 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure;[2] *Assigned Commissioner's Amended Scoping Memo and Ruling*[3] (Amended Scoping Ruling); the *Administrative Law Judge's Ruling Issuing Staff Report*[4] (ALJ Ruling); and the *E-Mail Ruling Cancelling Evidentiary Hearing and Further Modifying the Track Two Proceeding Schedule*[5] (E-Mail Ruling), the California Community Choice Association[6] (CalCCA) submits this Track 2 Reply Brief.

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[2] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021).

[3] *Assigned Commissioner's Amended Scoping Memo and Ruling*, Rulemaking (R.) 25-02-005 (Feb. 3, 2026).

[4] *Administrative Law Judge's Ruling Issuing Staff Report,* R.25-02-005 (Mar. 27, 2026).

[5] *E-Mail Ruling Cancelling Evidentiary Hearing and Further Modifying the Track Two Proceeding Schedule*, R.25-02-005 (Apr. 24, 2026).

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

I. INTRODUCTION

The Joint Investor-Owned Utilities (Joint IOUs) seek a bargain-basement deal funded by non-IOU customers. Their bundled customers (Current Bundled Customers) get exclusive use of Renewable Energy Credits (REC) partially paid for by customers that left bundled service after the RECs were created (Later Departing Customers). When the Joint IOUs use the RECs for Current Bundled Customer Renewable Portfolio Standard (RPS) compliance, they propose there be ***no reimbursement to the Later Departing Customers who paid for those RECs.*** The Joint IOUs get an extraordinary bargain—a potentially several hundred-million-dollar benefit ***for free***—on the backs of non-IOU customers.[7]

Energy Division Staff recognizes that "later departed customers paid in part for [the banked RECs]" and that those RECs "still have an RPS compliance value."[8] Similarly, the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) recognizes that the failure to provide Later Departing Customers with value proportional to the amount they paid for the RECs violates the indifference statutes:

> If an IOU uses Pre-2019 Banked RECs to meet current bundled customers' RPS compliance obligations without crediting departed customers who helped pay for those RECs through the PCIA, those departed customers do not receive the value of assets procured on their behalf. This violates the requirements of Section 366.2(g) that departed customers receive a fair and equitable share of benefits remaining with bundled service customers. If Pre-2019 Banked RECs provide current RPS compliance value to bundled customers, ***that value constitutes a benefit remaining with bundled service that the statute requires be fairly and equitably credited to departed load.***[9]

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7 Exh. CCA-01 at 16:8-11.

8 Staff Report, at 5-8 ("[Energy Division] staff observe that these banked RECs – which were funded in part by later departed customers—do have value in that they can be used for compliance.").

9 Exh. CalAdv-01 at 2.

But the Joint IOUs continue to state that the value provided to Later Departing Customers should be $0.

Statutory indifference is typically achieved through the contemporaneous allocation of costs and benefits among bundled and unbundled customers to ensure that neither group subsidizes the other. This situation is unique, given the RECs were paid for prior to 2019, and are only being used today. While initially all customers who paid for the RECs were bundled, that has now changed, and the only group with the ability to use the RECs are Current Bundled Customers. Absent a corrective valuation or allocation, Later Departing Customers will receive none of the compliance value associated with the RECs they funded. This creates a departure from statutory indifference because one group of customers paid for an asset while another group receives the full benefits of that asset. The purpose of Track 2 is to address this unique circumstance and ensure that the value of Pre-2019 Banked RECs is recognized in a manner that preserves indifference among bundled and unbundled customers.

In their Opening Brief, the Joint IOUs seek to shift the Commission's attention from the narrow issue presented in Track 2 to broader debates regarding the historical Power Charge Indifference Adjustment (PCIA) methodology. Putting aside the fact that the customers at issue ***were all bundled customers*** when the RECs were created, and, therefore, equally benefitted from or were harmed by any prior cost shifts, the Commission need not resolve every historical issue to answer the question before it. The record demonstrates that Pre-2019 Banked RECs continue to provide RPS compliance value, that bundled customers retain that value today, and that Later Departing Customers helped fund the assets producing that value but have never received (and are not currently receiving) any benefits. The Commission should therefore reject the Joint

IOUs' request to adopt a $0 valuation and instead adopt a methodology that fairly allocates the value of Pre-2019 Banked RECs consistent with the statutory indifference mandate.

In response to the Joint IOUs' Track 2 Opening Brief, the Commission should:

- Reject the Joint IOUs' argument that the Commission's past interim decisions tie its hands. Track 2 was established to resolve the unsettled issue of how Pre-2019 Banked RECs should be valued in the PCIA, and all parties bear the burden of demonstrating that their proposal best satisfies the indifference standard. The Commission makes its Track 2 decision on a blank slate.
- Reject the Joint IOUs' attacks on CalCCA's proposals. Contrary to the IOUs' assertions:
    - The RPS compliance benefits from Pre-2019 Banked RECs were never valued in the pre-2019 ERRA rates that Later Departing Customers paid when they were still bundled customers;
    - Prior cost shifts are a red herring since both Later Departing Customers and Current Bundled Customers were bundled customers when pre-2019 rates were set;
    - Later Departing Customers will never benefit from RECs for which they paid under a $0 valuation, meaning a $0 valuation increases costs for Later Departing Customers;
    - The current PCIA methodology does not foreclose CalCCA's proposals; and
    - CalCCA's allocation proposal is feasible and lawful.
- Reject the Joint IOUs' proposed modifications to Staff Proposal 4. Those modifications would leave bundled customers with all the benefits that were paid for by both bundled and Later Departing Customers.
- Reject the Joint IOUs' thin timeliness arguments. The IOUs base those arguments on legal doctrines that do not apply to a prospective rulemaking and, regardless, the "claim" did not accrue until the IOUs began using Pre-2019 Banked RECs for Current Bundled Customer RPS compliance. CalCCA has consistently challenged the resulting $0 valuation since that time.

Instead, the Commission should:

- Adopt the proposed method of valuing Pre-2019 Banked RECs used for bundled customer RPS compliance that CalCCA recommends in its Opening Brief (*i.e.*, using the RPS market price benchmark (MPB) and crediting that value to the vintage corresponding to the year any such REC was generated);
- In the alternative, adopt the allocation method CalCCA recommended in its testimony and Opening Brief; and
- If the Commission does not adopt either of these valuation or allocation proposals rooted in the indifference requirements, it should adopt CalCCA's 90/10 composite

(of the RPS MPB and a new PCC-3 REC MPB) price proposal that CalCCA recommended in its Opening Brief.

II. NO PRIOR COMMISSION DECISION PREVENTS COMMISSION ACTION IN TRACK 2

Nothing prevents the Commission from adopting CalCCA's proposal. The Joint IOUs suggest the Commission's hands are tied by mischaracterizing their own $0 valuation proposal as existing law, as part of the existing PCIA methodology, and as a necessary outcome based on prior Commission decisions.[10] This argument not only wrongly disclaims the Joint IOUs' obligation to justify their proposed outcome (because they state it is already the status quo), it recasts a contested policy question as CalCCA's burden alone to overcome. The valuation of Pre-2019 Banked RECs remains unsettled, which is why the Commission established this Track 2 as the venue to decide this issue. Even if the Commission agrees that prior decisions conflict with CalCCA's proposal, it is not bound by those prior decisions. The Commission makes its decisions in this case on a blank slate, and all parties bear an equal evidentiary burden to support their proposals.

A. Track 2 Was Established to Resolve the Unsettled Issue of Pre-2019 Banked REC Valuation

The Joint IOUs' claim that CalCCA alone bears the burden of proving its proposal is just and reasonable presupposes that the Commission has already unambiguously determined that Pre-2019 Banked RECs should receive a $0 valuation when used for bundled customer compliance.[11] That is wrong; the Commission has not done so in either this rulemaking or in the

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[10] *See* Joint IOU Opening Brief at 4 ("In this Track 2, CalCCA is the party proposing to change the IOUs' rates through a change in the Commission-adopted PCIA ratesetting methodology; therefore, CalCCA has the burden of bringing forward evidence sufficient to prove that is proposals will result in just and reasonable rates.").

[11] *See* Joint IOU Opening Brief at 3 (arguing that existing Commission "guidance" should be "maintained."). The Joint IOUs also claim that the parties resolved this issue "by party agreement" in the former PCIA rulemaking. *See* Joint IOU Opening Brief at 45. But they do not, and cannot, show that

Energy Resource and Recovery Account (ERRA) cases. The Commission exclusively scoped the issue of determining the proper value of Pre-2019 Banked RECs into this Track 2 to finally resolve this unsettled "exigent" issue.[12]

The Commission itself has stated that its past rulemaking decisions are ambiguous as to the appropriate PCIA accounting for Pre-2019 Banked RECs:

> [w]hile we recognize that parties have different perspectives about the direction in D.19-10-001 and its applicability to pre-2019 RECs, we do not have the record to fully evaluate them here. We may consider the issue in a future rulemaking.[13]

The Joint IOUs even acknowledge that in Energy Division's Staff Report, staff "characterize the treatment of Pre-2019 Banked RECs as 'unresolved' by D.18-10-019 and D.19-10-001."[14]

The Commission's ERRA decisions also do not support the Joint IOUs' claims that this matter was resolved in a way that establishes a $0 valuation as the baseline and shifts the burden to CalCCA. While the Joint IOUs only focus on instances in which the Commission permitted Southern California Edison (SCE) to assign the Pre-2019 Banked RECs $0, they ignore instances in which the Commission has *also* approved assigning these Pre-2019 Banked RECs an RPS MPB valuation in Pacific Gas and Electric Company's (PG&E) prior ERRA Forecast cases.[15] More fundamentally, the Commission has repeatedly made clear that ERRA decisions are *not* the proceedings in which policy is made—instead, policy is made in rulemakings—requiring the

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there was ever an agreement with CalCCA or any CCA as to how Pre-2019 Banked RECs would be accounted for in the PCIA.

