MARCH FILINGS

California Community Choice Association

SUBMITTED 03/04/2025, 02:08 PM

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

1. Please state your organization's position and provide questions or comments on Intra-cluster Prioritization of Use of Existing SCD/RNU Headroom

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (CAISO) Track 3 Final Proposal.

CalCCA continues to support the CAISO's proposal to use its transmission plan deliverability (TPD) allocation process scoring methodology to allow generators to interconnect up to an amount that will not trigger the need for a long lead-time (LLT) short circuit upgrade or other reliability network upgrades. This proposal will provide opportunities for projects to come online and obtain deliverability more quickly when there is headroom, helping to alleviate the current interconnection capacity scarcity.

2. Please state your organization's position and provide your organization's questions or comments on the Modifications to the TPD Allocation Process

CalCCA supports the proposed modifications to the TPD allocation process, including the new definitions for the TPD allocation groups and the three opportunities to seek and retain a TPD allocation. This support is contingent upon a future IPE initiative addressing opportunities for energy-only (EO) projects to later obtain deliverability without enabling the EO pathway to circumvent a competitive process for TPD allocation.

While the Final Proposal prohibits EO projects in Cluster 15 and later from ever seeking a TPD allocation, there are legitimate reasons why projects may pursue interconnection via the EO process, such as a willingness on the part of both developers and LSEs to contract for a period of time for EO deliveries. CalCCA, therefore, proposed in its comments to the Draft Final Proposal that the CAISO should not prevent EO projects from *ever* seeking deliverability. Instead, if a project enters the queue and comes online as EO, the project should be allowed to submit a *new* interconnection request and follow the intake and study process for obtaining deliverability.[1] The Final Proposal states that the CAISO has considered the issue of EO resources seeking TPD, identified several policy issues that need to be discussed with stakeholders, and determined that the issue will need to be deferred to a future IPE initiative.[2] CalCCA supports moving forward with seeking the CAISO Board of Governors and Federal Energy Regulatory Commission approval of the Final Proposal contingent upon the commitment to consider these issues in a future Interconnection Process Enhancements initiative.

CalCCA continues to support the proposed requirement for offtakers to confirm active PPAs annually for projects within the power purchase agreement (PPA) group to retain their deliverability allocations. This will help ensure PPAs are executed in good faith rather than with the intention of getting scored in the highest TPD allocation group and then canceling the PPA after receiving a TPD allocation. In addition, CalCCA supports categorizing projects within the PPA group based upon whether its PPA is with an offtaker that has an RA obligation. This will result in a meaningful differentiation of projects that meet versus exceed the minimum requirement, because it bases its ranking on RA obligations which drive the need for TPD. It will also provide for uniform treatment of all PPAs with load-serving entities.

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[1] CalCCA Comments on the IPE Track 3 Draft Final Proposal (Jan. 29, 2025) (CalCCA January 29 Comments): https://stakeholdercenter.caiso.com/Comments/AllComments/8a955f32-33fc-4025-8bc3-f693c5636ad4#org-78cfcc2e-4148-4886-8da4-b884e0910de5.

[2] Final Proposal, at 26-27.

3. Please state your organization’s position and provide your organization’s questions or comments on the Adjusted 2nd Interconnection Financial Security Posting for Cluster 14 Parked Projects

CalCCA has no comments at this time.

4. Please state your organization’s position and provide your organization’s questions or comments on the Process for Reserving TPD for Long Lead Time Generation and Storage Resources

CalCCA appreciates the Final Proposal’s clarifications in response to CalCCA’s requests in comments to the Draft Final Proposal.[1] Specifically, CalCCA supports: (1) the CAISO’s recognition that it and CPUC “should be careful not to oversize TPD reservations for these resources to the point that other technologies are unable to obtain TPD when commercially viable and support system portfolio needs;” and (2) the CAISO’s view of its proposed process as a “limited option to ensure that policy-driven, long lead-time location-constrained resources that require their own specific transmission actually have that transmission available to them by the time they are ready to interconnect.”[2] CalCCA also supports the CAISO’s clarification that the process for identifying long lead-time resources requiring TPD reservations does not apply to any particular procurement entity and that once a LLT resource seeks a deliverability allocation, it would need to follow the standard process for TPD allocation.

[1] CalCCA January 29 Comments.

[2] Final Proposal, at 46.

5. Please state your organization’s position and provide any additional feedback on the broader track 3 initiative, including requests for the scope of the next IPE initiative

As described in Section 3, CalCCA recommends the scope of the next IPE initiative include a process for energy-only (EO) projects to later obtain deliverability without enabling the EO pathway to circumvent a competitive process for TPD allocation.

California Community Choice Association

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

1. Track 1: Please provide your organization's feedback on modeling improvements undertaken and additional improvements to consider.

The California Community Choice Association (CalCCA) supports the California Independent System Operator's (CAISO) modeling improvements. Specifically, CalCCA supports the CAISO's improved methodology for modeling hydro using 25 years of historical data and random draws of 500 hydro-year profiles. Previous CAISO analysis in the working group demonstrated through sensitivity simulations that hydro assumptions have significant impacts on loss-of-load expectation (LOLE) events, so increasing the number of hydro samples used in the model is a significant improvement over relying on an average hydro year. In addition, CalCCA supports the updates to storage modeling to model resource level characteristics, as well as the updates to outage rate modeling to use recent historical outage management system data.

2. Track 1: Please provide your organization's feedback on the qualifying capacity accreditation and PRM proposals discussed.

See CalCCA's responses to questions 3-5 below.

3. Track 1: Please provide your organization's feedback on the development of default qualifying capacity accreditation and PRM approaches and any preferred path the CAISO should pursue. In needed, what additional analysis would help inform the decision.

Most LSEs participate under the California Public Utilities Commission's (CPUC) resource adequacy (RA) program and, therefore, do not use the CAISO's default counting rules or planning reserve margin (PRM). Before adopting default counting rules and default PRM, the CAISO should benchmark its own counting rules and PRM with the CPUC's by identifying the PRM necessary to meet a 0.1 LOLE standard. The CPUC has moved to a Slice-of-Day (SOD) model that accounts for capacity in all hours. The CPUC's LOLE study will use that SOD model to determine their PRM. With hourly granularity, it can be expected that the CPUC RA requirements will capture all reliability needs. The CAISO should work with the CPUC to ensure that the CAISO studies using a different counting methodology (i.e., effective load carrying capability with a single RA value versus an exceedance with different values in all hours) have consistent overall results.

4. Track 1: Regarding the direction of CAISO's UCAP proposal, please share your organization's feedback on key elements discussed at the workshop such as implementation through CAISO NQC process, assessment hours, and interaction with LRA QC methodologies.

The CAISO should continue its work to develop and implement a UCAP counting methodology. Such a methodology has the potential to better incentivize resource maintenance and availability than the status quo, which relies on the RA availability incentive mechanism (RAAIM) and forced outage substitution rules. CalCCA provides the following recommendations to the CAISO, which are consistent with CalCCA's recommendations in its March 3, 2025, RA Track 3 Opening Comments in the CPUC's RA proceeding, Rulemaking (R.) 23-10-011. As discussed in more detail below, the CAISO should: (1) coordinate with the CPUC; (2) verify PRM impacts through an LOLE study; (3) apply UCAP to all eligible RA resources, regardless of whether it was shown for RA during the time of a forced outage; (4) use a supply cushion approach; (5) adopt the CPUC Energy Division's proposed weighting; (6) minimize impacts to existing contracts; (7) develop a methodology to calculate UCAP for new resources without a class average; and (8) work with stakeholders to better define UCAP-eligible outages for storage resources.

The CAISO and CPUC Should Coordinate Development of a UCAP Counting Methodology

The CAISO and the Commission should work together to develop a uniform UCAP counting methodology. The CPUC has its active RA proceeding, R.23-10-011, to evaluate UCAP. The CAISO and CPUC Energy Division staff should work together to ensure that progress in the CPUC's proceeding and CAISO stakeholder initiative are aligned. To this end, the comments herein mirror CalCCA's March 3, 2025, comments submitted to the CPUC in R.23-10-011, in response to Track 3 proposals. The CAISO and CPUC should also coordinate with other LRAs to the extent possible.

The CAISO Should Conduct a LOLE Study to Verify that UCAP Adoption Will Result in an Equal and Opposite Adjustment to the PRM

Since the current PRM accounts for forced outages and the resource's net qualifying capacity (NQC) does not, any change to resource counting should be met with an equal and opposite offset in the PRM. Before implementing UCAP counting rules, the CAISO should provide data showing that this equal and opposite effect will materialize in the LOLE study that sets the PRM. If the offset is not equal and opposite, the CAISO should begin a dialogue with stakeholders to examine why. A shift to UCAP counting that does not meet this criterion appears flawed and deserving of further consideration to either perfect the UCAP calculation methodology or determine whether it is suitable in California. To validate this, the CAISO will need to perform a LOLE analysis. Given the time necessary to perform this calculation and for stakeholders to evaluate the result, the CAISO should not implement UCAP any earlier than 2028.

The CAISO Should Apply UCAP to All Eligible RA Resources Regardless of Whether it is Shown for RA at the Time of Forced Outage

The CAISO should apply UCAP to all resources regardless of whether the resource has been shown for RA at the time of the forced outage. Forced outages largely appear to be beyond the generator's control except for performing regular maintenance. Therefore, not counting an outage based upon the resource not being shown for RA will largely coincide with luck and not with any form of incentive. In addition, the CPUC should avoid mechanisms that encourage entities to show only the bare minimum to meet RA requirements. If an LSE has excess capacity, it should be encouraged to show a long RA position to the CPUC so that as many resources as possible are required to participate in the CAISO energy and ancillary services markets. With RAAIM, this incentive does not exist as resources would rather not be shown since it would take a financial risk. Similarly, if UCAP is only calculated for resources that are shown, the incentive to show the bare minimum will continue. Finally, if UCAP depends on RA showing status, this will further encourage LSEs to hold long positions to substitute for a forced outage. This is common practice in RA under RAAIM and has contributed to heightening RA scarcity. The CAISO should develop rules that encourage parties to either show or sell excess RA positions to avoid tight capacity market conditions.

The CAISO Should Continue to Develop a Supply Cushion to Identify Forced Outages that Apply to a Resource's UCAP

Using a supply cushion to identify the forced outages that are used to calculate UCAP sets correct incentives. While in any given year, market participants do not know *a priori* which hours will be the most constrained, history predicts that these hours will primarily occur during the peak and net load peak of the summer. This history will give generators proper incentives to perform maintenance before the historically tightest hours. If and when those hours change, they will likely occur slowly, with one or a few hours moving to historically unseen periods. This movement will inform generators of what to expect in coming years and when to prepare their resources for reliable operation.

The CAISO Should Adopt Energy Division's Proposed Weighting in Its RA Track 3 Proposal in R.23-10-011

The CAISO should adopt Energy Division's proposal for a weighting of UCAP for resources that equates to a weight of 44.45 percent, 33.33 percent, and 22.22 percent for the three-year period from most recent to most distant.[1] This proposal is reasonable and should be adopted. Weighing the most recent year more highly than the others will provide an incentive to perform major maintenance that will significantly impact the ability to provide RA quickly. It will also provide an incentive to perform routine maintenance to avoid having increased forced outages.

The CAISO Should Minimize Impacts on Existing Contracts

To the extent practical, the CAISO should seek to minimize impacts on existing contracts. The CAISO should, therefore, seek to use existing terminology as those terms are often used in formulating contracts. The most relevant for this discussion is the NQC. Currently, the NQC is defined as the amount of Qualifying Capacity (QC) adjusted by the CAISO for deliverability. If the total provision of RA is now dependent on forced outage rates, the NQC should be that amount of QC derated by UCAP. In the alternative, the QC could account for the derate of UCAP, which would be consistent with the treatment of renewable resources whose QC is determined by an exceedance methodology that accounts for both fuel availability and resource outages. Either method is acceptable since RA contracts are generally denominated in NQC and should account for what the LSE can use to satisfy RA requirements.

The CAISO Should Adopt a Methodology for New Resources Without a Class Average

When assigning UCAP to a new resource at commercial operation without an existing class of technology, the CAISO should use a similar technology where available. For example, a new enhanced geothermal resource would use the class average for geothermal. This will likely serve as a reasonable starting point. In addition, if the CAISO adopts the weighting proposed above, the general related class average will be quickly replaced. If no similar technology exists, the CAISO should use an aggregate of a general classification. For example, if a new flow battery achieves commercial operation, the CAISO should use an aggregate of other storage technologies, which would currently include battery and pumped hydro. Again, this would quickly be replaced by resource-specific outages given the CAISO's proposed weighting.

The CAISO Should Work with Stakeholders to Consider UCAP-Eligible Outages for Storage Resources

The UCAP should be developed to account for outages due to equipment failures. Critically, this will need to consider battery storage that is not available because any charging has already been used, and the resource is not available due to its state of charge and not due to equipment failure. The CAISO should also work with stakeholders to determine how to address storage resources that are receiving Investment Tax Credits and will only charge from its host renewable resource. In this case, evaluating the reliability of such resources may need to account for outages caused by fuel availability to charge the battery.

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[1] *Administrative Law Judges Ruling on Energy Division's Track 3 Proposals and Joint Staff Qualifying Capacity Proposal Status Update*, R.23-10-011 (Jan. 21, 2025), Attachment 2: http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=555183934.

5. Track 1: Please provide your organization's feedback on accounting for ambient derates, particularly the interaction between a resource's NQC after accounting for ambient derates, the NQC after potentially being reduced for UCAP, and the must offer obligation. Would you support the direction discussed and if not, what changes or analysis are required.

The CAISO puts forth two options for estimating ambient derates: (1) a historical lookback; and (2) unit capability testing. The CAISO should utilize a combination of both approaches, starting with a historical lookback. A calculation based on historical data is less burdensome than capability testing. If a resource does not have sufficient historical data, or disputes the CAISO's historical lookback calculation, the CAISO should allow for unit capability testing.

Whether the CAISO uses ambient derates for a resource's QC or NQC (inclusive of UCAP) will impact the resources' must-offer obligation. If the CAISO includes ambient derates into a resource's QC, then the resource's must-offer obligation will also be reduced by the amount of the ambient derate. If the CAISO includes ambient derates into a resource's NQC (inclusive of UCAP), then the resource's must-offer obligation will not automatically be reduced by the amount of the ambient derate, and the resource will need to submit an outage card to reflect the ambient derate.

To determine which approach the CAISO should pursue, the CAISO should investigate how other ISOs and

RTOs incorporate ambient derates into resource counting and evaluate how each option impacts the risk of meeting the must-offer obligation with a resource with ambient derates and who bears the cost of that risk.

6. Track 2: For the outage and substitution proposal leaning, please provide your organization's recommendation and rationale for what threshold to use for conditional outages, including the pros and cons of different alternatives.

CalCCA supports the straw proposal direction of allowing conditional approval of planned outages without substitution, and if an outage would result in a reliability impact, offering a voluntary planned outage substitution pool for SCs to procure substitute capacity. This approach will allow for more opportunities to perform planned maintenance necessary to support reliable grid operation while retaining the responsibility of providing substitution on the entity in control of the outage.

CalCCA has no comments at this time on the threshold to use for conditional outages. The CAISO should put forth a straw proposal based upon its expertise managing outages and system reliability under various grid conditions for stakeholder feedback.

7. Track 2: For the outage and substitution proposal leaning, please provide your organization's recommendation and rationale for the product definition design attributes (granularity, participation, type of RA, and quantity). For participation, should offering to the pool and procuring from the pool be mandatory or voluntary for buyers and/or sellers? Why or why not?

The CAISO supports a *voluntary* planned outage substitution pool. Holders of excess RA should retain their ability to use the capacity how they choose. Mandatory participation in a pool, even with a right-of-first refusal, would provide an incentive for entities not to show excess RA. Instead, the pool should more easily enable sellers to voluntarily offer their excess RA to the market for substitution.

8. Track 2: For the outage and substitution proposal leaning, please provide your organization's feedback on visibility options. What type of information would help stakeholders understand the certainty of being able to take outages if relying on excess shown RA and the voluntary pool?

CalCCA has no comments at this time.

9. Track 2: For the outage and substitution proposal leaning, please provide your organization's feedback on access priority. Would the right of first refusal for the entity showing the capacity for substitution purposes overcome incentives to hold capacity back?

CalCCA has no comments at this time.

10. Track 2: For the outage and substitution proposal leaning, please provide your organization's feedback on the price and procurement mechanism design attributes.

CalCCA has no comments at this time.

11. Track 2: Please provide your feedback on adding "urgent" as an outage type. Are there any other outage types that should be considered in the straw proposal, if so, in what way are

they not covered by the outage types available today?

The CAISO should couple UCAP with clarifications to the definitions of outage types (forced, planned, urgent, and opportunity) so that generators are clear about how to define their outages, and to which outage types UCAP applies. In the straw proposal, the CAISO should explain the intended outcomes of adding “urgent” as an outage type and how doing so will clarify outage reporting.

The CAISO should also categorize its nature of work categories into those that do and do not count towards resources’ UCAP and ensure no one nature of work should be used for both UCAP-eligible outages and non-UCAP-eligible outages. The CAISO should also revisit its bid insertion rules to ensure that resources are incentivized to properly submit outages when they are unavailable so that UCAP values accurately reflect availability.

12. Track 2: Please provide your organization’s feedback on the joint LSE presentation.

CalCCA has no comments at this time.

13. Track 2: Please provide your organization’s feedback on DMM’s presentation.

CalCCA has no comments at this time.

14. Track 2: Optionally, please provide your organization’s preliminary feedback on the availability and incentive mechanism straw proposal leaning discussion. A follow up working group meeting will be scheduled the week of March 3, 2025.

The CAISO should further explore the “measuring unavailable RA” concept. UCAP incentivizes resources to always be available because they cannot perfectly predict when supply cushion hours will occur. Resources should also have a financial incentive to be available during the most extreme grid conditions if possible because forced outages during most critical periods have greater negative impacts on the grid. CalCCA may have additional comments on this topic after the March 3, 2025, working group meeting.

15. Track 3: Please provide your organization’s feedback on the Track 3 Resource Visibility discussion as a whole.

CalCCA agrees that the CAISO operators should have enhanced visibility into the capacity available for the capacity procurement mechanism in high-risk months. In addition, increasing transparency of non-confidential, aggregated data would provide stakeholders the ability to better assess RA market trends.[1] For these reasons, CalCCA supports the CAISO developing a process to obtain increased visibility about RA resources and their availability to California.

The CAISO and stakeholders should further consider how to implement such a process so that it balances information accuracy and administrative burden. Compiling this information involves multiple parties and a chain of events that will be difficult to track. The CAISO’s straw proposal options are good starting points, but the CAISO and stakeholders will need to further consider these two objectives when developing the details.

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[1] For example, in 2024, the CAISO began posting historical aggregated RA showing information: https://www.caiso.com/documents/historicalresourceadequacyaggregatedata.xlsx. This information has greatly improved the transparency of shown RA.

16. Track 3: Does your organization have any feedback on or suggested redlines to the list of capacity status categories discussed as potential reporting requirements for RA-eligible capacity not shown as RA?

The capacity status categories generally capture the reasons RA-eligible resources are not shown.

17. Track 3: Does your organization have feedback on any other aspects of the potential design such as reporting frequency?

Reporting frequency should generally match the RA program's monthly frequency. To limit the administrative burden of reporting, the CAISO could require reporting of changes from previously reported information.

18. Track 3: Please provide your organization's feedback on the presentation by Middle River Power.

Middle River Power LLC (MRP) proposes an RA transaction ledger to log transactions into a CAISO system so the CAISO has visibility into RA-eligible resources. MRP states this concept "can eliminate manual updates of supply plans."[1] CalCCA is concerned with a proposal that would eliminate supply plans. RA plans and supply plans are needed to confirm a resource's RA status by the seller and the buyer. A validated supply plan triggers an RA resource's must-offer obligation. Proposals to increase visibility into shown and non-shown RA capacity should ensure both the buyer and seller confirm the RA status of the capacity, so that the CAISO can perform its validation and apply must offer obligation to shown RA resources.

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[1] Middle River Power LLC, *Visibility Solution Concept* (Feb. 11, 2025) at Slide 4: https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-Middle-River-Power-Visibility-Solution-Concept-Feb-11-2025.pdf.

California Community Choice Association

SUBMITTED 03/12/2025, 03:46 PM

Contact
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1. **Please provide your organization's comments on the draft Reliability Assessment**

   The California Community Choice Association (CalCCA) has no comments at this time.

2. **Please provide your organization's comments on the draft Policy Assessment**

   CalCCA has no comments at this time.

3. **Please provide your organization's comments on the draft Economic Assessment**

   CalCCA has no comments at this time.

4. **Please provide your organization's comments on the draft Frequency Response Assessment**

   CalCCA has no comments at this time.

5. **Please provide your organization's Economic Study Requests**

   CalCCA has no comments at this time.

6. **Please provide your organization's Maximum Import Capability (MIC) expansion requests. Any confidential details should not be included in this comment template and should instead be emailed to regionaltransmission@caiso.com**

   CalCCA has no comments at this time.

7. **Please provide your organizations comments on the Transmission Planning Process Infrastructure-related policy concepts**

   CalCCA appreciates the opportunity to provide the California Independent System Operator (CAISO) with Transmission Planning Process and infrastructure-related policy concepts. As proposed in CalCCA’s comments to the CAISO’s Interconnection Process Enhancements (IPE) Track 3 Final Proposal,[1] the CAISO should consider the issue of energy-only (EO) resources seeking transmission plan deliverability (TPD) in the next IPE initiative. While the IPE Track 3 Final Proposal prohibits EO projects in Cluster 15 and later from ever seeking a TPD allocation, there are legitimate reasons why projects may pursue interconnection via the EO process, such as a willingness on the part of both developers and load-serving entities to contract for a period of time for EO deliveries. CalCCA, therefore, requests the CAISO reconsider preventing EO projects from *ever* seeking deliverability. Instead, the CAISO could explore allowing a project that enters the queue and comes online as EO to submit a *new* interconnection request and follow the intake and study process for obtaining deliverability. The IPE Track 3 Final Proposal states that the CAISO has considered the issue of EO resources seeking TPD, identified several policy issues that need to be discussed with stakeholders, and determined that the issue will need to be deferred to a future IPE initiative.[2] The CAISO should commit to considering EO resources seeking TPD in the next IPE initiative.

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[1] *CalCCA Comments on CAISO Interconnection Process Enhancements Track 3 Final Proposal* (Mar. 4, 2025): https://stakeholdercenter.caiso.com/Comments/AllComments/45f69a3e-5151-4edb-9866-59b1511b1856#org-25d31bf5-e55d-45d2-b2b8-769846dcb3cb.

[2] *Id.,* at 26-27.

8. Please provide any additional comments on the Draft Study Plan and February 26th, 2025 Stakeholder Meeting

CalCCA has no additional comments at this time.

DOCKETED	
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Project Title:	Electricity and Gas Demand Forecast
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STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

IN THE MATTER OF: *2025 Integrated Energy Policy Report (2025 IEPR)*	DOCKET NO. 25-IEPR-03 RE: California's Economic Outlook

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE FEBRUARY 26, 2025, IEPR COMMISSIONER WORKSHOP ON CALIFORNIA'S ECONOMIC OUTLOOK

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March 12, 2025

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STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

IN THE MATTER OF: *2025 Integrated Energy Policy Report (2025 IEPR)*	DOCKET NO. 25-IEPR-03 RE: California's Economic Outlook

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE FEBRUARY 26, 2025, IEPR COMMISSIONER WORKSHOP ON CALIFORNIA'S ECONOMIC OUTLOOK

The California Community Choice Association[1] (CalCCA) submits these comments on the *IEPR Commissioner Workshop on California's Economic Outlook* (Workshop), held on February 26, 2025. The Workshop solicited comments from California Energy Commission (Commission) Commissioners, energy demand forecasters, Commission Staff, and stakeholders on California's evolving economic and demographic landscape that serve as a key foundation for the California Energy Demand Forecast (CEDF).

I. INTRODUCTION

CalCCA appreciates the opportunity to comment on the Workshop, and specifically on the impact of data centers on the CEDF. Load growth associated with data center development is a novel and difficult process to perfect. CalCCA encourages the Commission and stakeholders to

[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance 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.

continue to monitor progress of data center site development and energy usage to refine forecasts going forward. The loads tend to be lumpy (*i.e.,* they arrive in large portions at specific sites rather than at a steady rate like other smaller user load growth) and can come online quickly. Accuracy in forecasting for data center load growth is important to the data center developer (to ensure they will be able to energize the facility), the California Public Utilities Commission (CPUC) (for distribution planning), the California Independent System Operator (CAISO) (for transmission planning), and all load serving entities (LSE) (for energy, capacity, and Renewables Portfolio Standard (RPS) needs). Each of these parties must therefore be involved in any process to forecast the load growth of data centers, as each is critical for reliability and affordability. To address these concerns, the Commission should:

- Collaborate with all parties (CPUC, CAISO, IOUs, data center developers, and LSEs) to plan for data center load growth as it will impact transmission, distribution, and generation needs;
- Focus on the accuracy of the data center load forecast and clearly state any projected energy efficiency gains over time, since both factors are critical in balancing reliability and affordability; and
- Provide greater visibility regarding the location, status, and size of data center load growth within forecast updates.

Addressing these three points will enable more cost-effective planning to serve anticipated data center energy needs.

II. THE COMMISSION SHOULD WORK JOINTLY WITH ALL RELEVANT STAKEHOLDERS IN DATA CENTER LOAD GROWTH PLANNING AS IT WILL IMPACT TRANSMISSION, DISTRIBUTION, AND GENERATION NEEDS

The Commission should work jointly with all relevant stakeholders, including the CPUC, CAISO, the IOUs, data center developers, and LSEs, in data center load growth planning as it will impact transmission, distribution, and data center energy needs. Deployment of a new data center can cause the need for transmission, distribution, and generation development. It is, therefore, necessary to include all that will be impacted by those three developments. The CPUC will need to be involved in energization to serve the new customer, including the development of distribution capacity. The CPUC will also need to approve any IOU need for new generating resources to serve the data center. This typically occurs through the CPUC's Integrated Resource Planning (IRP) process regarding generation needs. The IRP also informs CAISO planning for the development of new transmission capacity. While the transmission and distribution needs analysis can be accomplished on an IOU-area basis, the need for new generation also depends on the load forecast for LSEs. LSE's involvement in the forecast process for new data center load growth is critical to make the forecast accurate. With an accurate forecast, LSEs can then plan to procure new resources to meet the data center load energy, capacity, and RPS needs.

In addition, LSEs dramatically range in size. The 2024 IEPR energy forecast for 2025 demonstrates that CCAs represented by CalCCA were forecast to serve between 163 gigawatt hours (GWh) to 10,529 GWh.[2] In a study of the range of projections for United States Data Center Growth, the consulting firm Energy + Environmental Economics (E3) estimates that based on an assumed 86 percent data center load factor, a 200 megawatts data center would be expected to consume 1,507 GWh annually. [3] For a CCA represented by CalCCA, that is anywhere from a 14 percent to a 925 percent increase in energy served. By comparison, the 2024 IEPR shows the IOU-area energy consumption forecast for 2025 between 17,078 to 92,442 GWh. That same data center would only constitute a 1.6 to 8.8 percent increase for the entire IOU area. Even the largest CCA represented by CalCCA would experience a percent increase in

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[2] CEC CED 2024 Baseline Forecast LSE and BAA Tables https://efiling.energy.ca.gov/GetDocument.aspx?tn=261526&DocumentContentId=97921.

[3] *Load Growth is Here to Stay, But are Data Centers?*, Energy + Environmental Economics (June 2024), at 2 (fn. 1): https://www.ethree.com/wp-content/uploads/2024/07/E3-White-Paper-2024-Load-Growth-Is-Here-to-Stay-but-Are-Data-Centers.pdf.

energy served greater than the smallest IOU. Incorrect forecasts, therefore, disproportionately put CCAs at risk of over- or under-procurement.

The Commission should ensure that *all* relevant parties, including the CCAs, are involved in forecasting new data center growth expected within their area. Accurately forecasting new energy needs will enable CCAs to better plan procurement to meet their customers' energy, RPS, and capacity needs in a cost-effective manner. LSEs need to have access to the assumptions and methodologies for the forecasts specific to their service territory to ensure they can manage compliance risk effectively and efficiently. Failing to forecast accurately can either result in rates that are too high (forecast data center load does not materialize or energy efficiency gains suddenly result in decreased load, even though the energy, RPS, and capacity have been procured) or a lack of reliability (no new data center procurement, but the data center is brought online straining existing generating capabilities). Neither outcome is acceptable. Including the CCAs in data center forecasting for their respective areas will help to avoid these adverse outcomes.

The Commission should begin with transparency to ensure the forecasting accuracy of data center growth. The Commission should provide data to each LSE on the location, size, and status of any proposed data center forecasted in each LSE service area. Providing this data will enable each LSE to work with the Commission and the data center to ensure the LSE is prepared to serve it upon energization.

In addition, CCA governing boards are made up of local government officials that may be able to inform forecasts and assist with communications between parties in permitting for the facility in the CCA area. Identifying these new data centers in the Commission's forecast, particularly if that identification occurs before the permit application, can help bring parties together sooner to ensure a smooth energization and allow timely planning for LSEs to cost-effectively procure clean, reliable resources.

III. CONCLUSION

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

Respectfully submitted,

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

Order Instituting Rulemaking to Establish Energization Timelines.	R.24-01-018

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING CLARIFYING NEXT STEPS FOR FLEXIBLE SERVICE CONNECTIONS, MODIFYING PHASE 2 SCHEDULE, AND REQUESTING PARTY COMMENTS

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March 13, 2025

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SUMMARY OF RECOMMENDATIONS

CalCCA provides the following recommendations to the Commission:[1]

- Firm FSCs should be made available on all circuits to optimize grid capacity for load growth and ensure reliable operation of the distribution grid;
- Customers on unconstrained circuits opting into firm FSCs with non-firm import capacity and DER owners that supply this capacity should be compensated, as they both provide a beneficial grid service; and
- The Commission should ensure a level playing field for IOU and CCA generation service and flexibility solutions to allow customers to choose the best option for their needs.

[1] Acronyms used in the Summary of Recommendations are defined in the body of this document, *California Community Choice Association's Opening Comments on Administrative Law Judge's Ruling Clarifying Next Steps for Flexible Service Connections, Modifying Phase 2 Schedule, and Requesting Party Comments*, dated March 13, 2025.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Energization Timelines.	R.24-01-018

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING CLARIFYING NEXT STEPS FOR FLEXIBLE SERVICE CONNECTIONS, MODIFYING PHASE 2 SCHEDULE, AND REQUESTING PARTY COMMENTS

California Community Choice Association[2] (CalCCA) submits these opening comments pursuant to the *Administrative Law Judge's Ruling Clarifying Next Steps for Flexible Service Connections, Modifying Phase 2 Schedule, and Requesting Party Comments*[3] (Ruling), dated February 7, 2025. Among other items, the Ruling clarifies the next steps for the development of certain flexible service connection pathways, and requests party comments. The *E-Mail Ruling Granting Schedule Amendment*,[4] dated February 20, 2025, extends the date for submitting Opening Comments to March 13, 2025, and Reply Comments to March 27, 2025.

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 Clarifying Next Steps for Flexible Service Connections, Modifying Phase 2 Schedule, and Requesting Party Comments*, Rulemaking (R.) 24-01-018 (Feb. 7, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K603/556603068.PDF.

4 *E-Mail Ruling Granting Schedule Amendment*, R.24-01-018 (Feb. 20, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M557/K609/557609764.PDF.

I. INTRODUCTION

Rapid electric load growth in response to California's aggressive greenhouse gas (GHG) reduction efforts has resulted in significant delays in energizing new loads, including electric vehicle (EV) charging infrastructure, data centers, housing, and commercial and agricultural facilities. Much of this new load can materialize more quickly than investor-owned utilities (IOUs) are able to plan for and upgrade distribution capacity. D.24-10-030[5] in the Commission's High Distributed Energy Resource proceeding[6] recently outlined several "bridging strategies" for IOUs to accommodate energization requests before completing the necessary grid upgrades. These bridging strategies include temporary limits on how much power a new load can import and IOU- and customer-owned distributed energy resources (DER).