[12] *See Assigned Commissioner's Amended Scoping Memo and Ruling,* R.25-02-005 (Feb. 3, 2026), at 2 ("[I]n the 2026 ERRA Forecast proceedings, the narrower issue of the appropriate valuation of [RECs] generated prior to January 1, 2029, and used for bundled service customer compliance, for the purpose of calculating the PCIA . . . emerged as *exigent*.") (emphasis added).

[13] D.24-08-004, *Decision Denying Petition for Modification of Decision 23-06-006*, R.17-06-026 (Aug. 7, 2024), at 5.

[14] Joint IOU Opening Brief at 45.

[15] CalCCA Opening Brief at 22, and n.101.

issue to be resolved in this rulemaking.[16] As CalCCA explained in its Opening Brief, when the Commission did approve the $0 valuation (over CalCCA's objections) in prior ERRA Forecast proceedings, it only did so as an *interim* solution.[17]

B. The IOUs' "Precedent" Arguments Misconstrue the Nature of Commission Decision-Making

The IOUs' reliance on the Commission's interim $0 valuations as binding "precedent" misapprehends the nature of Commission decision-making. *Stare decisis* "applies only to judicial precedents," and Commission decisions are entitled to no such effect.[18] The Commission's prior decisions on Pre-2019 Banked RECs expressly contemplated reconsideration of this issue on a statewide basis, and Track 2 is that forum. Similarly, if the Commission agrees the prior PCIA methodology, or even D.19-10-001,[19] did not expressly and specifically prognosticate the need to value Pre-2019 RECs at the benchmark, in the event future customers might depart from bundled service without having those RECs used on their behalf, the Commission's hands still are not tied. The Commission is free to value Pre-2019 Banked RECs at the RPS MPB in

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[16] D.18-01-009, at 10 (finding that policy issues and other industry-wide practices such as changes to the PCIA methodology are properly addressed in rulemaking dockets, such as R.17-06-026); *see* D.24-12-039, *Decision Approving Southern California Edison Company's 2025 Energy Resource Recovery Account-Related Forecast Revenue Requirement*, Application (A.) 24-05-007 (Dec. 19, 2024), at 69; D.18-01-009, *Decision Adopting Pacific Gas and Electric Company's 2018 Energy Resource Recovery Account Forecast and Generation Non-Bypassable Charges and Greenhouse Gas Forecast Revenue and Reconciliation*, A.17-06-005 (Jan. 11, 2018), at 10 (finding that policy issues and other industrywide practices such as changes to the PCIA methodology are properly addressed in rulemaking dockets, such as R.17-06-026).

[17] *See* CalCCA Opening Brief at 35, n.170 (citing four different ERRA decisions using the following language: "interim", "on an interim basis for the purpose of this decision," "for this proceeding," and "interim").

[18] *Consumers Lobby Against Monopolies v. Pub. Util. Comm'n* (1979) 25 Cal.3d 891, 902 (superseded on other grounds as explained in *New Cingular Wireless PCS, LLC v. Pub. Util. Comm'n* (2016) 201 Cal.3d 652); *City of Los Angeles v. Pub. Util. Comm'n* (1975) 15 Cal.3d 680, 698; *Cf.* Pub. Util. Code § 1708.

[19] D.19-10-001, *Decision Refining the Method to Develop and True Up Market Price Benchmarks*, R.17-06-026 (Oct. 10, 2019).

compliance with the statutory indifference framework, and the only requirement—a reasoned explanation for doing so in line with that framework—is amply supplied by the record.

C. All Partes, Including the Joint IOUs, Bear an Equal Evidentiary Burden in This Proceeding

Given that the Commission expressly reserved this issue for consideration in a rulemaking, and because *stare decisis* does not tie the Commission's hands, all parties bear an equal evidentiary burden in this proceeding.[20] In a rulemaking, all parties "have equal standing where their proposals are concerned: they must show by a preponderance of evidence that the Commission should adopt their proposal, rather than an alternative."[21] All parties bear the burden of production "for those parts of their showing that ask the Commission to disregard a competing proposal[.]"[22] That means the Joint IOUs' $0 valuation proposal must overcome the same burden as CalCCA's proposal. The Joint IOUs cite in their Opening Brief to this very language that both parties have "equal standing" and the burden to prove their proposal should be adopted.[23] Their attempt to evade their burden of proving that a $0 valuation is just and reasonable by shifting that burden to CalCCA should be rejected.

III. THE JOINT IOUS' ATTACKS ON CALCCA'S PROPOSALS DO NOT REBUT THE RECORD EVIDENCE THAT VALUING OR ALLOCATING PRE-2019 BANKED RECS PRESERVES INDIFFERENCE

Throughout this proceeding, the Joint IOUs have attempted to sidestep and confuse the following simple, central points:

- Current Bundled Customers and Later Departing Customers paid the *same amount* for the Pre-2019 Banked RECs through their rates at the time the RECs were banked for future use;

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20 *See* CalCCA Opening Brief at 7 (citing D.18-10-019 at 32).

21 D.18-10-019, *Decision Modifying the Power Charge Indifference Adjustment Methodology*, R.17-06-026 (Oct. 11, 2018), at 32.

22 D.18-10-019 at 32.

23 Joint IOU Opening Brief at 4, n.12.

- Even assuming Then-Bundled Customers previously realized the energy and GHG-free value of the RPS generation underlying the RECs, customers realize the value of the Pre-2019 Banked RECs only when the RECs are used for RPS compliance, making banked RECs unique among other components of the PCIA methodology;
- Later Departing Customers will never benefit from the RPS compliance value of the Pre-2019 Banked RECs under the Joint IOUs' $0 valuation proposal; and
- When the RECs are used for RPS compliance, the indifference statutes require that both customer groups who paid for the RECs receive the associated benefits, or else a cost shift and effective cost increase will result.[24]

CalCCA's Opening Brief already addressed the major arguments the Joint IOUs deploy in their Opening Brief that fail to overcome these central points.[25] This section addresses these briefly as well as a few novel claims and extensions the Joint IOUs introduce in their Opening Brief, all of which are similarly unavailing.

A. The RPS Compliance Benefits from Pre-2019 Banked RECs Were Never Recognized in Pre-2019 ERRA Rates

As in testimony, much of the Joint IOUs' Opening Brief focuses on past grievances about pre-2019 ratemaking—which they acknowledge the record does not support revisiting but simultaneously claim cannot be ignored. In sum, the Joint IOUs argue CalCCA's proposal ignores past cost shifts, "attempts to retroactively reallocate value to Later Departing Customers;" "impose[s] a new methodology to value REC attributes already included in the IOUs' historical pre-2019 rates;" seeks a "partial refund of generation rates that the IOUs

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[24] *See* Exh. CCA-01 at 11:18-19, 12:6-13:2, 14:3-16; Exh. CCA-02 at 11:20-12:16, 29:9-21.

[25] For example, the following Joint IOU arguments were addressed by CalCCA's Opening Brief: (1) this would be "double payment" for the same product (Joint IOU Opening Brief at 15; CalCCA Opening Brief at 23-25); (2) the value for these RECs was already incorporated at the time of generation (Joint IOU Opening Brief at 16-17; CalCCA Opening Brief at 70-72); (3) this is a change to rates paid a decade ago (Joint IOU Opening Brief at 19; CalCCA Opening Brief at 70-72); (4) these RECs cannot be traded and therefore have no market value (Joint IOU Opening Brief at 13, 16, 28; CalCCA Opening Brief at 51-52); and (5) these RECs cannot be incorporated in the Power Content Label (Joint IOU Opening Brief at 30-32; CalCCA Opening Brief at 52-54).

charged over a decade ago;" and values RECs a second time, all at "the expense of today's bundled service customers," causing a cost shift.[26]

None of these arguments address the fundamental question in this Track 2: is it fair to deny departed customers the same benefits bundled customers receive when Pre-2019 Banked RECs are used for current RPS compliance? When that happens, Current Bundled Customers finally receive the compliance benefits from banked RECs they paid for in pre-2019 rates.[27] Later Departing Customers—who also paid for those RECs—do not receive that same benefit under the interim $0 valuation methodology and, therefore, are not left indifferent.[28]

This question has nothing to do with prior cost shifts. The two customer groups at issue (Current Bundled Customers and Later Departing Customers) were identically situated (when they were both Then Bundled Customers) and paid the same rates in the RECs' generation year.[29] Whether they paid too much or too little for Pre-2019 Banked RECs, they both paid too much or too little in equal measure. Whether they suffered or benefitted from any cost shift that existed from the prior methodology, they both suffered or benefitted from that cost shift in equal measure. Past cost shifts are a red herring.

The question also has nothing to do with reallocation, revaluation, or partial refunds because Then-Bundled Customers did not benefit from the RECs' compliance value in the first place. In order for the compliance benefits of a REC to be reallocated, revalued, refunded, or "re"-anything, the compliance benefits had to have been recognized a first time. That did not happen until now, when the IOUs began using the Pre-2019 Banked RECs to meet Current Bundled Customers' compliance obligations. Those customers now enjoy their benefits when a

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26 Joint IOU Opening Brief at 13-19.
27 Exh. CCA-01 at 9:8-10, 12:6-13:12, 14:3-13, Attachment A.
28 Exh. CCA-03 at 9:5-9, 10:14-19, 1:4-14.
29 Exh. CCA-01 at 12:6-13:8.

Pre-2019 Banked REC is used for compliance because it reduces the costs the IOUs would otherwise need to incur to supply that same MWh of renewable energy. Later Departing Customers deserve an equivalent "avoided cost" benefit.

The Joint IOUs argue that "the PCIA historical mechanism" already satisfied section 366.2(g) because the net unavoidable costs in PCIA rates were reduced by the value of "benefits" included in the historical generation rate.[30] In doing so, the Joint IOUs cite the credit given to departed load at the time for the "total portfolio forecast value of forecast energy, RECs, and the value of RA using the historical MPBs set by the Commission at that time."[31] However, when the Joint IOUs' claim that customers already received a "benefit" through CAISO revenues or GHG-free attributes,[32] they focus on the wrong attributes. CAISO revenues do not include the RPS compliance benefits of a REC.[33] That is the energy component of renewable energy.[34] GHG-free attributes do not include the RPS compliance benefits of a REC.[35] That is the GHG-free component of renewable energy.[36]

They also focus on the wrong customers. As explained *ad nauseum* by CalCCA's witness in this case, [37] and in CalCCA's Opening Brief,[38] the only customers that received the value of RPS compliance benefits from Pre-2019 Banked RECs were the customers that had already departed bundled service when the RECs were generated, *i.e.*, Previously Departed Customers.

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30 Joint IOU Opening Brief at 21.
31 Joint IOU Brief at 21.
32 Joint IOU Opening Brief at 19-22.
33 *See* Exh. CCA-01 at 6:1-8:12.
34 *See* Exh. CCA-01 at 6:1-8:12.
35 Exh. CCA-01 at 6:1-8:12.
36 Exh. CCA-01 at 6:1-8:12. The Commission did not recognize GHG-free attributes until 2023 via D.23-06-006.
37 *See, e.g.,* Exh. CCA-01 at 10:17-16-11, Attachment A; Exh. CCA-02 at 5:1-7:13, 9:23-11:14, 28:14-29:5.
38 *See, e.g.,* CalCCA Opening Brief at 15-17, 21-22, n. 99, 67-69.

Previously Departed Customers are not the customer group at issue here, and CalCCA's proposals do not apportion any costs or benefits to them.

It is true that, when these RECs were generated, Then-Bundled Customers were responsible for the entire cost of generation resources, less a payment from Previously Departed Customers for a share of the above market costs of those resources. That is how the PCIA operates. To calculate that payment from Previously Departed Customers, the Commission calculated the forecast cost of generation and then subtracted the value of that generation. One of the sources of value was RECs. [39] The IOUs used the RPS MPB to help determine what the 'above market costs' of those generation resources were (those that exceeded the RPS MPB).[40] The Commission then calculated which proportion of the 'above market costs' would be borne by Previously Departed Customers (using load proportion), and that was the amount that Previously Departed Customers paid to reduce Then-Bundled Customers' costs.[41] The RPS MPB acted as a credit to Previously Departed Customers (the higher it was, the lower Previously Departed Customers rates fell) and a charge to Then-Bundled Customers (the higher it was, the higher Then-Bundled Customers rates rose).[42]

However, that does not mean Then-Bundled Customers received the value of the RECs' RPS compliance benefits. It just means that if the PCIA did not exist, Then-Bundled Customers would have paid for the entirety of the cost of RPS generation resources in that year. While Then-Bundled Customers received this "credit" from Previously Departed Customers for the PCIA rates they would have paid, it was received equally by all Then-Bundled Customers proportionate to their load. The payment from Previously Departed Customers certainly was not

39 *See generally* Exh. CCA-01 at Attachment A.
40 *See generally* Exh. CCA-01 at Attachment A.
41 *See generally* Exh. CCA-01 at Attachment A.
42 *See generally* Exh. CCA-01 at Attachment A.

specific to, and it did not convey any value from, the benefit of avoiding RPS compliance purchases. That benefit was shelved until the REC was used for compliance. The bottom line is that any assertion that Later Departing Customers have already benefitted from the compliance value of Pre-2019 Banked RECs is patently false and should not mislead the Commission.

Lastly, the Joint IOUs argue that the fact that current CCA customers may pay extra now for products exceeding annual RPS minimums (*i.e.*, "deep green" or "100 percent" renewable) "undermin[es] the credibility of CalCCA's central hypothetical construing Later Departing Customers *as bereft of value* when IOUs exceeded RPS obligations when they were bundled service customers, and remain awaiting additional value from the generation rates they paid more than a decade ago."[43] What Later Departing Customers choose to purchase from the CCA now is irrelevant to the value they are entitled for bank-able attributes for which they already paid.[44] The Joint IOUs are arguing that because Later Departing Customers choose to purchase a premium product now, they are not entitled to be reimbursed for prior payments and instead should subsidize Current Bundled Customers by allowing them to use the Later Departing Customers' share of RECs for free. That is not indifference. The point is, again, that these customer groups were identically situated when they paid for the generation resources that produced the RECs, and now only one of the customer groups (Currently Bundled Customers) gets to benefit from the RECs when they are used for compliance.

B. The Current PCIA Methodology Does Not Prohibit CalCCA's Proposal

The Joint IOUs' claim that the current PCIA methodology has never been, and cannot be, implemented in line with CalCCA's proposal should be rejected. The Joint IOUs are correct that

[43] Joint IOU Opening Brief at 20 (emphasis added).

[44] Even if it were relevant, the same can be said for IOU customers, some of whom undoubtedly also prefer "deep green" energy today.

the indifference statutes, and the PCIA methodology adopted by the Commission to implement those statutes, do not *expressly* address the unique circumstance of Pre-2019 Banked RECs and their feature of deferred value from past payment of costs. However, contrary to the IOU argument that CalCCA seeks to implement section 366.2(g) in isolation of the other indifference statutes to its benefit,[45] CalCCA's proposal directly complies with the interrelated statutes within the indifference framework by:

- Ensuring that *all* customer groups remain indifferent;[46]
- Ensuring that Current Bundled Customers do not experience any cost increase as a result of the implementation of a CCA program by requiring that *only* the value gained by the Current Bundled Customers from the costs paid by Later Departing Customers is realized;[47]
- Remedying the cost increase experienced by Later Departing Customers as a result of an allocation of costs not incurred on Later Departing Customer's behalf when Current Bundled Customers use the share of Pre-2019 Banked RECs paid for by Later Departing Customers;[48]
- Remedying the shifting of costs from Current Bundled Customers to Later Departing Customers when Current Bundled Customers use the share of Pre-2019 Banked RECs paid for by Later Departing Customers;[49] and
- Reducing the costs paid by Later Departing Customers by the value of benefits remaining with bundled service customers (*i.e.*, the Later Departing Customer share of the Pre-2019 Banked RECs), or in the alternative providing Later Departing Customers an allocation of those benefits.[50]

The suggestion that CalCCA's proposal hinges on one statutory provision, or is contrary to the State's indifference framework, is not credible.

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45 The Joint IOUs' state that "Section 366.2(g) cannot reasonably be implemented in isolation of the other subsections of Section 366.2(g)." *See* Joint IOU Opening Brief at 9. However, there is only one subsection in Section 366.2(g), so CalCCA assumes the Joint IOUs' are referencing all other indifferent statute subsections.

46 *See* Cal. Pub. Util. Code §§ 365.2, 366.2(a)(4), 366.3. All subsequent code sections cited herein are references to the California Public Utilities Code unless otherwise specified.

47 Cal. Pub. Util. Code §§ 365.2, 366.2(a)(4), 366.3.

48 Cal. Pub. Util. Code §§ 365.2, 366.3.

49 Cal. Pub. Util. Code § 366.2(a)(4).

50 Cal. Pub. Util. Code § 366.2(g).

The provision of value to Later Departing Customers is not somehow "outside" the current PCIA methodology constituting a "separate credit" to Later Departing Customers.[51] Instead, the unique bankable nature of RPS attributes, and the resulting deferred value, is the reason a later valuation must occur through the PCIA when the RECs are used for RPS compliance. Within the RPS methodology, the Commission allowed the Joint IOUs to place RECs funded by bundled customers on the 'shelf' for future use. Other attributes, like resource adequacy (RA) and energy, do not have this same feature allowing such deferred use.[52] While the Joint IOUs have vigorously argued that all allocations of costs and value occurred when the RECs were banked, logic tells us otherwise. Bundled customers at the time paid generation rates covering the costs of the renewable generation components of the PCIA portfolio.[53] As part of that, the utilities banked a REC compliance attribute on those customers' behalf.[54] To claim now that no current value attaches to those RECs when they are later pulled off the 'shelf' and used for the benefit of bundled compliance raises the obvious question: why put them in the bank if they have no value?[55] These RECs will be used for compliance value today (or tomorrow). Any ambiguity in their future value is therefore resolved today (or tomorrow). Departed load must receive the benefit of these attributes for which they paid.[56]

While the RECs were banked in previous years, CalCCA has explained repeatedly how its proposal will not reach back and true up prior PCIA rates or refund any previously-paid ERRA generation rates.[57] Rather, the use of the banked REC now requires acknowledgement of

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51 Joint IOU Opening Brief at 9.
52 CalCCA Opening Brief at 12, 68-69.
53 Exh. CalCCA-01 at 9:8-10.
54 Exh. CCA-01 at Attachment A-1.
55 CalCCA Opening Brief at 12, 68-69.
56 *See* Cal. Pub. Util. Code § 366.2(g).
57 CalCCA Opening Brief at 69-72.

the RPS compliance benefit value that must be provided to the customer groups that originally paid for that attribute, to ensure indifference *under the existing PCIA methodology*.