The Ruling raises important questions regarding firm Flexible Service Connections (FSC), which can result in reducing delays in energization by allowing customers to partially energize new loads on capacity-constrained circuits. FSCs, combined with DER, demand response, and other load flexibility options, can also help distribution system operators (DSO) better manage capacity on unconstrained circuits while ensuring reliable grid operation.

CalCCA provides overall recommendations regarding firm FSCs before responding to Ruling question 10 regarding the circumstances under which a customer should be eligible for an FSC.[7] Overall, CalCCA urges the Commission to ensure a level playing field for community

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5 Decision (D.) 24-10-030, *Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Maps*, R.21-06-017 (Oct. 23, 2024), at 89-93: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M544/K154/544154869.PDF.

6 *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*, R.21-06-017 (Jun. 24, 2021) (High DER Proceeding): https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:R2106017.

7 CalCCA is concurrently filing comments in the High DER Proceeding in response to a Ruling regarding medium- and longer-term flexible connection options, including non-firm import capacity. *See*

choice aggregators (CCA) and their customers in the context of the FSC framework. CalCCA provides the following recommendations in response to the Ruling:

- Firm FSCs should be made available on all circuits to optimize grid capacity for load growth and ensure reliable operation of the distribution grid;
- Customers on unconstrained circuits opting into firm FSCs with non-firm import capacity and DER owners that supply this capacity should be compensated, as they both provide a beneficial grid service; and
- The Commission should ensure a level playing field for IOU and CCAs generation service and flexibility solutions to allow customers to choose the best option for their needs.

II. FIRM FSCS SHOULD BE MADE AVAILABLE ON ALL CIRCUITS TO OPTIMIZE GRID CAPACITY AND ENSURE RELIABLE OPERATION OF THE DISTRIBUTION SYSTEM

Firm FSCs should be made available to customers applying for new or expanded service on both constrained and unconstrained circuits to optimize grid capacity and ensure reliable operation of the distribution grid. Building and transportation electrification are key to the state's efforts to reduce GHG emissions, but they also pose significant challenges for grid planning and timely energization of customer loads. Firm FSCs offer a potential solution for customers on constrained circuits to partially energize loads by limiting the amount of electricity they import until the necessary grid upgrades are completed. They can also be leveraged to increase capacity on unconstrained circuits to accommodate unanticipated load growth, defer or eliminate the need for costly grid upgrades, and improve reliability. Firm FSCs should, therefore, be allowed on both constrained and unconstrained circuits to optimize existing grid capacity.

Assigned Commissioner's and Administrative Law Judge's Ruling Seeking Additional Information from Parties, Setting Forth Further Direction, and Modifying Schedule for Track 3, R.21-06-017 (Feb. 7, 2025) (High DER Ruling): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K602/556602955.PDF.

Forecasting the magnitude and precise location of electrification-related load growth is difficult and imprecise, making it challenging to predict which circuits will experience capacity constraints.[8] Large unanticipated loads, such as EV fast chargers or data centers, can be developed much more quickly than the IOUs' ability to plan for and upgrade grid infrastructure, as discussed in a recent Staff Proposal in the High DER Proceeding:

> Major upgrades to the distribution circuits can take up to three years to execute, and major upgrades to substations can take up to eight years. EV charging stations, by contrast, can request service equivalent to a new neighborhood or factory but can be installed in a matter of weeks.[9]

Given the difficulty of predicting which circuits may experience rapid load growth, DSOs should use all available tools and resources to optimize capacity on every circuit.

In addition, the Smart Inverter Operationalization Working Group Report (SIOWG Report) in the High DER Proceeding[10] describes how Limited Load Profiles (LLP),[11] as part of FSC agreements (FSCA), can be combined with DER to provide beneficial grid services:

> Operational flexibility could also extend optionally to import limits by including firm import limits (possibly per scheduled times as is currently possible for export limits) as well as additional non-firm import capacity that could be used if authorized by the DSO in Limited Load Profiles. This approach might be used to avoid, minimize, or defer distribution system upgrades, whether paid for by the DER owner or by ratepayers.[12]

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8 *See*, e.g., *Staff Proposal for the High DER Proceeding*, R.21-06-017 (Apr. 5, 2024) (High DER Staff Proposal), at 24: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M529/K078/529078850.PDF.

9 *Ibid.*

10 Xanthus Verdant, *Smart Inverter Operationalization (SIO) Working Group Report, Business Cases and Use Cases*, R.21-06-017 (Feb. 1, 2024): https://gridworks.org/wp-content/uploads/2024/02/Smart-Inverter-Operationalization-Working-Group-Report-Feb.1.24.pdf.

11 Limited Load Profiles are agreements for customers adding new loads that combine fixed import limits with additional non-firm import capacity if authorized by the DSO based on forecasted grid conditions.

12 *Id.*, at 32.

While non-firm import capacity is a medium- to longer-term issue and the subject of the High DER Ruling, there is clearly value in allowing FSCs on all circuits as soon as possible. The Commission should, therefore, authorize the use of firm FSCs on both constrained and unconstrained circuits and expedite the development and deployment of FSCs for non-firm import capacity.

III. CUSTOMERS AND DER OWNERS/AGGREGATORS PROVIDING OPERATIONAL FLEXIBILITY SHOULD BE COMPENSATED

Increased operational flexibility allows DSOs to better manage available capacity during normal and abnormal conditions and defer or avoid grid upgrades. This, in turn, helps reduce energization delays and supports meeting the state's electrification and GHG reduction goals. Customers choosing firm FSCs to allow partial energization on constrained circuits can experience benefits in the form of reduced energization times. However, customers opting into FSCs with firm import limits to increase capacity on unconstrained circuits also provide a valuable grid service and should be adequately compensated.

While the Ruling focuses on firm import limits, the issue of making firm FSCs available to customers on unconstrained circuits requires a discussion of non-firm import capacity. A customer applying for service on an unconstrained circuit has no real incentive to enter into an FSCA that restricts their ability to import energy. If the customer did enter into such an agreement, however, this customer would benefit from access to non-firm import capacity supplied by DERs owned or controlled by other parties. The customer accepting firm import limits and the DER owners/aggregators supplying the non-firm import capacity would then need adequate compensation for this arrangement to work. The SIOWG Report offers the following observation on a potential arrangement for compensation:

> Although incentives and/or compensation are out-of-scope for the SIOWG, it may be that this shift in managing the export and/or import of power could involve such compensation, or other incentives such as grid informed retail rates which incentivize DER on when to increase or decrease imports or exports.[13]

Regardless of the type of compensation, both the party accepting firm import limits/non-firm capacity imports and the DER owner/aggregator supplying additional capacity would need adequate compensation to be incentivized to provide these beneficial grid services.

IV. IOU BRIDGING SOLUTIONS SHOULD NOT PREVENT CCAS FROM SERVING CUSTOMERS ON A LEVEL PLAYING FIELD

The Commission must ensure that CCAs and their customers operate on a level playing field with FSC solutions. Given that the IOUs own the distribution system and that requests for energization are made to the IOU, each IOU has a built-in "structural advantage," which creates a risk of influencing customers in favor of IOU-centric energy supply or program options. The Commission should, therefore, implement express reporting, notice, and other data-sharing requirements to ensure the delivery or FSC service is not tied to IOU generation service or other programs. The Commission should also ensure that the IOU FSC tariffs or agreements do not exclude the ability of CCAs to serve FSC customers or participate in bridging options.

Between this proceeding and the High DER Proceeding, a framework for FSC solutions is being developed. The FSC customer options within this framework may include the following arrangements:

- **Firm Import Limit FSCA:** an arrangement whereby a customer agrees to a firm limit on how much electricity they can import from the distribution system. This can be used as a temporary measure to allow a customer to partially energize on a constrained circuit until the system is upgraded to serve the customer fully or as a longer-term measure to help DSOs manage capacity on unconstrained circuits;

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13 *Id.*, at 33.

- **LLP:** an arrangement whereby a customer agrees to a firm limit on the amount of electricity it can import, plus an additional, non-firm amount of electricity it can import if authorized by the DSO, based on forecasted grid conditions.

- **Firm Import/Export Limit:** an agreement establishing firm limits on the amount of electricity a DER owner can import from or export to the distribution grid.

- **Non-Firm Import/Export Limit:** an agreement allowing a DER owner to exceed its firm import/export limits if authorized by the DSO, based on forecasted grid conditions.

Customers planning new or additional loads will learn about FSCs and other established temporary bridging options from IOUs when they submit an energization application to the IOU. D.24-10-030 requires IOUs to develop bridging strategies to accommodate energization requests that trigger capacity upgrades.[14] These strategies include temporary constraints on load imports and IOU- and customer-owned DER. However, D.24-10-030 does not address how customers will be made aware of alternatives for generation service or other non-IOU bridging options. The Commission should, therefore, implement express reporting, notice, and other data-sharing requirements to ensure that customers of CCAs are aware of all options for generation service, as well as other IOU and CCA bridging solutions.

For example, CCAs have deployed or have plans to deploy DER Management Systems (DERMS) to dispatch customer-owned DERs.[15] These CCA DERMS can be configured to receive real- and near-real-time dispatch signals from an IOU DERMS, providing operational flexibility during normal and abnormal operating conditions and supporting the deployment of FSCs throughout the grid. Customers should be allowed to participate in these and other CCA-offered programs as an alternative to IOU offerings. Since IOUs are generally the first point of

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[14] D.24-10-030, Ordering Paragraph 18, at 197: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M544/K154/544154869.PDF.

[15] *See*, *e.g.*, *Richmond Advanced Energy Community Includes Virtual Power Plant and Zero Net Carbon Homes for Underserved Residents* (Jun. 21, 2022): https://mcecleanenergy.org/mce-unveils-plans-for-virtual-power-plant-to-benefit-disadvantaged-richmond-residents-and-businesses/.

contact for new loads, the Commission should implement express reporting, notice, and other data-sharing requirements to ensure delivery or FSC service is not tied to IOU generation service or other programs. The Commission should also ensure that the IOU FSC tariffs and agreements do not exclude the ability of CCAs to serve FSC customers or participate in bridging options.

V. CALCCA COMMENTS ON THE QUESTIONS ON FIRM FLEXIBLE SERVICE CONNECTIONS

Pilot and Process Learnings

1. What learnings from past and ongoing large IOU FSC pilots and processes can inform the design of LLP?

CalCCA has no response at this time.

2. Are there FSC processes in other jurisdictions whose learnings should be considered? If so, what are those jurisdictions and the associated learnings?

CalCCA has no response at this time.

3. What is an appropriate temporal granularity for LLP schedules? For example, will the simple monthly or seasonal import-limit granularity utilized within Limited Generation Profiles (LGP) be sufficient for LLP schedules? If not, why not?

CalCCA has no response at this time.

4. What elements of LGP adopted in R.17-07-007 and LGP Resolutions should be adapted for development of LLPs? In what ways can implementation of LLP employ approaches from the LGP process? In what ways should LLP design and implementation differ from LGP?

CalCCA has no response at this time.

5. How can Load ICA results and data inform and enable LLPs? Is there another existing means to inform and enable LLP other than Load ICA?

CalCCA has no response at this time.

Equipment Requirements and Certification

6. To implement static LLPs what device(s) are required for customers to install to control load and prevent power consumption (i.e., imports) from exceeding the scheduled LLP? Is PCS sufficient for this task?

CalCCA has no response at this time.

7. **Is a PCS certified to UL 3141 Issue 2,4 sufficient to operationalize static LLPs? If no, why not, and are there alternative existing standards or equipment the Commission should consider for LLP participation?**

CalCCA has no response at this time.

8. **When do stakeholders expect UL 3141 Issue 2 certified equipment to be readily available to support LLP?**

CalCCA has no response at this time.

9. **Is there a size threshold (e.g., absolute [MW] or relative [percent of total feeder rating] site capacity) that necessitates equipment commissioning or telemetry? If so, what is that threshold and what need does it raise?**

CalCCA has no response at this time.

Energization Queue and Circumstances for LLP

10. **Under what circumstances should a customer be eligible for FSCAs? What type or class of customer should be eligible for FSCAs and why? Should FSCAs be reserved for when a circuit is constrained? Should customers be able to elect to engage in an FSCAs on an unconstrained circuit to aid in creating circuit capacity for additional customers?**

As discussed in sections II, III, and IV above, CalCCA supports using FSCs on both constrained and unconstrained circuits to provide operational flexibility to support the rapid growth of transportation and building electrification. Given the short development time and difficulty in predicting where these loads may appear on the grid, DSOs must use every available tool to optimize capacity on all circuits. The widespread use of FSCs is one such tool that is readily available and has the potential to not only provide operational flexibility but also yield infrastructure investment savings. Furthermore, customers opting into FSCs for firm import/non-firm import capacity on unconstrained circuits and DER owners supplying the non-firm import capacity provide valuable grid services and should be compensated to help incentivize the realization of maximum FSC benefits. Finally, the Commission should ensure a level playing field with respect to the established FSC framework to ensure CCA generation service and flexibility options remain available to customers.

11. How should the Utilities address multiple requests for FSCAs on the same circuit?

CalCCA has no response at this time.

Tariffs, Rules, Agreements, and Forms

12. What are the applicable tariffs, rules, agreements, and forms that may need modification? What should those modifications be? Is there a need for differences between different IOUs' versions of these documents? If so, what is this need based upon?

CalCCA has no response at this time.

13. Are there any unique considerations that must be included in modifications to rules, agreements, and/ or forms (e.g., such as for onsite generation, electric vehicles, or emergency conditions)?

CalCCA has no response at this time.

14. Are there other steps needed to implement FSCs? If so, what are these steps?

CalCCA has no response at this time.

VI. CONCLUSION

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

Respectfully submitted,

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

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resource Future.	R.21-06-017

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON ASSIGNED COMMISSIONER'S AND ADMINISTRATIVE LAW JUDGE'S RULING SEEKING ADDITIONAL INFORMATION FROM PARTIES, SETTING FORTH FURTHER DIRECTION, AND MODIFYING SCHEDULE FOR TRACK 3

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March 13, 2025

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SUMMARY OF RECOMMENDATIONS

CalCCA provides the following recommendations to the Commission:[1]

- Dynamic FSCs can help reduce energization delays and mitigate or avoid grid upgrades and should be developed and deployed as quickly as possible;
- Customers opting into firm FSCs with non-firm import capacity and DER owners that supply this capacity provide a beneficial grid service, and both should be compensated; and
- The Commission should ensure a level playing field for IOU and CCA flexibility solutions to allow customers to choose the best option for their needs.

[1] Acronyms used in the Summary of Recommendations are defined in the body of this document, *California Community Choice Association's Opening Comments on Assigned Commissioner's and Administrative Law Judge's Ruling Seeking Additional Information from Parties, Setting Forth Further Direction, and Modifying Schedule for Track 3*, dated March 13, 2025.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resource Future.	R.21-06-017

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON ASSIGNED COMMISSIONER'S AND ADMINISTRATIVE LAW JUDGE'S RULING SEEKING ADDITIONAL INFORMATION FROM PARTIES, SETTING FORTH FURTHER DIRECTION, AND MODIFYING SCHEDULE FOR TRACK 3

California Community Choice Association[2] (CalCCA) submits these opening comments pursuant to the *Assigned Commissioner's and Administrative Law Judge's Ruling Seeking Additional Information from Parties, Setting Forth Further Direction, and Modifying Schedule for Track 3*[3] (Ruling), dated February 2, 2025, and *Email Ruling Correcting Error in the February 7, 2025, Ruling in Regard to the Filing Date for Opening Comments*, dated February 10, 2025.[4] The Ruling provides further direction for next steps in Track 3 of the proceeding, including but not limited to the development of certain flexible grid connection policies related

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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 *Assigned Commissioner's and Administrative Law Judge's Ruling Seeking Additional Information From Parties, Setting Forth Further Direction, and Modifying Schedule for Track 3*, Rulemaking (R.) 21-06-017 (Feb. 7, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K602/556602955.PDF.

4 *Email Ruling Correcting Error in the February 7, 2025, Ruling in Regard to the Filing Date for Opening Comments*, R.21-06-017 (Feb. 10, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K602/556602566.PDF.

to Smart Inverter Operationalization (SIO) issues and the associated tariff rules. The Ruling also modifies the proceeding schedule and requests party comment on specific questions concerning flexible grid connections. The subsequent Email Ruling[5] extends the date for submitting Opening Comments to March 13, 2025, and Reply Comments to March 27, 2025.

I. INTRODUCTION

California's efforts to reduce greenhouse gas (GHG) emissions are driving the rapid growth of transportation and building electrification. This growth is outpacing the investor -owned utilities' (IOU) ability to upgrade the distribution grid to accommodate this new load, resulting in significant energization delays. The state is also experiencing an affordability crisis, with utility customers paying some of the highest rates for electricity in the nation driven largely by the distribution and transmission costs of serving customers. Fortunately, there are alternatives to costly infrastructure upgrades, including Flexible Service Connections (FSC).

The Ruling seeks input on dynamic FSCs, which are medium- to longer-term tools that can help distribution system operators (DSO) better manage capacity on both constrained and unconstrained circuits while ensuring reliable grid operation. CalCCA provides overall recommendations regarding dynamic FSCs before responding to the Ruling's question 2, regarding how FSCs can facilitate timely energization of new load.[6] Overall, CalCCA urges the California Public Utilities Commission (Commission) to ensure a level playing field for

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[5] *Email Ruling Granting Schedule Amendment*, R.21-06-017 (Feb. 20, 2025) (Email Ruling): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M557/K608/557608542.PDF.

[6] CalCCA is concurrently filing comments in the Energization Proceeding in response to a Ruling regarding near-term firm import flexible service connections. *See Order Instituting Rulemaking to Establish Energization Timelines*, R.24-01-018 (Jan. 25, 2024) (Energization Proceeding): https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:R2401018; *Administrative Law Judge's Ruling Clarifying Next Steps for Flexible Connections, Modifying Phase 2 Schedule, and Requesting Party Comments,* R.24-01-018 (Feb. 7, 2025) (Energization Ruling): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K603/556603068.PDF.

community choice aggregators (CCA) and their customers in the context of the FSC framework. CalCCA provides the following recommendations in response to the Ruling:

- Dynamic FSCs can help reduce energization delays and mitigate or avoid grid upgrades and associated costs and should be developed and deployed as quickly as possible;
- Customers opting into firm FSCs with non-firm import capacity and distributed energy resource (DER) owners that supply this capacity provide a beneficial grid service, and both should be compensated; and
- The Commission should ensure a level playing field for IOU and CCA flexibility solutions to allow customers to choose the best option for their needs.

II. DYNAMIC FSCS SHOULD BE DEVELOPED AND DEPLOYED TO MEET THE ENERGIZATION AND AFFORDABILITY CHALLENGES FACING THE GRID

Dynamic FSCs should be developed and deployed as quickly as possible to address the significant delays in energizing new loads. As California grapples with the dual challenges of energization delays and a rate affordability crisis, the Commission is exploring alternatives to costly grid upgrades. FSCs and other load flexibility options can help utilities reduce or eliminate the need for distribution upgrades, reducing energization times and easing the cost burden on ratepayers, and should be developed and deployed as quickly as possible.

The Ruling addresses dynamic/non-firm flexible grid connections, which are characterized as medium- to longer-term solutions. Dynamic FSCs include non-firm export and import capacity that govern the interaction between DERs, loads with firm import limits, and the DSO. The Energization Ruling is considering the near-term use of firm FSCs to allow partial energization of new loads on constrained circuits and to increase capacity on unconstrained circuits. Firm FSCs must be combined with non-firm import capacity for customers to accept firm import limits on unconstrained circuits.

The combination of dynamic/non-firm import and export capacity and firm import limits for new load allows DSOs to optimize capacity on existing circuits. The SIO Working Group

Report (SIOWG Report)[7] describes how Limited Load Profiles (LLP),[8] as part of FSC agreements (FSCA), can be combined with DER to provide beneficial grid services:

> Operational flexibility could also extend optionally to import limits by including firm import limits (possibly per scheduled times as is currently possible for export limits) as well as additional non-firm import capacity that could be used if authorized by the DSO in [LLPs]. This approach might be used to avoid, minimize, or defer distribution system upgrades, whether paid for by the DER owner or by ratepayers.[9]

Without the ability to import non-firm capacity, only customers located on constrained circuits will make use of firm import limits for partial energization of their loads. To make full use of near-term firm FSCs on all circuits, it is imperative to develop and deploy dynamic/non-firm FSCs as quickly as possible.

III. CUSTOMERS AND DER OWNERS/AGGREGATORS PROVIDING OPERATIONAL FLEXIBILITY SHOULD BE APPROPRIATELY COMPENSATED

Increased operational flexibility allows DSOs to better manage available capacity during normal and abnormal conditions and defer or avoid grid upgrades. This, in turn, helps reduce energization delays and supports meeting the state's electrification and GHG reduction goals. Customers and DER owners/aggregators that provide flexibility should be adequately compensated to realize the benefits of improved operational flexibility.

A customer applying for service on an unconstrained circuit has no real incentive to enter into an FSCA that restricts their ability to import energy. If the customer did enter into such an agreement, however, this customer would benefit from access to non-firm import capacity

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7 Xanthus Verdant, *Smart Inverter Operationalization (SIO) Working Group Report, Business Cases and Use Cases*, R.21-06-017 (Feb. 1, 2024): https://gridworks.org/wp-content/uploads/2024/02/Smart-Inverter-Operationalization-Working-Group-Report-Feb.1.24.pdf.

8 LLPs are agreements for customers adding new loads that combine fixed import limits with additional non-firm import capacity if authorized by the DSO based on forecasted grid conditions.

9 *Id.*, at 32.

supplied by DERs owned or controlled by other parties. The customer accepting firm import limits and the DER owners/aggregators supplying the non-firm import capacity would then need adequate compensation for this arrangement to work. The SIOWG Report offers the following observation on a potential arrangement for compensation:

> Although incentives and/or compensation are out-of-scope for the SIOWG, it may be that this shift in managing the export and/or import of power could involve such compensation, or other incentives such as grid informed retail rates which incentivize DER on when to increase or decrease imports or exports.[10]

Regardless of the type of compensation, both the party accepting firm import limits/non-firm import capacity and the DER owner/aggregator supplying the additional capacity would need adequate compensation to be incentivized to provide these beneficial grid services.

IV. THERE MUST BE A LEVEL PLAYING FIELD FOR IOU AND NON-IOU FLEXIBILITY SOLUTIONS

The Commission must ensure that CCAs and their customers operate on a level playing field with FSC solutions. Given that the IOUs own the distribution system and that requests for energization are made to the IOU, each IOU has a built-in "structural advantage," which creates a risk of influencing customers in favor of IOU-centric energy supply or program options. The Commission should, therefore, implement express reporting, notice, and other data-sharing requirements to ensure the delivery or FSC service is not tied to IOU generation service or other programs. The Commission should also ensure that the IOU FSC tariffs or agreements do not exclude the ability of CCAs to serve FSC customers or participate in bridging options.

Between this proceeding and the Energization Proceeding, a framework for FSC solutions is being developed. The FSC customer options within this framework may include the following arrangements:

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[10] *Id.*, at 33.

- **Firm Import Limit FSCA:** an arrangement whereby a customer agrees to a firm limit on how much electricity they can import from the distribution system. This can be used as a temporary measure to allow a customer to partially energize on a constrained circuit until the system is upgraded to serve the customer fully or as a longer-term measure to help DSOs manage capacity on unconstrained circuits;

- **LLP:** an arrangement whereby a customer agrees to a firm limit on the amount of electricity it can import, plus an additional, non-firm amount of electricity it can import if authorized by the DSO, based on forecasted grid conditions.

- **Firm Import/Export Limit:** an agreement establishing firm limits on the amount of electricity a DER owner can import from or export to the distribution grid.

- **Non-Firm Import/Export Limit:** an agreement allowing a DER owner to exceed its firm import/export limits if authorized by the DSO, based on forecasted grid conditions.

Customers planning new or additional loads will learn about FSCs and other established temporary bridging options from IOUs when they submit an energization application to the IOU. D.24-10-030 requires IOUs to develop bridging strategies to accommodate energization requests that trigger capacity upgrades.[11] These strategies include temporary constraints on load imports and IOU- and customer-owned DER. However, D.24-10-030 does not address how customers will be made aware of alternatives for generation service or other non-IOU bridging options. The Commission should, therefore, implement express reporting, notice, and other data-sharing requirements to ensure that customers of CCAs are aware of all options for generation service, as well as other IOU and CCA bridging solutions.

For example, CCAs have deployed or have plans to deploy DER Management Systems (DERMS) to dispatch customer-owned DERs.[12] These CCA DERMS can be configured to

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[11] Decision (D.) 24-10-030, *Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Maps*, R.21-06-017 (Oct. 23, 2024), Ordering Paragraph 18, at 197: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M544/K154/544154869.PDF.

[12] *See*, *e.g.*, *Richmond Advanced Energy Community Includes Virtual Power Plant and Zero Net Carbon Homes for Underserved Residents* (Jun. 21, 2022): https://mcecleanenergy.org/mce-unveils-plans-for-virtual-power-plant-to-benefit-disadvantaged-richmond-residents-and-businesses/.

receive real- and near-real-time dispatch signals from an IOU DERMS, providing operational flexibility during normal and abnormal operating conditions and supporting the deployment of FSCs throughout the grid. Customers should be allowed to participate in these and other CCA-offered programs as an alternative to IOU offerings. Since IOUs are generally the first point of contact for new loads, the Commission should implement express reporting, notice, and other data-sharing requirements to ensure delivery or FSC service is not tied to IOU generation service or other programs. The Commission should also ensure that the IOU FSC tariffs or agreements do not exclude the ability of CCAs to serve FSC customers or participate in bridging options.

V. CALCCA COMMENTS ON THE QUESTIONS ON DYNAMIC/NON-FIRM FLEXIBLE SERVICE CONNECTIONS

1. In response to the SIO Reports, parties generally supported prioritizing flexible grid connections, interconnection and grid services, operational flexibility with firm/non-firm capacity, and non-firm export/import limits in Track 3 of this rulemaking. Given these initial comments, where do parties believe implementation of changes will be most effective in ensuring that Distribution System Operators and DERs have the necessary flexible grid connections to enable the use cases outlined in the SIOWG report?

CalCCA has no response at this time.

2. How can flexible grid connections and associated tools contribute to meeting the needs of a decarbonized future with regards to addressing timely energization (medium and long term), including distribution system capacity shortfalls, equitable access to the grid, and cost containment?

As discussed in sections II., III., and IV. above, FSCs may provide an alternative to costly grid upgrades by providing DSOs with operational flexibility to optimize capacity on existing grids. Firm FSCs that allow for non-firm import capacity provided by DER owners/aggregators facilitate partial energization on constrained circuits until distribution upgrades can be completed, reducing energization delays. Similarly, DER owners/aggregators with dynamic/non-firm import/export limits and customers adding load on unconstrained circuits under firm FSCs help DSOs optimize capacity, potentially deferring or eliminating the need for grid upgrades altogether. This dual benefit should be leveraged as much as possible because it provides a feasible option to address energization timelines and access to the distribution grid, while putting downward pressure on distribution investment costs.

Additionally, CalCCA recommends that customers and DER owners/aggregators that provide operational flexibility on the distribution grid be compensated to allow these benefits to be fully realized. Finally, the Commission should ensure a level playing field with respect to the established FSC framework to ensure customers have access to CCA generation service and flexibility options, as they may also have DERMS platforms that can be configured to respond to signals from an IOU DERMS.

3. When considering the examination of static (i.e., firm) and dynamic (i.e., non-firm) flexible grid connections for imports and exports:

(a) What are the project type and specific examples that would benefit from the development of the more complex use cases identified in the High-DER Proceeding and SIO Report(s) record to date involving non-firm import and export limits? Explain if these project types are load only, generation only, or combined load and generation.

CalCCA has no response at this time.

(b) Based on your response to question 3(a), what import and export limiting technology will be needed?

CalCCA has no response at this time.

4. As the investor-owned utilities operationalize Advanced Distribution Management Systems and Distributed Energy Resource Management Systems (DERMS), which types and sizes of DERs should be able to communicate with the DERMS in each system development stage and for which SIOWG use case?

CalCCA has no response at this time.

5. Since the SIO Ruling was issued in May 2024, have any new developments occurred with technology, Commission proceedings, certifications or methods for addressing SIO reports, or use cases that should be reflected in the record of this proceeding?

CalCCA has no response at this time.

6. How should the Commission evaluate the cost-effectiveness and rate impact of SIOWG use cases and methods for operationalizing them?

CalCCA has no response at this time.

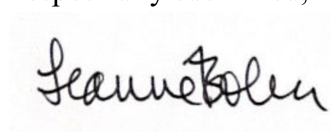
7. What, if any, additional information should the Commission consider in development of a proposal for addressing the issues in Track 3?

CalCCA has no response at this time.

VI. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the comments 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

March 13, 2025

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

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.23-10-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE ASSIGNED COMMISSIONER'S AMENDED SCOPING MEMO AND RULING

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March 17, 2025

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SUMMARY OF RECOMMENDATIONS

CalCCA recommends that the Commission:[1]

- Reject PG&E's, SDG&E's, and MRP's unfounded recommendations to defer or reject hourly load obligation trading;

- Continue to develop and vet the LOLE modeling and use this updated modeling to confirm or update the 2027 PRM given party comments significantly diverge on the exact level at which to set the PRM;

- Adopt a system RA waiver because it is clear that RA price mitigation is necessary and a system RA waiver best meets affordability and reliability objectives;

- Commit to collaborating with the CAISO to address open issues associated with allowing EO co-located resources to provide RA value;

- Adopt PG&E's recommendation to publish test UCAP values in 2027 to allow LSEs to assess their existing portfolios;

- Reject SCE's proposal to reverse the local RA CPE timeline change because, as explained by Shell and Microsoft, it is premature and unsupported by new facts or evidence;

- If the Commission adopts SCE's proposal to clarify the local RA CPE procurement obligations resulting from the data request, as supported by Calpine, retain the ability for LSEs to sell to the CPE;

- Consider how best to account for LDES and PSH charging sufficiency needs in a future RA proceeding; and

- Adopt Leap's proposed change to the hours DR resources can obtain QC values and consider broader reforms to enable greater DR participation in a future proceeding.

[1] Acronyms used in the Summary of Recommendations are defined in the body of this document, *California Community Choice Association's Reply Comments on Assigned Commissioner's Amended Scoping Memo and Ruling*, dated March 17, 2025.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.23-10-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE ASSIGNED COMMISSIONER'S AMENDED SCOPING MEMO AND RULING

California Community Choice Association (CalCCA) submits these reply comments pursuant to the *Assigned Commissioner's Amended Scoping Memo and Ruling*[2] (Ruling), dated November 1, 2024. The Ruling amends the previous Scoping Memo[3] issued in this proceeding on December 18, 2023, to designate issues as Track 3 and to set a schedule for Track 3. Except as expressly set forth in the Ruling, the terms of the previously issued Scoping Memo remain unchanged. CalCCA also responds to the *Administrative Law Judge's Ruling on Energy Division's Hour Offset Workshop Slides and Load Migration Update*[4] (February 25 Ruling), dated February 25, 2025, which provides updated Energy Division Track 3 proposal analyses and allows parties to incorporate comments on the analyses in reply comments.

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2 *Assigned Commissioner's Amended Scoping Memo and Ruling*, Rulemaking (R.) 23-10-011 (Nov. 1, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M544/K652/544652400.PDF.

3 *Assigned Commissioner's Scoping Memo and Ruling*, R.23-10-011 (Dec. 18, 2023) (Scoping Memo): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M521/K589/521589385.PDF.

4 *Administrative Law Judge's Ruling on Energy Division's Hour Offset Workshop Slides and Load Migration Update*, R.23-10-011 (Feb. 25, 2025): https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=557607541.

I. INTRODUCTION

In these reply comments, CalCCA addresses seven themes within parties' Opening Comments.[5] *__First__*, many parties' Opening Comments support CalCCA's hourly load obligation trading proposal.[6] The few parties who do not support hourly load obligation trading either: (1) express concerns that CalCCA has already addressed in its Proposal[7] or Opening Comments; or (2) present red herrings that distract from the demonstrated benefits of hourly load obligation trading.[8] The California Public Utilities Commission (Commission) should adopt hourly load obligation trading to promote Resource Adequacy (RA) affordability and enhance transactability of the slice-of-day (SOD) program.