C. Both CalCCA's Primary Valuation Proposal and its Alternate Allocation Proposal Respect and Utilize the PCIA Methodology

1. CalCCA's Proposal Utilizes the PCIA's Existing Vintaging Tool and Does Not Require Individualized Customer Analysis

In testimony, CalCCA's witness repeatedly explained that the appropriate accounting for Pre-2019 Banked RECs utilizes the long-standing PCIA vintaging tool[58] to allocate the value of the previously purchased Banked RECs to the appropriate *customer groups*.[59] At the hearing, PG&E admitted that, when it previously used the same methodology CalCCA is proposing, PG&E did not need to track individual customers or determine that individual customers had an individual ownership claim to Pre-2019 Banked RECs.[60] CalCCA's Opening Brief already explained why the Commission should reject the Joint IOUs' interpretation of D.06-07-030[61] as prohibiting the use of customers' vintages to distribute the benefits of these banked RECs when used for bundled customer compliance.[62] First, CalCCA is not proposing to track individual customers or provide individual bill credits, which was the proposal the Commission rejected in D.06-07-030.[63] Second, the Commission issued D.06-07-030 before the legislature created

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58 *See generally* D.08-09-012, *Decision on Non-Bypassable Charges for New World Generation and Related Issues*, R.06-02013 (Sept. 4, 2008) (considering arguments regarding and establishing a vintaging methodology).

59 Exh. CCA-01 at 29:1-6; Exh. CCA-02 at 4:13-22, 17:4-19:9; Exh. CCA-04 at 13:10-11, 16:18-21. *See also* CalCCA Opening Brief at 54-56.

60 Opening Brief at 56 (citing Vol. 1 Tr. 105:6-10; 106:23-107:19 (Joint IOU Panel [Brown, Morien, Pulgar])).

61 D.06-07-030, *Opinion Regarding Direct Access and Departing Load Cost Responsibility* [*sic*] *Surcharge Obligations*, R.02-01-011 (July 20, 2026).

62 *See* CalCCA Opening Brief at 54-55. *Contra* Joint IOU Opening Brief at 35.

63 CalCCA Opening Brief at 55.

section 366.2(g) to clarify that IOU generation procurement costs paid by the customers of a CCA shall be reduced by the value of any benefits that remain with bundled service customers.[64]

Nevertheless, the Joint IOUs continue to claim that CalCCA's approach runs afoul of the PCIA by its treatment of customers as individuals, not groups.[65] The Joint IOUs characterize the defined terms "Later Departing Customers" and "Previously Departed Customers" as if they are a foreign, new invention that violates the PCIA methodology.[66] They are not. These terms (which the Assigned Commissioner also adopted for convenience)[67] are simply more streamlined ways of referring to multiple, similarly situated vintages of customers using one term. Take 2015 Banked RECs used for compliance in 2026: for these RECs, the group of vintages before 2015 have—for convenience—been labeled with the defined term "Previously Departed Customers," while vintages 2015 through 2025 are grouped in the defined term "Later Departing Customers" with vintage 2026 labeled "Currently Bundled Customers."[68] There is therefore no conflict between what section 366.2(g) requires and the Commission's historical group-focused approach to the PCIA (what the Joint IOUs call the Commission's "Total Portfolio" approach).[69]

2. The Commission Can Allocate Pre-2019 Banked RECs When IOUs Use them for Compliance, Not Just When Load Departs

When challenging CalCCA's alternate allocation solution, the Joint IOUs claim that the Commission *could* have allocated a right or claim to the value of these RECs when customers departed,[70] but cannot now. That is incorrect. *First*, as noted above, no prior Commission decisions tie the Commission hands to act to address a current cost shift.

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64 CalCCA Opening Brief at 55.
65 Joint IOU Opening Brief at 32-35.
66 Joint IOU Opening Brief at 9.
67 Amended Scoping Ruling at 3.
68 *See* CalCCA Opening Brief at 14.
69 *Contra* Joint IOU Opening Brief at 10.
70 Joint IOU Opening Brief at 33.

Second, the he Joint IOUs claim that the Commission could allocate Pre-2019 Banked RECs at the time of departure because, unlike CalCCA's allocation proposal, this would allocate the risk that Pre-2019 Banked RECs would never be used for compliance along with the benefit.[71] But CalCCA's allocation proposal *also* apportions to Later Departed Customers risks along with the benefits. Under CalCCA's allocation proposal, Later Departing Customers bear the risk that the Joint IOU never use Pre-2019 Banked RECs for compliance. If the Joint IOUs do not tap their bank to use Pre-2019 Banked RECs paid for by Currently Bundled Customers, there would be no trigger to allocate the Pre-2019 Banked RECs paid for by Later Departing Customers, and those RECs would remain unused on the Joint IOUs' books. Therefore, the Joint IOUs fail to identify relevant distinctions between an allocation at departure (which they claim is permitted) and an allocation at use (which they claim is not).

Third, in taking this position, the Joint IOUs demonstrate that numerous of their other arguments are incorrect. For example, while the Joint IOUs' proposal to allocate RECs at the time they were generated is ambiguous as to how it would operate, it only makes sense if the quantity of Pre-2019 Banked RECs allocated depends on when an individual customer departs. And presuming the Joint IOUs do not propose to treat each individual as an individual (which the Joint IOUs say clashes with the PCIA methodology), then the proposal would have to allocate Pre-2019 Banked RECs conditioned on a customer's vintage.[72] Therefore, the Joint IOUs admit that it is possible to respect the group-based nature of the PCIA methodology by providing the benefits of Pre-2019 Banked RECs to departed customers based on their vintage. [73] This further

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Joint IOU Opening Brief at 33.

[72] Exh. CCA-01 at 7:6-7 ("Customers are assigned vintage years according to the date the customer departed bundled IOU service.").

[73] *Compare* Joint IOU Opening Brief at 33 *with* Joint IOU Opening Brief at 34-35.

undermines the Joint IOUs' argument that the consideration of customers based on their vintage is anathema to the PCIA methodology.[74]

Fourth, this argument also clearly undermines the Joint IOUs' claim that allocation of RECs is prohibited under section 399.15 because Pre-2019 Banked RECs cannot be transferred.[75] For example, consider customers who departed in 2024. The Joint IOUs do not say that their allocation-at-departure proposal is time limited based on which vintage customers are in. So for these 2024 vintage customers, all Pre-2019 Banked RECs were retired in WREGIS before they departed service (because 2024 is more than 36 months after December 31, 2018—the last date on which Pre-2019 RECs could have been generated).[76] As the Joint IOUs point out, that means these Pre-2019 Banked RECs cannot be transacted.[77] But if, as the Joint IOUs argue, the Commission *could have* lawfully allocated Pre-2019 Banked RECs to those vintage 2024 customers two years ago upon departure, when they were already not transactable, then the Commission can lawfully allocate RECs to those vintage 2024 customers this year, despite the fact that they remain not transactable.[78]

D. The Joint IOUs' Zero-Valuation Approach Imposes an Unlawful Cost Shift and Cost Increase to Later Departing Customers by Allowing Current Bundled Customers to Receive the Entire Value of Pre-2019 Banked RECs Funded by Later Departing Customers

The Joint IOUs also argue that the zero-valuation approach does not impose an unlawful cost shift on Later Departing Customers, but that CalCCA's valuation proposal will impose a cost increase on Current Bundled Customers.[79] CalCCA's Opening Brief explains how the PCIA

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74 *See* Joint IOU Opening Brief at 34-35.
75 *See* Joint IOU Opening Brief at 37.
76 Joint IOU Opening Brief at 36-37.
77 Joint IOU Opening Brief at 36-37.
78 *See* CalCCA Opening Brief at 57.
79 Joint IOU Opening Brief at 10-12, 13-16

does not use "finders-keepers" logic: Current Bundled Customers that 'keep' the RECs do not suffer a 'cost increase' if they are made to pay Later Departing Customers for the RECs for which those Later Departing Customers originally paid.[80] Instead, Current Bundled Customers receive the value of the REC bank share that they paid for, and pay Later Departing Customers for the REC bank share that they are using but have not previously paid for.[81] On the other side of that same coin: if Current Bundled Customers 'keep' the RECs today without paying the current value for them, that is a 'cost shift' and 'cost increase' to Later Departing Customers that originally paid for them but never received a benefit.[82] In other words, when the banked RECs are finally used, the proportionate benefit paid for by Current Bundled Customers and Later Departing Customers must then be proportionally provided, or the party not receiving their share of the benefit will experience a cost shift and cost increase.

E. CalCCA's Alternate Allocation Proposal is Feasible and Legal

If the Commission determines not to value Pre-2019 Banked RECs at the RPS MPB, the Commission can, in the alternative, use section 366.2(g)'s allocation option to ensure that Later Departing Customers receive the benefit of the Pre-2019 Banked RECs for which they paid.[83] CalCCA provided testimony and briefing to explain how the Commission could implement this through offsetting entries to the LSEs' Excess Procurement Bank quantities on their respective RPS Compliance Reporting Template filings.[84] The Joint IOU Opening Brief agrees that the RPS compliance showing occurs through, in part, the submission of compliance reports to the Commission.[85]

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80 CalCCA Opening Brief at 34.
81 CalCCA Opening Brief at 22-25.
82 *See* Exh. CCA-01 at 25:5-11; Exh. CCA-02 at 5:10-17, 8:4-14.
83 CalCCA Opening Brief at 25-29.
84 CalCCA Opening Brief at 57 (citing Exh. CCA-03 at 23:1-14).
85 Joint IOU Opening Brief at 38.

The Joint IOU Opening Brief does not comment on CalCCA's explanation of how such offsetting entries would work utilizing the RPS Compliance Reporting Template filings.[86] That is despite the fact that CalCCA discussed these forms in its Direct Testimony addressing the Staff Report.[87] Instead, the Joint IOUs focus on a prior option (explaining how such offsetting entries could work using the Renewable Net Short form) that CalCCA only discussed in its initial Direct Testimony.[88]

The Joint IOUs also claim that retired RECs cannot be used for another retail sellers' RPS compliance.[89] CalCCA already explained that the allocation proposal complies with relevant laws and commission precedents because:

- the allocation proposal complies with section 399.15(b)(2)[90] by leaving unchanged both:
  - the manner in which RPS compliance quantities were established in D.19-06-023;[91] and
  - the resulting percentages used to establish compliance period quantities for all retail sellers,
- the Commission has already used similar allocation for the Cost Allocation Mechanism (CAM) in the Commission's RA compliance program, by permitting an IOU to procure resources on behalf of bundled and unbundled customers, retain ownership, and count some of that RA towards other LSE's compliance obligations,[92] and

86 The Joint IOUs' Opening Brief does, however, fault CalCCA's factual witness for not making legal arguments regarding the allocation option. Joint IOU Opening Brief at 37. CalCCA's testimony was factual, and was not sponsored by a lawyer. Exh. CCA-01, Attachment B (Curriculum Vitae of Brian Dickman). As is standard practice before the Commission, CalCCA's legal brief addresses legal issues. *See*, *e.g.*, CalCCA Opening Brief at 25-29, 49-51.

87 Exh. CCA-03 at 23:1-14.

88 Joint IOU Opening Brief at 36-38.

89 Joint IOU Opening Brief at 37-38.

90 Requiring the Commission to "[E]stablish the quantity of electricity products from eligible renewable energy resources to be procured by the retail seller for each compliance period. These quantities shall be established in the same manner for all retail sellers and result in the same percentages used to establish compliance period quantities for all retail sellers."

91 D.19-06-023, *Decision Implementing Provisions of Senate Bill 100 Relating to Procurement Quantity Requirements Under the California Renewables Portfolio Standard*, R.18-07-003 (June 27, 2019).

92 CalCCA Opening Brief at 27-28.

- the Commission has also already allocated Diablo Canyon Power Plant capacity in a similar manner.[93]

Therefore, CalCCA's alternate allocation proposal complies with statute and reflects tools the Commission has previously used to allocate benefits.

IV. IF THE COMMISSION REJECTS VALUATION OF THE PRE-2019 BANKED RECS AT THE RPS MPB, THE COMMISSION SHOULD ADOPT CALCCA'S 90/10 ALTERNATIVE COMPLIANCE VALUATION PROPOSAL

If the Commission chooses to estimate the compliance value of these Pre-2019 Banked RECs, in violation of section 366.2(g) and the rest of the State's statutory indifference framework (by rejecting CalCCA's valuation and alternate allocation proposals), it should adopt CalCCA's 90/10 proposal for the reasons stated in CalCCA's Opening Brief.[94] This 90/10 methodology reflects the fact that Pre-2019 Banked RECs can replace PCC-1 RECs for compliance purposes, but that the Joint IOUs may use PCC-3 RECs for up to 10% of their RPS obligations.[95] This proposal was, in part, meant to respond to Cal Advocates' Testimony:

> Like PCC 3 RECs, Pre-2019 Banked RECs are unbundled from energy and do not contribute to an LSE's Power Content Label. However, like PCC 1 RECs, Pre-2019 Banked RECs can be used indiscriminately to meet LSE RPS obligations. The Commission should consider valuing Pre-2019 Banked RECs based on the attributes they share with PCC 1 and PCC 3 RECs.[96]

Adopting this 90/10 proposal would mechanically reduce the value paid for the use of these Pre-2019 Banked RECs below the price for which PCC-1 RECs transact in the marketplace, as measured by the RPS MPB.[97]

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93 CalCCA Opening Brief at 28 n.136.
94 CalCCA Opening Brief at 30-32.
95 CalCCA Opening Brief at 31.
96 Exh. CalAdv-01 at 8:4-8.
97 *See* Exh. CCA-03 at 25:9-26:11; Exh. JIOU-05 (showing that PCC-3 RECs trade at a price below PCC-1 RECs).

The Joint IOUs' response to CalCCA's 90/10 proposal simply repeats their arguments regarding the RPS MPB: *i.e.*, the Joint IOUs claim they would still choose to strand Pre-2019 Banked RECs (despite their price being lower than what one could purchase PCC-1 RECs for on the market), and that this would lead to "the same negative downstream consequences" as CalCCA's RPS MPB proposal.[98] The fact the Joint IOUs threatened all of these "same" consequences without caveat for two different proposals—one of which would, as an arithmetic certainty, be below what PCC-1s trade for in the market—should give the Commission even more cause to question whether these catastrophic predictions are likely to occur.

The Joint IOUs also claim, for the first time, that CalCCA's proposal cannot be adopted because it does not account for the fact that LSEs can use PCC-2s to account for a portion of RPS compliance.[99] As CalCCA explained previously, CalCCA's 90/10 alternative proposal was in part a response to Cal Advocates' testimony *supra* arguing that Pre-2019 Banked RECs retain characteristics of both PCC-1s and PCC-3s.[100] Throughout the course of this Track 2, neither Cal Advocates, the Joint IOUs, nor Commission Staff have claimed that Pre-2019 Banked RECs have similarities to PCC-2 RECs that are relevant to calculating the compliance value these RECs provide to the Joint IOUs when they are used for bundled load RPS compliance.

V. THE RECORD DOES NOT SUPPORT THE JOINT IOUS' DIRE PREDICTIONS OF DOWNSTREAM CONSEQUENCES

CalCCA's Opening Brief clearly explained that the Joint IOUs have cried wolf over the existence and magnitude of the alleged downstream impacts of CalCCA's valuation and

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98 Joint IOU Opening Brief at 52-54.

99 Joint IOU Opening Brief at 54. *See also* Cal. Pub. Util. Code § 399.16(b)(2) (describing PCC-2 RECs as those "[f]irmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California balancing authority.")

100 Exh. CCA-03 at 24:18-25:13.

allocation proposals.[101] The alleged downstream impacts all assume that the prices they are required to pay to use Pre-2019 Banked RECs for compliance purposes will render the use of these RECs uneconomic.[102] But as CalCCA demonstrated, the reasonably expected rate impacts and market impacts are essentially nonexistent and partially avoidable, because:

- The REC market is currently oversupplied and prices are low.[103]
- The likely impact on customers' bills is miniscule (*i.e.*, SDG&E is projecting to use zero Pre-2019 Banked RECs in 2027, with other confidential impacts explained in redacted form).[104]
- The impact of this decision will not be compressed into the next year or two, it will extend much further.[105]
- The Joint IOUs will have the opportunity to readjust any plans they have during this time period.[106]
- The impact on VAMO strategy and offering is overstated because all the RPS MPB valuation would cause the Joint IOUs to choose which RPS compliance strategies to undertake with all resources valued appropriately.[107]

CalCCA's proposal is the only one that complies with the controlling law and ensures indifference. The record clearly shows that Joint IOUs have exaggerated both the likelihood and expected magnitude of any downstream effects of adopting this legally required proposal.