__Second__, parties' Opening Comments diverge on the right level of planning reserve margin (PRM) needed to meet reliability targets and which price mitigation proposal to adopt, if any. The divergence in recommendations on the appropriate level of the PRM and the RA price data provided in Energy Division's Proposal: (1) necessitates continued development and vetting of Energy Division's loss of load expectation (LOLE) modeling; and (2) demonstrates the importance of price mitigation measures. The Commission should commit to further developing and vetting LOLE modeling and revising, if necessary, the PRM for 2027. The Commission

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5 References to parties' Opening Comments herein refer to Opening Comments filed in this proceeding (R.23-10-011), on or about March 3, 2025.

6 *See* American Clean Power – California (ACP-CA) Opening Comments, at 15; Alliance for Retail Energy Markets (AReM) Opening Comments, at 3; the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) Opening Comments, at 10-11; the Clean Energy Buyers Association (CEBA) Opening Comments, at 7; the Center for Energy Efficiency and Renewable Technologies (CEERT) Opening Comments, at 3; the California Environmental Justice Alliance (CEJA) Opening Comments, at 11-12; Hydrostor, Inc. (Hydrostor) Opening Comments, at 9; Microsoft Corporation (Microsoft) Opening Comments, at 12-13; and Shell Energy North America (US), L.P. (Shell) Opening Comments, at 4-5.

7 References to parties' Proposals herein refer to Proposals filed in this proceeding (R.23-10-011), on or about January 17, 2025.

8 *See* Middle River Power LLC (MRP) Opening Comments, at 21-22; Pacific Gas and Electric Company (PG&E) Opening Comments, at 10-11; and San Diego Gas and Electric Company (SDG&E) Opening Comments, at 16-17.

should also adopt a system RA waiver process because tight supply margins are expected to persist into 2026, the effective PRM has not worked well thus far, and the system RA waiver process will provide better price protection to all load-serving entities (LSE) while maintaining LSE incentives to continue commercially reasonable efforts to procure.

Third, parties generally support providing additional opportunities for co-located resources to provide reliability value,[9] and raise open issues that the Commission and the California Independent System Operator (CAISO) should resolve to enable energy-only (EO) resources to provide RA.[10] The Commission should commit to coordinating with the CAISO to resolve these open issues to unlock additional RA capacity as soon as possible.

Fourth, parties directionally support the Commission's further development of an unforced capacity (UCAP) counting methodology for resources that do not already receive a qualifying capacity (QC) value based on historical performance or probabilistic modeling.[11] PG&E recommends providing test UCAP values in 2027 to prepare for 2028 implementation.[12] The Commission should adopt PG&E's recommendation as a way for LSEs to assess how UCAP will impact their existing portfolios and future procurement needs.

Fifth, Microsoft and Shell correctly detail how SCE's proposal to reverse the local RA central procurement entity (CPE) timeline change is premature and provides no new facts to justify the reversal.[13] The Commission should, therefore, reject SCE's proposal. In addition, if

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9 *See* ACP-CA Opening Comments, at 11-12; CEJA Opening Comments, at 9; and Southern California Edison Company (SCE) Opening Comments, at 14.

10 *See* CAISO Opening Comments, at 11; PG&E Opening Comments, at 10; and Terra-Gen, LLC (Terra-Gen) Opening Comments, at 14-15.

11 *See* AReM Opening Comments, at 5; CAISO Opening Comments, at 8-10; Calpine Opening Comments, at 2-3; CEERT Opening Comments, at 2-3; PG&E Opening Comments, at 13-14; and SCE Opening Comments, at 14-15.

12 *See* PG&E Opening Comments, at 13-14.

13 *See* Microsoft Opening Comments, at 13-14; and Shell Opening Comments, at 5-6.

the Commission adopts Calpine's recommendation to adopt SCE's proposed clarification of the purpose of the local RA CPE data request by netting LSE-contracted local capacity from the CPE requirement, then the Commission must adopt a process that retains LSEs' ability to sell to the CPE.

Sixth, parties make a variety of recommendations on how to account for charging sufficiency needs of long-duration energy storage (LDES), including pumped storage hydro (PSH) and other LDES resources.[14] The Commission should consider how best to account for LDES and PSH charging sufficiency needs in a future RA proceeding.

Seventh, Leap provides additional context, including a broader set of reforms, to enable greater demand response (DR) participation in RA.[15] This context intends to support its proposal to allow DR resources to receive QC values outside the availability assessment hours (AAH). The Commission should adopt Leap's proposal to provide DR QC values outside the AAH and consider broader reforms in a future RA proceeding.

In response to party Opening Comments, CalCCA therefore recommends that the Commission:

- Reject PG&E, SDG&E's, and MRP's unfounded recommendations to defer or reject hourly load obligation trading;
- Continue to develop and vet the LOLE modeling and use this updated modeling to confirm or update the 2027 PRM given party comments significantly diverge on the exact level at which to set the PRM;
- Adopt a system RA waiver because it is clear that RA price mitigation is necessary and a system RA waiver best meets affordability and reliability objectives;

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[14] ACP-CA Opening Comments, at 12-15; Cal Advocates Opening Comments, at 15-17; Calpine Corporation (Calpine) Opening Comments, at 6-7; CEERT Opening Comments, at 3; CEJA Opening Comments, at 9-10; Hydrostor Opening Comments, at 4-8; PG&E Opening Comments, at 5-8; SCE Opening Comments, at 11-13; SDG&E Opening Comments at 12-14; and Terra-Gen Opening Comments at 7-8.

[15] *See* Leapfrog Power, Inc. (Leap) Opening Comments.

- Commit to collaborating with the CAISO to address open issues associated with allowing EO co-located resources to provide RA value;
- Adopt PG&E's recommendation to publish test UCAP values in 2027 to allow LSEs to assess their existing portfolios;
- Reject SCE's proposal to reverse the local RA CPE timeline change because, as explained by Shell and Microsoft, it is premature and unsupported by new facts or evidence;
- If the Commission adopts SCE's proposal to clarify the local RA CPE procurement obligations resulting from the data request, as supported by Calpine, retain the ability for LSEs to sell to the CPE;
- Consider how best to account for LDES and PSH charging sufficiency needs in a future RA proceeding; and
- Adopt Leap's proposed change to the hours DR resources can obtain QC values and consider broader reforms to enable greater DR participation in a future proceeding.

II. PG&E'S, SDG&E'S, AND MRP'S UNFOUNDED RECOMMENDATIONS TO DEFER OR REJECT THE ADOPTION OF HOURLY LOAD OBLIGATION TRADING MUST BE REJECTED

The Commission should dismiss recommendations by PG&E, SDG&E, and MRP to reject or defer the adoption of CalCCA's proposal to allow LSEs to transact load obligations hourly, which was supported by multiple parties for its ability to increase the affordability and transactability of the SOD RA program.[16] As discussed below, both PG&E and SDG&E raise issues in which the answers are largely self-evident. MRP proposes an overly restrictive limit aimed at ensuring LSEs procure more 24 by seven resources even if the grid as a whole is already reliable. For the following reasons, the Commission should reject PG&E's, SDG&E's, and MRP's unfounded recommendations to defer or reject CalCCA's load obligation trading proposal.[17]

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16 *See* ACP-CA Opening Comments, at 15; AReM Opening Comments, at 3; Cal Advocates Opening Comments, at 10-11; CEBA Opening Comments, at 7; CEERT Opening Comments, at 3; CEJA Opening Comments, at 11-12; Hydrostor Opening Comments, at 9; Microsoft Opening Comments, at 12-13; and Shell Opening Comments, at 4-5.

17 *See* CalCCA Proposal, at 3-18; *see also Workshop on Track 3 Proposals in R.23-10-011* (Feb. 12, 2025) (February 12 Workshop Presentation), at 92-102: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/r23-10-011/ra-track-3-workshop-feb-12.pdf.

A. The Commission Should Reject PG&E's Assertions that CalCCA's Hourly Load Obligation Trading Proposal Has "Shortcomings" and Has an Unidentified Need

PG&E states, "[f]irst, it's unclear to PG&E how penalties work in CalCCA's proposal."[18] PG&E later states, "[t]hird, CalCCA hasn't effectively addressed how expansion restrictions would or would not apply in the case of a compliance failure."[19] Load obligation trading is simply another product that can be used to meet compliance obligations. It has no impact on the current penalty mechanism. If an entity uses a load obligation trade and is compliant, the entity will not receive a penalty, will not accumulate any points, and will not be prohibited from expansion. If the entity participated in load obligation trades and the combination of those trades and resource procurement did not meet their obligation, then they would be penalized as they are today (including financial penalties, points accumulation, and expansion prohibitions) based upon the hour with the largest deficiency.[20] It is not clear why PG&E believes that the proposal is incomplete without this description since CalCCA's proposal never intended to change the penalty framework.

Next, PG&E states, "[s]econd, PG&E is concerned with how penalties would interact with tiers. For example, an LSE in a higher penalty tier could theoretically trade its obligation to an LSE in a lower penalty tier so that each LSE is better off but undermines the penalty system."[21] If PG&E has a concern that an entity will participate in a load obligation trade that makes itself short to spare the compliance of a different entity, then PG&E should explain why it does not have the same concern with resource trading. After all, an entity could sell a resource,

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18 PG&E Opening Comments, at 10.

19 *Id.,* at 11.

20 D.23-04-010, *Decision on Phase 2 of the Resource Adequacy Reform Track*, R.21-10-002 (Apr. 7, 2023), at A-8: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M505/K753/505753716.PDF.

21 PG&E Opening Comments, at 11.

making itself short to help another LSE meet its compliance obligation. There have not been any accusations of this behavior occurring today, and there should be no anticipation that just because load obligation trading is implemented, it will become a problem. Since the very outcome that PG&E is theorizing can already be accomplished, its argument is baseless.

PG&E concludes:

> Finally, while CalCCA performed analysis demonstrating that efficiencies could be gained from adopting load trading, the analysis was performed on confidential data that isn't available to parties to review. Therefore, it's unclear if the efficiencies couldn't be gained through standard supply-side trades or through other changes such as a facilitation of combined compliance showings.[22]

As CalCCA stated during the February 12, 2025, workshop, the analysis of the ability for long positions held by CCAs to completely address the short positions held by CCAs was performed with confidential data because the Commission had yet to release its own data on this topic. At the same workshop, Energy Division presented similar data that demonstrates the same effect for all Commission-jurisdictional LSEs.[23]

CalCCA and the Commission's analyses demonstrate the efficiencies of load obligation trading. The data demonstrates that supply-side transactions were insufficient to address the shortfall, even when the obligation was binding in the 2025 year-ahead RA (YARA) showing. Additional tools to increase transactability are needed to meet individual LSE obligations since the aggregation of showings meets overall system reliability even though some LSEs had hours of deficiencies.

In addition, PG&E's remark that "it's unclear if the efficiencies couldn't be gained through . . . other changes such as a facilitation of combined compliance showings"[24] is also

22 *Ibid.*
23 *See* February 12 Workshop Presentation, at 71-75.
24 PG&E Opening Comments, at 11.

perplexing as it fails to provide any detail or proposal on the functioning of "a facilitation of combined compliance showings" for the Commission and parties to consider such a recommendation. Currently, no processes exist to allow multiple LSEs to submit a single showing. If there were, and LSEs combined short and long positions across hours to produce a compliant outcome, this would appear to act very much like a load obligation trade. Therefore, it may be that PG&E's encouragement to examine a combined compliance showing supports the CalCCA load obligation trading proposal.

B. The Commission Must Dismiss SDG&E's Unsupported Claims Regarding Hourly Load Obligation Trading

SDG&E opens their comments with a general statement that load obligation trading should not be allowed as it would "encourage leaning and inequitable outcomes" that would further challenge affordability.[25] To the contrary, CalCCA proposed load obligation trading as a method for LSEs to procure their obligations through one additional mechanism <u>*to avoid*</u> leaning and inequitable outcomes. Creating more mechanisms for compliance will actually promote affordability.

Leaning would occur if the Commission evaluated system RA showings in aggregate, and if the aggregated showings met the needs, did not evaluate any individual showings to see if individual LSEs were deficient. Load obligation trading enables an entity that is long on RA in a given hour to buy (at a negative price) a load obligation from another LSE. In doing so, the buyer can monetize their RA portfolio and reduce its customer cost. The load obligation selling entity will pay their share of the RA for the hour(s) that it sold. There simply is no leaning in this case. Presumably, if entities engage in load obligation trading, that is because it is a better option than procuring a full resource where that full resource is not necessary to meet reliability needs. This

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25 SDG&E Opening Comments, at 3.

means that in that case paying another LSE is more affordable for the load-selling entity and more desirable than selling an entire resource for the load-purchasing entity.

SDG&E further opposes load obligation trading without providing enough detail to completely understand, much less rebut, their assertions. SDG&E states:

> CalCCA's hourly load obligation trading proposal lacks critical detail. But what is clear is that the proposal involves an unduly complex, derivative-based mechanism that would result in further divergence from the CAISO RA program, decrease overall reliability, and potentially create detrimental perverse incentives for market participants. CalCCA's assertion that hourly load obligation trading will enable LSEs to "fully optimize RA resources and reduce costs for all LSEs" is offered with no evidentiary support. Similarly, the claim by CalCCA that its proposal would "promote affordability without compromising reliability" is unsubstantiated. Indeed, significant concerns exist regarding the feasibility of implementation and the potentially negative impact of the proposal on grid stability.[26]

SDG&E's claims are baseless, as CalCCA spent a great deal of time during the workshop and in writing explaining how load obligation trading can work. This includes an example of how the Commission could easily check compliance. Yet SDG&E offers nothing more in comments than that it is "unduly complex."

It is further unclear why SDG&E refers to load obligation trading as a derivative-based mechanism. A derivative is a financial contract based on the underlying value of the asset. Load obligation trading is a physical contract for one party to assume an RA obligation from another. While the price of that contract could formulate around the cost of an RA resource to meet an obligation, this does not make the transaction derivative-based. The cost of many transactions in the market are based upon the price of an alternative (*e.g.,* hydro generation use at a given point

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26 *Id.,* at 16.

is typically priced at the cost of the anticipated most expensive hours of the year (referred to as "opportunity cost") and yet the energy price from hydro is not referred to as a derivative).

SDG&E's claims that this mechanism would further diverge from the CAISO RA program, reduce reliability, and result in perverse outcomes are also unsubstantiated. The CAISO process would remain unchanged as a result of load obligation trading, as CalCCA has already discussed.[27] The CAISO would not need to know about the trade. This could result in backstop costs being allocated to an entity that sold its load obligation because the CAISO did not recognize that transaction. In addition, the parties to a load obligation trade could address this potential cost within their contract or simply assume the risk to address Commission compliance. CalCCA has demonstrated, and the Commission has produced evidence, that the 2025 YARA showings, in aggregate, produce a reliable outcome. Commission-provided evidence also suggests that despite a reliable outcome, some LSEs can expect to receive a penalty. CalCCA's presentation at the February 12, 2025, workshop also demonstrates the potential for significant cost savings resulting from hourly load obligation trading.[28] Contrary to SDG&E's claim, load obligation trading allows for more effective transactions that are expected to be less expensive while providing the incentives for reliability.

SDG&E falsely asserts that CalCCA's proposal does not provide evidence that it can "fully optimize RA resources and reduce costs for all LSEs."[29] In its proposal and workshop presentation, CalCCA provided an analysis of the improved ability of parties to meet obligations strictly from the resources that were already shown in the 2025 YARA,[30] which was further

27 CalCCA Proposal, at 5.
28 *See* February 12 Workshop Presentation, at 96.
29 *See* SDG&E Opening Comments, at 16.
30 *See* CalCCA Proposal, at 8-11, and February 12 Workshop Presentation, at 95-96.

substantiated by a similar presentation from Energy Division.[31] SDG&E's ignoring the information already provided does not make CalCCA's claims unsubstantiated. As discussed in response to PG&E, CalCCA has demonstrated that load obligation trading is not detrimental to reliability. CalCCA has also demonstrated that load obligation trading presents no perverse incentives, since those that have been raised can already be executed with currently available mechanisms, and no accusations of pursuing those incentives have been raised.

SDG&E also requests workshops on load obligation trading despite the multiple workshops already conducted:

> CalCCA's hourly load obligation trading proposal, as presently formulated, is deficient in several critical respects. Its lack of specificity, and failure to adequately address key concerns related to market power, liquidity, pricing safeguards, penalty structures, and interagency coordination make it infeasible to implement. Accordingly, the Commission should reject CalCCA's proposal. If the Commission is inclined to consider proposals for hourly-transactable RA products, it should direct that all such proposals be comprehensively vetted through a workshop process and/or a dedicated track of this proceeding that enables stakeholders to collaboratively develop a more robust framework that prioritizes grid reliability and equitable outcomes for all market participants.[32]

The Commission has conducted multiple workshops on hourly load obligation trading, and a considerable amount of time was dedicated to the topic in each workshop. CalCCA first presented its hourly load obligation trading proposal in 2024,[33] and again in 2025.[34] In CalCCA's proposal and its presentation at the February 12, 2025, workshop, CalCCA built upon the information gathered in the 2024 workshop to provide other details where parties expressed

31 *See* February 12 Workshop Presentation, at 71-75.
32 SDG&E Opening Comments, at 17.
33 *Workshop on Track 1 Proposals in R.23-10-011* (Feb. 14, 2024), at 135-142: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/ra-oir-track-1-workshop----all-slides.pdf.
34 *See* February 12 Workshop Presentation, at 92-102.

specific concerns (*e.g.,* demonstrating specifically how a showing would occur and how the Commission could evaluate compliance). CalCCA's opening comments have also provided a maximum limit to load transactions in response to party concerns.[35] It is disingenuous for SDG&E to now ask to extend this discussion further due to unspecified concerns of market power, liquidity, pricing safeguards, penalty structure, and interagency coordination for implementation. Many of these issues CalCCA has addressed and SDG&E does not describe how the responses are insufficient. Other items are so undefined that it is unclear what the concern is and what, if anything, would need to be done to address it.

SDG&E also cautions that load obligation trading could create an imbalance in the geographic dispersion of RA resources stating, "[p]ermitting LSEs to contract for load obligations outside their designated service areas could exacerbate existing transmission bottlenecks or create new ones, potentially leading to adverse grid operational consequences."[36] While again, SDG&E's comment is not entirely clear, this issue appears to be a reference to a prior discussion regarding Path 26. In 2019, Energy Division staff proposed removing the Path 26 constraint from the RA program as it was unlikely that the Path 26 constraint would be violated.[37] It is worth noting that the analysis performed by Energy Division staff in 2019 focused on the location of ***resources***. It is the location of the resources, and the proportion of which are procured, that could, under extreme circumstances, cause a violation of Path 26. It is hard to understand how load obligation trading, which would still require that procurement of a sufficient amount of resources for system needs, would exacerbate this

35 *See* CalCCA Opening Comments, at 10-11.

36 SDG&E Opening Comments, at 17.

37 *See* Energy Division, *Path 26 Constraint Presentation*: https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy/energy_programs/electric_power_procurement_and_generation/procurement_and_ra/ra/cpuc-path-26.pdf.

constraint. Based on the Energy Division proposal, the Commission in D.19-06-026 removed the Path 26 constraint from the RA program stating:

> In consideration of the support for SCE and Energy Division's proposal, the Commission adopts the proposal to eliminate the Path 26 constraint effective upon the date of this decision. The Commission directs Energy Division to continue reviewing the potential for procurement activity that may violate Path 26 constraints.[38]

Since D.19-06-026, CalCCA is not aware of any issuance by the Energy Division demonstrating that procurement activity has violated Path 26 constraints. In addition, the CAISO has not performed any backstop procurement to address RA procurement that violated the Path 26 constraint. SDG&E has therefore provided no reason to believe that a different set of system RA resources will be procured if load obligation trading is allowed, let alone if that change in procurement would violate the Path 26 constraint.

SDG&E also believes that it is premature to introduce a mechanism to comply with an RA program that has already been dramatically altered, stating that:

> [i]ntroducing a new market for an untested product now, while the Commission is still in the process of implementing a fundamentally revised RA compliance framework, would be imprudent. Adding new products to the Commission's RA program at this time risks systemic disruption and unintended negative consequences for all market participants."[39]

Contrary to SDG&E's contention, the issue is not the introduction of new mechanisms to comply. Rather the problem is the lack of existing mechanisms enabling compliance. That is, prior to SOD, RA was a ***monthly*** requirement with a ***monthly*** product to meet compliance needs. SOD moved the requirements to ***hourly*** but continued with a ***monthly*** product. This disconnect has resulted in the

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[38] D.19-06-026, *Decision Adopting Local Capacity Obligations for 2020-2022, Adopting Flexible Capacity Obligations for 2020, and Refining the Resource Adequacy Program*, R.17-09-020 (July 5, 2019) at 52: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M309/K463/309463502.PDF.

[39] SDG&E Opening Comments, at 17.

system as a whole being compliant while individual LSEs suffer some hours of non-compliance, as matching the product to the need is exceedingly difficult. Finally, SDG&E is not clear on what "systematic disruption and unintended negative consequences" need to be addressed before adopting the proposal. CalCCA provided ample information, including a proposal, the structure, the evaluation of compliance, and data on the need for load obligation transactions.

The burden to refute CalCCA's well-formulated and supported proposal must be more than the blanket statements by PG&E and SDG&E. For these reasons, the Commission should reject PG&E and SDG&E's recommendations for the Commission to not adopt hourly load obligation trading.

C. The Commission Should Reject MRP's Proposed Limitation on Hourly Load Obligation Trading, in Favor of CalCCA's Proposed Limit

MRP contends that the Commission should place severe restrictions on the ability to participate in load obligation trades, stating:

> If the Commission elects to adopt hourly load obligation trading, MRP recommends the Commission adopt also [sic] appropriate guardrails. Specifically, the Commission should allow LSEs to trade only three individual hours of their RA obligations for each compliance month. Because RA resources must be available for a minimum of four-hour duration, if an LSE is deficient in four or more hours, then the LSE should be procuring additional physical RA resources to cover that short position rather than selling the load that it's unable to serve to another LSE.[40]

MRP's association to the minimum duration of a resource to qualify for RA is misguided. First, under SOD, it is questionable whether such a mechanism should still exist. If a one-hour battery can address a deficiency in RA need and the resource has a must-offer obligation (MOO) from the CAISO for the entire day, it could indeed meet the reliability need. Second, most resources (storage being the exception) have a contiguous output. That is, solar will generate in

[40] MRP Opening Comments, at 22.

consecutive hours when the sun is shining, wind will generate in consecutive hours while the wind is blowing, and any 24 by seven resource is capable of generating in all hours consecutively. Load obligations, due to the nature of the resources procured and the shape of load, may not have a contiguous need or may have a need that exceeds four hours. These needs may also come during hours in which procuring a duration-limited resource will not provide the necessary capacity because the resource is not capable of generating during the hours in which the LSE is short. In short, MRP's recommendation is to ensure that LSEs procure more 24 by seven resources even if the grid as a whole is already reliable. In its opening comments, CalCCA provided a better alternative to limiting hourly load obligation trades that is not tied to the minimum duration of resources.[41] The Commission should therefore reject this modification to CalCCA's proposal as being a costly change that does not improve reliability. For all of these reasons, the Commission should adopt CalCCA's hourly load obligation trading proposal.

III. PARTIES DISAGREE ON THE LEVEL OF PRM NEEDED TO ACHIEVE 0.1 LOLE, INDICATING THE COMMISSION MUST CONTINUE TO DEVELOP AND VET THE LOLE MODELING AND USE THIS UPDATED MODELING TO CONFIRM OR UPDATE THE 2027 PRM

The Commission should commit to continuing to develop and vet Energy Division's LOLE modeling and to using this updated modeling to either confirm or update the PRM for 2027. Throughout this proceeding, the level at which to set the PRM to meet a 0.1 LOLE standard has been extremely uncertain and controversial among parties. Energy Division has put forth multiple iterations of LOLE analysis and recommended 2026 PRMs. In Track 2 of this proceeding, the Commission ultimately decided that further revision of the 2026 PRM analysis was necessary to correct errors and address issues raised by parties.[42] Uncertainty has continued

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41 *See* CalCCA Opening Comments, at 10-11.
42 D.24-12-003.

in Track 3, as demonstrated by the broad range of recommended PRMs in parties' Opening Comments. For example, SCE includes modeling that indicates a PRM of 15.5 percent would meet a 0.1 LOLE target, due to modified import and load forecast error assumptions,[43] while the Western Power Trading Forum (WPTF) recommends a PRM of 22.5 percent for May through October and 21 percent for all other months.[44]

There has been insufficient time to fully discuss and vet the PRM given the broad range of analyses and recommendations from parties. Given this, although Energy Division's proposal states Energy Division staff will conduct another LOLE study for RA compliance year 2028,[45] the Commission should commit to immediately continuing to develop and vet LOLE analysis and use this updated model to either: (1) confirm the PRM adopted in the Commission's forthcoming Track 3 decision; or (2) update the PRM for 2027 if Energy Division and parties conclude an update would increase the accuracy of the PRM.

IV. THE COMMISSION SHOULD ADOPT A SYSTEM RA WAIVER, AS PARTY OPENING COMMENTS REFLECT CONTINUED UNCERTAINTY AROUND THE PRM, ENERGY DIVISION AND CAL ADVOCATES' STACK ANALYSES DEMONSTRATE CONTINUED MARKET TIGHTNESS, AND A WAIVER BEST MEETS AFFORDABILITY AND RELIABILITY OBJECTIVES

The Commission should adopt a system RA waiver process given: (1) parties' opening comments demonstrate significant uncertainty remains around the PRM necessary to meet a 0.1 LOLE target; (2) Energy Division[46] and Cal Advocates[47] have demonstrated the tight supply margin expected to persist into 2026, potentially resulting in continued high RA prices; and (3)

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43 *See* SCE Opening Comments, at 2.
44 *See* WPTF Opening Comments, at 4.
45 *See* Energy Division Staff Proposal, at 16.
46 *See* February 12 Workshop Presentation, at 56: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/r23-10-011/ra-track-3-workshop-feb-12.pdf.
47 *See* Cal Advocates Opening Comments, at 4.

the ability for a system RA waiver to provide better price protection to all LSEs while maintaining LSEs' incentives to continue commercially reasonable efforts to procure. Specifically, the Commission should: (1) adopt a PRM no higher than Energy Division's revised PRM proposal of 21 percent in summer months and 20 percent in non-summer months;[48] and (2) allow LSEs to request a waiver for RA obligations above 15.5 percent, the level SCE found supports a 0.1 LOLE.[49] The Commission should consider this alternative as it would provide reliability and address market power concerns while recognizing the uncertainty around the level of PRM needed to meet a 0.1 LOLE target.

A. The Commission Should Set the PRM No Higher than 21 Percent in Summer Months and 20 Percent in Non-Summer Months and Consider a Combination of SCE's PRM Proposal Along with a Waiver Process

The Commission should adopt a system RA waiver, especially given the significant uncertainty that remains regarding the PRM necessary to meet a 0.1 LOLE target, as described in Section III. CalCCA agrees with PG&E that given Energy Division's revised recommendation following the identification of the electrical demand hour offset error,[50] "[i]t would be potentially imprudent to set the PRM in the summer months at 22.5 [percent], even considering adoption of one of the mitigating proposals offered by Energy Division, and would likely increase costs without meaningfully enhancing reliability."[51] Therefore, the Commission should adopt a PRM no higher than Energy Division's revised PRM proposal of 21 percent in summer months and 20 percent in non-summer months. While this change is clearly prudent to resolve the electrical demand hour offset error, significant uncertainty remains about the level of PRM necessary to meet a 0.1 LOLE target.

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48 February 25 Ruling, Attachment 2.
49 SCE Opening Comments, at 2.
50 February 25 Ruling, Attachment 2.
51 PG&E Opening Comments, at 4.

In addition, Cal Advocates created its own 2026 stack analysis with more conservative assumptions and found the supply stack insufficient to meet a 21 percent PRM.[52] Cal Advocates also states that suppliers may be able to exert market power even below the 17 percent PRM.[53] This, and the continued uncertainty around the correct PRM, makes it even more critical for the Commission to ensure the RA program includes a price mitigation mechanism to ensure LSEs are not subjected to excessively high RA costs to meet a PRM that potentially exceeds the 0.1 LOLE target.

For these reasons, the Commission should adopt a system RA waiver process combined with SCE's proposal on the PRM advanced in its opening comments. SCE performed its own LOLE study and concluded that a PRM of 15.5 percent met the 1-in-10 reliability need.[54] Despite this lower need for RA, SCE supports a PRM of 17 percent for all LSEs with no opportunity for waiver and no effective PRM. Considering that SCE found a reliable grid at 15.5 percent and Cal Advocates found the potential for market power below 17 percent, a reasonable compromise would be to adopt the Energy Division staff proposal for a waiver with a modification to offer a waiver for any quantity above 15.5 percent. Doing so would mitigate the potential for market power, as noted by Cal Advocates, but also set a minimum quantity without waiver sufficient to meet the LOLE study performed by SCE.

In summary, the Commission should: (1) adopt a PRM no higher than Energy Division's revised PRM proposal of 21 percent in summer months and 20 percent in non-summer months; and (2) allow LSEs to request a waiver for RA obligations above 15.5 percent. The Commission

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52 *See* Cal Advocates Opening Comments, at 4.
53 *Id.*, at 7.
54 SCE Opening Comments, at 6-7.

should consider this alternative as it would provide reliability and address market power concerns while recognizing the uncertainty around the level of PRM needed to meet a 0.1 LOLE target.

B. The Commission Should Reject ACP-CA's, the CAISO's, and Calpine's Assertions that RA Price Mitigation Mechanisms are Unnecessary, Given Tight Supply Margins and Historically High RA Prices

The Commission should adopt RA price mitigation mechanisms given continued tight supply margins expected for 2026 and historically high RA prices impacting RA affordability in recent years. ACP-CA, the CAISO, and Calpine suggest that Energy Division's price mitigation proposals are unnecessary because of new additions to the supply stack.[55] However, the Commission's stack analysis *does not* clearly demonstrate resolution to recent capacity tightness. Energy Division's stack analysis demonstrates a very small supply margin in September 2026[56] that is likely insufficient on its own to promote RA affordability. In addition, the amount of surplus is uncertain. Cal Advocates created its own 2026 stack analysis with more conservative assumptions and found the supply stack insufficient to meet a 22.5 percent PRM, as well as a 21 percent PRM. [57] In addition, Cal Advocates states that suppliers may be able to exert market power even below the 17 percent PRM.[58] The RA program, therefore, continues to be ripe for the potential exertion of market power.

The CAISO also erroneously views a waiver as contrary to California Public Utilities Code section 380.[59] Section 380 states that the Commission "shall determine and authorize *the*

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55 *See* ACP-CA Opening Comments, at 10; CAISO Opening Comments, at 4; and Calpine Opening Comments, at 4-6.

56 *See* February 12 Workshop Presentation, at 56: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/r23-10-011/ra-track-3-workshop-feb-12.pdf.

57 *See* Cal Advocates Opening Comments, at 4.

58 Cal Advocates Opening Comments, at 7.

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

most efficient and equitable means for achieving"[60] seven different objectives, including "minimizing the need for backstop procurement by the Independent System Operator."[61] This *does not* imply the Commission should minimize the need for backstop procurement *at any cost*. In fact, at the inception of the local RA program, the Commission found a local RA waiver "is necessary as a market power mitigation measure"[62] and adopted it because of concerns over the ability of suppliers to exercise market power at the expense of ratepayers. The Commission states with respect to the local RA waiver's interaction with the CAISO backstop:

> ... we are not proposing to eliminate reliance upon CAISO backstop procurement altogether. We are instead attempting to foster LSE procurement in a way that reduces procurement by the CAISO as much as possible. As the Staff Report observes, our continued, though presumably minimal, reliance on backstop procurement will have the effect of capping how much income generators may expect to receive if they do not execute [RA requirements] contracts. The waiver trigger that we adopt in the following section is the means by which this market power mitigation is accomplished.[63]

The local RA process has effectively incorporated a waiver process to mitigate potential market power in local areas while minimizing reliance on the CAISO backstop by establishing criteria for demonstrating commercially reasonable efforts LSEs must meet before being granted a waiver. Energy Division's proposed system RA waiver includes similar criteria that would minimize the need for CAISO backstop to only instances where LSEs could not procure RA despite commercially reasonable efforts. Energy Division has provided data showing RA prices are unprecedently high, and party recommendations to forego solutions that could mitigate against these high prices would exacerbate the State's energy affordability challenges.[64]

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60 Cal. Pub. Util. Code § 380(h) (emphasis added).

61 *Ibid.*

62 D.06-06-046, *Opinion on Local Resource Adequacy Requirements*, R-05-12-013 (June 30, 2006), at 71: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/57644.PDF.

63 *Id.*, at 70.

64 Ruling, Attachment A, at 11-12.

For these reasons, the Commissions should reject party recommendations to forego price mitigation proposals. As described below, a system waiver process would best mitigate against market power in the RA program and should be adopted.

C. A System RA Waiver is the Superior RA Price Mitigation Proposal, and the Commission Should Reject Party Recommendations for an Effective PRM Over a Waiver

The Commission should adopt a system RA waiver process rather than an effective PRM. CalCCA disagrees with AReM that the effective PRM has "worked sufficiently" thus far.[65] The effective PRM is not binding, meaning it essentially provides *only the investor-owned utilities (IOUs)* with a waiver for procurement above 17 percent. While the IOUs would effectively have a waiver, other LSEs would not, even though the IOUs and other LSEs would be competing for the same RA capacity at the same time. The IOUs' effective PRM procurement practices are not transparent. Therefore, although the effective PRM comes with a requirement for the IOUs to first attempt to sell excess from their own portfolio to LSEs before using it for the effective PRM, it is not clear how the IOUs attempt to sell excess. It is also not clear when the IOUs enter into contracts for effective PRM resources relative to when other LSEs are negotiating for their own PRM requirements. If the IOUs procure above 17 percent and LSEs are deficient in meeting their own PRM, costs are incurred for the effective PRM procurement *and* the penalties associated with LSE deficiencies while overall not having procured RA above the minimum threshold.

Additionally, as noted by the CAISO, the CAISO cannot use its Capacity Procurement Mechanism (CPM) mechanism to backstop for shortfalls in IOU effective PRM procurement.[66] Alternatively, setting the PRM with a waiver in place allows for CAISO backstop when

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[65] AReM Opening Comments, at 3.
[66] CAISO Opening Comments, at 6.

necessary if LSE procurement does not meet the PRM. This process has been effectively used in the context of local RA, in which waivers exist as a price mitigation tool.

ACP-CA, CAISO, and Calpine express concerns about Energy Division's proposed price threshold for a waiver relative to the cost of new resources or recently observed RA prices.[67] These parties ignore that the current RA program has no price protection for RA products and significant financial and non-financial penalties for non-compliance. This means that without price protection, LSEs can be forced to pay any price to comply with their RA obligations. CAISO's backstop, on the other hand, does have price protection for capacity products via its CPM soft offer cap. The soft offer cap is rightly based on the going forward fixed costs of the assumed marginal resource for the purpose of mitigating against market power. While suppliers can request to exceed the soft-offer cap, which is currently $7.34 per kilowatt (kW) -month, by justifying its costs at the Federal Energy Regulatory Commission, CalCCA is not aware of any resource attempting to justify higher costs. This suggests the CAISO's soft offer cap would properly cover the going forward fixed costs of RA resources. Energy Division's proposed price thresholds for a waiver exceed the CPM soft offer cap in every month a waiver would be eligible. Once the RA market returns to competitive levels, it would be expected that RA prices fall below these thresholds, and LSEs would be able to procure sufficient RA capacity such that they would not need to apply for a waiver. This outcome occurs regularly in local RA procurement where resources offer at prices below the threshold established by the Commission when under competition.

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[67] ACP-CA Opening Comments, at 9-10; CAISO Opening Comments, at 4; and Calpine Opening Comments, at 5.

The Commission should also reject claims by the CAISO and Terra-Gen that a waiver process can diminish incentives to bring new resources online,[68] weaken signals for capacity RA contracting,[69] and result in LSEs relying on the waiver instead of obtaining needed capacity.[70] Incentives to bring new resources online are already provided by the Integrated Resource Planning (IRP) proceeding (R.20-05-003). The IRP proceeding focuses on ensuring sufficient new capacity is developed to support reliability requirements, and the RA program focuses on ensuring those resources are available to serve CAISO load, which the CAISO appears to recognize in its comments, stating:

> [t]he Commission should ensure that IRP planning and procurement work hand in hand with the RA program such that the resource fleet available in the RA timeframe can effectively meet the 0.1 LOLE reliability target. The Commission should also consider whether IRP will ensure sufficient supply margins to support competition in the RA timeframe.[71]

LSEs and developers have been working diligently to bring new resources online to support the IRP mid-term reliability procurement orders, but circumstances outside their control, such as supply chain challenges and interconnection delays, can result in project delays that can negatively impact the RA supply stack.

In addition, Energy Division's proposal does not weaken incentives for RA contracting or allow LSEs to rely on a waiver rather than on procurement of RA capacity. An LSE's ability to obtain a waiver is dependent on it making commercially reasonable efforts to procure sufficient RA capacity to meet its obligations. If an LSE chooses to forego these reasonable efforts, the

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68 CAISO Opening Comments, at 8.
69 *Ibid.*
70 Terra-Gen Opening Comments, at 2.
71 CAISO Opening Comments, at 5.

Commission will not grant a waiver and the LSE will continue to be subject to significant penalties for non-compliance.

Finally, a waiver allows the Commission to adopt a PRM for all LSEs that best supports a 0.1 LOLE. The Commission should reject PG&E's proposal for a "gradual increase" in the PRM "with a 17 [percent] requirement for the 2026 compliance year and an 18 [percent] PRM requirement once market price benchmark [MPB] issues have been resolved in the Power Charge Indifference Adjustment (PCIA) proceeding."[72] The Commission should base the PRM upon the LOLE study results and provide equal opportunities for waivers to IOU and non-IOU LSEs to equitably ensure customers are not harmed by high costs. The PCIA MPB has no relevance to the amount of RA LSEs must procure to meet reliability targets. Instead, it is a benchmark to reflect the estimated value of RA capacity for ratemaking purposes. Further, the methodology for calculating the PCIA MPB methodology is being considered in R.25-02-005,[73] and is not an issue for the present proceeding.

D. Cal Advocates' Cost Analysis of Energy Division's Proposals is Unclear and Does Not Support Adoption of an Effective PRM Over a Waiver

Cal Advocates presents Table 1 to support its contention that an effective PRM would be the most cost-effective price mitigation proposal.[74] Table 1 presents two columns with estimated cost data. The first column shows the difference in cost compared to the costs of historical procurement by the IOUs to meet an effective PRM and each LSE meeting their minimum 17 percent PRM using the 2022 RA Report to calculate RA pricing. The second column shows the same analysis using the 2024 MPB rather than the 2022 RA Report. However, in the first row, the

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[72] PG&E Opening Comments, at 5.

[73] *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): https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:R2502005.

[74] Cal Advocates Opening Comments, at 8.

cost of the effective PRM under the 2024 MPB is lower than the cost of the effective PRM under the 2022 RA Report price. It is difficult to understand and interpret this result given that the 2024 RA MPB was $26.26/kW-month while the 2022 RA report gives monthly RA values, with the highest month at $13.48/kW-month, nearly half the price of the MPB. It is unclear how the incremental cost of the effective PRM could be less expensive under significantly higher prices.

The next two rows of Table 1 are equally puzzling. These two rows, which attempt to estimate the costs of Energy Division's waiver proposal assuming LSEs either comply or use waivers, report that it is less expensive for LSEs to fully comply with their RA requirements rather than obtain a waiver for 3,500 megawatts (MW). It is difficult to understand how taking a waiver for a total of 3,500 MW will result in a cost higher than not taking a waiver. This is further confounding considering the CAISO backstop cost at $7.34/kW-month, which is far less than the proposed waiver threshold from Energy Division's proposal.

Cal Advocates' statement that "the market power issue could be serious enough that the resources LSEs need for compliance with a 17 [percent] PRM could also exert market power"[75] does not support the effective PRM in lieu of a waiver. Instead, it questions whether Energy Division's proposed minimum quantity of 17 percent to obtain a waiver is low enough. Cal Advocates follows this statement with a footnote stating, "Proposal B comes with no opportunity for LSEs to escape high prices needed to achieve their 17 [percent] PRM obligations, even if LSEs can waive additional capacity needed for the 22.5 [percent] PRM under Proposal B."[76] The effective PRM, Cal Advocates' preferred proposal, would *<u>also</u>* not afford any escape from high prices for procurement up to 17 percent because the effective PRM only waives IOU obligations for procurement above 17 percent. Under the effective PRM, the potential for the exertion of

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75 Cal Advocates Opening Comments, at 7.

76 *Ibid.*

market power raised by Cal Advocates would be exacerbated since the IOUs will attempt to procure not only a 17 percent PRM but a higher effective PRM at the same time that non-IOUs are attempting to procure a 17 percent PRM. It is, therefore, perplexing how the effective PRM will be significantly less expensive than affording all LSEs at least some opportunity to avoid the exercise of market power.

Finally, Cal Advocates appears to ignore the cost of RA penalties themselves. While a penalty for an IOU may result in a disallowance funded by shareholders, CCAs do not have shareholders. Indeed, no profit exists from which a penalty could be taken, as CCAs are not-for-profit organizations. This means that any penalty assessed will be a cost to the CCA customer. This is ignored in Cal Advocates' analysis used to support their preferred option of no waivers for LSEs with an effective PRM for the IOUs. For these reasons, the Commission should reject this analysis and adopt a waiver process to avoid the exercise of market power and to temper overinflated capacity market prices.

V. THE COMMISSION SHOULD COMMIT TO COLLABORATING WITH THE CAISO TO ADDRESS OPEN ISSUES ASSOCIATED WITH ALLOWING EO CO-LOCATED RESOURCES TO PROVIDE RA VALUE

The Commission should commit to collaborating with the CAISO to address open issues to enable the EO components of co-located resources to provide RA value. CalCCA's proposal recommends the Commission allow the EO component of a co-located resource to be shown for RA when the combination of the EO component and the deliverable component does not exceed the deliverable MW at the point-of-interconnection (POI) in any individual hour. Many stakeholders directionally support the proposal.[77] Others highlight issues that require resolution before the Commission and CAISO adopt it.[78]

The CAISO states that "all RA resources should be subject to a MOO" and that a CAISO tariff change would be required to apply a MOO to EO resources.[79] CalCCA agrees. The CAISO also states that CalCCA's proposal "may require the CAISO to revisit how it studies and establishes deliverability for RA resources," because "the CAISO does not study whether [EO] resources can serve the aggregate of CAISO load" or "award deliverability status to co-located resources at the POI level."[80] While the CAISO currently does not award deliverability status to co-located resources at the POI-level, it does effectively provide deliverability to hybrid resources based on deliverable MW at the POI rather than at the individual component level because hybrid resources also have multiple components but have a single resource ID.

CalCCA's proposal requires a methodology to ensure deliverability limits are not exceeded when a co-located resource has multiple off-takers.[81] SCE proposes to address this issue by only allowing EO co-located resources to count as RA if the co-located resource has a single off-taker.[82] SCE's recommendation should not be the solution to addressing the issue of multiple off-takers of co-located resources. More investigation is needed into the number of co-located resources with multiple off-takers to ensure a solution is tailored to meet the needs of the market. If it is common for co-located resources to have multiple off-takers, then the

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77 *See* ACP-CA Opening Comments, at 11-12; CEJA Opening Comments, at 9; and SCE Opening Comments, at 14.

78 *See* CAISO Opening Comments, at 11; PG&E Opening Comments, at 10; and Terra-Gen Opening Comments, at 14-15.

79 CAISO Opening Comments, at 11.

80 *Id.*, at 11-12.

81 CalCCA Proposal, at 25.

82 SCE Opening Comments, at 14.

Commission should develop a solution that meets the needs of the market rather than institute a blanket restriction on showing EO co-located resources with multiple off-takers.

Because CalCCA's proposal has the potential to unlock up to 2,035 MW of RA capacity from existing resources,[83] the Commission should commit to working with the CAISO in the CAISO's ongoing RA Modeling and Program Design initiative to resolve open issues, such as establishing a MOO and ensuring deliverability limits are not exceeded when a co-located resource has multiple offtakers. This will enable EO resources to provide RA value in the SOD program.

VI. THE COMMISSION SHOULD ADOPT PG&E'S RECOMMENDATION TO PUBLISH TEST UCAP VALUES IN 2027 TO ALLOW LSES TO ASSESS THEIR EXISTING PORTFOLIOS

The Commission should adopt PG&E's recommendation to develop test UCAP values in 2027[84] for two reasons. *First*, the change in UCAP (i.e., the decrease in total system Net Qualifying Capacity (NQC)) should be completely offset by a reduction in the PRM. A publication of UCAP values in 2027, along with modeling to calculate the PRM with those values, will help confirm this. *Second*, even if the NQC and PRM completely offset each other at a system-wide level, different LSEs and generators will be impacted by the change differently. It is, therefore, critical to provide information as far forward as practical to enable those entities to take the necessary actions to comply in 2028 if UCAP is adopted. The Commission should examine the results of its test UCAP values and resulting PRM in 2027, and work with stakeholders to ensure that the results will enable a smooth implementation in 2028 or to develop an alternative implementation plan.

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[83] CalCCA Opening Comments, at 13.

[84] PG&E Opening Comments, at 17

VII. SCE'S PROPOSAL TO REVERSE THE LOCAL RA CPE TIMELINE CHANGE MUST BE REJECTED BECAUSE, AS SHELL AND MICROSOFT EXPLAIN, IT IS PREMATURE AND UNSUPPORTED BY NEW FACTS OR EVIDENCE

The Commission should reject SCE's proposal to reverse the local RA CPE procurement timeline change adopted in D.24-12-003[85] because, as Microsoft and Shell state, SCE's proposal is premature and provides no new facts or evidence. The Commission modified the CPE procurement timeline to lock in CPE allocation earlier because it "will increase certainty for LSEs to understand how much system and flexible RA they may need to procure."[86] CalCCA agrees with Microsoft that:

> ... more time for procurement and contract negotiations [will] enable purchasers to secure better deals and foster a smoother local procurement process... SCE's proposal to reverse course on a very recently issued Decision is premature as it will be assessed at the end of the 2027 RA year.[87]

Additionally, CalCCA agrees with Shell that:

> SCE provides no new facts or analysis to justify its request that the Commission change course on a proposal that it adopted less than three months ago, and which the Commission implemented on an interim basis subject to further review. Instead, SCE simply incorporates by reference arguments that it raised—and the Commission rejected—in Track 2 of this proceeding. The Commission should not entertain SCE's attempt to re-litigate issues that the Commission has already resolved only a few months ago.[88]

While MRP states that locking in procurement two years in advance "increases the likelihood that the CPE will either over-procure or under-procure,"[89] *failing* to lock in CPE procurement two years in advance increases over-procurement or under-procurement risks. With

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85 *See* D.24-12-003, *Decision on Track 2 Issues*, R.23-10-011 (Dec. 12, 2024), at 40-45: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M549/K295/549295013.PDF.

86 *Id.* at 43.

87 Microsoft Opening Comments, at 14.

88 Shell Opening Comments, at 5-6.

89 MRP Opening Comments, at 18.

CPE allocations locked in well enough in advance, LSEs have time to adjust their procurement plans to account for these allocations. This could include selling off excess RA if their CPE allocations make them long or procuring additional RA if they still have open positions. If, instead, LSEs over- or under-procure because they cannot predict their CPE allocations, they will not be made aware until it is too late to adjust their procurement.

MRP also states that it is concerned that the timeline modification would result in the hybrid CPE becoming "even more of a 'front stop' mechanism"[90] in which the CPE "simply passes the reliability procurement function to the CAISO backstop procurement."[91] MRP, therefore, proposes that LSEs be allocated CPE deficiencies to avoid CAISO backstop procurement.[92] The Commission should reject MRP's recommendation. The CPEs' requirements have always been 100 percent in years one ***and*** two. If there is a deficiency in CPE procurement after accounting for what LSEs include in response to the local RA CPE data request process adopted in D.24-12-003, then it is likely a result of insufficient capacity in the local area and/or market power. Per D.20-06-002, CPEs are allowed to defer to CAISO backstop in these instances.[93] The ability for CPEs to defer to CAISO backstop must be maintained, as the CAISO's CPM process is designed to mitigate against market power and the Commission's system RA program currently is not, given the absence of a system RA waiver.

SCE's proposal is premature and provides no new facts or evidence as to why the Commission should change course on a decision made only a few months ago. In addition, reversing the timeline adopted in D.24-12-003 ***would not*** exacerbate over- or under-procurement

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[90] *Id.*, at 19.
[91] *Ibid.*
[92] *See Ibid.*
[93] D.20-06-002, *Decision on Central Procurement of the Resource Adequacy Program*, R.17-09-020 (June 17, 2020) at 67: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M340/K671/340671902.PDF.

risk and the Commission must retain the CPEs' ability to defer to CAISO backstop to protect against the potential exertion of market power. The Commission should, therefore, reject SCE's proposal and MRP's modified proposal.

VIII. IF THE COMMISSION ADOPTS SCE'S PROPOSAL TO CLARIFY THE LOCAL RA CPE PROCUREMENT OBLIGATIONS RESULTING FROM THE DATA REQUEST, AS SUPPORTED BY PARTIES, IT MUST RETAIN THE ABILITY FOR LSES TO SELL TO THE CPE

The Commission must ensure that LSEs retain the ability to sell to the CPE if the Commission adopts SCE's proposal to clarify the local RA CPE procurement obligations resulting from the local RA CPE data request process. Calpine supports SCE's proposal to reflect local requirements net of local capacity LSEs have already contracted.[94] CalCCA supports providing clarity around how the information collected in the data request process should be used by the CPEs. However, if the Commission adopts a clarification that nets capacity contracted by LSEs from the CPEs' requirements, the Commission must do so with a process that continues to allow LSEs the opportunity to sell to the CPE. There are multiple ways the Commission could accomplish this need. For example, CalCCA's Opening Comments suggest the Commission could ask LSEs in its data request which local RA capacity under contract they plan to offer to the CPE and only reduce the CPE's procurement target by the amount of local capacity LSEs do not plan to offer to the CPE.[95] If the Commission elects to adopt SCE's proposal, as recommended by Calpine, the Commission must modify it to include a process for LSEs to sell their excess local capacity to the CPE.

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[94] Calpine's Opening Comments, at 7-8.
[95] CalCCA's Opening Comments, at 20.

IX. THE COMMISSION SHOULD CONSIDER HOW BEST TO ACCOUNT FOR LDES AND PSH CHARGING SUFFICIENCY NEEDS IN A FUTURE RA PROCEEDING

While parties disagree on a specific methodology for charging sufficiency associated with LDES and PSH,[96] it is clear that ignoring charging needs can degrade reliability. Parties have introduced a number of potential solutions and highlighted differences in resource types that the Commission should consider.[97] For example, SCE points out that PSH with open loop flows may need less charging than other storage facilities.[98] While this may be true, SCE does not contend that open loop PSH will not need at least some excess capacity from other RA resources to ensure charging sufficiency. In developing charging sufficiency requirements and a 24-hour SOD RA requirement, the Commission has recognized the importance of ensuring the RA program accounts for energy needs. Placing requirements on some, but not all, storage will create an unlevel playing field and could result in a grid that is not reliable, even when the RA showings produce compliant outcomes. If the Commission cannot make a decision based on the information provided thus far, it should immediately scope this issue into the next RA proceeding to create such rules. This is increasingly important as the IRP proceeding's mid-term reliability procurement order contains LDES requirements for LSEs, and the Commission asked the California Department of Water Resources (CDWR) to examine the central procurement of LDES. LSEs and CDWR must be able to assess the value of a resource when conducting procurement and RA is a significant value stream for all resources. Without clarity on the counting of LDES and PSH resources, LSEs and CDWR will be unable to determine the RA value of such resources, making procurement difficult.

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96 ACP-CA Opening Comments, at 12-15; Cal Advocates Opening Comments, at 15-17; Calpine Opening Comments, at 6-7; CEERT Opening Comments, at 3; CEJA Opening Comments, at 9-10; Hydrostor Opening Comments, at 4-8; PG&E Opening Comments, at 5-8; SCE Opening Comments, at 11-13; SDG&E Opening Comments at 12-14; and Terra-Gen Opening Comments at 7-8.

97 *Ibid.*

98 SCE Opening Comments, at 13.

X. THE COMMISSION SHOULD ADOPT LEAP'S PROPOSED CHANGE TO THE HOURS DR CAN OBTAIN A QC AND CONSIDER BROADER REFORMS TO ENABLE GREATER DR PARTICIPATION IN A FUTURE PROCEEDING

The Commission should adopt Leap's proposal to allow DR to obtain QC values outside of the AAHs consistent with their demonstrated capability. Leap's Opening Comments include an attached whitepaper that "contextualize[s] its 24-hour NQC proposal in a broader set of reforms that would enable greater DR participation in RA."[99] CalCCA continues to support Leap's proposal to allow DR resources to receive QC values outside of the AAHs and encourages the Commission to consider broader reforms to enable increased DR and distributed energy resource participation in the RA program. The Commission should consider these reforms in a future RA proceeding.

XI. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the comments 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

March 17, 2025

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[99] Leap Opening Comments, at 3.

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**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 OPENING COMMENTS ON THE ORDER INSTITUTING RULEMAKING AND ENERGY DIVISION STAFF REPORT

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On behalf of
California Community Choice Association

March 18, 2025

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SUMMARY OF RECOMMENDATIONS[1]

CalCCA provides the following recommendations:

- ✓ The Commission should approach the OIR in the context of its obligation to both bundled and unbundled customers to administer the PCIA framework fairly and accurately;

- ✓ The Commission should consider the broader context surrounding PCIA policy and current market conditions;

- ✓ For the Track One Staff Proposals, the Commission should:

    - Model the impacts of all scenarios on the RA MPB (including the combination of Proposals Two and Five) and require the IOUs to demonstrate the estimated system average PCIA rate impacts of different proposals;

    - Reject Proposal One. Upending the RA MPB framework by including in the costs of all transactions deliverable in a year, rather than near-term transactions executed for that year, produces an outcome-driven solution that does not reflect current market value as required by the "mark to market" portfolio valuation methodology adopted in D.18-10-019 and D.19-10-001. It thus leaves the overall methodology with a mix of apples and oranges: current prices for energy and RPS versus a blend of current and historical prices for RA.

    - Adopt Proposals Two through Five. Each of the Proposals will increase the accuracy, but not upend the framework, of the RA MPB:

        - Proposal Two utilizing a single RA MPB incorporating System, Local, and Flex values should be adopted to maximize representative transactions;

        - Proposal Three excluding affiliate transactions from the MPB calculation should be adopted to mitigate the risk of RA MPB manipulation;

        - Proposal Four excluding swap and sleeve transactions should be adopted to the extent the Commission can objectively and transparently identify such transactions; and

[1] Acronyms used in this Summary of Recommendations are defined in the body of this document, *California Community Choice Association's Opening Comments on 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. 17, 2025).

- Proposal Five utilizing monthly values for the overall RA MPB should be adopted to best reflect seasonality of RA prices;

✓ Order legal briefing on the complex issue of retroactively applying any of the Track One modifications to true-up the 2025 Forecast RA MPB;

✓ Finalize the Track Two scope only after the completion of Track One – however, the following items should be preliminarily scoped for Track Two:

- Consideration of structural changes to the PCIA including:
    - Sunsetting the PCIA to allow IOUs unencumbered access to the PCIA portfolios in an environment of growing load and the ability to take advantage of the hedge value of the long-term resources in the PCIA portfolio;
    - Allocating PCIA resources proportionally to unbundled and bundled customers to minimize ongoing debates on valuation methodology, to more accurately account for full value, and to reduce customer rate volatility;
    - Revisiting the PCIA GHG-free methodology to ensure GHG-free resources are accurately valued in the PCIA portfolio;
- Adopting scoping issues proposed in the OIR, including:
    - Consideration of ERRA-specific implementation guidance for the RA Slice of Day framework;
    - Consideration of a framework for re-vintaging utility-owned PCIA-eligible resources and contract vintaging; and
    - Consideration of Bundled Procurement Plan processes;
- Considering other issues raised but not resolved in past ERRA cases, including:
    - Treatment of pre-2019 banked RECs; and
    - The IOUs' Common Cost Allocation methodologies.

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 OPENING COMMENTS ON THE ORDER INSTITUTING RULEMAKING AND ENERGY DIVISION STAFF REPORT

The California Community Choice Association[2] (CalCCA) submits these opening comments in response to the *Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes*[3] (OIR) and the *Chief Administrative Law Judge's Ruling Adding Energy Division Report to the Record and Setting the Schedule for Comments on the Report*[4] (Ruling), both dated February 26, 2025. The OIR was issued to consider changes to rules and processes applicable to the electric

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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. Community Choice Aggregators (CCA) were enabled by the California Legislature to allow local governments to aggregate their constituents' electricity load and reach climate and economic goals. They now serve more than 14 million California customers in more than 200 towns, cities, and counties, equivalent to 37 percent of customers in the IOU territories.

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

[4] *Chief Administrative Law Judge's Ruling Adding Energy Division Report to the Record and Setting the Schedule for Comments on the Report,* R.25-02-005 (Feb. 26, 2025).

fuel and purchased power (Energy Resource Recovery Account (ERRA)) annual forecast and compliance proceedings, as well as changes to the Power Charge Indifference Adjustment (PCIA). The Ruling requests responses in opening and reply comments on the OIR and the ED Staff Report[5] on the 2024-2025 Resource Adequacy (RA) Market Price Benchmark (MPB), attached as Appendix A to the Ruling.

I. INTRODUCTION

The fairness of the PCIA methodology – one of the most complex ratemaking mechanisms under the Commission's jurisdiction – is in the eye of the beholder. When market prices rise, and PCIA rates fall, bundled customers[6] see higher generation rates as less of the cost of the PCIA portfolio is recovered from unbundled customers.[7] When market prices fall, and PCIA rates rise, non-IOU load-serving entities (LSE) must maintain rate stability for their unbundled customers while still recovering their costs. The PCIA also creates challenges for LSEs serving both bundled and unbundled customers in hedging their procurement costs, albeit in different ways. And PCIA volatility, as the rate tracks market conditions, affects all LSEs and the customers they serve.

In the face of these challenges, stability, consistency, and durability in PCIA ratemaking are critical. While tempting, result-driven changes in the PCIA methodology to address impacts on one group of customers under current market conditions will not support stability or consistency. Likewise, piecemeal modification of PCIA elements does not support these goals; for example, calculating the value of one portfolio product using short-term market measures and another

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5 *Energy Division Staff Report of the 2024-2025 Resource Adequacy Market Price Benchmark*, R.25-02-005 (Feb. 26, 2025) (ED Staff Report).

6 Bundled customers receive both generation and delivery service from an IOU.

7 Unbundled, or departed, customers receive generation service from either a CCA or a direct access (DA) provider (also referred to as an Electric Service Provider (ESP)).

product using long-term measures would be internally inconsistent. The Commission's direction in this proceeding must be guided by these objectives in coordination with its statutory obligations.

The central question in this rulemaking is how the Commission can best meet its statutory obligation to avoid cost shifts in applying Public Utilities Code sections 365.1, 366.2, and 366.3.[8] These statutes require the Commission to ensure "indifference" and prevent "cost shifts" among bundled customers, and unbundled customers. To achieve these objectives with respect to a customer departing IOU service for a CCA, section 366.2(d)-(f) permits the IOUs to recover any net unavoidable electricity costs incurred while the CCA customer was served as an IOU bundled customer. Critically, however, section 366.2(g) requires the Commission to reduce the amount of estimated "net *unavoidable* [IOU] electricity costs" paid by CCA customers "by the *value* of any benefits that remain with bundled service customers, unless the customers of the [CCA] are *allocated* a fair and equitable share of those benefits."[9] The Commission's current construct uses both approaches.[10] It offsets PCIA *costs* with portfolio *value* using short-term MPBs for RA, brown power, and Renewables Portfolio Standard (RPS) products. In addition, it *allocates* RPS attributes to unbundled customers.

The calculation of the IOU PCIA portfolio cost and value therefore depends on market prices, including for RA, which rise and fall over time. Thus, the value of the IOU PCIA portfolio similarly rises and falls over time.

As noted in the OIR, recent high RA market prices have increased the value of the IOU PCIA portfolios.[11] This has recently resulted in a PCIA credit (rather than a charge) on bills of

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

9 Pub. Utils. Code § 366.2(g) (emphasis added).

10 *See* D.18-10-019, *Decision Modifying the Power Charge Indifference Adjustment Methodology*, R.17-05-026 (Oct. 19, 2018).

11 OIR at 14.

some departed load customers. This credit is in stark contrast to steep charges on departed load customer bills in previous years. The OIR, the ED Staff Report, and Commissioners' remarks at the Commission voting meeting adopting the OIR,[12] all point to concerns over whether the existence of a credit on unbundled customer bills may suggest a cost shift.[13] Such statements overlook the Commission's explicit acknowledgement in its Decision establishing the current MPB framework that such a credit should occur: "[t]he PCIA framework should allow for a net credit to departing load customers if utility portfolios provide positive net market value as demonstrated through actual recorded market transactions and realized revenues."[14] Indeed, if the value of the portfolio retained by the IOU exceeds what bundled customers are paying for it, then a credit to unbundled customers is warranted.

It would be tempting for the Commission, given its traditional regulatory orientation, to solely focus on ensuring bundled customer rates remain low. However, the Commission's general obligation to adopt "just and reasonable" rates and to prevent cost shifts requires it to ensure, as noted by Commission President Alice Reynolds, that *both* bundled and unbundled customers "get the benefits of investments made on their behalf."[15]

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[12] All references herein to Commissioner Remarks refer to the remarks provided by the Commissioners at the February 20, 2025, Commission meeting at which the OIR was adopted.

[13] *See* OIR at 14-15 ("A PCIA credit does not necessarily suggest a cost shift between bundled and unbundled customers. It can accurately reflect a rebalancing of the costs and market value of the resources the IOUs retain in the portfolio for use by bundled customers. However, it only leads to customer indifference if the MPB accurately reflects the market value of the entire PCIA portfolio"); ED Staff Proposal at 6 ("In general, a PCIA credit to unbundled customers recovered through higher rates for bundled customers is only warranted if the market value being applied to the entire portfolio is accurate"); Commissioner M. Baker Remarks (stating that while ""these transfers are not problematic in theory, they raise the question of whether the risk is symmetrical").

[14] D.18-10-019, at 160.

[15] Commissioner A. Reynolds Remarks.

The Commissioners also generally framed the proceeding as one to ensure "affordability."[16] While the *magnitude* of IOU costs (as opposed to IOU *customer* costs) is certainly an affordability issue, the *division* of those costs among bundled and unbundled customers is a zero-sum game among different customer sets, not one of affordability for customers overall. In short, the Commission cannot require unbundled customers to carry the burden of higher rates to ensure affordability for bundled customers.

CalCCA's comments focus on three key issues. ***First***, the Commission must approach the OIR with the intent to ensure equitable allocation of cost responsibility among *all* LSEs and their customers. ***Second***, Energy Division's Track One Proposals to modify the RA MPB on an expedited basis should focus on accuracy through minor refinements to the RA MPB framework rather than a wholesale rework of that framework. Therefore, Proposal One regarding incorporating long-term transactions in the calculation of the *value* of RA capacity should be rejected. This outcome-driven approach is not only inconsistent with the established methodology of valuing the RA MPB with current market prices, but also mixes apples with oranges and leads to internal inconsistency in the application of the methodology. Simply put, the price paid for a product historically is not an indicator of the product's value today. Proposals Two through Five should be adopted as improvements to the accurate assessment of value, with the conditions expressed herein. ***Third***, CalCCA preliminarily addresses the Track Two scope, categorization, and schedule.