VI. THE JOINT IOUS' ALTERNATIVE STAFF PROPOSAL FOUR MODIFICATIONS SHOULD BE REJECTED

Despite acknowledging that it was not seeking to accomplish the legal requirement of indifference, Energy Division staff proposed four "compromise" valuation options for

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101 CalCCA Opening Brief at 36-51.
102 Joint IOU Opening Brief at 22-25.
103 CalCCA Opening Brief at 44-45.
104 CalCCA Opening Brief at 38. While PG&E claims that there will be disproportionate socioeconomic impacts of CalCAA's proposal (due to where bundled and unbundled customers tend to live in that one IOUs' territory), Joint IOU Opening Brief at 23, CCAs serve over 55% of the load in PG&E's territory, including many socioeconomically disadvantaged communities that would suffer their own impacts if PG&E uses RECs they paid for without compensating them.
105 CalCCA Opening Brief at 43-44.
106 CalCCA Opening Brief at 46.
107 CalCCA Opening Brief at 49.

consideration that are meant to approximate the 'compliance' value of Pre-2019 Banked RECs. CalCCA agrees with the Joint IOUs that a compromise is not necessary,[108] however that is because the law is clear that indifference requires that Later Departing Customers receive the *value* of the benefit conferred to Current Bundled Customers, which can occur only through CalCCA's valuation or allocation proposals. CalCCA also agrees with the Joint IOUs that the Commission should not adopt any of Staffs' four proposals,[109] and has explained why these proposed compromises are all flawed, arbitrary, and/or illogical.[110]

After spending ten full pages explaining why all of the Staff Report options should be rejected given their "lack of a policy or legal foundation," the Joint IOUs provide caveated support for Staff Proposal 4 conditioned on several modifications.[111] While as stated in its Opening Brief, CalCCA does not support Staff Proposal 4 as it would not ensure indifference for all customers,[112] if the Commission were to adopt Staff Proposal 4, it should reject four of the Joint IOUs' six requests. These requested modifications are targeted by the Joint IOUs to change Staff Proposal 4 to value Pre-2019 Banked RECs at a near-zero valuation and retain maximum flexibility to strand this little value owed to Later Departing Customers.

First, there should be no 'fixed buckets' of customers as recommended by the Joint IOUs.[113] The statutes do not incorporate a limitation requiring indifference only for customers who departed in 2026 and before.[114] And while the comparative size of departed load and bundled load changes over time, performing this calculation is not complex. The Joint IOUs

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108 Joint IOU Opening Brief at 47.
109 Joint IOU Opening Brief at 46-52.
110 CalCCA Opening Brief at 58-67.
111 Joint IOU Opening Brief at 54.
112 CalCCA Opening Brief at 61-67.
113 *See* Joint IOU Opening Brief at 57.
114 CalCCA Opening Brief at 64.

already calculate it, and that is especially true because the Joint IOUs generally have significant advanced notice that load will be departing. Once the Joint IOUs know or forecast that number, they can make their RPS plans accordingly.

Second, the Commission should reject the Joint IOUs' claim that the Commission's Decision should prohibit the use of this valuation for any Pre-2019 Banked RECs used for compliance before 2026.[115] To the extent the Joint IOUs or the Commission want to consider how to value Pre-2019 Banked RECs used for compliance before 2026, the Commission can make that determination in any ongoing proceedings and need not rule that out here.[116] That is especially true because those RECs used for compliance in 2025 are identical to those used in 2026 for RPS purposes. The RECs used for compliance in 2025 and 2026 can all be lumped together and added to those used for compliance in 2027 to calculate whether the Joint IOUs met their RPS compliance obligation for Compliance Period 5 (2025-2027).[117]

Third, the Joint IOUs seek to use a Tier 2 Advice Letter to implement any version of Staff Proposal 4 the Commission adopts, and to continue using a $0 valuation to the extent that implementation is not completed in time for a particular ERRA case.[118] While CalCCA does not oppose using a Tier 2 Advice Letter, the Commission's decision on how to value Pre-2019 Banked RECs should apply to the 2027 ERRA Forecast cases and any future ERRA Forecast case.

Fourth, the Joint IOUs seek to use a PCC-3 MPB as the value for any Pre-2019 Banked RECs that were paid for by Later Departing Customers,[119] despite the fact that these RECs can be used to offset PCC-1 obligations and that PCC-1 RECs trade for a premium above PCC-3.[120]

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115 Joint IOU Opening Brief at 57.
116 CalCCA Opening Brief at 64-65.
117 Cal. Pub. Util. Code § 399.15(b)(1)(E).
118 Joint IOU Opening Brief at 59-60.
119 Joint IOU Opening Brief at 60.
120 CalCCA Opening Brief at 65 (citing Vol. 1 Tr. 145:18-20, 151:2-6 (Dickman); Exh. JIOU-5).

CalCCA has already explained the myriad reasons why Pre-2019 Banked RECs are identical, for RPS compliance purposes, to those PCC-1 RECs Energy Division uses to calculate the RPS MPB.[121] The Joint IOUs' suggestion is a transparent attempt to identify the lowest positive number above $0 that they could theoretically defend and urge the Commission to adopt it.[122]

The Joint IOUs do make two suggestions to modify Staff Proposal 4 that, were the Commission to adopt Staff Proposal 4, CalCCA does not oppose.[123] The Joint IOUs' first and fourth suggestions are meant to address methodological issues in Staff's proposal that improperly credit the wrong customers. The first addresses how to ensure that Previously Departed Customers do not receive a credit for these RECs, and the fourth addresses how to ensure that Currently Bundled Customers do not benefit twice.[124] In fact, CalCCA has already proposed a methodology that addresses both of these concerns (crediting the value of the RECs to the vintage year in which they were generated).[125] For these reasons, if the Commission adopts Staff Proposal 4, all but the Joint IOUs' first and fourth recommended modifications should be rejected.

VII. THE JOINT IOUS' TIMELINESS ARGUMENT FAILS BECAUSE ANY CLAIM REGARDING THE VALUE OF PRE-2019 BANKED RECS ACCRUED ONLY WHEN THE IOUS BEGAN USING THOSE RECS TO SATISFY CURRENT RPS COMPLIANCE OBLIGATIONS

The Joint IOUs' argument that CalCCA and its members failed to act timely on the Pre-2019 Banked REC valuation claim is legally flawed and factually inaccurate.[126] To support their argument that CalCCA or its members should have litigated the question of Pre-2019 Banked REC valuation *in the years before the IOUs sought to use those RECs for RPS compliance,* the

121 CalCCA Opening Brief at 51-54.
122 *See* CalCCA Opening Brief at 64.
123 *See* CalCCA Opening Brief at 66.
124 Joint IOU Opening Brief at 56, 58.
125 Exh. CCA-04 at 16:11-17:21.
126 *See* Joint IOU Opening Brief at 2, 6, 10, 37, 40-41.

Joint IOUs cite to statutes of limitations, the doctrine of laches, and the RPP.[127] As set forth below, however, the Joint IOUs' argument fails given: (1) none of the legal principles cited by the Joint IOUs require a party to act before a claim to value accrues (*i.e.,* the harm to Later Departing Customers does not occur until the Current Bundled Customers use the RECs for their own RPS compliance); and (2) CalCCA and its member CCAs have consistently challenged this valuation when the claim accrued, and the resolution of the issue has been interim until now when the Commission agreed to finally consider the issue in this Track 2.

The Joint IOUs' argument that CalCCA and its member CCAs failed to timely challenge the zero Pre-2019 Banked REC valuation does not comport with California law. The Joint IOUs stretch several legal doctrines both in law and equity to generally claim that relief cannot be granted to a party that "sits on its rights." These doctrines govern Commission complaints and applications for rehearing, as well as laches, none of which are applicable to a prospective rulemaking.[128] The Joint IOUs then claim that CalCCA and the CCAs should have challenged "the compliance of the Commission-adopted pre-2019 methodology with the indifference mandate" soon after D.11-12-018,[129] when they knew the IOUs could bank the RECs for future compliance and that the PCIA contained no provision for payment or allocation to future

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127 Joint IOU Opening Brief at 41-42.

128 The Joint IOUs cite Public Utilities Code section 735 creating a statute of limitations to seek reparations for a finding by the Commission of unreasonable rates. *See* Joint IOU Opening Brief at 41-42. They also cite rights in equity and the doctrine of laches that bars a party unreasonably delaying challenging an action resulting in disadvantaging other parties. *Ibid.* Finally, the Joint IOUs cite section 1731(a) requiring the filing of an application for rehearing (pursuant to RPP 16.1(a)) within 30 days of a Commission decision for a cause of action in court to accrue, and the requirement that a petition for modification of a Commission decision must be filed within one year of the effective date of a decision (or a justification as to why the filing was delayed must be provided). *Ibid.*

129 D.11-12-018, *Decision Adopting Direct Access Reforms*, R.07-05-025 (Dec. 1, 2011).

departing load.[130] The Joint IOUs further claim that CalCCA and the CCAs could have raised their concern in 2019 during the R.17-06-026 Working Group process.

Despite the Joint IOUs claim of "prejudice" as a result of CalCCA's and the CCA's alleged non-action, all of these claims have a glaring fundamental flaw—no harm to Later Departing Customers occurred until the IOUs sought to use the Pre-2019 Banked RECs for Current Bundled Customer compliance. Under California law, a cause of action does not accrue until a party suffers harm.[131] No Later Departing Customer suffered any cognizable injury until the IOUs began using Pre-2019 Banked RECs—funded by those customers while they were bundled customers—to satisfy Current Bundled Customer RPS compliance obligations without providing the associated value to the Later Departing Customers who paid for them. As set forth in CalCCA's testimony:

> [t]he Joint IOUs were not using Banked RECs to meet their RPS compliance obligations before 2019. Given these circumstances, it was not necessary to address this issue historically as there was no need to value Pre-2019 Banked RECs when they were not being used for compliance. The issue is significant now given the IOUs' recent use of Pre-2019 Banked RECs for Current Bundled Customer RPS compliance. The magnitude of the accumulated Pre-2019 Banked RECs and potential cost shift exceeding $1.5 billion resulting from the Joint IOUs' use of those RECs should compel the Commission to set the correct policy now.[132]

Therefore, the fact that CalCCA or the CCAs did not challenge the valuation until the IOUs started using the RECs comports with California law which finds that a cause of action only accrues when harm—the failure to provide value to Later Departing Customers—occurred.