Specifically, CalCCA provides the following recommendations:

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16 *See* Commissioner D. Houck Remarks ("I want to highlight the need to carefully consider affordability for customers when updating the PCIA calculations even with [the OIR's] tight schedule").

- ✓ The Commission should approach the OIR in the context of its obligation to both bundled and unbundled customers to administer the PCIA framework fairly and accurately;
- ✓ The Commission should consider the broader context surrounding PCIA policy and current market conditions;
- ✓ For the Track One Staff Proposals, the Commission should:
  - Model the impacts of all scenarios on the RA MPB (including the combination of Proposals Two and Five) and require the IOUs to demonstrate the estimated system average PCIA rate impacts of different proposals;
  - Reject Proposal One. Upending the RA MPB framework by including in the costs of all transactions deliverable in a year, rather than near-term transactions executed for that year, produces an outcome-driven solution that does not reflect current market value as required by the "mark to market" portfolio valuation methodology adopted in D.18-10-019 and D.19-10-001. It thus leaves the overall methodology with a mix of apples and oranges: current prices for energy and RPS versus a blend of current and historical prices for RA.
  - Adopt Proposals Two through Five. Each of the Proposals will increase the accuracy, but not upend the framework, of the RA MPB:
    - o Proposal Two utilizing a single RA MPB incorporating System, Local, and Flex values should be adopted to maximize representative transactions;
    - o Proposal Three excluding affiliate transactions from the MPB calculation should be adopted to mitigate the risk of RA MPB manipulation;
    - o Proposal Four excluding swap and sleeve transactions should be adopted to the extent the Commission can objectively and transparently identify such transactions; and
    - o Proposal Five utilizing monthly values for the overall RA MPB should be adopted to best reflect seasonality of RA prices;
- ✓ Order legal briefing on the complex issue of retroactively applying any of the Track One modifications to true-up the 2025 Forecast RA MPB;
- ✓ Finalize the Track Two scope only after the completion of Track One – however, the following items should be preliminarily scoped for Track Two:
  - Consideration of structural changes to the PCIA including:

- o Sunsetting the PCIA to allow IOUs unencumbered access to the PCIA portfolios in an environment of growing load and to provide an ability to take advantage of the hedge value of the long-term resources in the PCIA portfolio;
- o Allocating PCIA resources proportionally to unbundled and bundled customers to minimize ongoing debates on valuation methodology, to more accurately account for full value, and to reduce customer rate volatility;
- o Revisiting the PCIA GHG-free methodology to ensure GHG-free resources are accurately valued in the PCIA portfolio; and

- Adopting scoping issues proposed in the OIR, including:
    - o Consideration of ERRA-specific implementation guidance for the RA Slice of Day framework;
    - o Consideration of a framework for re-vintaging utility-owned PCIA-eligible resources and contract vintaging; and
    - o Consideration of Bundled Procurement Plan processes; and
- Consideration of other issues raised but not resolved in past ERRA cases, including:
    - o The Treatment of pre-2019 banked RECs; and
    - o The IOUs' Common Cost Allocation methodologies.

II. THE COMMISSION HAS A CONTINUING OBLIGATION TO BOTH BUNDLED AND UNBUNDLED CUSTOMERS TO ADMINISTER THE PCIA FRAMEWORK FAIRLY AND ACCURATELY

The Commission has a continuing obligation to both bundled and unbundled customers to administer the PCIA framework fairly and accurately. This obligation, to ensure indifference and the prevention of costs shifts for both bundled and unbundled customers, requires the Commission to not favor one sector of customers over another. As set forth below, the implementation of the PCIA has played out over time generally in favor of bundled customers. The Commission must approach the OIR with the intent to ensure equitable allocation of cost responsibility among *all* LSEs and their customers, specifically by: (1) ensuring indifference among both bundled and unbundled customers; (2) understanding that the PCIA is a zero-sum game, and therefore that overall affordability cannot be achieved by the PCIA methodology which simply allocates costs approved in other proceedings; (3) acknowledging that bundled customers benefit from guaranteed cost recovery from departed customers for PCIA-eligible resources; (4) resisting results-oriented modifications of the RA MPB to benefit bundled customers under current market conditions; (5) understanding that both bundled and unbundled customers may benefit through the PCIA at any one time depending on market and regulatory conditions; and (6) viewing the ERRA process through past ERRA cases and the advantages enjoyed by the IOUs.

A. The Commission Has an Obligation to Ensure Indifference for Both Bundled and Unbundled Customers

AB 117[17] envisioned CCAs as a way for local municipalities to partner with state agencies like the Commission to drive energy efficiency and conservation, increase reliance on renewable resources, and ensure grid reliability. The Legislature requires the Commission to ensure the success of that vision by: (1) enforcing cooperation by the IOUs "with any [CCAs] that investigate, pursue, or implement CCA programs;" [18] (2) "foster[ing] fair competition between CCAs and IOUs;"[19] (3) certifying CCA plans;[20] (4) preventing cost shifts between bundled and departing load customers;[21] (5) ensuring that a CCA is "solely responsible" for its own procurement, unless otherwise expressly authorized by statute;[22] and (6) ensuring CCA RPS

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17 Assembly Bill No. 117 (AB 117) (2002) Ch. 838, Stats. 2002 (Sept. 24, 2002); Cal. Pub. Utils. Code § 380.

18 Cal. Pub. Utils. Code § 366.2(c)(9)-(11).

19 Senate Bill No. 790 (SB 790) (2011) Ch 599, Stats. 2011 (Oct. 8, 2011), at § 2(h).

20 Cal. Pub. Utils. Code § 366.2(c)(5)-(8).

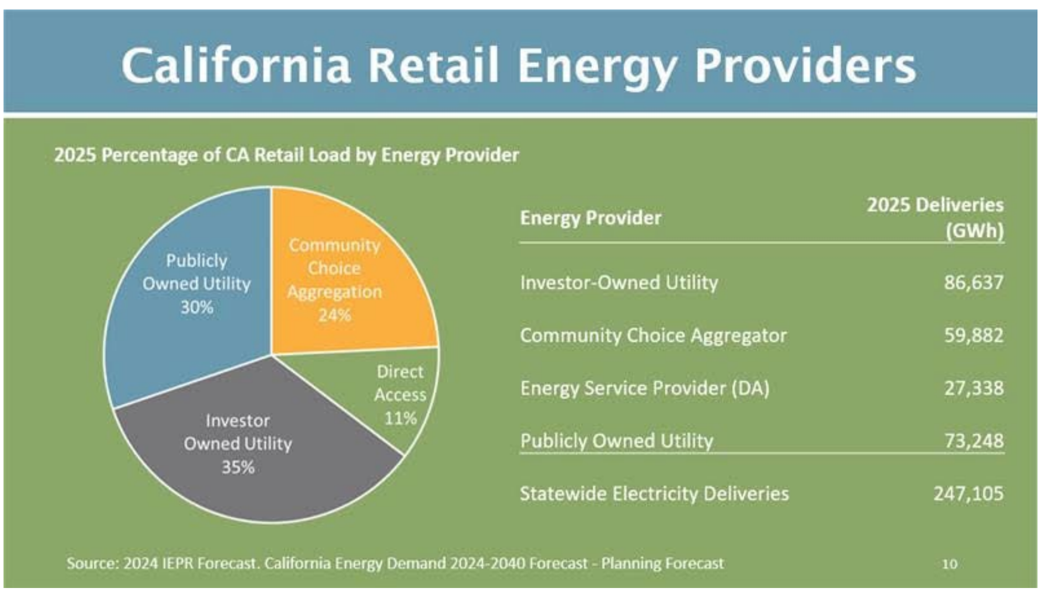
21 *Id.* §§ 366.2(a)(4), 366.3.

22 *Id.* § 366.2(g).

and RA compliance.[23] The Commission is required to "provide [CCAs] with the opportunity to compete on a fair and equal basis with other load serving entities, and to prevent [IOUs] from using their position or market power to undermine the development or operation of [CCAs]."[24] The Commission has more recently found that "[f]inancially sound CCAs benefit customers as a whole," and that "CCAs are in the public interest, in that CCAs allow for a publicly managed alternative to private utility procurement of resources." [25]

These obligations—especially the obligation to ensure *both* bundled and unbundled customer indifference—are more essential than ever, as departed customer load from CCAs and ESPs is forecasted to be approximately equal to bundled customer load in 2025, as shown in Figure 1, below.

FIGURE 1



23 *Id.* §§ 399.11, 380.

24 Decision (D.) 12-12-036, *Decision Adopting a Code of Conduct and Enforcement Mechanisms Related to Utility Interactions with Community Choice Aggregators, Pursuant to Senate Bill 790,* R.12-02-009 (Dec. 28, 2012), at 2; *see also* SB 790, at § 2(h).

25 D.24-09-005, *Decision Extending Current Proportional Allocation of Payment on Past-Due Bills Between Investor-Owned Utilities and Community Choice Aggregators,* R.18-07-005 (Sept. 18, 2024), at 8, 16.

The parity between bundled and unbundled load in California underscores the need for the Commission to approach the issues raised in the OIR in a transparent manner that does not lower costs for one group of customers to the detriment of another group of customers.

B. Overall Customer Affordability Will Not be Achieved Through Modifications to the RA MPB and Should Not Be Used as a Justification to Benefit Bundled Customers

Overall customer affordability will not be achieved through modifications to the RA MPB and cannot be used as a justification to benefit bundled customers. Affordability of electric services is a critical issue in California. Executive Order N-5-24 requires the Commission to closely examine various ratepayer-funded programs to determine which are underperforming or could be funded via alternative means in order to address customers' bills.[26] The order builds on efforts the Commission has undertaken since 2018 to address the question of affordability.[27] CalCCA members support these efforts and are seeking solutions—both within and outside of Commission proceedings and programs—to improve the affordability of electricity in California.

Commissioner Matthew Baker's remarks from the dais are correct to point out the high level of revenue requirements at issue in the ERRA cases,[28] and it is true the decisions the Commission makes in this proceeding will have impacts on customer bills. However, other Comments from the dais—echoing problematic statements from Pacific Gas and Electric Company (PG&E) during its 2025 ERRA Forecast proceeding trying to link the RA MPB to

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26 Executive Order N-5-24 (Oct. 30, 2024).

27 *See, e.g., Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service*, R.18-07-006 (July 12, 2018).

28 Commissioner M. Baker Remarks ("As the OIR points out…the ERRA alone accounts for over seven billion [dollars] … in customer bills … from the state's largest [IOUs]").

affordability[29]—incorrectly suggest the current ERRA and PCIA processes are a means to address affordability.[30]

While the ERRA ratemaking process tabulates the generation portion of customers' bills, such ratemaking does not create new costs or reduce costs. It simply passes through costs from the California's energy market and from Commission-approved cost recovery or directives in General Rate Cases, or program applications, and other proceedings approving IOU cost recovery. It also reflects costs driven by Commission mandates in other policy proceedings, such as the Integrated Resource Plan (IRP), RA, or RPS proceedings. The size of the pie is determined in all of these cases, and ERRA ratemaking simply slices the pie into pieces allocated to bundled and unbundled customers. ERRA ratemaking is thus a zero-sum game and cannot provide an affordability lever.

A review of the PCIA framework helps demonstrate why arguments linking the PCIA or the RA MPB to affordability should not be endorsed. Within the ERRA, certain utility generation costs are PCIA-eligible. The Indifference Amount is the difference between the IOU supply portfolio cost[31] and the market value of the IOU's supply portfolio as demonstrated in Figure 2, below.

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29 *See Opening Brief of Pacific Gas and Electric Company*, A.24-05-009 (Oct. 21, 2024), at 4 ("PG&E expects that the severe increases of the MPBs will blunt any affordability benefit that could be enjoyed by bundled service customers, leaving those customers worse off, and not indifferent, due to load departure."); *see also Pacific Gas and Electric Company's (U 39 E) Comments on the Proposed Decision,* A.24-05-009 (Dec. 2, 2024), at 5 (describing the perceived misalignment between lower energy prices and bundled customer rates as due to unreasonable MPBs).

30 Commissioner D. Houck Remarks ("I want to highlight the need to carefully consider affordability for customers when updating the PCIA calculations even with [the OIR's] tight schedule").

31 D.11-12-018, *Decision Adopting Direct Access Reforms*, R.07-05-025 (Dec. 1, 2011), at 8-9 (describing how to derive the indifference principle from total PCIA Portfolio Cost, which includes capital investment recovery and fixed operations and maintenance costs determined in a GRC for utility-owned generation (UOG), purchased power such as that from power purchase agreements (PPA), fuel costs for UOG and PPAs with tolling agreements, and California Independent System Operator (CAISO) grid charges and revenues, net of any sales.)

FIGURE 2

Key to the issues raised in this OIR is portfolio market value, which is derived from total eligible resource output multiplied by the MPBs, an administratively determined set of proxy values that represents the market value of the IOU's resource portfolio.[32] The MPBs are estimates of the value per unit associated with the three principal sources of value in the utility portfolio:[33] Energy Value, [34] RPS Value,[35] and RA Value.[36] Each MPB must be multiplied by the relevant portfolio volume as part of the overall calculation of Portfolio Market Value.[37] The overall formula can be seen in Figure 3, below:

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[32] D.19-10-001, *Decision Refining the Method to Develop and True Up Market Price Benchmarks*, R.17-06-026 (Oct. 10, 2019), 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.").

[33] A fourth value is Greenhouse Gas-Free (GHG-free) attributes. *See, generally*, D.23-06-006, *Decision Addressing Greenhouse Gas-Free Resources, Long-Term Renewable Transactions, Energy Index Calculations, and Energy Service Providers' Data Access* (Jun. 13, 2023), at 2 (creating an option for IOUs to: (1) continue voluntary allocation of hydro GHG-free energy; or (2) to apply a new GHG-Free market price benchmark when calculating the Indifference Amount, and resulting PCIA rates, per D.23-06-006). To date, both PG&E and Southern California Edison Company (SCE) have opted to allocate GHG-free attributes rather than value them at the benchmark.

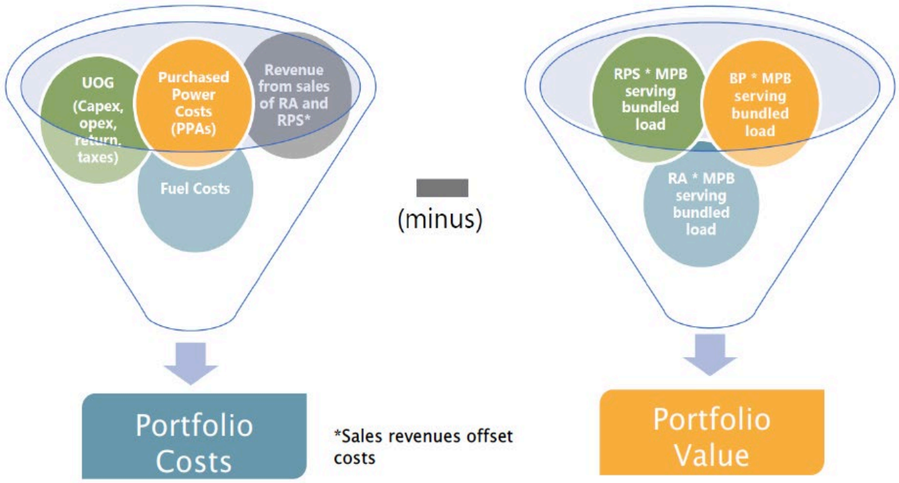
[34] D.19-10-001, at 6 ("Energy Value is the estimated financial value, measured in dollars, that is attributed to the generation component of a utility portfolio for a given year").

[35] *Ibid.* ("RPS Value is the estimated financial value, measured in dollars, that is attributed to the renewable energy component of a utility portfolio for a given year above and beyond the Energy Value").

[36] *Ibid.* ("RA Value is the estimated financial value, measured in dollars, that is attributed to the [RA] component of a utility portfolio for a given year").

[37] *Ibid.* ("Each [MPB] must be multiplied by the relevant portfolio volume as part of the overall calculation of Market Value").

FIGURE 3



Within this framework, the portfolio value all but determines which customers will pay for which costs. The market cost to serve bundled customers is recovered only from bundled customers via the ERRA rate. All costs that rise above the market value of the IOUs' portfolio are recovered from both departed and bundled customers via the PCIA.[38] If the forecasted portfolio market value increases, all other things equal, the Indifference Amount decreases. If the Indifference Amount decreases, the PCIA decreases, and departed customers pay less. If the Indifference Amount increases, the PCIA increases, and departed customers pay more. The result is a zero-sum game between bundled and unbundled customers. Any change to the RA MPB that decreases its value will result in departed customers paying more and bundled customers paying less, and vice versa.

Given the stakes of shifting costs between bundled and unbundled customers, the Commission must carefully approach "fixing" the RA MPB in Track One based on the issues identified in the ED Staff Report, as set forth more fully in section III., below. Indeed, the

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[38] The total generation costs for a bundled customer are its ERRA rates plus the PCIA rate. The total generation costs for a departed customer are the PCIA plus the cost of procurement of their CCA or ESP.

expedited nature of Track One should dictate that any RA MPB changes should be mere "tweaks" to increase accuracy rather than a wholesale reconfiguring of the RA MPB methodology. In addition, modification of the PCIA in Track One should not simply be a question of *bundled* customer affordability: departed customers bear the burden of costs lifted from the shoulders of bundled customers, and vice versa. Affordability *cannot and must not* only mean "bundled customer affordability." Accuracy, fairness, transparency, stability, and consistency must be the Commission's goal.

The best proceedings to address customer affordability are those which shape transmission, distribution, and generation cost recovery: the GRCs, IOU rate of return cases, and the RA, IRP, and RPS proceedings. Specific to older procurement, the best way to improve affordability is to unwind legacy costs in the PCIA portfolio, thereby reducing costs for all customers rather than one group at the cost of another. The early termination of the Ivanpah solar thermal power plant contract is an example of such an effort.[39] In addition, stricter enforcement of contractual violations through termination of agreements can create cost reductions within the PCIA.

C. The PCIA and ERRA Frameworks Currently Benefit Bundled Customers

While focusing in this OIR on updating and reforming the PCIA and ERRA frameworks, the Commission should recognize the significant benefits conveyed to bundled customers through the current scheme. As set forth below, the PCIA structure includes a built-in benefit allowing the IOUs and their remaining bundled customers to receive guaranteed cost recovery for their PCIA-eligible resources. Simply because the present market does not benefit bundled customers, the Commission should not create an "interim fix" to ensure that benefit. Indeed,

[39] *See* PG&E Advice Letter 7485-E, *2023 PCIA RFI, Termination of Power Purchase Agreements between Solar Partners II, LLC and Pacific Gas and Electric Company and between Solar Partners VIII, LLC and Pacific Gas and Electric Company* (Jan. 17, 2025).

evaluation of historical PCIA rates demonstrates the benefits to bundled customers over the past many years. These benefits are also reflected in past ERRA cases implementing the PCIA in which bundled customers have significantly benefitted. This OIR should therefore examine how to ensure the PCIA and ERRA frameworks simply do what they were originally intended to do: prevent cost shifts and ensure indifference among all bundled and unbundled customers.

1. Bundled Customers Benefit from Guaranteed Cost Recovery from Departed Customers for PCIA-Eligible Resources

The OIR and Staff Proposals fail to mention *the key benefit* of the PCIA to IOUs and their remaining bundled customers – the requirement for departed customers to pick up the tab for PCIA-eligible resources the IOUs no longer need and are unable or unwilling to sell. The current framework effectively *guarantees cost recovery* of the IOU legacy generation portfolios regardless of: (1) how many bundled customers the IOUs serve; (2) how many kilowatt-hours of electricity the IOUs sell; (3) the price at which the IOUs bid their resources into CAISO; or (4) whether the IOUs are able—or willing—to sell their excess RECs or capacity. No other kind of business in California—and certainly no other LSE in California—enjoys a perpetual guarantee that it will recover its costs if it loses customers, customers buy less, or the business cannot or will not sell its excess inventory. It is critical the Commission does not lose sight of this enormous benefit to the IOUs and bundled customers.

2. The Commission Should Not Modify the PCIA Methodology Simply to Benefit Bundled Customers in the Present Market

The Commission should not modify the PCIA methodology simply to benefit bundled customers in the present market. Restrictions in Bundled Procurement Plans (BPPs) should not result in increased unbundled customer costs under the PCIA. PG&E complained in its 2025 ERRA Forecast case that the current PCIA framework was inequitable because it exposed PG&E

to short-term RA market prices that cannot be hedged.[40] The argument stems from the fact that PG&E's current BPP effectively requires it to purchase 48 percent of its Retained RA capacity, *i.e.*, capacity that is PCIA-eligible that PG&E uses for its own purposes, from departed customers at the RA MPB.[41] To hedge the cost of changes to the RA MPB, PG&E would have needed to secure additional long-term contracts several years ago while simultaneously selling a portion of the existing PCIA-eligible portfolio associated with departing load.[42] According to PG&E, its BPP, the nature of the PCIA portfolio, and other Commission precedent do not allow it to do so.[43]

Commissioner Baker echoed PG&E's concerns in comments from the dais, stating that the need for the IOUs to keep their existing resources "presents a bit of a dilemma because selling PCIA-eligible capacity and repurchasing it at market prices is inefficient and would unnecessarily raise costs for customers."[44] He stated that "exceedingly high-priced RA markets have entirely reversed the directions of payments for the PCIA so that bundled ratepayers are now paying

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[40] *See* A.24-05-009, Exh. PGE-01C, at 2-9:21 to 2-13:13 (describing the potential impact of forecasted high RA prices on bundled customer generation rates and departed load customer PCIA rates).

[41] *Id.* at 2-10:17 to 2-10:20 ("Since PG&E bundled service customers are currently a minority of customers in its service area, those customers are purchasing a significant portion, 48 percent in 2023, of the RA retained for their compliance from departed load customers at the applicable RA MPBs").

[42] *Id.* at 2-12:13 to 2-12:19 ("Hedging this current RA market exposure would have required PG&E to have entered into additional long-term contracts a number of years ago that would have exceeded projected bundled service customer needs, a practice that is inconsistent with the positions taken by PG&E and other stakeholders in previous proceedings and is inconsistent with the direction in past Commission decisions, while simultaneously further selling from the existing PCIA-eligible portfolio").

[43] *Id.* at 2-12, n. 23 (citing to D.15-10-031, *Decision Approving 2014 Bundled Procurement Plans*, R.13-12-010 (Oct. 23, 2015), at 20, "…thus hedging beyond the bundled customers is over-hedging, harmful to the public interest, and should be rejected"; *see also* D.13-11-024, *Decision Conditionally Accepting 2013 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan and On-Year Supplement*, R.11-05-005 (Nov. 20, 2013), at 43 ("PG&E states that an [additional] bank is needed to mitigate risks…DRA objects to PG&E's proposed level of [additional] banked procurement on the basis that it is not cost-effective or necessary for ratepayers….''); D.21-05-030, *Phase 2 Decision on Power Charge Indifference Adjustment Cap and Portfolio Optimization*, R.17-06-026 (May 24, 2021), 40-44, 58 ("Solutions should reduce excess and/or uneconomic resources in IOUs' PCIA portfolios. 'Excess resources' are defined as resources that are not necessary to meet bundled customers' needs and compliance requirements"); D.18-10-019, at 97-104).

[44] Commissioner Baker Remarks.

unbundled customers for the market value of the retained RA. Although these transfers are not problematic in theory it does raise the question of if the risk is symmetrical."[45] While symmetrical risk is of course the central goal of the PCIA, the structure of the methodology is intended to reflect the current value of the retained assets, and therefore providing the benefit of the current high market value to unbundled customers should not raise a red flag.

The deeper problem with PG&E's framing is that it recasts an apparently longstanding practice under the BPPs as a problem with the PCIA. And it shifts the entirely hypothetical cost of that practice (there is no evidence IOUs would have fared better with other procurement strategies) from bundled customers to unbundled customers. It was not unbundled customers that required that IOU customers buy preferentially or exclusively from the PCIA portfolio, yet it is those customers who may be required to pay for those practices.

3. Evaluation of Historical PCIA Rates Demonstrates Bundled Customer Benefits

The existing framework has conveyed substantial benefits to bundled customers, even when PCIA prices are negative. Post-D.18-10-019, PCIA rates spiked, foisting major costs onto CCA residential ratepayers in 2019 and beyond. At the same time, residential bundled customers experienced a relative rate reduction. The three figures below show average residential PCIA rates for the three IOUs since 2012.

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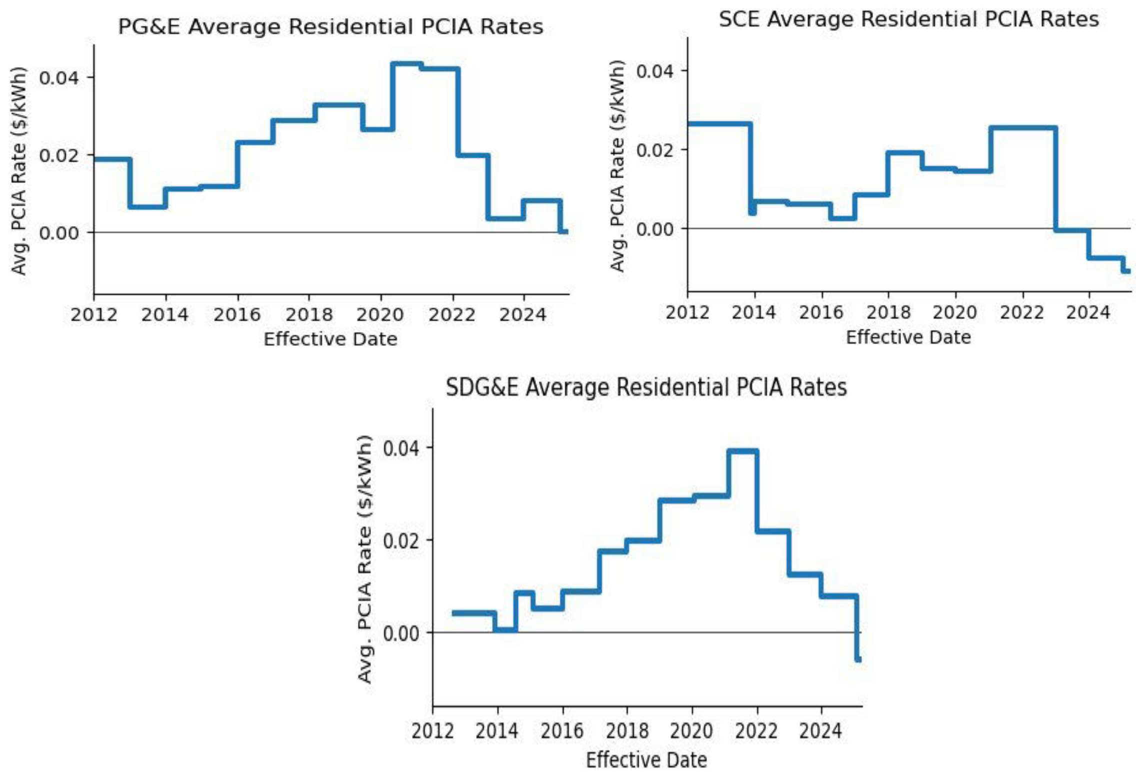
[45] The *practical* application of the PCIA MPBs, and the PCIA more generally, tells a different story. As the value of RA has increased over the past few years, much of that value has been allocated to more recent vintages. That means that even when the overall Indifference Amount is negative, *i.e.*, the value of the portfolio outweighs the cost of the portfolio, many CCA customers in the older vintages still pay positive PCIA rates while bundled customers pay negative PCIA rates. This phenomenon can be seen in Figure 7, below, showing how a larger portion of the negative indifference amounts in 2023-2025, in PG&E's service territory, is attributed to bundled customers.

FIGURE 4

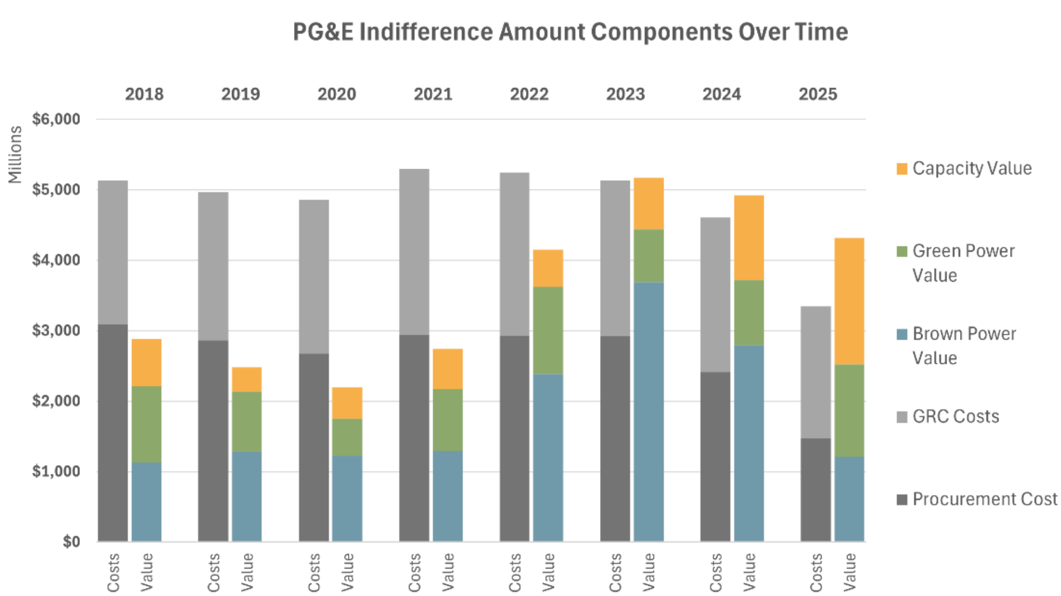


Two things are clear from the Figure 4 charts: (1) PCIA rates increased from 2019 through 2023, *i.e.*, after the Commission implemented the current framework; and (2) negative PCIA rates are a clear exception to historical trends, and not the norm.

Perhaps the most misplaced and concerning part of the Commission's apparent perspective – as voiced in the OIR, ED Staff Report, and remarks from the dais is the implicit suggestion that a return to these high PCIA rates, or even positive PCIA rates, would somehow right the ship of indifference in California. Indifference does not require high PCIA rates be paid by unbundled customers, and as described *infra*, the possibility of negative PCIA rates were part of the framework the Commission put into place.

Further, the ED Staff Report appears to suggest that the RA MPB specifically has resulted in a large increase in value of the IOUs' portfolios in recent years.[46] However, changes to the RA MPB and the Energy Index have tended to cancel each other out since 2023, with the overall value of PG&E's portfolio (for example) decreasing since then—not increasing. This can be seen in Figure 5 below, showing the components of PG&E's indifference amount calculation over time. Note how from 2023 to 2025, the blue portion of the market value bars (*i.e.*, the Energy Value or "Brown Power") moves in an opposite direction to the gold portion (*i.e.*, the Capacity Value), with the overall value of the portfolio decreasing since 2023.

FIGURE 5

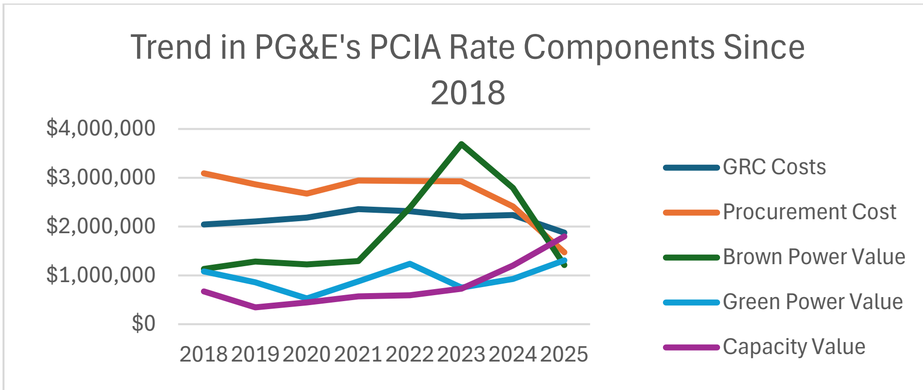


Taking a more holistic view of the different components of the PCIA rate shows a much more complex picture on what is driving PCIA rate changes than what is stated in the OIR.

46 *See* ED Staff Report, at 6 ("System RA MPBs are the main driver of the increases in each IOU's total portfolio market value included in their respective ERRA Forecast filings, which has yielded the PCIA as a credit") (emphasis added).

Indeed, the RA MPB has not been nearly as volatile as the Energy Index or the changes in procurement costs for PG&E, as shown in Figure 6, below:

FIGURE 6

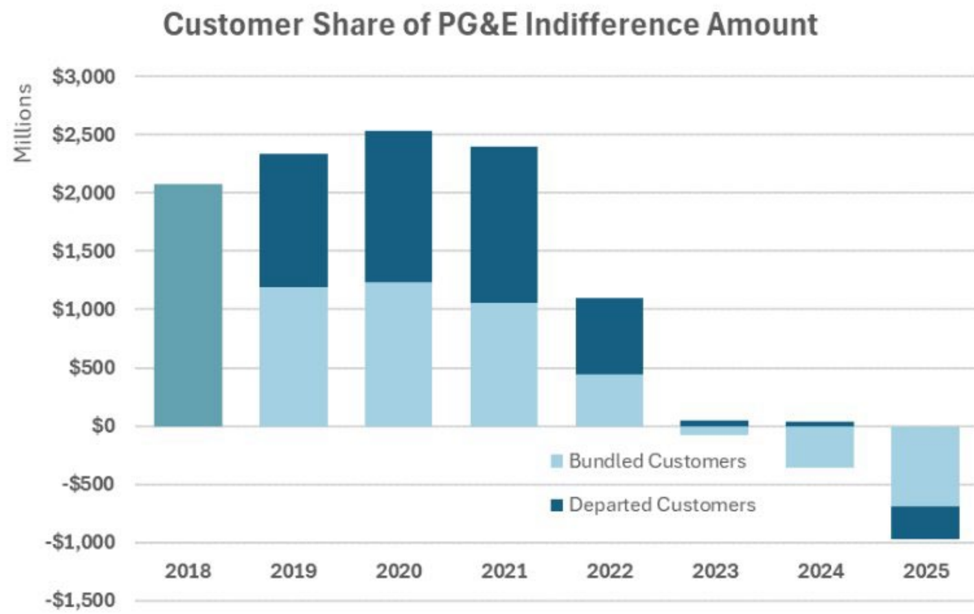


The ED Staff Report creates an erroneous impression in arguing that the proposals are needed because "the system RA Forecast and Final MPBs have seen the most volatility since the current PCIA MPB methodology was adopted in D.18-10-019."[47]

Finally, even when the overall Indifference Amount is negative, *i.e.*, the value of the portfolio outweighs the cost of the portfolio, many CCA customers in the older vintages still pay positive PCIA rates while bundled customers pay negative PCIA rates. This phenomenon can be seen in Figure 7 below, showing how a larger portion of the negative indifference amounts (i.e., *credits* to customers) in 2023-2025 in PG&E's service territory is actually credited to bundled customers, who represent only one-third of PG&E's load, and not unbundled customers, who represent roughly two-thirds of PG&E's load.

[46] ED Staff Report, at 5.

FIGURE 7



It is clear from this figure that departed load (dark blue) still paid above-market costs and positive PCIA rates in 2023 and 2024 even though the overall Indifference Amount was negative. This is because older vintages still contained above-market costs, while newer vintages, including those for bundled customers, enjoyed the net benefits of resources with lower costs. A specific example of this type of procurement is PG&E's mid-term reliability procurement, which are assigned to vintage 2021, enjoy a high valuation, and were procured at lower costs compared to other capacity. All of this taken together demonstrates the significant benefits conveyed to bundled customers through the PCIA.

4. Past ERRA Forecast Cases Demonstrate How the IOUs Take Advantage of the ERRA Process to Benefit Bundled Customers

Past ERRA Forecast cases demonstrate how the IOUs take advantage of the ERRA processes to benefit bundled customers through the PCIA. The OIR suggests "the ERRA process itself is intended to function as an individual electric IOU's annual forecast and accounting review, not as a forum for evaluating or setting policy."[48] It goes on to state "[a] certain amount of policy decision-making is inherent within a thorough consideration of customer programs and procurement obligations" even in the expedited ERRA cases. [49]

While the Commission has policed its prohibition on policymaking effectively in many cases,[50] the reality is the ERRA Forecast proceedings sometimes go well past ministerial acts to modify policies and PCIA ratemaking to the benefit of bundled customers. The most prejudicial of these events is when such changes occur in the October Update, which only the IOUs are able to submit. Proposals to change policy and ratemaking in the October Update are especially troublesome because it is an extremely time-compressed period of the ratesetting process, frequently leaving intervenors weeks or days to respond to voluminous testimony updates, while still giving the IOUs another opportunity to respond to concerns intervenors raise.[51]

As an example, in D.24-12-039 (deciding SCE's 2025 ERRA Forecast case), the Commission shifted $335.8 million in benefits to SCE's bundled customers on the backs of departed customers via a last-minute, substantive proposal in SCE's Alternate October Update (AOU) offered in response to a Ruling requesting "procedural mechanisms" tied to potential under collections in the RA MPB.[52] D.24-12-039 adopted SCE's AOU in full, including SCE's

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48 *See* OIR at 10.

49 *Id.* at 11.

50 *See Assigned Commissioner's Scoping Memo and Ruling*, A.22-05-014 (Aug. 12, 2022), at 1-2 (denying consideration of SCE's Green Share rate option because it "is newly proposed' and "the parties and the Commission would be required to address new program rules and standards within the compressed time frame of this proceeding, a process that could reduce the time used to address and resolve this proceeding's other issues and adversely impact the proceeding schedule").

51 *See, e.g., Assigned Commissioner's Scoping Memo and Ruling*, A.24-05-007 (Aug. 14, 2024), at 4 ("SCE is directed to prepare, serve, and file by October 21, 2024, an Alternate October Update as described in its October 14, 2024 comments to the Mechanisms Ruling."); *Email Ruling Directing Southern California Edison Company to File an Alternate October Update, Providing Opportunity for Response and Reply, and Clarifying Schedule,* A.24-05-007 (Oct. 16, 2024).

52 *See California Community Choice Association's Comments on Proposed Decision*, A.24-05-007 (Dec. 2, 2024), at 1 ("The Proposed Decision takes extra-procedural steps to grant $335.8 million in benefits to SCE's bundled customers on the backs of departed customers").

proposal to recategorize almost half of its PCIA-eligible capacity portfolio from System RA and Flexible RA to Local RA (RA Categorization Proposal). [53] The Commission adopted the RA Categorization Proposal not only for the 2025 forecasted indifference amount, but also for the 2024 true-up, changing the rules of PCIA ratesetting at "halftime", *i.e.*, between the forecast and the true-up.[54] The result was SCE counting 4,500 megawatts (MW) as Retained Local RA -_ capacity all parties to the proceeding agreed was used as System RA during 2024 and forecasted to be used as System RA in 2025.[55] That amounted to 1,500 MW beyond *the entirety of the Central Procurement Entity's (CPE) Local RA obligation* for all of SCE's service territory. The case suggests the Commission is evaluating PCIA questions through a lens of what benefits bundled customers, and illustrates the clear advantages given to bundled customers when the Commission allows IOUs to propose changes to the rules at the last minute.

In both process and substance, the current PCIA framework has worked to the benefit of bundled customers since its inception in 2018. The fact that market forces have shifted to put more IOU resources at or above market value, thereby reducing PCIA revenue requirements, does not automatically mean something is wrong with the PCIA that must be corrected on an expedited basis with potential retroactive effect. Indeed, it may mean the PCIA is providing the type of indifference the Commission and the Legislature originally intended.

III. COMMENTS ON TRACK ONE PROPOSALS

The OIR states the Commission will consider adopting some or all of Energy Division's proposals to mitigate the impacts of "[r]apid changes to the marginal price of RA" through

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53 A.24-05-007, Exh. SCE-09 at 2:5-7 (explaining how SCE's AOU changes "how SCE applies System, Flexible, and Local RA MPBs to its PCIA portfolio *for both its 2024 true-up* and its 2025 forecast") (emphasis added).

54 *Ibid*.

55 *See California Community Choice Association's Comments on Proposed Decision*, A.24-05-007 (Dec. 2, 2024), at 2.

"consider[ation of] whether the current RA MPB formulation reflects the market value of the entirety of the IOU [PCIA] portfolio."[56] The ED Staff Report identifies "two sets of issues with the current RA MPB methodology": (1) "the current methodology fails to capture all transactions for deliverability in year n"; and (2) fails to exclude non-market or non-arm's length transactions that may not reflect genuine market prices."[57]

The ED Proposal, considered in the OIR, sets forth five proposals:

1) Include all transactions available for given delivery year for all system, flex, and local RA forecast and final adders;
2) Consider using one value for all MPBs, including system, local and flexible;
3) Exclude affiliate transactions from the calculation of the MPB;
4) Exclude swap and sleeve transactions from the MPB; and
5) Consider using monthly values for the MPBs.[58]

As set forth below, Proposal One should be rejected because it would constitute an outcome-driven wholesale rework of the current RA MPB framework as it requires the value of the retained RA to be calculated with historical transactions rather than the current market value. Adopting this approach would create an apples-and-oranges PCIA calculation, mixing short-term, current values for RPS and Brown Power and long-term values for RA. Proposals Two through Five, however, should be adopted with the conditions set forth below, as they all simply increase the accuracy within the current framework. In all events, the Commission's adoption or rejection of any of the proposals must only occur after adequate and transparent data and modeling is provided to demonstrate the rate impacts on both bundled and unbundled customers.

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56 OIR at 19.

57 ED Staff Report, at 6.

58 OIR at 18-23. A sixth proposal, called "Placeholder proposals," notes that the Commission may consider adopting an "interim methodology" for 2026, to be followed by a more complete reexamination for the following year, presumably in Track Two. *Id.* at 23.

A. Any Commission Decision on the Staff Proposals Must Be Based on Transparent Data and Modeling Demonstrating the Rate Impacts on Bundled and Unbundled Customers

Any Commission decision on the ED Staff proposals must be based on transparent data and modeling demonstrating the rate impacts on bundled and unbundled customers. As an initial matter, significant data needed by parties (and ED Staff) to evaluate the ED Staff proposals is lacking, including relative rate impacts to bundled and unbundled customers of *any* ED Staff proposal. Therefore, parties must resort to reproducing utility ratemaking from 2025 to determine how much the PCIA will change for each vintage as a result of the ED Staff proposals. In addition, the analysis of combining ED Staff proposals in section 5 of the ED Staff Report fails to provide modeling for each Proposal, and different combinations of Proposals, preventing parties from viewing a full picture of potential outcomes. Any impact on the RA MPB and customer rates should be supported by transparent modeling of impacts for all scenarios. Prior to the Commission adopting or rejecting any of the ED Staff proposals as recommended below, the Commission must transparently demonstrate the estimated rate impacts of their proposals. The Commission should also, after it calculates the MPBs for all scenarios, order the IOUs to present system average PCIA rate impacts for each vintage. Approving significant ratemaking methodology changes prior to demonstrating the relative rate impacts to bundled and unbundled customers would be a half measure, does not provide a complete understanding of critical changes, and does nothing to dispel notions of Commission bias towards IOUs and bundled customers.

B. Proposal One Should be Rejected as Inclusion in the RA MPB of All Transactions Deliverable, Rather Than Transacted, in a Year Does Not Reflect Current Market Value as Required by the RA MPB Framework

Proposal One to include all transactions available for a given delivery year in the calculation of the RA MPB should be rejected as it fails to provide to departed customers the *current value* of bundled customers' retained RA. The ED Staff Report cites reduced liquidity and low transaction volumes as reasons to include *all* long-term and short-term contracts with deliverability in a particular year "to more accurately capture all procurement costs."[59] However, one year of rate volatility negatively impacting bundled customers does not justify abruptly modifying the RA MPB to favor bundled customers. In addition, ED Staff's concern regarding low transaction volumes can be addressed by the adoption of the ED Staff proposal to combine the three RA benchmarks into one, which CalCCA supports as set forth below in section III.C.

Proposal One should be rejected as it: (1) is inconsistent with the Commission's directive in D.18-10-019 that departed customers be credited for the *current* market value of RA, not the long-term average cost, of retained RA; (2) is an outcome-driven solution that would abruptly upend an established methodology to achieve a higher PCIA simply to mitigate the effect of current market conditions on bundled customers; and (3) creates and internally inconsistent methodology, blending both short- and long-term benchmarks.

1. The Cornerstone of the Current PCIA Framework is to Assess the IOU PCIA Portfolios at their Current Market Value

Section 365.2 mandates indifference for departed customers, requiring the Commission to "ensure that departing load ***does not experience any cost increases*** as a result of the allocation of costs that were not incurred on behalf of the departing load."[60] Under section 366.2, unbundled customers are responsible solely for "estimated net unavoidable electricity costs" when determining indifference, and those costs "shall be reduced by the *value of the* benefits" in the IOUs' portfolios that accrue to bundled customers.[61] Not only are the value of the benefits that remain with bundled customers half of the indifference equation, but they are also the lynchpin of

59 ED Staff Proposal, at 9.
60 Cal. Pub. Util. Code § 365.2.
61 *Id.* at § 366.2(f)(2), (g).

the Track One issues the Commission raises. The benefits side of the indifference equation manifests in the market value portion of the PCIA ratemaking formula discussed *supra* in Figure 2.

The question of how to determine the value of capacity that remains with the IOUs for their own use was determined in D.18-10-019. The cornerstone of that approach is to value an attribute at the price at which it can be *bought and sold*.[62] Thus, the Commission adopted a version of a mark-to-market approach for determining the value of assets common across many industries, with the RA Adder "calculated using reported *purchase and sales* prices of IOU, CCA, and ESP transactions *made* during (year n-1) for deliveries in (year n)."[63] The decision states TURN "speaks for most parties" when it asserted that the prior method of valuing RA capacity, the published going forward costs of constructing a combined cycle generation turbine, "'has very little relationship to *the actual market prices at which all LSEs buy and sell RA capacity*.'"[64] While their initial proposal was rejected, the IOUs supported the idea of valuing Retained RA at the price at which it could be bought and sold.[65]

The OIR includes numerous statements that muddy these waters, suggesting inputs to the RA MPB only represent a marginal amount of the total capacity procured to meet IOU obligations,[66] only represent incremental capacity to meet certain compliance requirements, [67] only represent a small fraction of the RA resources procured,[68] and only leads to customer indifference if the MPB is accurate. [69] However, these statements *still* go to the accuracy of the

62 *See* D.18-10-019, at 73.
63 *Ibid.* (emphasis added).
64 *Id.* at 36 (emphasis added).
65 *See* D.18-10-019, at 149 (stating "TURN and the Joint Utilities, on the other hand, support the proposed benchmarks.").
66 ED Staff Report, at 8.
67 *Ibid.*
68 *Id.* at 9.
69 OIR at 15.

current methodology in assessing market value *today* and *not* to the question of whether the current market value should be used, or a series of historical costs, or whether the calculation of value should be discarded in favor of a calculation of historic costs. That is, the reasoning in D.18-10-019 is still sound: the value of an asset is the price at which it can be sold *today*—not the price at which it was procured or could have been sold five or more years ago. While the Commission is right to seek to assess whether the MPB accurately reflects *current* market value, it should not abandon the notion of the current value altogether.

Further, the fact remains that in 2024 the market value of the IOUs' portfolios *was high*. As the ED Staff Report recognizes to some degree, the high RA MPBs for 2025 illustrated the market conditions CalCCA's members have navigated in recent years.[70] The parties to the ERRA Forecast proceedings largely agreed there was scarcity in the RA market,[71] which is an issue that CalCCA and its member CCAs have attempted to tackle repeatedly and in earnest in other proceedings.[72]

Capacity transactions from the Federal Energy Regulatory Commission's (FERC) data Electronic Quarterly Reports, which can act as a public proxy for the confidential transactions reported to Energy Division to calculate the RA MPB, also clearly bear out these high market prices. The weighted-average price of capacity purchased by California LSEs shows that, in recent years, the IOUs sold capacity at prices that exceeded even the current actual RA MPBs. On average, across the Summer of 2024, PG&E sold 425 MW of capacity each month at an

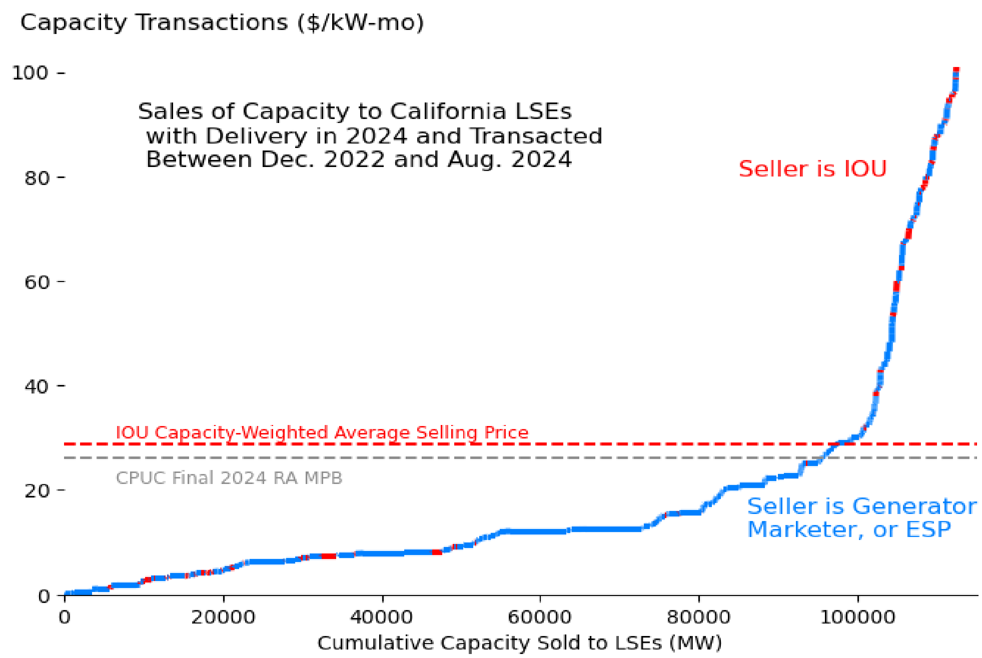
70 *See* ED Staff Report, at 5-9.

71 A.24-05-009, *Pacific Gas and Electric Company Prepared Testimony*, at 2-13:19-21 (May 15, 2024) (citing market scarcity to justify its proposal to cap the RA MPB).

72 *See* R.23-10-011, *Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations; see also* CalCCA RA Whitepaper, *California's Constrained Resource Adequacy Market: Ratepayers Left Standing in a Game of Musical Chairs* (Jan. 16, 2024): https://cal-cca.org/resource-adequacy.

average price of $56.5/ kilowatt (kW) -month. Across all sales to California LSEs with delivery in 2024 and transaction dates between December 2022 and August 2024, the timeframe used by the Energy Division to calculate the System RA MPB, IOUs sold capacity at a capacity-weighted average price of $28.87/kW-month, which was higher than the 2024 final System RA MPB of $26.26/kW-month.[73] Across this period, IOU sales of capacity to California LSEs were among the highest priced transactions, as shown in Figure 8, below:

FIGURE 8



*Source: CalCCA analysis of FERC Electronic Quarterly Reports.

Given that the RA MPBs were calculated using real market data in 2025, just as the Commission ordered in D.18-10-019,[74] it should come as no surprise that the value of the IOUs' capacity portfolios is high.

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73 *Energy Division Market Price Benchmark Calculations 2024 REVISED* (Nov. 5, 2024).

74 *See* A.24-05-009, October 4, 2024, MPB Calculations; *see also* D.18-10-019, Appendix 1.

2. Inserting Long-Term Transactions into the Existing RA MPB Calculation is an Outcome-Driven Solution to a Short-term Market Uptick and Should be Rejected

As demonstrated in the ED Staff Report, inserting long-term transactions into the existing RA MPB calculation would significantly lower the 2025 RA MPB, thereby likely decreasing bundled customer rates (and therefore increasing unbundled customer rates).[75] The ED Staff Report states that "the lower RA adder prices reflect lower RA price and higher total transaction volumes, and therefore may be a more accurate proxy for the portfolio cost for deliverability in a given year."[76] However, the RA MPB methodology is not based on the cost of long-term transactions – rather, the methodology gathers current transactions that reflect the cost to sell RA in the current market. As noted above in Figure 8, the RA market price was high in 2024, which is and should be reflected in the MPB. While a short-term "credit" to unbundled customers may be unsettling for Energy Division and the IOUs, the RA MPB methodology was designed to swing according to the market, which it has. Therefore, "correcting" this swing through an artificial outcome-based proposal to include long-term transactions which will lower the MPB is not in line with the RA MPB framework.

The market can move in either direction. CalCCA is deeply concerned that if outcomes are the driving principle behind determining the benchmarking period then there could be a drive to revert to the current methodology when prices change. The way to avoid this is by maintaining consistency over time and not changing the current benchmarking period. As a result, Proposal One should be rejected as not consistent with the valuation of Retained RA in the RA MPB methodology.

[75] *See* ED Staff Report, at 24, Figure 7 (stating that the proposed 2025 Forecast MPB would be reduced from $40.31 to $15.51 under Proposal 1).
[76] *Id.* at 14.

3. Incorporating Long-Term Values in the RA MPB Produces an Internally Inconsistent Methodology

In D.18-10-019, the Commission adopted a PCIA methodology that values all products in the PCIA portfolio using short-term market values. The Commission found that a short-term methodology was "consistent with California energy policy goals and mandates."[77] In addition, adopting short-term benchmarks for RA and RPS products retains consistency with the most straightforward and accurate benchmark: Brown Power. Shifting from a short-term valuation to a long-term valuation for purposes of the interim RA MPB would be a significant change in methodology and would result an overall benchmark that is internally inconsistent. The Commission should thus reject Proposal One and defer any significant changes in methodology to Track Two.

C. Proposal Two Utilizing a Single RA MPB Incorporating System, Local, and Flex Values Should be Adopted to Maximize Representative Transactions

The Commission should use a single RA MPB category that combines System, Flex, and Local RA to maximize representative transactions and increase accuracy in setting the RA MPB. This change will provide two primary benefits to the MPB as it will: (1) reduce sample size issues if one or more RA categories have low transaction volumes for a given year; and (2) prevent unrealistic depictions of the RA market in the RA MPB. The ED Staff Report presents the volume of transactions across the three RA categories in Figure 3, which shows that Flex and System RA transactions were significantly lower than Local RA transactions when calculating the 2024 Final and 2025 Forecast RA MPBs.[78] Low volumes for the 2024 Final and 2025 Forecast RA MPBs led ED Staff to weigh options to keep transaction volumes in the calculation

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77 D.18-10-019, at 128.

78 *Id.* at 6.

higher when the MPBs were published in October of 2024.[79] Combining all three RA categories eliminates potential issues arising from low transaction volumes for one or more RA categories and maximizes the overall transaction sample size, which can create a more robust RA MPB.

The second benefit provided by combining System, Flex, and Local RA in the MPB calculation is the prevention of unrealistic depictions of the RA market in the RA MPB. In the 2024 Final and 2025 Forecast RA MPBs, the System RA MPB is higher than Local and Flex RA MPBs. This is not the first time this has occurred and suggests that System RA required a premium over Local and Flex RA, an unrealistic result that suggests this is a statistical artefact, rather than a true market value dynamic. For example, if Party A wanted to exchange a strip of Flex RA for System RA with Party B, then Party A would pay a premium to Party B. This is not the case in reality. Regardless of the numerical cause of this backwards result, combining the RA MPBs into one MPB would avoid this issue altogether, contributing to the robustness of the RA MPB. As a result, Proposal Two combining the System, Flex, and Local RA in one MPB calculation will increase the accuracy of the RA MPB and should be adopted.

D. Proposal Three Excluding Affiliate Transactions from the MPB Calculation Should be Adopted to Mitigate the Risk of RA MPB Manipulation

The Commission should exclude affiliate transactions as defined by the OIR when calculating the RA MPB to mitigate the risk of RA MPB manipulation and distorting the accuracy of the RA MPB. Excluding affiliate transactions simply increases accuracy of the market price by excluding transactions that may not be at arm's length and therefore do not represent a true market value. Non-arm's length affiliate transactions could artificially increase or decrease the MPB.

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[79] *Addendum to October 2, 2024, Market Price Benchmark Calculations 2024*, A.24-05-007, A.24-05-009, A.24-05-010 (Oct. 9, 2024) (discussing low transaction volumes and why Energy Division Staff did not remove affiliate and swap transactions from the RA MPB calculation).

Further, the Commission should adopt objective criteria to identify and exclude affiliate transactions from the MPB.[80] Criteria should be objective to ensure ED Staff do not need to make subjective decisions as to include or exclude transactions. Given the need to apply PCIA rules consistently to provide ratepayers with stability, allowing broad staff discretion could detract from that consistency and credibility over time. In addition, to the extent manipulation in affiliate transactions is suspected under objective criteria, the Commission should investigate and take any necessary enforcement actions to address that manipulation.

E. Proposal Four Excluding Swap and Sleeve Transactions Should be Adopted to the Extent the Commission Can Objectively and Transparently Identify Such Transactions

The Commission should exclude swap and duplicative sleeve transactions to the extent the Commission can identify such transactions in an objective and transparent manner. The ED Staff Report identified swaps with unusually high prices. As identified by the ED Staff Report, swap transactions involve the exchange of two RA products which may involve a premium for the product and an unusually high price.[81] This contrasts with duplicative sleeve transactions, which may over-count the number of transactions because one party transacted RA on behalf of another party and passed on the RA at the same price or with a premium. The original RA transaction with another market participant is a genuine market transaction, whereas the second transaction is not, and therefore should be excluded in the RA MPB calculation.

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[80] Although ED Staff indicated they identified affiliate transactions, they also stated in the ED Staff Report that they do not currently have the data to exclude affiliate transactions. *See* ED Staff Report, at 12 (stating that ED does not have the necessary data to exclude swap, sleeve, or affiliate transactions, and therefore the impacts of Proposals 3 and 4 were not modeled in the report).

[81] *See* ED Staff Report, at 12 ("In these swap transactions, the overall price is less important than the price spread; for example, an LSE swapping 20 MW of system RA for local RA could report the system price at $25/kW-month and the local price at $30/kW-month, resulting in an additional cost of $5/kW-month for the local capacity. Likewise, this same transaction could be priced at $125/kW-month for the system and $130/kW-month for the local RA, with the same effect, a $5/kW-month premium for the local product.").

The criteria for excluding swap and duplicative sleeve transactions should be transparent, objective, and serve the purpose of excluding all transactions which are not genuine market transactions. Transparency is important so that stakeholders understand what is or is not included in the RA MPB calculation. Criteria should be objective to ensure ED Staff do not need to make subjective decisions as to include or exclude transactions. Given the need to apply PCIA rules consistently to provide ratepayers with stability, allowing broad staff discretion could detract from that consistency and credibility over time. Lastly, exclusion criteria should serve the purpose of ensuring that RA transactions included in the MPB calculation are reflective of the RA market. With such criteria, Proposal Four should be adopted to increase the accuracy of the RA MPB.

F. Proposal Five Utilizing Monthly Values for the Overall RA MPB Should be Adopted to Best Reflect Seasonality of RA Prices

The Commission should utilize monthly values for the RA MPB rather than a single weighted average to reflect seasonality of RA prices. The current calculation creates a weighted average RA price and applies that to all RA, regardless of the delivery month. As prices between summer and winter months diverge, however, seasonality is more important to capture. Currently, RA in January would be overpriced in the MPB and RA in September would be underpriced. Using monthly values ensures transactions in one month do not push or pull average prices in another month, creating an MPB more robust to market trends driven by seasonality. Monthly RA MPB values will also reduce issues of RA transaction imbalances across months. If a delivery month has more or fewer transactions than typical, this difference is more visible to stakeholders and will not skew an overall weighted average. Transparency can also be improved as stakeholders can view monthly values. Seeing a single, weighted RA value can seem like a black box to those without access to the confidential data ED Staff reviews to generate MPBs. Simple changes to the PCIA template and Portfolio Allocation Balancing

Account workpapers can accomplish shifting to a monthly RA benchmark. As a result, Proposal Five should be adopted as it will increase the accuracy of the RA MPB.

G. The Commission Should Require Briefing on Whether Any Track One Revisions to the RA MPB Can be Applied Retroactively

The Commission should order legal briefing on the complex issue of whether any Track One modifications to the RA MPB methodology can be applied retroactively to true-up the 2025 Forecast RA MPB. The Commission states that "[o]ur goal in expediting [Track One] of the OIR is to allow Energy Division to issue MPBs in October 2025 utilizing the new methodology approved."[82] While applying any new methodology prospectively to the 2026 Forecast would be proper, retroactively trueing up 2025 rates with an entirely new methodology raises significant legal issues which should be examined through legal briefing. As a result, CalCCA requests that the Commission order the parties to submit legal arguments on this issue.

IV. COMMENTS ON TRACK TWO SCOPING ITEMS

While Track Two scope should only be finalized after the completion of Track One, CalCCA preliminary proposes the following scoping items for Track Two:

- Consideration of structural changes to the PCIA including:
    - Sunsetting the PCIA to allow IOUs unencumbered access to the PCIA portfolios in an environment of growing load;
    - Allocating PCIA resources as a mechanism for more accurate accounting for full value and reducing customer rate volatility; and
    - Revisiting the PCIA GHG-free methodology to ensure it is valued in the PCIA portfolio;
- Adopting scoping issues proposed in the OIR, including:
    - Consideration of ERRA-specific implementation guidance for the RA Slice of Day Framework;

[82] OIR at 18.

- Consideration of a framework for re-vintaging utility-owned PCIA-eligible resources and contract vintaging; and
- Consideration of Bundled Procurement Plan processes to increase liquidity of assets with PCIA portfolios;

- Consideration of other issues raised but not resolved in past ERRA cases, including:
    - The treatment of pre-2019 banked RECs;[83] and
    - The IOUs' Common Cost Allocation methodologies.[84]

V. CATEGORIZATION

CalCCA agrees with the Commission categorization of the proceeding as ratesetting.

VI. NEED FOR HEARINGS

CalCCA agrees that hearings are likely unnecessary for Track One. CalCCA reserves the right to request hearings for Track Two.

VII. COMMUNICATIONS

CalCCA consents to "email only" service and requests that the following individuals be added to the service list for R.25-02-005, on behalf of CalCCA:

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83 *See, e.g.,* D.23-11-094. *Southern California Edison Company's 2024 Energy Resource Recovery Account Forecast*, A.23-06-001 (Dec. 1, 2023), at 60 ("Should SCE determine that the use of RECs banked in or before 2018 is necessary for its bundled service RPS compliance, it should value those RECs at zero, as it proposed. We further agree with Cal Advocates that the issue of the valuation of RECs banked in or before 2018 would not be appropriately addressed in a single IOU's annual ERRA forecast application proceeding. This Decision adopts an interim solution and authorizes SCE to make modifications necessary to implement the interim solution in 2024.").

84 *See, e.g.,* D.24-12-040, *Decision Approving San Diego Gas and Electric Company's 2025 Electric Procurement Revenue Requirement Forecasts, 2025 Electric Sales Forecast, and Greenhouse Gas Related Forecasts,* A.24-05-010 (Dec. 23, 2024), at 33-34 ("The record is insufficient to show the extent of this issue and whether there would be a material cost shift because there is insufficient information concerning the major tasks performed by the Procurement Group and the amount of labor and non-labor resources devoted to such tasks. Thus, we find that there is sufficient risk and uncertainty to not authorize SDG&E's proposed new method at this time… And as stated above, the new methods proposed by SDG&E and the Joint CCAs will benefit from a more thorough examination.").

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VIII. SCHEDULE

CalCCA agrees with the preliminary schedule provided that, within the timeframe the Commission has laid out, the ED Staff Report can be updated with: (1) clearer explanations surrounding what criteria will be used to exclude affiliate transactions and duplicative sleeve transactions; (2) more complete modeling of ED Staff's Proposals, including the impact of the combination of Proposals Two and Five on the System RA MPB; and (3) the system average PCIA rate impacts of different changes to the RA MPB in each service territory. Parties should also be afforded the ability to submit opening and reply comments on the updated ED Staff Report prior to a Proposed Decision being issued. In addition, CalCCA requests that the Commission order legal briefing on the issue of retroactively applying any modifications to the RA MPB as a result of the Track One Staff Proposals to the 2025 ERRA Forecast true-up.