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130 Joint IOU Opening Brief at 40.

131 *See Davies v. Krasna* (1975) 14 Cal.3d 502 (statute of limitation begins to run upon "actual and appreciable harm"); *see also City of Pasadena v. Superior Court* (2017) 12 Cal.App.5th 1340, 1348-49 ("'accrual' of an action is used in the sense of ripeness"; a "cause of action accrues 'when [it] is complete with all its elements' – those elements being wrongdoing, harm, and causation" (citing *Pooshs v. Philip Morris USA, Inc.* (2011) 51 Cal.4th 788, 797).

132 Exh. CCA-03 at 15:6-17, n.21.

As noted in CalCCA's rebuttal testimony, once the claim accrued, CalCCA promptly challenged the Joint IOUs' failure to provide value for Pre-2019 Banked RECs to Later Departing Customers. Specifically, CalCCA raised that challenge in the ERRA Forecast proceedings—the very proceedings in which the IOUs sought approval to use those RECs for Current Bundled Customer RPS compliance. While PG&E was valuing the Pre-2019 Banked RECs at the RPS MPB (until 2026 as set forth below), CalCCA challenged Southern California Edison Company's (SCE) zero valuation of Pre-2019 Banked RECs in SCE's 2024 ERRA Forecast Application proceeding.[133] At that time, SCE had filed a Petition for Modification (PFM) seeking clarity on the issue.[134] In the SCE 2024 ERRA Forecast Decision, the Commission directed an "interim process" for SCE to use post-2019 Banked RECs first before using Pre-2019 Banked RECs until the PFM is resolved.[135] The PFM was later denied, with the Commission stating that it may consider the Pre-2019 Banked REC issue in a future rulemaking given it did not have the record to decide the issue.[136] CalCCA continued to challenge SCE's use of a $0 valuation when it was raised in subsequent ERRA Forecast proceedings.[137]

While PG&E valued Pre-2019 Banked RECs at the RPS MPB in its 2023, 2024, and 2025 ERRA Forecast cases (which was approved by the Commission), CalCCA challenged PG&E's about-face in its 2026 ERRA Forecast case in which it proposed using SCE's zero

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133 *See Opening Brief and Comments of the California Community Choice Association,* A.23-06-001 (Oct. 27, 2023), at 9-22.

134 *See SCE's Petition for Modification of D.23-06-006*, R.17-06-026 (Sept. 11, 2023).

135 D.23-11-094, *Southern California Edison Company's 2024 Energy Resource Recovery Account Forecast*, A.23-06-001 (Nov. 30, 2023), COL 5-7, OP 9.

136 D.24-08-004, at 5.

137 *See California Community Choice Association's Comments on the Proposed Decision,* A.24-05-007 (Dec. 2, 2024), at 11-1; *California Community Choice Association's Comments on October Update / Concurrent Opening Brief*, A.25-05-008 (Oct. 29, 2025), at 19-38.

valuation method.[138] The Commission has continued to approve any zero or other valuation on an "interim" basis pending consideration of the issue in a rulemaking (see *supra*). Thus, even if the Joint IOUs could identify a cognizable injury before the ERRA Forecast proceedings (they cannot), CalCCA nevertheless acted promptly when the alleged harm became concrete and ripe for adjudication. Now, the Commission has decided to consider this policy question in a rulemaking where CalCCA has vigorously opposed the Joint IOUs' proposals. The Joint IOUs claim that CalCCA or the CCAs "sat on their rights" should therefore be disregarded.

VIII. CONCLUSION

CalCCA respectfully requests that the Commission adopt the recommendations set forth herein.

Respectfully submitted,

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June 25, 2026

[138] *See* D.22-12-044 (PG&E 2023 ERRA Forecast Decision), OP 1, D.23-12-022 (PG&E 2024 ERRA Forecast Decision)), OP 5, and D.24-12-038 (PG&E 2025 ERRA Forecast Decision) (all approving PG&E's valuation of Pre-2019 Banked RECs at the RPS MPB); *but see* D.25-12-027 (PG&E 2026 ERRA Forecast Decision), at 31 (approving PG&E's zero valuation of Pre-2019 Banked RECs, stating that this approach is interim until the Commission can consider the issue in a rulemaking). CalCCA has challenged PG&E's changed approach for 2026 rates in an Application for Rehearing in the PG&E 2026 ERRA Forecast docket, which is still pending. *See California Community Choice Association's Application for Rehearing of Decision Approving PG&E's 2026 ERRA Account Related Forecast Revenue Requirement and 2026 Electric Sales Forecast,* A.25-05-011 (Jan. 12, 2026).

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.25-10-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2027-2029, FLEXIBLE CAPACITY OBLIGATIONS FOR 2027, AND PROGRAM REFINEMENTS

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June 29, 2026

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SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends that the Commission:

- Adopt party recommendations to remove the $0 bidding and revenue allocation requirements for IR and RC, or at minimum, expressly state that these requirements do not apply to existing contracts;

- Deny SDG&E's recommendation to reject LOT with prejudice, because SDG&E bases its recommendation on a misleading classification of LOT as fundamentally incompatible with the RA program;

- Reject PG&E's finding that the large load meet-and-confer process is a reasonable interim solution;

- Address party concerns that the PD would result in double counting storage nonlinearity in QC and UCAP values; and

- Adopt SCE's clarification on the value of EO resources' excess charging sufficiency remaining with the EO generators.

[1] Acronyms used herein are defined in the body of this document.

The California Community Choice Association (CalCCA) submits these reply comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Adopting Local Capacity Obligations for 2027-2029, Flexible Capacity Obligations for 2027, and Program Refinement*[2] (PD), dated June 1, 2026.

I. INTRODUCTION

Party Opening Comments[3] present a diverse set of recommended changes to the PD but largely coalesce around one fundamental issue: the PD's flawed treatment of imbalance reserve (IR) and reliability capacity (RC) bidding and revenue allocation. Parties raise numerous factual, legal, and practical issues with the PD's requirement that suppliers bid $0 dollars for IR and RC and transfer any IR and RC revenue to the resource adequacy (RA) buyer.[4] Parties largely agree that the PD should be modified in this regard, as these issues will likely result in unnecessary costs and reliability issues.

SDG&E recommends the Commission reject hourly load obligation trading (LOT) with prejudice,[5] making misleading claims about the compatibility of LOT and the RA program.[6] The Commission should not reject LOT with prejudice, because the LOT proposal is designed to ensure sufficient physical capacity to meet system RA requirements, subject to penalties, consistent with existing RA trading mechanisms while reducing costs to ratepayers.

Other comments address the PD's proposed meet-and-confer process for large loads and storage and energy-only (EO) resource counting. In response to these comments, CalCCA recommends that the Commission should:

- Adopt party recommendations to remove the $0 bidding and revenue allocation requirements for IR and RC, or at minimum, expressly state that these requirements do not apply to existing contracts;

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2 Proposed *Decision Adopting Local Capacity Obligations for 2027-2029, Flexible Capacity Obligations for 2027, and Program Refinement*, Rulemaking (R.) 25-10-003 (June 1, 2026).

3 References herein to Opening Comments refer to those submitted on June 22, 2026, in R.25-10-003.

4 *See* American Clean Power - California (ACP-CA) Opening Comments, at 7-11; California Independent System Operator Corporation (CAISO) Opening Comments, at 2-11; Calpine LLC (Calpine) Opening Comments, at 3-7; California Energy Storage Alliance (CESA) Opening Comments, at 13-15; Independent Energy Producers Assocatiation (IEP) Opening Comments, at 4; Large-Scale Solar Association and Solar Energy Industries Association (LSA/SEIA) Opening Comments, at 4-8; Middle River Power, LLC, (MRP) Opening Comments, at 7-9; Pacific Gas & Electric Company (PG&E) Opening Comments, at 2-8; Rev Renewables, LLC (Rev Renewables) Opening Comments, at 4-10; Southern California Edison Company (SCE) Opening Comments, 13-14; San Diego Gas & Electric Company (SDG&E) Opening Comments, at 2-10; Terra-Gen, LLC (Terra-Gen) Opening Comments, at 4-8; Vistra Corp. (Vistra) Opening Comments, at 11-14; and Western Power Trading Forum (WPTF) Opening Comments, at 5-10.

5 SDG&E Opening Comments, at 11-13.

6 *Id.*, at 12.

- Deny SDG&E's recommendation to reject LOT with prejudice, because SDG&E bases its recommendation on a misleading classification of LOT as fundamentally incompatible with the RA program;
- Reject PG&E's finding that the large load meet-and-confer process is a reasonable interim solution; and
- Address party concerns that the PD would result in double counting storage nonlinearity in the qualifying capacity (QC) and unforced capacity (UCAP) values;
- Adopt SCE's clarification on the value of EO resources' excess charging sufficiency remaining with the EO generators.