IX. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

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Respectfully submitted,

/s/ Tim Lindl

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On behalf of
California Community Choice Association

March 18, 2025

VERIFICATION OF ANDREW D. MILLS

Rule 6.2 of the California Public Utilities Commission's Rules of Practice and Procedure, state that "[a]ll comments which contain factual assertions shall be verified. Unverified assertions will be given only the weight of argument." Therefore, pursuant to Rules 1.11 and 6.2, I, Andrew D. Mills, declare as follows:

I am the Director of Data Analytics at the California Community Choice Association (CalCCA), and an expert witness supporting CalCCA in the *Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes,* Rulemaking 25-02-005, and am authorized to make this verification on CalCCA's behalf.

The following statements or figures in the foregoing document are true of my own knowledge except as to matters that are stated on information and belief, and as to those matters, I believe them to be true:

- Figure 1, page 9
- Figure 4, page 18 (created charts from data provided by Brian Dickman, which on information and belief I believe to be true)
- Figure 7, page 21 (created charts from data provided by Brian Dickman, which on information and belief I believe to be true)
- The following paragraph on Page 28-29:

Capacity transactions from the Federal Energy Regulatory Commission's (FERC) data Electronic Quarterly Reports, which can act as a public proxy for the confidential transactions reported to Energy Division to calculate the RA MPB, also clearly bear out these high market prices. The weighted-average price of capacity purchased by California LSEs shows that, in recent years, the IOUs sold capacity at prices that exceeded even the current actual RA MPBs. On average, across the Summer of 2024, PG&E sold 425 MW of capacity each month at an average price of $55.5/ kilowatt (kW) -month. Across all sales to California LSEs with delivery in 2024 and transaction dates between December 2022 and August 2024, the timeframe used by the Energy Division to calculate the System RA MPB, IOUs sold capacity at a capacity-weighted average price of $28.87/kW-month, which was higher than the 2024 final System RA MPB of $26.26/kW-month. Across this period, IOU sales of capacity to California LSEs were among the highest priced transactions, as shown in Figure 8, below.

- Figure 8, page 30

I declare under penalty of perjury in the State of California that the foregoing is true and correct.

Executed on March 17, 2025, at Oakland, California.

Andrew D. Mills

Andrew D. Mills
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VERIFICATION OF BRIAN DICKMAN

Rule 6.2 of the California Public Utilities Commission's Rules of Practice and Procedure, state that "[a]ll comments which contain factual assertions shall be verified. Unverified assertions will be given only the weight of argument." Therefore, pursuant to Rules 1.11 and 6.2, I, Brian Dickman, declare as follows:

I am Partner at NewGen Strategies & Solutions, LLC, and the expert witness supporting the California Community Choice Association (CalCCA) in the *Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes,* Rulemaking 25-02-005, and am authorized to make this verification on CalCCA's behalf.

The following statements and figures in the foregoing document are true of my own knowledge except as to matters that are stated on information and belief, and as to those matters, I believe them to be true:

- Figure 4, page 18 (provided data for charts created by Andrew Mills, which on information and belief I believe to be true)
- Figure 5, page 19
- Figure 6, page 20
- Figure 7, page 21 (provided data for charts created by Andrew Mills, which on information and belief I believe to be true)
- The following paragraph on page 21:

It is clear from this figure that departed load (dark blue) still paid above-market costs and positive PCIA rates in 2023 and 2024 even though the overall Indifference Amount was negative. This is because older vintages still contained above-market costs, while newer vintages, including those for bundled customers, enjoyed the net benefits of resources with lower costs. A specific example of this type of procurement is PG&E's mid-term reliability procurement, which are assigned to vintage 2021, enjoy a high valuation, and were procured at lower costs compared to other capacity.

I declare under penalty of perjury in the State of California that the foregoing is true and correct.

Executed on March 17, 2025, at Vancouver, Washington.

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

Implementing Senate Bill 846 Concerning Potential Extension of Diablo Canyon Power Plant Operations	Rulemaking 23-01-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION

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" #$%&(!)#!
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
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Dated: March 20, 2025

TABLE OF CONTENTS

TABLE OF AUTHORITIES

SUMMARY OF RECOMMENDATIONS

- ¥ The Commission[1] should prohibit PG&E from spending VPF revenues on projects that benefit its generating assets.

- ¥ The Commission should adopt the changes to the Proposed Decision’s Findings of Fact and Conclusions of Law listed in Appendix A to these comments.

1 Acronyms and defined terms used in the Summary of Recommendations are defined in the body of these comments.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Implementing Senate Bill 846 Concerning Potential Extension of Diablo Canyon Power Plant Operations	Rulemaking 23-01-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON THE PROPOSED DECISION

The California Community Choice Association[2] (CalCCA) submits these comments on Administrative Law Judge (ALJ) Atamturk's **+,#-#&./!0'12&#%3#%4+34&!5'!*[3] (Proposed Decision) in the above-captioned proceeding pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission).

Scoping Issue 1 in this Phase 2 asks: "Whether the Commission should continue to use the general framework and definitions for the use of the surplus performance-based fees as adopted in D.23-12-036 in the post-2024 period."[4] Consistent with their proposals in Pacific Gas and Electric Company's (PG&E) recently-concluded inaugural Diablo Canyon Extended Operations Forecast proceeding,[5] multiple intervening parties—including CalCCA—

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 !"#$%$&'()*+',-&-$.*$.*"/0&'*1*2&&3'&, Rulemaking (R.) 23-01-007 (Feb. 28, 2025).

4 4&&-5.'(*6$77-&&-$.'#8&*47'.('(*9,$%-.5*:'7$*0.(*;3<-.5*=$#*"/0&'*1*$=*"#$,''(-.5 (Scoping Memo), R.23-01-007 (June 25, 2024), at 2.

5 4%%<-,0>-$.*$=*"0,-=-,*?0&*0.(*@<',>#-,*6$7%0.A*>$*;',$B'#*-.*63&>$7'#*;0>'&*>/'*6$&>&*>$* 93%%$#>*@C>'.('(*D%'#0>-$.*$=*+-0E<$*60.A$.*"$F'#*"<0.>*=#$7*9'%>'7E'#*GH*1I1J*>/#$35/*+','7E'#* JGH*1I1K*0.(*=$#*4%%#$B0<*$=*"<0..'(*@C%'.(->3#'*$=*1I1K*L$<37'>#-,*"'#=$#70.,'*M''&, Application (A.) 24-03-018 (Mar. 29, 2024).

recommend the Commission adopt principles that condition PG&E's volumetric performance fee (VPF) spending in the post-2024 period. CalCCA proposes:

1. VPF funds should be used on projects providing benefits to the largest number of customers possible, including bundled and unbundled customers.
2. VPF funds should be used first on projects related to electric distribution to help reduce upward pressure on distribution rates.
3. VPF funds should not be used on projects that benefit PG&E's generation assets.

These principles would not only ensure PG&E's VPF spending falls within the "critical public purpose priorities" listed in Senate Bill (SB) 846,[6] but would also avoid enriching PG&E's shareholders and maximize equitable benefits to customers.

The Proposed Decision does not adopt the principles that CalCCA and other intervening parties propose. However, the Proposed Decision acknowledges that intervenors' proposals with respect to PG&E's VPF spending "all share a common theme: benefitting ratepayers through the efficient spending of VPFs in ways that reduce upward pressure on rates."[7] The Proposed Decision therefore "strongly encourages PG&E to take [the proposals'] underlying reasoning into account during the VPF planning process."[8] The Proposed Decision further encourages PG&E to "look for opportunities to structure and plan expenditures in ways that provide additional benefits to ratepayers", and adopts affordability "as a guiding principle in VPF spending[.]"[9] Finally, to the extent PG&E "takes advantage of opportunities to align with the guiding principle of reducing upward pressure on rates", the Proposed Decision directs PG&E to explain that alignment in its spending plan submittals.[10]

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6 Those critical public purpose priorities are listed at Cal. Pub. Util. Code § 712.8(s)(1)(A)-(F).
7 9''*Proposed Decision at 15.
8 9''*-(. at 14.
9 9''*-(. at 15-16.
10 9''*-(. at 16.

The Proposed Decision takes a step in the right direction by encouraging PG&E to consider affordability when designing VPF spending, but it does not go far enough. The Commission should adopt CalCCA's spending principles because those principles give PG&E far more concrete guidance on how to focus and prioritize its VPF spending. Principle 3 (prohibiting the use of VPF funds on generating assets), in particular, would help ensure PG&E's VPF spending not only benefits customers, but provides <u>equitable</u> benefits. That is because spending on transmission and distribution helps all PG&E customers, whereas spending on generating assets risks disproportionately benefiting PG&E's bundled customers. As the Alliance for Nuclear Responsibility (A4NR) points out in its Phase 2 Proposals, "[a]n electrical corporation using "surplus" performance-based fees to fund improvements on its own generation system would potentially be discriminating against those of its distribution and transmission customers who are not also generation customers"—*26 6,* "customers of direct access providers and community choice aggregators, who obtain their electric generation from providers other than PG&E, SCE or SDG&E."[11]

The Proposed Decision should therefore adopt CalCCA's proposed VPF spending principles. Contrary to the Proposed Decision, nothing in SB 846 in California law prevents the Commission from adopting spending principles that supplement or advance the requirements of section 712.8(s)(1) and (s)(2)—such as those CalCCA proposes. At minimum, the Commission should adopt CalCCA's principle 3 (which A4NR's proposals echo) and thereby avoid raising the thorny equity issues that will arise if PG&E spends VPF revenues on its generating assets. In the alternative, to the extent the Commission wants to avoid foreclosing all spending that

[11] Alliance for Nuclear Responsibility's Proposals on Phase 2 Issues at 4 (Aug. 15, 2024).

*1#$(. !*benefit PG&E's generation assets, the Commission should expressly direct PG&E to prioritize VPF spending on distribution and transmission projects.

I. PG&E SHOULD NOT USE VPF FUNDS ON PROJECTS THAT BENEFIT ITS GENERATING ASSETS

According to SB 846, to the extent it is not needed for Diablo Canyon, VPF revenue must be spent to accelerate, or increase spending on, the following public purpose priorities:[12]

(A) Accelerating customer and generator interconnections.

(B) Accelerating actions needed to bring renewable and zero-carbon energy online and modernize the electrical grid.

(C) Accelerating building decarbonization.

(D) Workforce and customer safety.

(E) Communications and education.

(F) Increasing resiliency and reducing operational and system risk.

Consistent with D.23-12-036[13], the Commission's annual review of PG&E's VPF spending plans must focus on determining whether the proposed spending properly falls within one or more of the categories listed above, and that the spending would not result in double recovery in rates, cause compensation to be paid out to PG&E shareholders, or cause PG&E to earn a rate of return on any of the expenditures.[14] However, to guide PG&E in its prioritization of projects funded with VPF revenue in the post-2024 period, CalCCA recommends the Commission adopt the following spending principles:

1. VPF funds should be used on projects providing benefits to the largest number of customers possible, including bundled and unbundled customers.

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12 Cal. Pub. Util. Code § 712.8(s)(1).

13 Decision (D.) 23-12-036, +',-&-$.* 6$.(->-$.0<<A* 4%%#$B-.5* @C>'.('(* D%'#0>-$.&* 0>* +-0E<$* 60.A$.*N3,<'0#*"$F'#*"<0.>*"3#&30.>*>$*9'.0>'*O-<<*PQR, R.23-01-007 (Dec. 15, 2023).

14 2(S at 114.

2. VPF funds should be used first on projects related to electric distribution to help reduce upward pressure on distribution rates.

3. VPF funds should not be used on projects for PG&E's generation assets.

The Proposed Decision does not adopt these spending principles "due to statutory limitations[.]"[15] Here, the Proposed Decision commits legal error. Nothing in SB 846 or in any other provision of California law prevents the Commission from adopting additional principles that ensure PG&E's VPF spending within the public purpose priorities listed at section 712.8(s)(1)(A)-(F) of the Public Utilities Code also maximizes equitable benefits to its customers.

However, while the Proposed Decision does not adopt CalCCA's proposed spending principles, it acknowledges that intervenors' proposals with respect to PG&E's VPF spending "all share a common theme: benefitting ratepayers through the efficient spending of VPFs in ways that reduce upward pressure on rates."[16] The Proposed Decision endorses that theme and "strongly encourages PG&E to take [the proposals'] underlying reasoning into account during the VPF planning process."[17] The Proposed Decision further encourages PG&E to "look for opportunities to structure and plan expenditures in ways that provide additional benefits to ratepayers", and adopts affordability "as a guiding principle in VPF spending[.]"[18]

While the Proposed Decision correctly encourages PG&E to provide benefits to ratepayers, a more effective way for the Commission to ensure ratepayer benefit is to adopt specific, concrete principles that guide PG&E's VPF spending going forward. The Commission should therefore adopt CalCCA's proposed spending principles. In particular, the Commission should adopt CalCCA's spending principle 3 (prohibiting the use of VPF revenues on generating assets),

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15 9' ' Proposed Decision at 8.
16 9' '*-(. at 15.
17 9' '*-(. at 14.
18 9' '*-(. at 15-16.

because that principle will help ensure PG&E provides <u>equitable</u> benefits to its customers. Whereas VPF spending on electric distribution infrastructure will help all customers by reducing upward pressure on distribution rates, spending on generating assets can raise complex equity issues regarding the set of customers on whose behalf PG&E's investments are made. Those issues, in turn, implicate questions regarding the appropriate vintaging of PG&E's generating assets and whether PG&E will gain a competitive advantage over other load-serving entities in meeting its procurement requirements on account of revenue paid by all customers. The Commission can avoid having to resolve these thorny issues by prohibiting PG&E from using VPF revenues generation infrastructure. In the alternative, to the extent the Commission wants to avoid foreclosing all spending that ***1#$(. !***benefit PG&E's generation assets, the Commission should expressly direct PG&E to prioritize VPF spending on distribution and transmission projects, and spend VPF funds on generation projects only when eligible transmission and distribution-related projects are exhausted.

II. CONCLUSION

As the Proposed Decision recognizes, PG&E will collect approximately $167 million in VPFs in 2025, and similar amounts annually through 2030. These substantial collections can benefit PG&E's customers, but in order to ensure that outcome, the Commission should establish robust principles that focus PG&E's spending. CalCCA and other intervenors have proposed such guardrails, and the Commission has the authority to adopt those proposals. At minimum, the Commission should adopt CalCCA's proposed principle 3 and prohibit PG&E from spending VPFs on its generating assets. CalCCA requests the Commission adopt the changes to the Proposed Decision presented in Appendix A to these comments and grant any other relief the Commission deems just and reasonable.

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

Dated: March 20, 2025

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION

CalCCA's Recommended Changes to Findings of Fact and Conclusions of Law

Pursuant to Rule 14.3 (b) of the Commission's Rules of Practice and Procedure, CalCCA offers the following index of recommended changes to the Proposed Decision, including proposed additions to the Proposed Decision's Findings of Fact and Conclusions of Law. CalCCA's proposed revisions appear in underline and ~~strike-through~~.

Findings of Fact

1. Certain p~~P~~arty proposals on the general framework and definitions for the use of the volumetric performance fees either failed to comply with the relevant statutory requirements, addressed issues that have already been resolved, or were unpersuasive.

Conclusions of Law

2. It is reasonable and appropriate to continue to use the general framework and definitions for the use of the volumetric performance fees as adopted in D.23-12-036 in the post-2024 period~~.~~, however, it is reasonable to supplement that framework with the following principles:

    1. VPF funds should be used on projects providing benefits to the largest number of customers possible, including bundled and unbundled customers.

    2. VPF funds should be used first on projects related to electric distribution to help reduce upward pressure on distribution rates.

    3. VPF funds should not be used on projects that benefit PG&E's generation assets.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Implementing Senate Bill 846 Concerning Potential Extension of Diablo Canyon Power Plant Operations	Rulemaking 23-01-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION
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Dated: March 25, 2025

SUMMARY OF RECOMMENDATIONS

CalCCA[1] recommends that the Commission:

- ¥ Reject PG&E's arguments that the Proposed Decision imposes impermissible requirements, and adopt the Proposed Decision which establishes guardrails to require PG&E to provide an estimate of the number of customers benefitting from proposed VPF projects and how those proposals address the issue of affordability.

CalCCA additionally recommends that the Commission adopt the following CalCCA proposals for guidelines regarding VPF funds:

1. VPF funds should be used on projects providing benefits to the largest number of customers possible, including bundled and unbundled customers;
2. VPF funds should be used first on projects related to electric distribution to help reduce upward pressure on distribution rates; and
3. VPF funds should not be used on projects that benefit PG&E's generation assets.

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

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Implementing Senate Bill 846 Concerning Potential Extension of Diablo Canyon Power Plant Operations	Rulemaking 23-01-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REPLY COMMENTS ON THE PROPOSED DECISION

The California Community Choice Association[2] (CalCCA) submits these reply comments on Administrative Law Judge (ALJ) Atamturk's *+,#-#&./!0'12&2#%1#%1+34&!5[3] (Proposed Decision) in the above-captioned proceeding pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission).

I. INTRODUCTION

Amidst an electric rates affordability crisis, the Phase II Proposed Decision reasonably seeks to require Pacific Gas and Electric Company (PG&E) to provide information on customer benefits with future Volumetric Performance Fee (VPF) spending requests. Though the Proposed Decision rejects CalCCA's proposed principles for VPF spending, it requires PG&E to include both an estimate of how many customers will stand to benefit from a proposed VPF project and how proposed projects will address affordability in future VPF plans. In Opening Comments, PG&E argues that the Proposed Decision commits legal error by requiring this information because its goes beyond what Public Utilities Code section 712.8 requires.[4] This is not the case. The Proposed Decision's requirements do not create additional public purpose criteria; these requirements are guardrails that implement the statutory scheme. CalCCA therefore recommends

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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 !"#$%$&'()*+',-&-$.*$.*"/0&'*1*2&&3'&, R.23-01-007 (Feb. 28, 2025).

4 "0,-4-,*50&*0.(*67',8#-,*9$:%0.;<&*=>*?@*6A*B%'.-.C*9$::'.8&*$.*"#$%$&'(*+',-&-$.*$.*"/0&'*1*2&&3'&D R.23-01-007, at 2-3 (Mar. 20, 2025).

that the Commission reject PG&E's arguments that the Proposed Decision imposes impermissible requirements and adopt the guardrails in the Proposed Decision.

CalCCA additionally recommends that the Commission adopt the following principles to constrain PG&E's use of VPF funds:

1. VPF funds should be used on projects providing benefits to the largest number of customers possible, including bundled and unbundled customers;

2. VPF funds should be used first on projects related to electric distribution to help reduce upward pressure on distribution rates; and

3. VPF funds should not be used on projects that benefit PG&E's generation assets.

II. THE COMMISSION SHOULD ADOPT THE PROPOSED DECISION'S GUARDRAILS FOR VPF SPENDING AND REJECT PG&E'S ARGUMENTS THAT THE PROPOSED DECISION IMPOSES IMPERMISSIBLE REQUIREMENTS

The Commission should adopt the Proposed Decision's guardrails for VPF spending and reject PG&E's arguments that the Proposed Decision imposes impermissible requirements. PG&E states that the Proposed Decision "legally errs by imposing requirements in addition to the six § 712.8(s)(1) public purpose priorities, first relating to affordability as a guiding principle, and second on estimating the number of customers participating or benefitting from the program."[5] PG&E cites to two canons of statutory construction: the "plain meaning rule" and *'6-,' &&2#!$%2$&* as support for its position.

PG&E first argues that the Proposed Decision inserts additional requirements outside of the "plain meaning" of the statute, which constitutes legal error. The "plain meaning rule" requires the plain language of a statute be given effect unless it is ambiguous.[6] Public Utilities Code section 712.8(s)(1)[7] which requires VPF compensation, "to the extent it is not needed for Diablo Canyon, . . . be spent to accelerate, or increase spending on, the following critical public purpose priorities[.]"[8] The statute goes on to list six specific public purpose priorities. PG&E is correct that neither the list of "critical public purpose priorities", nor the statutory requirement that PG&E must spend VPF compensation to accelerate or increase spending on those six priorities, is ambiguous.

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6 FG-8H'#*IJ*K$$(, 35 Cal. App. 5th 116, 123 (5th Dist. 2019).

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

8 Cal. Pub. Util. Code § 712.8(s)(1).

However, the Proposed Decision's guardrails do not add additional public purpose criteria outside of the statute's requirements. Rather, the Proposed Decision's requirements are a way of implementing the six public purpose priorities. Therefore, PG&E's "plain meaning" argument falls flat.

Second, PG&E argues that the Proposed Decision's additional requirements violate the '6-,'&&2#! $%2& doctrine, which requires! omissions from enumerated lists be interpreted as exclusions.[9] Therefore, PG&E argues that because the statute does not explicitly list the Proposed Decision's requirements, the legislature intentionally omitted them. Again, the Proposed Decision's requirements are not additional to the six public purpose priorities enumerated in Section 712.8 – rather, they are means of implementing the statutory requirements.

Overall, the Proposed Decision correctly recognizes that certain VPF expenditures—within the list of critical public purpose priorities—might confer "additional benefits to ratepayers",[10] such as, for instance, improving affordability. While the statute does not itself rank the six public purpose priorities according to their potential for ratepayer benefit—a fact the Commission notes in Decision (D.) 23-12-036[11]—nothing in the statute requires the Commission to accept PG&E's VPF spending plans when more customer-beneficial spending opportunities (within the confines of the enumerated public purpose priorities) are available. The Proposed Decision seeks to unlock those opportunities by encouraging PG&E to consider affordability when developing and implementing its VPF spending plan, and by requiring transparency on the number of customers benefiting from each program. These directives are not only practical and reasonable but wholly within the Commission's broad authority to supervise and regulate public utilities under Article XII of the California Constitution and section 701 of the Public Utilities Code. That broad authority is liberally construed.[12] It includes not only matters specified by California law, but includes matters incident to the Commission's express authority, provided those matters are "cognate and germane" to the regulation of public utilities and not in conflict with another statutory directive.[13] Here, the Proposed Decision's directives are inarguably germane to the regulation of public

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9 9-8;*$4*9$#$.0*IJ*L0377&, 166 Cal. App. 4th 418, 433 (4th Dist. 2008).

10 F''*Proposed Decision at 15.

11 Decision (D.) 23-12-036, +',-&-$.*9$.(-8-$.077;*M%%#$I-.C*6N8'.('(*B%'#08-$.&*08*+-0E7$* 90.;$.*L3,7'0#*"$G'#*"70.8*"3#&30.8*8$*F'.08'*O-77*PQR, R.23-01-007, at 114 (Dec. 15, 2023).

12 9$.&3:'#&*S$EE;*MC0-.&8*T$.$%$7-'&*IJ*"3E7-,*>8-7-8-'&*9$:J, 25 Cal. 3d 891, 905 (1979).

13 2(.

utilities because they seek to constrain PG&E's actions with respect to VPF spending. Further, those directives complement—not contradict—the statutory directive that PG&E use its VPF collections to accelerate or increase spending on enumerated critical public purpose priorities. As a result, PG&E's arguments that the Proposed Decision imposes impermissible requirements should be rejected.

III. THE PROPOSED DECISION SHOULD GO FURTHER TO ADOPT CALCCA'S RECOMMENDED VPF SPENDING GUARDRAILS TO ENSURE MAXIMUM CUSTOMER BENEFIT

CalCCA and other intervening parties explained, in Opening Comments, that the Proposed Decision can and should have gone further to establish guardrails on PG&E's VPF spending, including by adopting a set of principles to guide that spending *7 2)32%* the boundaries of the statutory public purpose priorities.[14] CalCCA proposes that:

- VPF funds should be used on projects providing benefits to the largest number of customers possible, including bundled and unbundled customers;
- VPF funds should be used first on projects related to electric distribution to help reduce upward pressure on distribution rates; and
- VPF funds should not be used on projects that benefit PG&E's generation assets.[15]

These principles will help ensure PG&E not only maximizes the benefits of VPF spending, but also distributes the benefits equitably. Importantly, none of these principles would contradict the statutory directive that PG&E use VPF compensation to accelerate or increase spending on the critical public purpose priorities listed at section 712.8(s)(1)(A)-(F). Therefore, and for the reasons described above, the statute does not prevent the Commission from adopting the guardrails CalCCA proposes in its Final Decision, and the Commission should do so.

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14 907-4$#.-0*9$: :3.-8;*9/$-,'*M&&$,-08-$.<&*9$: :'.8&*$.*8/'*"#$%$&'(*+',-&-$.*at 2-6*(Mar. 20, 2025) (CalCCA Comments); B%'.-.C*9$: :'.8&*$4*U/'*>8-7-8;*V'4$#:*L'8G$#W*$.*8/'*"#$%$&'(*+',-&-$.* $4*M(:-.-&8#08-I'*S0G*X3(C'*M80:83#W*$.*"/0&'*1*2&&3'& at 1-5 (Mar. 20, 2025) (Recommending the Commission establish binding requirements for future VPF spending to prevent PG&E from using VPF funds to benefit shareholders).

15 CalCCA Comments at 2-6.

IV. CONCLUSION

CalCCA requests the Commission: (1) reject PG&E's arguments that the Proposed Decision imposes unreasonable requirements on VPF spending; and (2) adopt the changes to the Proposed Decision presented in Appendix A to its comments on the Proposed Decision.

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Dated: March 25, 2025

Braun Blaising & Wynne, P.C.

Attorneys at Law

March 27, 2025

Via Electronic Email

California Public Utilities Commission – Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
(EDTariffUnit@cpuc.ca.gov)

Re: Protest of the Joint Community Choice Aggregators to the Joint Utilities' Equity Metrics Advice Letters (SCE Advice 5498-E; PG&E Advice 7530-E; and SDG&E Advice 4617-E)

Dear Energy Division Tariff Unit:

Pursuant to the California Public Utilities Commission's ("**Commission**") General Order ("**GO**") 96-B, the Joint Community Choice Aggregators ("**Joint CCAs**")[1] submit this protest of Southern California Edison Company's ("**SCE**") Advice Letter ("AL") 5498-E, Pacific Gas and Electric Company ("**PG&E**") AL 7530-E, and San Diego Gas & Electric Company ("**SDG&E**") AL 4617-E (collectively, the "**Equity Metrics Advice Letters**").[2] The Equity Metrics Advice Letters were jointly submitted by the Joint Utilities on March 7, 2025.

Pursuant to GO 96-B, the Joint CCAs submit this protest to the Equity Metrics Advice Letters on the grounds that the relief requested would violate a Commission order, and that the data contains material omissions. More specifically, and as explained further below the Joint Utilities' proposed metrics fail to comply with the requirements and intent of Commission Decision ("**D.**")24-10-030. By consolidating metrics, the Joint Utilities' metrics would lead to unjust and unreasonable outcomes by failing to adequately measure or address disadvantaged communities ("**DACs**") and medical baseline customers.

BACKGROUND

D.24-10-030, issued on October 23, 2024 in the High Distributed Energy Resources ("**High DER**") proceeding, R.21-06-017, directed the Joint Utilities to include metrics to track and evaluate equity in their distribution planning process.[3] Ordering Paragraph ("**OP**") 25 of

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[1] The Joint CCAs consist of Ava Community Energy ("**Ava**"), Marin Clean Energy ("**MCE**"), Redwood Coast Energy Authority ("**RCEA**") and Valley Clean Energy ("**VCE**").

[2] SCE, PG&E and SDG&E shall be collectively referred to below as the "**Joint Utilities**."

[3] The required metrics included in D.24-10-030 originated from an Energy Division Staff Proposal for the High DER Proceeding, which was issued as an attachment to the *Administrative Law Judges' Ruling Seeking Comments on Staff Proposal*, dated March 13, 2024 ("**Staff Proposal**"). Both the Staff

D.24-10-030 required the Joint Utilities to hold a workshop on equity metrics and, no later than 45 days after the workshop, submit a Tier 3 advice letter with a final set of equity metrics. D.24-10-030 explicitly identified five equity metrics to be explored at the workshop and included in the Joint Utilities' consideration, as follows:

1. California Alternate Rates for Energy (**"<u>CARE</u>"**) or Federal Electric Rate Assistance (**"FERA"**) Enrollment – the percentage of customers served by the relevant equipment/facility who are enrolled in CARE or FERA programs.

2. CalEnviroScreen "Priority Populations" Score – the percentile from CalEnviroScreen 4.0 (or most current version) for the area served by the equipment/facility.

3. DAC Status – whether the equipment/facility serves a disadvantaged community.

4. Tribal Community Status – whether the equipment/facility serves a Tribal community.

5. Medical Baseline Enrollment – the percentage of customers served by the equipment/facility who are on a Medical Baseline discount or equivalent.

The purpose of these metrics is to provide transparency on how historically at-risk communities (defined by income, geography, race/ethnicity, or health condition) are served by the distribution grid. The Commission intended these metrics to highlight the presence of vulnerable or disadvantaged populations on each circuit or project, as a first step toward assessing equity in distribution system planning.

On January 21, 2025, the Energy Division hosted the required Equity Metrics workshop. During this workshop, and in the Equity Metrics Advice Letters, the Joint Utilities proposed alternative metrics which deviate from the five explicit metrics above. SDG&E proposes two new metrics (a "Load Growth" metric and a "Project Initiation" metric), and PG&E/SCE jointly propose two different metrics (a "Grid Access" metric and a "Project Initiation" metric), utilizing regression analysis. The Joint Utilities assert that their proposed metrics are "more informative measures of equity" than the Commission's originally proposed metrics.[4] In proposing these alternative metrics, the Joint Utilities repurpose or omit the specific data points the Commission mandated to track, in violation of GO 96-B. The Joint CCAs submit this protest to support the Commission's requirement that the Joint Utilities *include* metrics that are developed through workshops and stakeholder input.

As discussed below, the Joint Utilities' proposals fail to meet the requirements of D.24-10-030. In particular, the proposals do not directly report several of the five required equity

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Proposal and Decision require the utilities to include metrics to track and evaluate equity in their distribution planning reporting. (*See, e.g.,* Staff Proposal at 91-92 and D.24-10-030 at 187 (Conclusion of Law 33).)

4 Equity Metrics Advice Letters at 3.

metrics, and the proposals sidestep important equity considerations, such as reliability and climate resilience, by declaring these considerations to be outside the scope of distribution planning. Approving these metrics as-is would conflict with the Commission's findings in D.24-10-030 and could leave critical inequities unmonitored. The Joint CCAs therefore protest the Equity Measure Advice Letters, as further described below.

PROTEST

A. The Equity Metrics Advice Letters are Inconsistent with the Express Directives and Intent of D.24-10-030.

The suggested metrics within the Equity Metrics Advice Letters are inconsistent with both the explicit directives and the implicit intent of D.24-10-030 and the underlying Staff Proposal. In D.24-10-030, the Commission clearly enumerated five equity metrics that the Joint Utilities were expected to include in their distribution planning reporting. Ordering Paragraph 25 further directed the Joint Utilities to hold a workshop to gather additional stakeholder input and then submit a Tier 3 advice letter to "request approval of a final set of equity metrics and any correlated variables."[5] This process was designed to ***refine and finalize the Commission-identified metrics with stakeholder input***, not replace them. Despite this direction, the Joint Utilities have chosen to redefine, consolidate, or replace the listed metrics, which is a direct deviation from the requirements in D.24-10-030. Rather than distinctly detailing how each of the Commission's five metrics will be addressed and calculated, the Joint Utilities combine the metric concepts into alternative suggestions. SDG&E proposes a "Load Growth" metric and a "Project Initiation" metric, while PG&E/SCE jointly propose a "Grid Access" metric and a "Project Initiation" metric – none of which clearly present the Commission's original metrics, nor do they demonstrate how stakeholder input from the workshop informed their approach. This is a violation of D.24-10-030 and the Staff Proposal, both of which required the Joint Utilities to include Staff's metrics, not reinvent them.