II. THE COMMISSION SHOULD ADOPT PARTY RECOMMENDATIONS TO REMOVE THE IR AND RC REQUIREMENTS OR, AT MINIMUM, SHOULD NOT APPLY THEM TO EXISTING CONTRACTS

No party expressly supports the PD's $0 bidding and revenue allocation requirements in all respects. Indeed, the majority expressed concern with one or more proposal elements.[7] Such broad opposition should be reviewed very carefully before the Commission proceeds with the PD as written.

CalCCA agrees with the CAISO that "bid restrictions do not eliminate underlying costs; they obscure them," and that the zero dollar bidding requirement would prevent resources from sending economic signals, inhibit the market's ability to select lower cost resources, and reduce transparency to the market.[8] Even without a $0 bid requirement, the requirement to flow the revenues through to the purchasing load-serving entity (LSE) fundamentally reduce the incentives for resources to bid efficiently, as there are no consequences or benefits to the generator for submitting a bid that does or does not clear. The LSE may likewise find themselves in a position where they lack complete knowledge about the resource's costs to instruct the generator to submit an efficient bid.

The only solution is to remove both the $0 bid and revenue flow through requirements. As CalCCA and other parties have described in Opening Comments, LSEs can negotiate fair transactions that will prevent the double payment of generators while still leaving the CAISO market mechanisms with efficient bids unaffected by or consistent with costs and revenues of contractual relationships.[9]

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[7] *See* ACP-CA Opening Comments, at 7-11; CAISO Opening Comments, at 2-11; Calpine Opening Comments, at 3-7; CESA Opening Comments, at 13-15; IEP Opening Comments, at 4; LSA/SEIA Opening Comments, at 4-8; MRP Opening Comments, at 7-9; PG&E Opening Comments, at 2-8; Rev Renewables Opening Comments, at 4-10; SCE Opening Comments, 13-14; SDG&E Opening Comments, at 2-10; Terra-Gen Opening Comments, at 4-8; Vistra Opening Comments, at 11-14; and WPTF Opening Comments, at 5-10.

[8] CAISO Opening Comments, at 7.

[9] *See* CalCCA Opening Comments, at 7; and CAISO Opening Comments, at 2-3.

The Commission should, at a minimum, not apply the requirements to existing contracts executed before this Decision is voted out. Several parties, including all three investor-owned utilities (IOU), object to the application of these provisions to existing contracts.[10] SDG&E, for example, cites the Commission's commitment to preserving the sanctity of existing contracts through Decision (D.) 19-03-012,[11] and the lack of an "extraordinary circumstances" in this case to override those prior decisions.[12]

III. SDG&E'S RECOMMENDATION TO REJECT LOT WITH PREJUDICE SHOULD BE DENIED

The Commission should dismiss SDG&E's recommendation to reject LOT with prejudice.[13] SDG&E claims that there are "structural and inherent" defects of LOT that make the mechanism "fundamental[ly] incompatib[le]" with the RA program. SDG&E bases these claims on: (1) suggestions that LOT is a financial substitution for a physical requirement; and (2) attempts to diminish the savings that could be realized by the LOT mechanism.[14] The Commission should reject SDG&E's recommendation for the following reasons.

First, the LOT mechanism is ***not*** a financial substitute for physical capacity. It is designed to ensure sufficient physical capacity to meet system RA requirements, subject to penalties, consistent with existing RA trading mechanisms. In this sense, LOT has the same fundamental structure as the CAM program, in which RA purchased by one LSE meets the obligations of other LSEs with their contracted physical capacity. Moreover, in reality, all energy and capacity contracts and transactions are financial mechanisms to ensure physical availability and delivery to the grid, making SDG&E's distinction misleading. CalCCA's LOT proposal would therefore continue to maintain the reliability and integrity of the RA program by ensuring all LSEs are responsible for procuring their fair share of physical capacity to meet reliability requirements.

Second, SDG&E and PG&E suggestions that there is no demonstrated need for LOT at this time[15] are fundamentally flawed for the reasons described in CalCCA's Opening Comments.[16] Benefits

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10 *See* PG&E Opening Comments, at 6-8; SCE Opening Comments, at 2-4; and SDG&E Opening Comments, at 5-8.

11 D.19-03-012, *Decision Denying Protect Our Communities Foundation Petition for Modification of Decision 06-09-021, Concerning Otay Mesa Energy Center*, R.01-10-024 (Mar. 28, 2019).

12 SDG&E Opening Comments, at 6.

13 *Id.*, at 12-13.

14 *Id.*, at 12.

15 PG&E Opening Comments, at 13-14; and SDG&E Opening Comments, at 11-13.

16 CalCCA Opening Comments, at 7-9.

of LOT can be realized both directly (*i.e.*, reducing the total amount of unnecessary RA procured) and indirectly (*i.e.*, reducing demand and putting downward pressure on RA prices) regardless of whether total RA supply exceeds total requirements, and could have totaled up to $180 million in 2025[17] at a time when electricity costs burden many Californians. Even if the RA supply stack has grown and prices have calmed since 2024, an exceptionally challenging time for RA procurement, there is no guarantee these conditions will not resurface, especially given uncertain load growth projections, modeled reliability needs surfacing by 2030, and continued challenges bringing new capacity online to address these needs. For these reasons, the Commission should reject SDG&E's recommendation.

IV. PG&E'S CLASSIFICATION OF THE MEET-AND-CONFER PROCESS FOR LARGE LOADS AS A REASONABLE INTERIM SOLUTION SHOULD BE REJECTED

PG&E finds the PD's meet-and-confer process for large loads "reasonable," with modifications to state that: (1) the information shared in the meet-and-confer process will be consistent with information in the IOUs' year-ahead load forecasts and Form 3; and (2) the IOUs, Staff, and the CEC will work together to finalize the details of the meet-and-confer requirements.[18] CalCCA disagrees that the PD is reasonable in this regard, and is concerned with PG&E's suggestion that *the IOUs*, not all LSEs, have the opportunity to inform the meet-and-confer requirements. Community Choice Aggregators (CCAs) are well-positioned to evaluate new load growth given their unique access to information, either from large load customers or their local permitting agencies. Consulting with CCAs, along with the IOUs, will ensure information used to develop the forecast is as accurate as possible.

While the information sharing opportunities that can be provided by a meet-and-confer process are valuable, they are not, and were never intended to be, an adequate substitute for a robust RA allocation process. The existing RA forecast, which is based heavily on the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) Demand Forecast, has worked well for many years under relatively stable load growth. However, the unprecedented forecast uncertainty present with the introduction of data centers necessitates a new process for allocating those loads to minimize reliability and affordability risks.

Forecasts are inherently subject to errors, and any forecast is, by its nature, immediately at risk of being overtaken by new facts on the ground. This is especially true where large, discrete, and uncertain nature of data center loads emerge, change, or fall away between forecast cycles. CalCCA's proposal

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17 CalCCA Opening Comments, at 8-9.

18 PG&E Opening Comments, at 12.

addresses these risks better than the existing process by incorporating actual interconnection information and milestones to supplement that CEC's forecast. That way, if the IEPR under-forecasts data center load, RA requirements can be updated to remain sufficient from a reliability perspective. Alternatively, if the IEPR over-forecasts data center load, RA requirements could be updated for affordability to ensure existing customers do not pay for unnecessary RA. The CalCCA proposal is therefore superior from a reliability and affordability perspective, and should be adopted.

V. THE PD SHOULD BE REVISED TO ADDRESS PARTIES' DOUBLE COUNTING CONCERNS FOR STORAGE NONLINEARITY

Parties generally agree that storage nonlinearity should be accounted for in resources' QC values. Several parties express concerns that the PD would account for nonlinearity both the QC methodology ***and*** the UCAP calculation.[19] CalCCA agrees with these parties that the PD risks double-penalizing storage resources for the same availability limitation. As stated by CESA, the Commission should account for nonlinearity in the QC rather than in its UCAP, given that it is a known capability limitation rather than a forced outage.[20] For these reasons, the Commission should account for nonlinearity in QC values, consistent with CalCCA's methodology in Opening Comments, and ensure that UCAP values do not further derate storage resources' RA value for nonlinearity.

VI. SCE'S RECOMMENDATION FOR ALLOCATING EO CHARGING SUFFICIENCY VALUE SHOULD BE ADOPTED

Several parties request that the Commission clarify the PD to specify how the excess charging sufficiency value of EO resources will be allocated.[21] The Commission should adopt SCE's requested clarification. That is, the charging sufficiency value that exceeds the amount required to charge the storage resource remains with the EO generating resource, rather than with the paired storage resource. This clarification is consistent with the intent of the proposals and the formula in the PD.

VII. CONCLUSION

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

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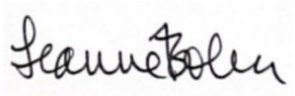
[19] ACP-CA Opening Comments, at 6-7; Alliance for Retail Energy Markets Opening Comments, at 5-6; and CESA Opening Comments, at 7-9.

[20] CESA Opening Comments, at 7-9.

[21] ACP-CA Opening Comments, at 3; LSA/SEIA Opening Comments, at 3-4; and SCE Opening Comments, at 7-8.

Respectfully submitted,



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