In addition, PG&E and SCE's proposed metrics are misleading and prone to misinterpretation. The Commission intended for the Joint Utilities to compare available capacity across different customer groups, enabling identification of underserved or under-resourced circuits or areas of equity concerns. However, the proposed metrics rely on a regression analysis that evaluates whether the number of customers in each customer group (*e.g.*, CARE, FERA, Medical Baseline, Tribal) correlates with (1) available grid capacity or (2) project initiation. This analysis fails to compare if available capacity is fairly distributed ***between*** customer groups. Instead, the analysis measures whether the number of customers ***within*** a group correlates with available capacity or project selection. In turn, these metrics could be misinterpreted to find that a circuit is being served equitably ***for customers within one customer group***, but not find that customers within that customer group are being underserved ***compared to another (potentially non-disadvantaged) customer group***.

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[5] D.24-10-030 at 201.

While the Joint Utilities assert that their proposed metrics are "more informative measures of equity,"[6] these analyses fail to comply with the Commission's request for granular data in OP 25. As a result, and in accordance with General Rule 7.4.2 (2), the Joint CCAs protest the Equity Metrics Advice Letters on the grounds that the outcome proposed by the Joint Utilities would violate D.24-10-030.

1. CARE/FERA Enrollment (Percent of Customers):

D.24-10-030 requires reporting the percentage of CARE/FERA customers on each circuit or facility. The Joint Utilities' proposal does *not* include any metric that directly reports this percentage. PG&E and SCE use the number of CARE/FERA customers only as an input to their regression-based Grid Access metric, but they do not propose to report a simple CARE/FERA percentage per circuit. While this Grid Access metric purports to evaluate whether available grid capacity is equitable across customer groups, it fails to identify the granular data and requirements required by the Commission.

SDG&E's proposal similarly does not report CARE/FERA percentages; it folds CARE customers into a broader "DAC circuit" designation. By omitting a standalone CARE/FERA metric, the Joint Utilities disregard an explicit requirement from OP 25 in D.24-10-030.

2. CalEnviroScreen Priority Populations Percentile:

D.24-10-030 calls for evaluating the Priority Populations Map and CalEnviroScreen 4.0 percentile for the area served by each piece of equipment. The Joint Utilities have not included any reporting of the actual percentile scores. Instead, the Joint Utilities use the CalEnviroScreen data only to decide if a circuit is above a threshold (75th percentile) to label it as serving a DAC. This binary approach eliminates the granular information the Commission explicitly requested (*i.e.*, how disadvantaged the community is on a percentile scale). By reducing this metric to a yes/no, the Joint Utilities misinterpret and truncate the Commission's directive.

3. DAC Status (Yes/No):

The Decision asks whether the equipment/facility serves a DAC, presumably to flag circuits in DACs. The Joint Utilities identify "DAC circuits," but they redefined "DAC" in a way that deviates from the Commission's intent. PG&E and SCE assert that "Disadvantaged communities (DACs) … is equivalent to the definition of Priority Populations" and therefore they "will not derive a separate metric for both" DAC and Priority Populations.[7] In other words, PG&E and SCE merge the CalEnviroScreen/priority population metric with the DAC yes/no metric, even though D.24-10-030 listed them separately.[8] In statutory interpretation, courts avoid interpretations that render provisions as redundant or insignificant, meaning that each requirement is significant and distinct.

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6 Equity Metrics Advice Letters at 3.

7 Equity Metrics Advice Letters at 5.

8 D.24-10-030 at 200.

This redefinition of DAC status not only departs from the Commission's directive but also undermines the meaningful identification of communities that may already be disadvantaged in the distribution planning process. Compounding this issue, the Joint Utilities' reliance on load growth as a proxy for infrastructure need poses a distinct equity concern. DACs often have lower load growth forecasts precisely because of historical underinvestment in them. In turn, DACs' energy consumption is low, but they spend more on energy relative to their income than higher income households. Focusing on load growth may continue resulting in underinvestment in energy efficiency, distribution upgrades, and other investments that create a cycle of perverse disincentives for DACs.

4. Tribal Community Status (Yes/No):

D.24-10-030 requires the Joint Utilities to indicate whether the equipment/facility serves a Tribal community. The Joint Utilities' proposals do not ensure this metric will be reported for each circuit. While PG&E/SCE at least include "Tribal community" as one of the customer group categories in their regression analysis, SDG&E's approach offers no separate identification of Tribal-serving circuits. For SDG&E, tribal communities are subsumed under the broad "DAC circuit" definition if they happen to overlap with other priority factors.[9] This means that the unique needs of Tribal communities could be masked. The omission of a clear, standalone Tribal indicator in the final metrics is a failure to carry out Metric 4 from D.24-10-030, as listed above.

The Commission explicitly requested information identifying whether a circuit serves a Tribal land or community. This information cannot be determined from SDG&E's combined DAC label, nor from PG&E/SCE's regressions unless one digs into underlying data. This is a clear inconsistency with the directive in D.23-10-030.

5. Medical Baseline Enrollment (Percent of Customers):

D.24-10-030 requires tracking the percentage of customers on Medical Baseline on each circuit. The Joint Utilities do not plan to report this percentage as a separate metric. PG&E/SCE again only use Medical Baseline customer counts as an input to their regressions, and even note that there "may not be sufficient statistical variation" in Medical Baseline data to produce a meaningful metric under the Commission's request.[10] Instead, SCE and PG&E note that their methodology would determine whether there is a significant metric for this customer group, but fails to provide granular data. SDG&E similarly does not report a Medical Baseline percentage. Instead, a single Medical Baseline customer would just contribute to labeling the circuit as a "DAC" by SDG&E's method.

By failing to explicitly report the proportion of Medical Baseline customers per circuit, the Joint Utilities are omitting Metric 5 as outlined in D.24-10-030. This omission is contrary to

[9] *See* Equity Metrics Advice Letters at 3.

[10] Equity Metrics Advice Letters at 6.

the Commission's expressed requirement to consider the needs of customers with medical equipment (often critically dependent on reliable power).

In summary, none of the Joint Utilities proposed metrics directly correspond to the five equity metrics the Commission explicitly required to be included and reported. Instead of providing the straightforward transparency envisioned in D.24-10-030, the Joint Utilities propose to roll some of these factors into composite metrics and drop others entirely. D.24-10-030's equity tracking mandate was aimed at shedding light on how distribution planning impacts vulnerable groups. By diverting to different metrics, the Joint Utilities risk obscuring that light. The relief requested (approval of these alternative metrics in lieu of the metrics set forth in D.24-10-030) is therefore inconsistent with both the letter of D.24-10-030 (which listed those five metrics to include) and its intent (to provide clear, granular equity data).[11] The Commission should require the Joint Utilities to include and report the metrics in D.24-10-030, not replace them with unproven substitutes.

B. The Equity Metrics Advice Letters Contain Omissions in the Analysis and Data that Undermine Equity.

The Joint Utilities' proposed metrics focus largely on internal planning indicators such as regression outputs and load growth proxies, omitting critical data that would reflect actual outcomes experienced by DACs. This is a material omission that fails to support the Commission's commitment to ensure equitable access to distribution service for historically at-risk communities. While the Decision did not expressly mandate metrics for reliability, resilience, or climate adaptation, these factors are central to equitable service and must be included to ensure metrics are meaningful. Further, the Commission's five metrics adequately encompass these factors in a way that the Joint Utilities' alterations do not encompass.

Metrics that only reflect planning inputs or correlations are not sufficient for evaluating equity in service delivery or infrastructure investment. DACs often suffer more frequent and/or longer outages and may be less able to cope with disasters, yet the proposed metrics provide no insight into these issues. By ignoring reliability and climate adaptation considerations entirely, the Joint Utilities are leaving out factors that are essential to evaluating whether the grid is equitably serving all communities. This omission directly undermines the Commission's goal of equity, reliability, and resilience.

Additionally, the metrics proposed by PG&E and SCE use a regression analysis between the metric (grid access and project initiation) and the number of customers within CARE/FERA, DAC, Tribal, and Medical Baseline customer groups. Under this approach, the proposed metrics are narrowly scoped to evaluate grid access and project initiation *within* these historically at-risk

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[11] In effect, the Joint Utilities are proposing new metrics, and this type of request by the Joint Utilities is inappropriate for advice letters. *See* General Rule 7.4.2 (5), which provides, as another grounds for protesting an advice letter, the fact that "[t]he relief requested in the advice letter requires consideration in a formal hearing, or is otherwise inappropriate for the advice letter process."

customer groups, based on number of customers, rather than comparison between at-risk customer groups and non-at-risk customer groups. At best, the metrics proposed by PG&E and SCE would limit the actions they could take to address inequitable access to distribution services, and at worst, these metrics would result in misleading conclusions, leading to actions that could further inequitable treatment of disadvantaged communities.

While SDG&E's proposed metrics do a better job comparing DAC customers to non-DAC customers, SDG&E rolls the five customer groups proposed by CPUC into one binary designation of DAC vs. non-DAC. This erases the granularity intended by the CPUC's proposed metrics, which can lead to misinterpretation of the data produced.

Lastly, the Joint Utilities do not clearly describe how they will use the proposed equity metrics to implement equitable distribution planning.

In short, failing to include any metric on service reliability, outage frequency/duration, or resilience measures is a material gap in the analysis. Additionally, the metrics proposed by the Joint Utilities, particularly those proposed by PG&E and SCE, can produce invalid or misleading results when evaluating the equitable treatment and outcomes in distribution planning and service for historically at-risk communities. For these reasons, the Joint CCAs further protest the Equity Metrics Advice Letters on the grounds that, as described in General Rule 7.4.2 (3), "[t]he data in the advice letter[s] contain material…omissions."

NOTICES

The Joint CCAs request that they be added to the service list for the Equity Metrics Advice Letters, and that they be notified of the issuance of a draft resolution addressing the Equity Metrics Advice Letters. Contact information for the Joint CCAs is as follows:

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CONCLUSION

For the foregoing reasons, the Joint CCAs urge the Commission to reject Advice Letters 7530-E, 5498-E, and 4617-E as submitted, or at minimum to require substantial modifications to ensure compliance with D.24-10-030. The Joint Utilities' proposed metrics do not satisfy the Commission's explicit requirements in D.24-10-030 and require modifications.

The Joint CCAs thank the Commission for its consideration of this protest.

Respectfully,

/s/ Jessica Melms

Jessica Melms
Scott Blaising
BRAUN BLAISING & WYNNE P.C.
melms@braunlegal.com

Attorneys for the Joint CCAs

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Service List: R.21-06-017

Comments on Discussion paper and Mar 03 discussion

Initiative: Demand and distributed energy market integration

Comment period

Mar 04, 2025, 04:00 pm - Mar 28, 2025, 05:00 pm

Submitting organizations

California Community Choice Association

California Community Choice Association

Submitted on 03/28/2025, 03:53 pm

Contact

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

1. Please provide your organization's feedback on the approach to the Working Group's goals, process, evolution of the Discussion paper, and Stakeholder Recommendations (pg. 2-5) in the DDEMI Discussion Paper. Any suggestions to improve the Working Group process or deliverables?

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the Demand and Distributed Energy Market Integration (DDEMI) Working Group and Discussion Paper. As described in detail in the sections below, CalCCA recommends, in summary, that the California Independent System Operator Corporation (CAISO):

- Prioritize: (1) improving the simplicity and accuracy of performance evaluation methodologies; (2) enhancing the economic-based demand response participation models through a modified proxy demand resource (PDR) model that considers exports; and (3) exploring distributed energy resource (DER) participation in wholesale markets and pathways for advancing demand flexibility;
- Provide an educational session early on in the working group process to help newer market participants learn about market participation options and related issues being explored in this initiative; and
- Seek to minimize implementation barriers and complexity associated with the performance evaluation methodologies while ensuring accurate performance calculations.

2. Please provide your organization's feedback on the overarching themes/areas and the associated scope items for problem statement formulation. Are there any additional themes/areas or individual scope items which should be explored further?

The CAISO should prioritize the following three themes within this initiative:

1. Performance Evaluation Methodologies: The current baseline methodologies create a high barrier to entry for smaller load-serving entities and program operators, including community choice aggregators. Simplifying and improving the accuracy of the baseline methodologies can help promote market diversity and competition, and accelerate the integration of clean resources. This supports state policy goals and overall market efficiency. DERs will play a key role in the state's portfolio and address local reliability and community needs. CalCCA supports exploring the items advanced by stakeholders, including: (1) modifying the control group settlement methodology; (2) moving the baseline methodologies to the business practice manuals; (3) using device-level measurement; and (4) creating alternative baseline methodologies.
2. Economic-based Demand Response Participation Models: The PDR model used for economic demand response participation will benefit from a holistic review to ensure it accurately reflects resource capabilities and minimizes barriers to participation. CalCCA supports evaluating a modified PDR (mPDR) model to more accurately reflect the capabilities of PDR resources that can export. The mPDR model has the potential to better account for the full capabilities of behind-the-meter (BTM) resources with storage. CalCCA also recommends that within this holistic assessment of economic Demand Response (DR) participation models, the CAISO should: (1) clearly document how to use the Demand Response Registration System Application Program Interface to increase the ability of market participants to develop their own processes that use it; (2) maintain clear data requirements to allow market participants to prepare for upcoming changes; and (3) enable easier maintenance of accurate registration records.
3. Distributed Energy Resource Participation: The current participation models for BTM storage should be re-evaluated to ensure they fully account for battery capabilities. CalCCA supports exploring BTM storage participation in the wholesale markets, as described in the discussion paper. The CAISO should also explore microgrid participation in the wholesale markets?and the resource adequacy (RA) program (including obtaining a net qualifying capacity, must-offer obligations, etc.).

3. Please provide your feedback on any specific topics that require further information/reference in order to facilitate substantive stakeholder conversation.

Early in the working group process, the CAISO should host an educational session on its existing DR and DER market participation models to help newer market participants learn about pathways for market participation and related issues. CalCCA proposes the following topics be addressed in this session:

Differences between supply-side and load-modifying participation pathway requirements;

Existing supply-side market participation models for DR and DER;

Registration requirements and maintenance of DR and DER registrations;

Participation requirements, data requirements, and existing baseline methodologies; and

California Public Utilities Commission and CAISO jurisdictional responsibilities and rules for obtaining RA credit for each participation model.

4. What feedback do you have on the challenges shared by Stakeholder presentations regarding service level load measurement & validation needed for control groups? Do the M&V and Performance Evaluation Methodology (PEM) options available today address the needs of diverse technologies? Are there additional technical challenges (e.g.,

technology-specific curtailment, control group validation, energy storage baselines) that should be considered in the working group?

CalCCA appreciates the stakeholder presentations on performance evaluation methodologies from Leap, Pacific Gas and Electric Company (PG&E), and Nostromo Energy. As described in section 2, above, CalCCA supports exploring improvements to the baselines, focused on increasing simplicity and accuracy. The Leap and PG&E presentations demonstrate that accuracy and participation benefits can be realized through the control group methodology. This methodology is not widely used due to implementation barriers, including difficulty accessing non-participant meter data.[1] Modifications to the baseline methodologies should seek to minimize implementation barriers and complexity such that market participants can leverage the baseline methodology that most accurately measures the performance of their resources.

[1] *See* PG&E presentation: https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-PGE-Settlement-Methodology-Mar-03-2025.pdf; and Leap presentation: https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-Leap-Prescriptive-Baselines-Mar-03-2025.pdf.

5. What topic(s) would your organization be interested in presenting (what is the problem/issue seeking to be addressed)? Which stakeholders would it impact?

CalCCA has no particular topics to be presented at this time but may be interested in presenting on issues as the initiative progresses.

APRIL FILINGS

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: Amulya Yerrapotu
Phone #: 415-464-6664
E-mail: ayerrapotu@mcecleanenergy.org
E-mail Disposition Notice to: ayerrapotu@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) #: 86-E

Tier Designation: 2

Subject of AL: 2026 Budget Request and Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff Program

Keywords (choose from CPUC listing): COMPLIANCE

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

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.24-05-065,

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: 5/1/25

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: Amulya Yerrapotu Title: Policy Analyst Utility/Entity Name: Marin Clean Energy Telephone (xxx) xxx-xxxx: (925) 378-6729 Facsimile (xxx) xxx-xxxx: Email: ayerrapotu@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

April 1, 2025

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

MCE Advice Letter 86-E

RE: 2026 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,[1] OP 3 of Resolution E-5125,[2] and OPs 2 and 3 of D.24-05-065,[3] 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") 2026.

TIER DESIGNATION

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

EFFECTIVE DATE

Pursuant to G.O. 96-B, MCE requests that this Tier 2 AL become effective on May 1, 2025, 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

[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.

renewable generation among residential customers in disadvantaged communities ("DACs"),[4] 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.[5] 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.[6] Furthermore, the Resolution specifies that Program Administrators must reconcile prior year budget forecasts and expenditures in their annual budget requests.[7] On December 4, 2023, MCE, as a part of the Joint CCAs, requested a two-month extension of the budget AL until April 1, 2023. On January 11, 2024, MCE, as a part of the Joint CCAs, amended the extension request to align with the IOUs, requesting an extension until May 1, 2024, or 30 days after the issuance of the Final Decision in proceeding A.22-05-022, whichever is later. On January 24, 2024, the Joint CCAs' extension request was granted. The Final Decision in proceeding A.22-05-022 was issued on June 7, 2024.[8]

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 voluntarily 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.

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

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[4] 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.
[5] D.18-06-027, p. 104, OP 17.
[6] Resolution E-4999, OP 2.
[7] Resolution E-4999, OP 4.
[8] D.24-05-065

DAC-GT and CS-GT budgets included in the IOUs' Energy Resource Recovery Account ("ERRA") Forecast in June 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.

PURPOSE

MCE hereby submits the budget request for PY 2026 for the DAC-GT program. Per Resolution E-4999, the budget request includes both the budget reconciliation for the previous PY (i.e., PY 2024) and the budget forecast for the upcoming PY (i.e., PY 2026). Additionally, MCE includes two corrections for inadvertent errors in last year's budget AL (MCE AL 79-E). Because D.24-05-065 closed the CS-GT program for future procurement and MCE has not already procured a project for the CS-GT program, MCE does not include CS-GT in the PY 2026 budget forecast. However, MCE continues to include CS-GT program costs in the PY 2024 budget reconciliation until the point of program closure upon issuance of D.24-05-065. In summary, MCE requests a total budget of $1,972,742 for the DAC-GT program for PY 2026, including corrections from MCE AL 79-E and PY 2024 DAC-GT and CS-GT reconciliation costs. Additional details can be found in Appendix A.

Once the Commission approves MCE's budget request, PG&E will be responsible for including the total budget request for MCE's DAC-GT program in the 2026 ERRA Forecast filing.[9] 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.[10]

In addition to the budget request, MCE submits its updated ME&O plan for PY 2026 as Appendix B.

CONCLUSION

MCE respectfully requests the Commission approve the budgets 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.

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[9] D.22-01-023, p. 28, OP 3. Modifies the due date for PG&E to file this annual Application to May 15, 2023. Because D.24-05-065 was not voted on until May 30, 2024, pushing this advice letter filing to July 8th, 2024 PG&E may need to include an updated budget in its October ERRA forecast update.

[10] Resolution E-5124, p. 10.

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:

Amulya Yerrapotu
Policy Analyst
Marin Clean Energy
1125 Tamalpais Ave
San Rafael, CA 94901
Email: ayerrapotu@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 Amulya Yerrapotu at (925) 378-6729 or by electronic mail at ayerrapotu@mcecleanenergy.org.

/s/ Amulya Yerrapotu

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Appendices

Appendix A: PY 2026 Budget Request
Appendix B: PY 2026 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 2026

Proposed by Marin Clean Energy

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TABLE OF FIGURES

1. BACKGROUND

MCE is a program administrator (PA) of the Disadvantaged Communities (DAC) Green Tariff (DAC-GT) and Community Solar Green Tariff (CS-GT) programs. Per Resolution E-4999, annual program budgets must be presented by program 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;
    b. Outreach and material costs;
    c. Local CBO/ sponsor costs (for CS-GT only).

In this program budget, MCE includes both the budget reconciliation for the previous program year (PY) (i.e., PY 2024) and the budget forecast for the upcoming PY (i.e., PY 2026). As D.24-05-065 closes the CS-GT program for future procurement and MCE has not already procured a CS-GT project, MCE does not include CS-GT program costs for PY 2026, and only includes CS-GT costs in the budget reconciliation for PY 2024 until program closure.

Additionally, MCE includes a correction for an inadvertent error in calculating the actual program costs in last year's budget advice letter (AL) (MCE AL 79-E).

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

1. Existing solar generation capacity at previous PY's close (i.e., December 31, 2024);

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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 2025 budget forecast. However, MCE still includes the CCA integration cost in the calculation of its administration cost cap, per Resolution E-5124.

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, 2024); 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:

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

2. BUDGET FORECAST FOR PY 2026

For PY 2026, MCE forecasts a total budget of $2,902,368 for the DAC-GT program. This budget forecast accounts for the program modifications established in D.24-05-065, including discontinuing the CS-GT program and rolling unused capacity into the DAC-GT program, increasing DAC-GT program capacity, and removing the Green-e certification requirement. 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 2026

Tab	Category	DAC-GT
1	Generation Cost Delta	$ 921,536
2	20% Bill Discount	$ 1,679,692
	Program Administration	
3a	Program Management	$ 115,280
3b	Information Technology	$ 13,635
3c	Billing Operations	$ 100,065
3d	Regulatory Compliance	$ 18,678
3e	Procurement	$ 14,620
	Subtotal Program Administration	**$ 262,278**
	Marketing, Education & Outreach	
4a	Labor Costs	$ 10,382
4b	Outreach and Material Costs	$ 28,480
	Subtotal ME&O	**$ 38,862**
	Total	**$ 2,902,368**

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

Generation Cost Delta

To date, MCE has been using interim solar generation resources to support the DAC-GT program while it is 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 is expected to come online in early 2026.

Decision 24-05-065 approves a 50% expansion of MCE's DAC-GT program capacity. Decision 24-05-065 also rolls any unused CS-GT capacity into MCE's DAC-GT program. MCE's DAC-GT program now has a total capacity of 8.249 MW. MCE plans to enroll new customers using an interim resource as it works to procure a resource to serve the remaining program capacity. MCE anticipates using the existing DAC-GT interim resource for this purpose.

As such, the DAC-GT generation cost delta budget forecast for the first three months of 2026 is based on the PPA price of the current interim solar generation resource, compared to the costs of serving customers under MCE's residential base tariff, the "Light Green" tariff. For the remainder of 2026, after the new dedicated solar resource comes online, 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. 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.[5] MCE then recovers these program costs via this budget AL filing.

In PY 2026, MCE expects to have approximately 5,805 customers enrolled in the DAC-GT program. D.24-05-065 expands MCE's DAC-GT program capacity by 3.609 MW. MCE estimates that it will be able to serve 2,540 customers with this new capacity, in addition to the existing 3,265 customers currently served by existing program capacity. MCE plans to enroll customers using an interim resource as it works to procure a new resource to serve the remaining program capacity. The PY 2026 forecast for the 20 percent bill discount is based on the actual average monthly bill discount provided to participating customers in 2024, with a 25% increase to account for forecasted increases in electricity rates. Future customers enrolled under the expanded capacity are assumed to have the same usage as existing customers.

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

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

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

directs PG&E to provide a cost estimate for implementing an automated billing solution, it is uncertain whether such a solution will be implemented. As such, for the time being, MCE assumes that billing costs will remain as they are now. Regulatory Compliance covers costs for regulatory 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. D.24-05-065 removes the Green-e certification requirement, instead ordering program administrators to independently track the retirement of RECs. MCE estimates those costs in the procurement forecast.

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.

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.[6] 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).[7] The ABAL was elevated from Tier 1 to Tier 2 to allow for additional review of this and other ABAL components.[8]

The 2026 budget forecast summarized above in Table 1 results in DAC-GT program administration budgets of 9% and ME&O budgets of 1%. As such, MCE does not require an adjustment to the program administration budget cap for DAC-GT for PY 2026.

4. BUDGET RECONCILIATION FOR PY 2024

MCE submitted a budget forecast for PY 2024 as a part of its 2024 Budget Request and Marketing, Education, and Outreach Plan in AL 69-E on April 3, 2023. The table below shows the forecasted and actual costs for PY 2024 per budget line item, as well as the true-up amount that will be carried forward to future program years.

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

Table 2: MCE Budget Reconciliation for PY 2024

Tab	Category	DAC-GT			CS-GT		
		Forecast	Actual	**True-up (Actual - Forecast)**	Forecast	Actual	**True-up (Actual - Forecast)**
1	Generation Cost Delta	$ 988,083	$ 561,365	**$ (426,718)**	$ -	$ -	**$ -**
2	20% Bill Discount	$ 280,035	$ 755,851	**$ 475,816**	$ -	$ -	**$ -**
	Program Administration						
3a	Program Management	$ 84,050	$ 12,281	**$ (71,769)**	$ 97,150	$ 12,281	**$ (84,869)**
3b	Information Technology	$ 30,537	$ 6,240	**$ (24,297)**	$ 19,009	$ 6,240	**$ (12,769)**
3c	Billing Operations	$ 76,735	$ 90,991	**$ 14,256**	$ 34,422	$ 6,141	**$ (28,281)**
3d	Regulatory Compliance	$ 7,860	$ 22,365	**$ 14,505**	$ 7,860	$ 12,991	**$ 5,131**
3e	Procurement	$ 26,815	$ 28,100	**$ 1,285**	$ 31,093	$ 786	**$ (30,307)**
3f	CCA Integration Costs	$ -	$ -	**$ -**	$ -	$ -	**$ -**
	Subtotal Program Administration	**$ 225,997**	**$ 159,976**	$ (66,021)	**$ 189,534**	**$ 38,439**	$ (151,096)
	Marketing, Education & Outreach						
4a	Labor Costs	$ 21,615	$ 3,220	**$ (18,395)**	$ 59,605	$ 2,260	**$ (57,345)**
4b	Outreach and Material Costs	$ 20,000	$ 15,969	**$ (4,031)**	$ 26,000	$ -	**$ (26,000)**
	Subtotal ME&O	**$ 41,615**	**$ 19,189**	$ (22,426)	**$ 85,605**	**$ 2,260**	$ (83,345)
	Total	**$ 1,535,730**	**$ 1,496,382**	$ (39,348)	**$ 275,139**	**$ 40,698**	$ (234,441)

5. CORRECTION OF MCE AL 79-E 2023 ACTUAL BILL DISCOUNT COSTS

While preparing its 2025 Budget Advice Letter, MCE discovered and corrected an inadvertent error in the calculation of the 2023 Actual Bill Discount Cost for the DAC-GT program. MCE AL 79-E incorrectly reported the 2023 Actual Bill Discount Cost as $1,489,780. After correcting the error, MCE's 2023 Actual Bill Discount Cost is $833,942. The difference in the actual bill discount costs amounts to $655,837.

MCE submits this correction to MCE AL 79-E as a separate line item in its 2026 Budget Request in Section 6.

As the calculation for the 2025 Forecast Bill Discount Cost is based on the 2023 Actual Bill Discount Cost, MCE AL 79-E also overestimates the 2025 Bill Discount Forecast. By design of the DAC-GT program, any unused funds due to this inadvertent overestimation will be returned in next year's budget advice letter when the Actual 2025 Bill Discount Cost is reconciled with the 2025 Forecast Bill Discount Cost.

6. 2026 BUDGET REQUEST

Based on the budget forecast for PY 2026 presented in Section 2, the budget reconciliation for PY 2024 presented in section 4, and the corrections to MCE AL 79-E presented in Section 5, MCE is requesting a total budget of $1,972,742 for the DAC-GT and CS-GT programs in this budget AL.

Table 3: MCE Budget Request for PY 2026

	DAC-GT	CS-GT	Total
Budget Carry-over from PY 2024	$ (39,348)	$ (234,441)	**$ (273,789)**
Budget Forecast for PY 2026	$ 2,902,368	$ -	**$ 2,902,368**
Correction to MCE AL 79-E	$ (655,837)	$ -	**$ (655,837)**
TOTAL	**$ 2,207,183**	**$ (234,441)**	**$ 1,972,742**

7. PROGRAM CAPACITY AND ENROLLMENT NUMBERS

MCE reports existing program capacity and customer enrollment numbers as of December 31, 2024, in Table 4 below. In PY 2024, enrolled customers were served with an interim solar resource, as discussed above.

Table 4: Program Capacity and Enrollment Count for DAC-GT and CS-GT for PY 2024

Category	DAC-GT	CS-GT
Existing program capacity (MW)	4.646	0
Participating customers (#)	3,265	0

In Table 5, MCE reports forecasted capacity and customer enrollment for PY 2026. As noted above, MCE estimates that the dedicated project to serve existing DAC-GT will come online in early 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 2026. MCE plans to enroll additional customers under the expanded capacity using an interim resource until a new resource can be procured.

Table 5: Forecasted Program Capacity and Enrollment Count for DAC-GT and CS-GT for PY 2026

Category	DAC-GT
Existing program capacity (MW)	4.646
Additional program capacity to be procured (MW)	3.609
Total program capacity (MW)	8.249
Estimated customer enrollment (#)	5,805

Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff Programs for Program Year 2026

Proposed by Marin Clean Energy

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1. PURPOSE AND GOALS

MCE will develop and implement 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.

MCE will develop and implement a targeted customer marketing, education, and outreach (ME&O) campaign for the DAC-GT program. Eligible customers for DAC-GT will be 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 CARE or FERA) and provide instructions on how to continue their program participation (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 commits to the following guiding principles throughout the ME&O engagement process for the DAC-GT program. MCE aims to:

- Achieve diverse and meaningful engagement that reflects the demographics of DAC communities in MCE's service area 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, MCE will enroll additional customers as identified by CalEnviroScreen 4.0 in the following order:

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

2. Customers who live in one of the top 25% of DAC census tracts and are in arrears (category 2); and
3. 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 customers in a category under the DAC-GT program, customers from the eligible category 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 below 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)**
6013305000	Contra Costa	94509	Antioch
6013306002	Contra Costa	94509	Antioch
6013306003	Contra Costa	94509	Antioch
6013307102	Contra Costa	94509	Antioch
6013306002	Contra Costa	94509	Antioch
6013327000	Contra Costa	94520	Concord
6013336201	Contra Costa	94520	Concord
6013309000	Contra Costa	94565	Pittsburg
6013310000	Contra Costa	94565	Pittsburg
6013311000	Contra Costa	94565	Pittsburg
6013312000	Contra Costa	94565	Pittsburg
6013314102	Contra Costa	94565	Pittsburg
6013314103	Contra Costa	94565	Pittsburg
6013314104	Contra Costa	94565	Pittsburg
6013314200	Contra Costa	94565	Pittsburg
6013314103	Contra Costa	94565	Pittsburg
6013314102	Contra Costa	94565	Pittsburg
6013365002	Contra Costa	94801	Richmond
6013375000	Contra Costa	94801	Richmond
6013376000	Contra Costa	94801	Richmond
6013377000	Contra Costa	94801	Richmond
6013379000	Contra Costa	94804	Richmond
6013380000	Contra Costa	94804	Richmond
6013381000	Contra Costa	94804	Richmond
6013382000	Contra Costa	94804	Richmond
6013358000	Contra Costa	94572	Rodeo

6013366002	Contra Costa	94806	San Pablo
6013368001	Contra Costa	94806	San Pablo
6013368002	Contra Costa	94806	San Pablo
6013369001	Contra Costa	94806	San Pablo
6013392200	Contra Costa	94806	San Pablo
6095250701	Solano	94590	Vallejo
6095250801	Solano	94592	Vallejo
6095250900	Solano	94590	Vallejo
6095251000	Solano	94590	Vallejo
6095251600	Solano	94590	Vallejo
6095251802	Solano	94589	Vallejo
6095251803	Solano	94589	Vallejo
6095251901	Solano	94589	Vallejo

4. ME&O TACTICS AND STRATEGIES

MCE will continue to use the communications and media content originally developed to promote DAC-GT, including direct mailers, email, and a webpage.

5. METRICS TRACKING

MCE uses multiple tactics for ME&O. Accordingly, a variety of metrics will be used to evaluate the effectiveness of each effort. The primary measure of effectiveness is the number of customers reached, which can be measured by the:

- 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.